UNIVERSIDAD DE CARABOBO

FACULTAD DE INGENIERIA

ESCUELA DE INGENIERIA ELECTRICA

OPTIMIZAR EL SISTEMA DE DETECCION Y DESPEJE DE FALLAS EN LOS CIRCUITOS DE 13,8 KV. DE ELEVAL, C.A

TUTOR ACADEMICO:

Nuncio Pinto

REALIZADO POR:

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Miguel A. Sanchez G.

VALENCIA, MAYO 1995

UNIVERSIDAD DE CARABOBO
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CERTIFICADO DE APROBACION

Nosotros los abajo firmantes miembros del jurado asignado para evaluar el proyecto de grado: "*OPTIMIZAR EL SISTEMA DE DETECCION Y DESPEJE DE FALLAS EN LOS CIRCUITOS DE 13,8 KV. DE ELEVAL, C.A*" realizado por los Brs: Dilio José Linares y Miguel A. Sanchez G. portadores de las Cédulas de Identidad Nros. 7.140.485 y 8.630.986, respectivamente, hemos revisado y aprobado dicho proyecto.

Ing° Nuncio Pinto
Presidente

Ing° Franklin Alvarez

Ing° Nelson Laya

VALENCIA, MAYO 1995

AGRADECIMIENTO

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A Electricidad de Valencia, C.A.

DEDICATORIA

A Dios Todopoderoso: quien siempre a iluminado el camino de mi vida y mis días.

A mi Madre: por que me ha enseñado la pureza del amor de madre, haciéndome sentir el más dichoso de todos los hijos. Por ello te confiero el título de Madre Ejemplar.

A mi Padre: Por todo su apoyo, consejos y enseñanzas, que hicieron posible que lograra llegar hasta el final de mi meta, siempre serás mi fuente de admiración, y por ello te confiero el título de Padre Ejemplar.

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Al Todopoderoso.

A mi madre: quien es la luz que ha guiado mis pasos y forjado mi espiritualidad y desbordando con su amor porque he sido motivo de su preocupación y razón de sus diarias oraciones, haciendome sentir el hijo más dichoso de todos los hijos...

A mi padre: fuente de admiración por sus valores que han formado mi personalidad y carácter, porque nunca bacilastes en hacer tu mayor esfuerzo para educarme, por enseñarme el verdadero valor de las cosas.

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EQUIPOS DE PROTECCION SUPLEMENTARIA EN CIRCUITOS DE DISTRIBUCION Y CRITERIOS DE APLICACION

INTRODUCCION

Una medida de progreso del hombre y las naciones es la cantidad de energía eléctrica por habitante. Si la medida es hecha en base al consumo residencial esta medida refleja inmediatamente una forma de vida. Si la energia eléctrica disponible es aplicada a los trabajadores en la industria esto es a la vez una medida de la productividad, y por lo tanto una guía de progreso humano. Por lo que se requiere un suministro continuo y confiable de energía elétrica. En base a ésto, se requiere de una alta confiabilidad y continuidad de servicio en todo el sistema eléctrico a fin de minimizar perdidas de carga debido a salidas no programadas en los circuitos eléctricos de distribución a causas de fallas eléctricas lo cual trae como consecuencia: Perdidas de horas - hombres, gastos en cuanto a determinar donde y porqué ocurrió la falla, instalación de nuevos equipos en reenplazo de aquellos que sufren daños y costos del material utilizado.

Una manera de aproximarse a la continuidad y confiabilidad de servicio es através de la optimización de los sistemas de protección, el cual permite seleccionar las dispositivos de protección suplementaria y el ajuste de las mismas para así aislar la menor porción del sistema eléctrico ante una falla en cualquier parte del mismo.

Por lo general se hace estudios de coordinación de proteciones cuando el sistema eléctrico es diseñado y construido; pero ésto no garantiza que la coordinación se mantendrá permanente debido a que cambian en las redes de distribución, así como tambien en los elementos que conforman a las mismas, esto trae como consecuencia modificaciones en los ajustes de protecciones.

El objetivo de este trabajo es hacer una evaluación del sistema de protección de las redes de distribución a nivel de 13.8Kv, para así proponer la optimización del mismo, para llevar a cada dicha tarea, se escoge un circuito tipo del universo existente en ELEVAL C.A. En este trabajo se evaluan las protecciones de sobre corriente de fase y tierra y se optimizan utilizando los dispositivos de protección suplementaria (reconectador, seccionalizador, fusible).

Adicionalmente se sugiere la colocación de aparatos indicadores de falla.

La coordinación de protecciones en este trabajo se hace en forma manual a partir de los resultados obtenidos de un programa digitalizador de circuitos eléctricos, que se utiliza para obtener valores de corriente de corto circuito, flujo de carga y caida de tensión en las diferentes secciones y nodos de las misma razon por la cual se actualiza y modela el circuito tipo.

Finalmente se propone lograr la operación remota del reconectador a través de un sistema de supervisión, control y adquisición de datos.

CAPITULO I

CAPITULO I

ELEVAL, C.A. Y SELECCION DEL CIRCUITO

1.1.- DESCRIPCION GENERAL DE LA EMPRESA:

1.1.1.- ANTECEDENTES:

La empresa fue fundada el *01* de Agosto de *1912* y es pionera en el área de Valencia para proveerla de energía eléctrica, estando el frente de la misma desde sus origenes Don Carlos Stelling.

La empresa comenzó con una planta hidroeléctrica que aprovechava una caida de agua de 266 mts de altura, la cual se encontraba en la quebrada de la Aguada. La toma se construyó en el lugar denominado AGUATAL, por donde atraviesa el río Torito, cuyo volumen de agua en verano era de doscientos (200) litros por segundo. La planta AGUATAL estaba constituida por dos (2) centrales, una llamada El Milagro equipada con 2 grupos de inercia y alternador con excitatriz, cada uno con una potencia de placa de 475 KVA, y una subestación interior en 5 Kv., para una salida de línea. La otra central recibía el nombre de La California, esta poseia dos (2) grupos de generaciones con turbinas Pelton, volante de inercia y alternador con excitatriz, cada uno con una potencia de placa de 500 KVA, y una subestación interior de 5 KV.

Actualmente estas obras no están en servicio, y es posible volverlas a activar.

En la década de los '30, se construyó la planta Br. ERNESTO STELLIG, planta que funcionana con gasoil y estaba ubicada en la Av. Bolívar Norte de Valencia. Poseía 6 generadores, el Nro. 1, Nro. 2, Nro. 3 y Nro. 4 con una capacidad de 2.500 KVA cada uno, el Nro. 5 y Nro. 6 con una capacidad de 500 KVA cada uno y se generaba en una tensión de 2.4 Kv a 20 Kv.

Para el año de 1952 la C.A. ELECTRICIDAD DE VALENCIA aumenta su generación de energía eléctrica ubicando una nueva planta en la Zona Industrial La Quizanda, entre los años 1955 y 1956, adquiriendo dos generadores (Nr. 1 y Nro. 2), con una capacidad de 2.500 Kw, cada uno, generando una tensión de 13,2 Kv.

En los años 1959 y 1960 la empresa adquiere dos nuevos generadores (Nr. 3 y Nro 4) con una capacida de 2.500 KW. cada uno, generando una tensión de 4,8 KV., y a través de transformadores se eleva la tensión a 13,8 Kv, estos cuatro generadores operaban a gasoil, a una frecuencia de 50 Hz.

Durante los años 1972 y 1973 se llevó a cabo el cambio de frecuencia de 50 Hz a 60 Hz en la empresa ELEVAL, motivo por el cual las unidades descritas anteriormente dejaron de prestar servicio.

Para el año 1960 la compañía adquiere una de las primeras trubinas a gas, que fue instalada en el año 1963, con una capacidad de 10 Mw. Esta turbina fue diseñada para operar con gasoil ó gas. Para el año de 1964 y principio de 1965 se istaló la turbina Nro. 2 con una capacidad de 12 Mw.

La trubina Nro. 3 se instaló en el año 1970 y principios de 1971 con una capacidad de 14 Mw, la turbina Nro. 4 se istaló el 13 de Diciembre de 1972 con una capacidad de 18 Mw.

La empresa adquiere 4 unidades más de 20 Mw cada una (Nro. 5, Nro. 6, Nro. 7 y Nro. 8) las cuales se instalaron en los años 1979, 1980, 1981 y 1982 respectivamente.

En el año 1972, se realizó la interconexión con CADAFE en la planta del Este, en 13,8 Kv.

Las Unidades a Turbogas Nro. 4, Nro. 5, Nro. 6 Nro. 7 y Nro. 8 fueron repotenciados en los años 1987, 1988, 1989, 1990 y 1991.

En el año 1991, la generación de C.A. ELECTRICIDAD DE VALENCIA fue de 554.925.000 KWH, y las compras de CADAFE fueron de 491.580.319 KWH., lo que dan un gran total DE 1.046.319 KWH.

1.1.2.- VISION DE ELEVAL.

Ser líder en servicio público mediante la utilización de recursos de calidad, orientando así la excelencia y la democratización del capital.

Esta visión es producto de la integración de las proposiciones siguientes:

- Ser la empresa de energía exclusiva del Estado y líder en el país, en la prestación de un óptimo servicio, considerando los intereses de la colectividad, trabajadores y accionistas.

- Líder del servicio de la región central, mediante la participación de un recurso humano altamente calificado y la tecnología más actualizada, manteniendo costos óptimos y una rentabilidad saludable.

- La consolidación de la empresa como líder en servicio en la región Central, a través de la democratización del capital y la participación de la delineación de las políticas de servicio en escala nacional.

- Ser la empresa de servicio público por excelencia a nivel nacional.

1.1.3.- MISION DE ELEVAL.

Las misiones de las gerencias son la base para el conjunto de metas de la compañía.

Satisfacer al cliente garantizándole servicio con calidad y excelencia.

Esta misión es producto de la integración de las proposiciones siguientes:

- Garantizar al usuario un servicio eléctrico continuo, confiable y de óptima calidad.

- Suministrar a los clientes un servicio eficiente a precios razonables.

- Estimular el desarrollo social y económico, a través de servicios orientados hacia la excelencia, basadas en condiciones de rentabilidad, desarrollo organizacional y aplicación de tecnología.

- Ofrecer un servicio público (electricidad) en la calidad requerida, de calidad óptima y a los precios más bajos posibles que permitan la permanencia financiera de la empresa, todo esto con el menor deterioro posible del medio ambiente.

1.1.4.- ORGANIZACION.

ELEVAL, C.A., se conforma de acuerdo a la siguiente estructura organizativa:

1.1.4.1.- Organización General de la Empresa.

- Presidente

- Vice-Presidencia Ejecutiva
  Unidades Staff adscrita a la Vice-Presidencia
  Ejecutiva.

- Adjunto a la Vice-Presidencia.

- Gerencia de Auditoría Interna

- Gerencia de Relaciones Institucionales

- Consultoría Jurídica

- Gerencia General

- Gerencia Ejecutiva Adscritas a la Gerencia General.

- Gerencia de Admnistración y Finanzas

- Gerencia Comercial

- Gerencia de Operaciones

- Gerencia de Desarrollo

- Gerencia de Planificación Corporativa

- Unidades de Staff adscritas a la Gerencia General.

- Gerencia de Estudios Tarifarios

- Gerencia de Recursos Humanos

- Gerencia de Protección de Ventas

1.1.4.2.- Organización del Nivel Gerencial Ejecutivo.

- Gerencia de Administración y Finanzas

Gerencias Adscritas:

- Gerencia de Compra y Suministro

- Gerencia de División de Contabilidad y Presupuesto.

- Gerencia de División de Tesorería

- Gerencia de Planificación Corporativa.

Gerencias Adscritas:

- Gerencia de Planificación.

- Gerencia de Calidad y Estadística.

- Gerencia de Estudios Tarifarios.

- Gerencia de Operaciones

Gerencia Adscritas:

- Gerencia de Producción

- Gerencia de Transmisión y Sub-estación

- Gerencia de Distribución

- Gerencia de Ingeniería de Operaciones

- Gerencia de Apoyo y Coordinación

- Gerencia de Desarrollo.

Gerencias Adscritas:

- Gerencia de Obras de Distribución

- Gerencia de Obras Especiales

- Gerencia de Administración y Control de Obras.

- Gerencia Comercial

Gerencias Adscritas:

-Gerencias de Servicios Técnicos.

- Gerencia de Atención al Cliente.

- Gerencia de Administración

En la Figura 1.1. se encuentra el organigrama correspondientes

ELEVAL C.A.

ORGANIZACION GENERAL DE LA EMPRESA

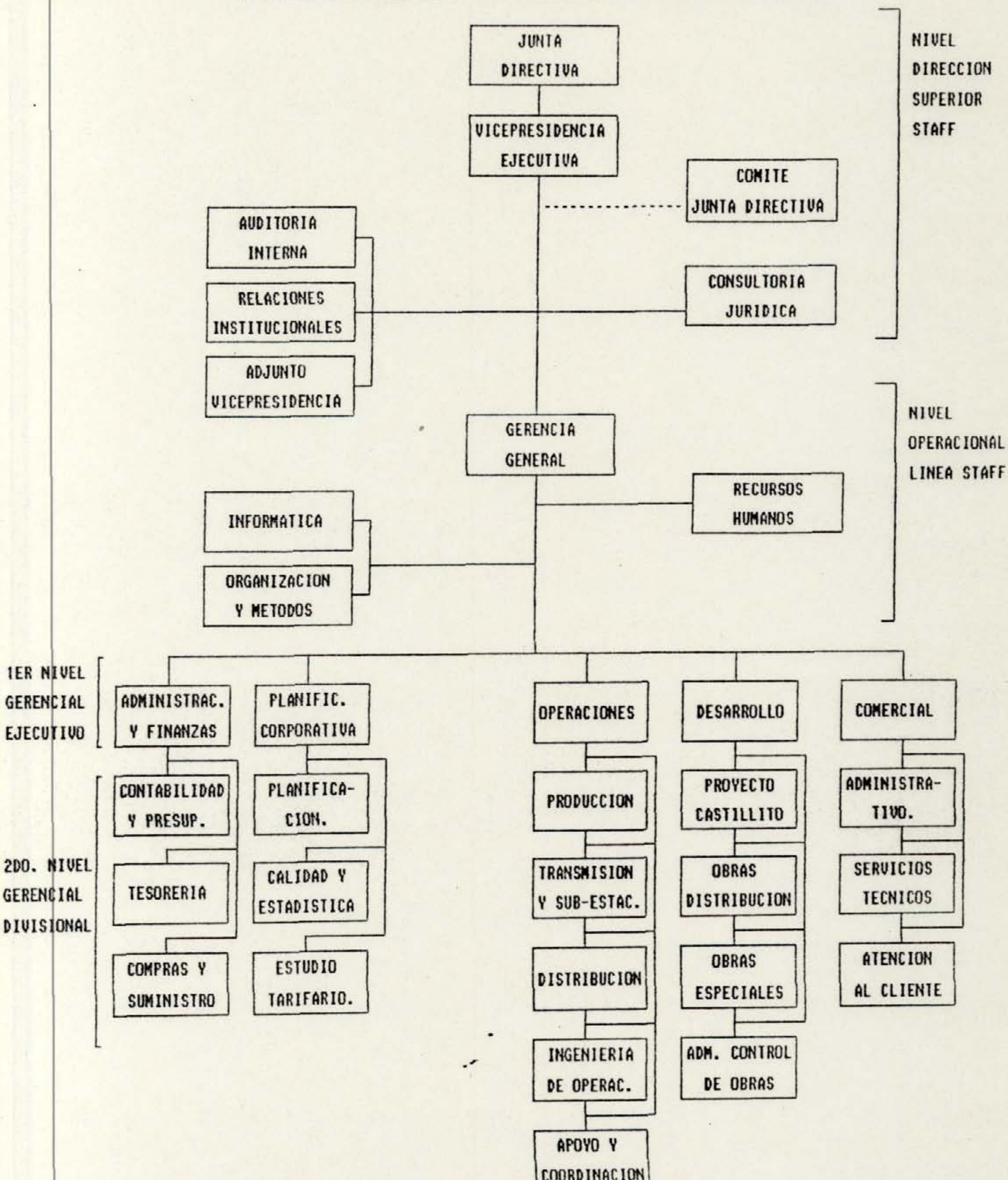

FIGURA 1.1.

1.1.5.- DESCRIPCION GENERAL DEL SISTEMA ELECTRICO ELEVAL, C.A.

El sistema eléctrico de ELEVAL, sirve un área total aproximado de 240 Km^2, en los municipios autónomos: Valencia, Guacara y Bejuma del Estado Carabobo, el cual comparte con ELEOCCIDENTE en un 40% de su extensión.

La demanda de potencia del sistema es de 197 Mw y la demanda anual de energía 1012 GWH con un porcentaje de pérdida técnica del diez por ciento (10%, 101 GWH) anual.

La relación Generación-Compra de energía es aproximadamente 573 GWH (51%) a 551 GWH (49%). ELEVAL tiene un total de 130 MVA instalados en SS/EE propias, el resto de la demanda la cubre con compras a CADAFE en voltaje de distribución, y con distribución directa desde los generadores de planta del Este.

El sistema consta de doce (12) sub-estaciones.

- Una (1) 115/13,8 KV.

Sub-Estación Castillito

- Tres (3) 34,5/13,8 KV.

Sub-Estación Centro

Sub-Estación Reserva.

Sub-Estación Camoruco Viejo.

- Siete (7) 13,8/2,4 KV.

(SE) Subestación Santa Rosa

Subestación Cabriales

Subestación Girardot

Subestación San Blas

Subestación Naguanagua

(SE) Viñedo

(SE) La Alegría

- Una (1) 34,5/2,4 Kv.

Subestación Reserva

Existe un sistema de sub-transmisión en 34,5 Kv cuya área de influencia es el sector Centro-Norte de Valencia y consta de tres subestaciones de distribución y Seis líneas que operan en lazo abierto.

La distribución se hace en 13,8 Kv (88%) en un sistema trifásico, 3 hilos; en estrella; y en menor proporción (12%) en 2,4 Kv en un sistema trifásico, 3 hilos en delta.

Hay un total de cuarenta y tres (43) circuitos en 2,4 Kv, con 80% de redes aéreas y 20% de redes subterráneas.

ELEVAL ha reiniciado este año (1994) el desmantelamiento paulatino del antiguo sistema de 2,4 Kv. el cual por su alto grado de obsolecencia y deterioro ocasionan problema, no solo operativo sino eléctrico en distancias zonas de la ciudad.

La ampliación del parque de generación mediante la incorporación de la planta Castillito (60 Mw) con tres turbos generadores de 20 Mw cada uno (obra en proceso).

Los alimentadores en 13,8 Kv interruptor principal con rele de sobrecorriente y fusibles en los ramales para los transformadores, Corta Corriente (fusible), respaldo con interruptor con relé sobrecorriente para protección de carga.

La gerencia ejecutiva de operaciones tiene bajo su responsabilidad el sistema operativo de la empresa de los sistemas de generación, transmisión y distribución.

El aspecto relevante es la dinámica de los programas de mantenimiento, reparación de equipos del sistema de redes eléctricas, cuyo objetivo es el mantenimiento constante del servicio.

Un sistema de subtransmisión que opera con protección sobrecorriente.

1.2.- CRITERIOS PARA ELEGIR EL CIRCUITO MODELO.

Dado que el sistema eléctrico de Electricidad de Valencia, C.A., existe un gran número de circuitos que alimentan los diversos puntos de la ciudad, se hizo necesario definir algunos criterios para determinar a cual circuito aplicar el estudio propuesto.

1.2.1.- CRITERIO LONGITUD.

Normalmente los circuitos de distribución eléctrica de ELEVAL, C.A., alimentan a los diversos puntos de la ciudad, lo que obliga a pensar que los circuitos son de una considerable longitud. Por esta razón, debe considerarse este aspecto al hablar de caida de tensión en una línea, sobre todo cuando se presenta una falla, en la tabla 1.1 se muestra algunos circuitos de diferentes subestaciones. Al presentarse una falla, se crea una incertidumbre para localizarla, en muchos casos se procede a recorrer casi la totalidad del circuito, y en otro caso se emplea la intuición para localizar la falla permanente.

1.2.2.- CRITERIO NUMERO DE FALLA Y SU NATURALEZA.

El factor número de falla indica desde el punto de vista eléctrico, cual de los circuitos es el más problemático. (Ver tabla 1.6). De acuerdo con lo datos suministrados por el departamento de estadística de operaciones eléctricas, se puede afirmar que las fallas pueden ser debidas a causas variables.

Las principales causas de fallas según las estadísticas son las siguientes:

- Puentes Rotos
- Falla pararrayo
- Aislador Roto
- Disparos en falso del interruptor
- Disparos del interruptor por mala coordinación de protecciones.
- Otros.

Muchas de estas fallas pueden ser minimizadas, más no eliminadas. Por ejemplo una forma de evitar falla por lluvia, es mantener los aisladores limpios, pero es bien conocido, que es prácticamente imposible realizar esta tarea en la totalidad de los circuitos.

Adicionalmente, existe de manera evidente, problema de coordinación entre los fusibles de los ramales y el interruptor principal, y estos a su vez con el interruptor de salida en la subestación, lo que origina operaciones indebidas del interruptor.

1.2.3.- CRITERIO ACCESIBILIDAD PARA LA LOCALIZACION DE LA FALLA.

Debido al crecimiento indiscriminado de las redes de distribución, tenemos como consecuencia, que los circuitos de 13,8 Kv. en muchas ocasiones pasan por lugares poco accesibles, es por ello que a la hora de hacer un estudio de protecciones, se tome en cuenta este parámetro.

La accesibilidad es un factor muy importante en el momento de corregir una falla, ya que de él depende directamente la duración de la misma.

1.2.4.- VARIABLE CARGA, TIPO DE CARGA Y CARACTERISTICA.

De acuerdo a la carga instalada, la calidad de servicio y la continuidad que son factores importantes del sistema eléctrico.

En esta etapa hay que discriminar los tipos de carga a considerar como son: Cargas Industriales, Comerciales, Residenciales y Cargas Especiales (Hospitales, Centros Asistenciales, Aeropuertos, etc.).

Una vez seleccionadas estos tipos de carga se jerarquizan de acuerdo al tipo de proceso continuo o no, que requiere un alto grado de continuidad de servicio. Esta selección permitirá escoger la combinación y ubicación de equipos.

1.2.5.- ELECCION DEL CIRCUITO A TRAVES DE LA MATRIZ DE EVALUACION.

Una vez obtenidos todos los factores necesarios para la elección del circuito de 13,8 Kv, se tomaron las siguientes consideraciones:

- Cada factor será evaluado en una escala del (1 al 5) de acuerdo al orden de importancia que contiene cada factor estudiado. El orden de importancia es decreciente (5 - 4 - 3 - 2 - 1).

- Los 5 factores evaluados en la matriz son los siguientes:

- **Carga Asociada:** Se tomó en cuenta la carga manejada en cada circuito. Para ello se obtuvo la máxima carga asociada durante el período de (Enero - Agosto) de 1994.

Ponderación:

CARGA	PUNTOS
0 - 99 Amp	1 (valor de menor peso)
100 Amp - 199 Amp	2
200 Amp - 299 Amp	3
300 Amp - 399 Amp	4
400 Amp - 500 Amp	5 (Valor de mayor peso)

TABLA 1.1

- **Tipo de Carga:** Para evaluar este factor se tomarán en cuenta los 3 tipos de carga que maneja ELEVAL, a la cual se le dió la siguiente ponderación:

TIPO DE CARGA	PUNTOS
RESIDENCIAL (RES)	1
COMERCIAL (COM)	2
INDUSTRIAL (IND)	3
(RES/RES)	4
(IND/COM)	5

TABLA 1.2

- **Longitud (Km):** Se tomó en cuenta solamente las distancias de los troncales de cada uno de los circuitos de 13,8 Kv. La ponderación de este factor se le dió de acuerdo a las diferentes distancias de los troncales de la siguiente manera:

LONGITUD (Km)	PUNTOS
0 - 2,9	1
3 - 5,9	2
6 - 7,9	3
8 - 10	4
10,1 - 12	5

TABLA 1.3

- **Fallas**: Para realizar el estudio de este factor, se tomaron en cuenta todas las fallas ocurridas por cada circuito en un período de (Enero - Agosto) de 1.994. (8 meses).

Para su evaluación se tomó el total de la suma de las fallas ocurridas por mes, durante todo el período antes mencionado:

Ponderación:

FALLAS No	PUNTOS
0 - 10	1
11 - 20	2
21 - 30	3
31 - 40	4
41 - 50	5

TABLA 1.4

- **Accesibilidad:** Se tomó en cuenta la facilidad de lleyada a los circuitos.

ACCESIBILIDAD	PUNTOS
FACIL	1
COMPLICADO	1,5
CRITICO	2

TABLA 1.5

FACTOR DE MERITO:

Es el producto de los cinco factores de evaluación antes mencionados, tal como se muestra en la Matriz de Evaluación.

TABLA DE FACTORES

SUB ESTACION	CIRCUITO	CARGA	TIPO DE CARGA	LONG (Km)	FALLAS No.	ACCESIBILIDAD
CASTILLITO	CASTILLITO I	290	CON/IND	4.12	10	FACIL
CASTILLITO	CASTILLITO II	260	CON/IND	3.55	10	FACIL
CASTILLITO	SAN DIEGO I	290	RES	10.82	20	FACIL
CASTILLITO	SAN DIEGO II	290	RES	8.52	28	FACIL
CASTILLITO	LAS GARCITAS	260	IND	6.61	6	COMPLICADO
CENTRO	SOUBLETT	340	RES/COM	6.02	4	CRITICO
CENTRO	CUATRICENTENARIO	475	RES	10.15	7	COMPLICADO
CENTRO	COLORADOS	400	RES	7.87	6	FACIL
CENTRO	CERAMICA	250	IND	7.13	8	CRITICO
CENTRO	INOS	80	IND	0.50	0	CRITICO
PLANTA DEL ESTE	CANAL I	300	RES/IND	8.89	14	FACIL
PLANTA DEL ESTE	CANAL II	300	IND	6.83	8	FACIL
PLANTA DEL ESTE	OFICINA	440	COM	5.30	5	FACIL
PLANTA DEL ESTE	SUCRE	320	COM	4.7	6	FACIL
PLANTA DEL ESTE	GUACARA II	280	IND	8.76	1	FACIL
PLANTA DEL ESTE	LOS GUAYOS	50	RES/COM	7.69	6	COMPLICADO
PLANTA DEL ESTE	FIRESTONE	400	IND	0.30	0	FACIL
PLANTA DEL ESTE	FLOR AMARILLA	290	RES	8.71	27	FACIL
PLANTA DEL ESTE	PARAPARAL	230	RES	11.81	48	FACIL
PLANTA DEL ESTE	ZIM	420	IND	4.60	13	FACIL
PLANTA DEL ESTE	OXICAR	200	IND	1.38	1	FACIL
PLANTA DEL ESTE	SAN BLAS	340	RES/COM	6.71	17	CRITICO
GUACARA II	LINEA 6	230	IND	5.8	8	FACIL
GUACARA II	LINEA 7	150	IND	1.41	1	FACIL
GUACARA II	LINEA 8	395	RES	4.80	10	FACIL
GUAPARO	GUAPARO I	360	RES	3.57	1	FACIL
GUAPARO	GUAPARO II	360	RES/COM	4.14	15	FACIL
RESERVA	TRIGAL NORTE	250	RES	3.72	10	FACIL
RESERVA	VIÑEDO	250	RES/COM	2.3	13	FACIL
RESERVA	PREBO	380	RES/COM	3.0	6	FACIL

TABLA DE FACTORES (CONT.)

SUB ESTACION	CIRCUITO	CARGA	TIPO DE CARGA	LONG (Km)	FALLAS No.	ACCESIBILIDAD
RESERVA	GUATAPARO	340	RES	3.80	10	FACIL
RESERVA	AV. BOLIVAR	320	RES/COM	3.2	10	FACIL
CARDENERA	CARDENERA I	305	RES	3.89	45	FACIL
CARDENERA	CARDENERA II	400	RES	6.33	20	FACIL
CARDENERA	CARDENERA III	475	RES/IND	7.94	17	FACIL
BARBULA	LINEA I	250	RES	10.33	22	CRITICO
BARBULA	LINEA II	195	RES	5.55	14	COMPLICADO

TABLA 1.6

MATRIZ DE EVALUACION

SUB ESTACION	CIRCUITO	CARGA	TIPO DE CARGA	LONG (Km)	FALLAS No.	ACCES	FACTOR DE MERITO
CASTILLITO	CASTILLITO I	3	5	2	1	1	30
CASTILLITO	CASTILLITO II	3	5	2	1	1	30
CASTILLITO	SAN DIEGO I	3	1	5	2	1	30
CASTILLITO	SAN DIEGO II	3	1	4	3	1	36
CASTILLITO	LAS GARCITAS	3	3	3	1	1.5	40.5
CENTRO	SOUBLETT	4	3	3	1	2	72
CENTRO	CUATRICENTENARIO	5	1	5	1	1.5	37.5
CENTRO	COLORADOS	5	1	3	1	1	15
CENTRO	CERAMICA	3	3	3	1	2	54
CENTRO	INOS	1	3	1	0	2	6
PLANTA DEL ESTE	CANAL I	4	4	4	2	1	128
PLANTA DEL ESTE	CANAL II	4	3	3	1	1	36
PLANTA DEL ESTE	OFICINA	5	2	2	1	1	20
PLANTA DEL ESTE	SUCRE	4	2	2	1	1	16
PLANTA DEL ESTE	GUACARA II	3	3	4	1	1	36
PLANTA DEL ESTE	LOS GUAYOS	1	3	3	1	1.5	13.5
PLANTA DEL ESTE	FIRESTONE	5	3	1	1	1	15
PLANTA DEL ESTE	FLOR AMARILLA	3	1	4	3	1	36
PLANTA DEL ESTE	PARAPARAL	3	1	5	5	1	75
PLANTA DEL ESTE	ZIM	5	3	2	2	1	60
PLANTA DEL ESTE	OXICAR	3	3	1	1	1	9
PLANTA DEL ESTE	SAN BLAS	4	3	3	2	2	144
GUACARA II	LINEA 6	3	3	2	1	1	18
GUACARA II	LINEA 7	2	3	1	1	1	6
GUACARA II	LINEA 8	4	1	2	1	1	8
GUAPARO	GUAPARO I	4	3	2	2	1	8
GUAPARO	GUAPARO II	4	3	2	2	1	48
RESERVA	TRIGAL NORTE	3	1	2	1	1	6
RESERVA	VIÑEDO	3	3	1	2	1	18
RESERVA	PREBO	4	3	2	1	1	24

MATRIZ DE EVALUACION (CONT.)

SUB ESTACION	CIRCUITO	CARGA	TIPO DE CARGA	LONG (Km)	FALLAS No.	ACCES	FACTOR DE MERITO
RESERVA	GUATAPARO	4	1	2	1	1	6
RESERVA	AV. BOLIVAR	4	3	2	1	1	24
CARDENERA	CARDENERA I	4	1	2	5	1	40
CARDENERA	CARDENERA II	5	1	3	2	1	30
CARDENERA	CARDENERA III	5	4	3	2	1	120
BARBULA	LINEA I	3	1	5	3	2	90
BARBULA	LINEA II	2	1	2	2	1.5	12

TABLA 1.7

1.2.5.1.- Elección del Circuito Modelo.

Después de haber analizado cada uno de los factores comprendidos en la matriz de evaluación donde fueron evaluados cada uno de los circuitos en 13,8 Kv. de conformar parte del sistema eléctrico de Eleval, se llegó a la conclusión que el circuito que reune las condiciones necesarias adecuadas a la matriz de evaluación es San Blas y, donde el valor numérico obtenido en la matriz debido a las variables longitud, carga,, tipo de carga, no de fallas, accesibilidad, justifican dicha decisión, (ver matriz de evaluación). Este circuito obtuvo mayor puntuación en la matriz de evaluación y en mutuo acuerdo con la gerencia de distribución se decidió que fueran objeto de estudios preliminares.

CAPITULO II

CAPITULO II

EQUIPOS DE PROTECCION SUPLEMENTARIA EN CIRCUITOS DE DISTRIBUCION Y CRITERIOS DE APLICACION

2.1.- GENERALIDADES

Se entiende por equipos de protección suplementaria todos aquellos equipos que complementan la función de la protección principal de la subestación. Estos equipos pueden ser: reconectadores, seccionalizadores y fusibles.

El reconectador es un dispositivo de protección que detecta e interrumpe sobrecorriente y reconecta automáticamente la linea. Su operación se rige por curvas caracteristicas inversas de tiempo corriente. Un seccionalizador es un dispositivo de seccionamiento que aisla automáticamente la sección de linea fallada de un sistema de protección, se usa normalmente respaldado por un reconectador o un interruptor con reconexión automática. Los fusibles son dispositivos fabricados con materiales que se funden con el paso a través de ellos de una corriente mayor de cierta magnitud.

Otro dispositivo que disminuye el tiempo de localización de fallas, permanentes es el indicador de falla (ver fig. 2.1). Existen dos grupos básicos de indicadores: los que utilizan el principio electrostático y los que utilizan el principio magnético. El funcionamiento básico de estos equipos es el siguiente: al ocurrir una falla, el torque que produce el flujo magnético y la corriente, hacen mover una bandera indicadora en la parte frontal del aparato; esta bandera en posición normal es blanca y en posición de falla es roja. La reposición de esta bandera puede ser automática o manual, según sea el tipo.

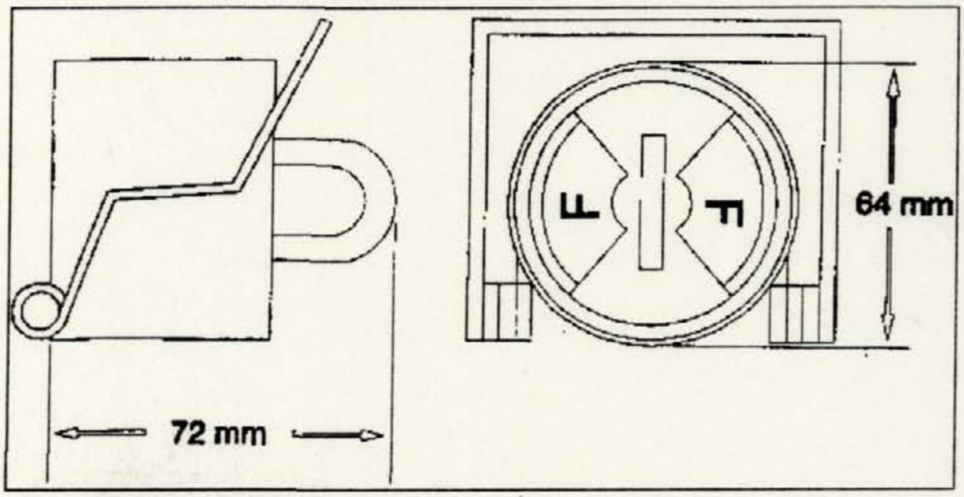

Figura 2.1. Indicador de Falla.

2.2.- ANTECEDENTES.

El crecimiento de las demanda en los ultimos años exigio un desarrollo de las redes de distribución, sin suficiente previa planificación, esto trajo como consecuencia, que Eleval C.A cuenta en estos momentos con alimentadores de cierta longitud, con alto número de derivaciones y con mezcla de tipos de carga (Industrial, Comercial, Residencial), lo que ha producido un sistema de redes con muy poca flexibilidad en la operación.

La mayoría de los circuitos de Eleval, C.A. operan en esquema radial cuya, única protección es el disyuntor principal de salida en la subestación, por lo que cualquier falla que se produzca en el circuito de 13,8 Kv. interrumpe la totalidad de la carga, lo cual trae como consecuencia la dificultad en la localización de la misma sin embargo, en la actualidad Eleval cuenta con 5 reconectadores, los cuales se encuentran ubicados de manera inetrmedia en los circuitos de 13,8 Kv.

Gracias a la utilización de estos equipos se pueden logar esquemas de protección suplementaria que en coordinación con la protección de la subestación, permiten una mayor selectividad y disminución sustancial de la duración promedio de las fallas. De esta manera se logran una mayor confiabilidad y disminución de las perdidas por la energía dejada de vender a los suscriptores.

2.3.- EVALUACION TECNICA DE CIRCUITOS.

Para la evaluación técnica de los circuitos, se tomarán en cuentas los siguientes factores:

- Calidad de servicio.
- Tipo de carga y caracteristicas
- Tipo de interrupciones (temporales y permanentes)
- Accesibilidad para la localización de la falla.

2.3.1.- CALIDAD DE SERVICIO.

La calidad de servicio en circuitos de distribución se traduce en términos generales como: mínimo número de interrupciones, baja duración promedio de las interrupciones, mínimos. KVA interrumpido por falla y nivel de tensión adecuado.

Con los esquemas de protección suplementaria se puede incidir en la duración promedio y los KVA interrumpidos. Al evaluar el circuito se deben tomar lo índices de fallas presentadas en el mismo.

2.3.2.- TIPOS DE CARGAS Y CARACTERISTICAS.

En esta etapa hay que discriminar los tipos de carga a considerar como son: Cargas industriales, comerciales, residenciales y cargas especiales (Hospital, centros asistenciales, aeropuertos etc).

Una vez seleccionado estos tipos de carga, las industriales y especiales se jerarquizan de acuerdo al tipo de proceso continuo o no, que requiere un alto grado de continuidad de servicio.

Esta selección permitirá escoger la combinación y ubicación de equipos.

2.3.3.- TIPOS DE FALLAS.

El porcentaje relativo a la ocurrencia de diferentes tipos de fallas en sistemas eléctricos de distribución varían ampliamente de acuerdo a diversos factores, tales como: Aislamiento a tierra, condiciones atmósfericas, configuración de los circuitos, método de aterramiento, calidad de construcción y condiciones locales.

Con el reporte de interrupciones se puede constatar el número de fallas por circuito, causas que la originan y duración de las mismas, con esta información, se puede estimar facilmente el porcentaje de fallas fugaces (transitorias) y permanentes que presenta cada circuito.

Por lo antes expuesto y sabiendo que los equipos de protección suplementaria despejan el 95% de fallas fugaces, se puede decidir sobre la aplicación de estos equipos para la protección de los circuitos eléctricos de distribución.

2.3.4.- ACCESIBILIDAD PARA LOCALIZACION DE FALLAS

Debido al crecimiento de las redes de distribución se tiene como consecuencia que los circuitos de 13.8 Kv en muchas ocasiones pasan por lugares poco accesibles, y es por *ello que* al momento de hacer un estudio de protecciones se debe tomar en cuenta este parámetro para la ubicación estratégica de los dispositivos de seccionamiento.

La accesibilidad es un factor de mucha importancia al momento de corregir una falla, ya que de él depende directamente la duración de la misma.

2.4.- ANALISIS ECONOMICO

Para justificar la inversión del equipo de protección, se hace necesario evaluar el costo de una interrupción de servicio en un alimentador tipo, para nuestro caso en particular evaluaremos el circuito elegido para el estudio de su sistema de protección.

Para evaluar los costos que implica la utilización del equipo de protección en el circuito elegido es necesario tener como base la capacidad en KVA y la longitud del mismo.

Debido a que el circuito elegido para el estudio es el circuito (San Blas) se tomó como base una capacidad de:

$$S = \sqrt{3} \times 340 \text{ Amp} \times 13{,}8 \text{ Kv} = 8126{,}78 \text{ KVA}$$

y tiene una longitud de : 6,71 KM

Otro aspecto importante utilizado para justificar la aplicación de equipos de protección en el circuito (San Blas) es el precio promedio de KWH el cual se calcula en base al sector que se le suministra energía.

Los sectores considerados y los precios de consumo podrán observarse en la tabla siguiente:

TABLA No. 2.1

SECTOR	PRECIO PROMEDIO KWH (BOLIVARES)
SOCIAL	2
RESIDENCIAL	4,3
COMERCIAL	13
COM/ESP	12
INDUSTRIAL	7

Luego haremos una tabla donde se muestra una distribución de carga en base a los 8126,782 KVA calculados como la carga total del alimentador del circuito San Blas. Esta tabla se muestra a continuación:

TABLA No. 2.2

Sector	% Carga	KVA	Factor Pot.	Carga (KWH)	Costo Prom. (Bs.)	Costo Total (Bs.)
Social	5	406,33	0.8	325,071	2	650,14
Residencial	40	3250,71	0.9	2925,64	4,3	12580,25
Comercial	30	2438,03	0.8	1950,42	13	25355,55
Com/Esp.	20	1625,35	0.8	1300,28	12	15603,41
Industrial	5	406,33	0.8	325,07	7	2275,49
TOTAL		8126,78				56464,68

Según la tabla No. 2.2 el costo de interrupción por energía dejada de vender es de Bs (56.464,86) en el circuito de san blas cuya capacidad total es de 8126,78 KVA. La duración de una interrupción es de un aproximado de 1 hora.

Para tener un costo total de la interrupción habría que sumar los costos de hora-hombre de las cuadrillas utilizadas para reparar la falla, costos de materiales, depreciación de equipos utilizados, etc. El promedio de interrupciones mensuales para el circuito San Blas es de 5 interrupciones mensuales.

EL CALCULO SERIA:

- Costo Interrupción: 56464,86 Bs/Interr.
- 5 Interrupciones/Mes: 60 Interr/Año
- Costo Anual Interrupciones: 60 Interr/Año X 56464,86 Bs/Interr = 3.387.891,6 Bs/Año.

Esta cantidad de dinero (3.387.891,6 Bs/Año) sería el total que ELEVAL dejaria de percibir cada año, actuando solamente el disyuntor de salida de la subestación. - Con la introducción de los equipos de protecciones (reconectador, seccionalizador y fusible), el cálculo se haría de la siguiente forma:

De las 5 (cinco) interrupciones mensuales 3 (tres). Son interrupciones temporales y 2 (dos) son interrupciones permanentes.

Sabemos que estros equipos de protección son capaces de despejar el 95% de todas las fallas temporales, luego, si existe una falla temporal los mismos estarían en capacidad de despejarla y se ahorra ésta cantidad de energía dejada de vender.

En el caso de que las fallas sean permanentes, los equipos de protección suplementaria tendrían capacidad para aislar la falla a la sección más mínima del alimentador, no perdiéndose la totalidad de la carga.

Para el caso de fallas permanentes se puede salvar la mayoría de los casos el 50% del alimentador.

Tomando en cuenta las fallas transitorias, calcularemos los costos de la siguiente forma:

- Costo Interrupción: 56464,86 Bs/Interr
- No Interrupciones Temporales: 3 Interr/Mes.
- Interrupciones Temporales Anuales: 36 Interr/Año.
- Costo Anual Interr.Temp: 36 Interr/año X 56464,86 Bs/Interr X 0,95 = 1931098,2 Bs/Año.

Para el caso de interrupciones permanentes, los cálculos serían los siguientes:

- Energía dejada de Vender 50%
- Costo de Interrupción: 56464,86 Bs/Interr.
- No. Interrupciones Permanentes: 2 Interr/Mes.
- Interrupciones Permanentes Anuales: 24 Interr/Año

- Costo Anual Inter Permanentes:

(24 Interr/Año x 56464,86 Bs/Interr x 0,5) = 677578,32 Bs/Año.

COSTO TOTAL: Costo Inter.Permanente + Costo Inter Temporal

COSTO TOTAL: 1931098,2 Bs/Año + 677578,32 Bs/Año =

= 2608676,52 Bs/Año

PERDIDAS TOTALES: 3.387.891,6 Bs/Año - 2608676,52 Bs/Año =

= 779215,08 Bs

Lo que nos daría como resultado que con los equipos de Protección Suplementaria, ELEVAL se ahorraría una cantidad de (2608676,52 Bs/Año). Con los equipos de Protección Suplementaria.

2.5.- CRITERIOS DE SELECCION, AJUSTES DE EQUIPOS Y ESQUEMAS DE PROTECCION SUPLEMENTARIA.

Seleccionado el circuito para aplicar los equipos de protección suplementaria. se procede a estudiar el esquema de protección más adecuado a dicho circuito los esquemas de protección se plantean según una serie de criterios de selección y ajustes en los diferentes equipos de protección.

2.5.1.- CRITERIOS GENERALES UTILIZADOS PARA LA SELECCION Y AJUSTES DE LOS EQUIPOS DE PROTECCION

2.5.1.1.- PROTECCION INTERRUPTOR DE SALIDA EN LA SUBESTACION.

Para los ajustes de los relés de sobrecorriente de fase de tiempo inverso de cada circuito, se fija una capacidad promedio de potencia por circuito, a la cual corresponde una determinada corriente de carga. Como criterio general de ajuste, se estima conveniente que los relés de sobrecorriente permitan una sobrecarga del 40% de la capacidad nominal asumida, con la cual la corriente de arranque de estos relés será del orden de 1,4 veces la corriente nominal de carga circuito (In). Este margen del 40% de sobre carga permitirá una operación más flexible de los sistemas de distribución, dando la posibilidad de enlaces o interconexiones de emergencia en caso de contingencia.

En el caso de que un circuito la capacidad nominal de un elemento (cable, transformador de corriente, interruptor, etc), sea menor a la corriente nominal asumida, se tomará como límite de arranque de los relés (pick-up), la corriente nominal de ese elemento, permitiendo la capacidad de carga que cada caso permita; en caso contrario se darán las recomendaciones necesarias para la justificación del elemento en cuestión.

En general se permiten los siguientes valores de sobrecarga, por encima de la capacidad del elemento.

- Cable aislado.. 0%
- Transformador de corriente.................. 20%
- Conductor desnudo............................... 40%
- Interruptores... 0%
- Transformador de potencia.................. 30%

Referente al ajuste de los relés instantáneos de fase, se aplica el criterio de que el mismo debe permitir una carga de restablecimiento en frio (cold load pick-up) de 2,5 veces la corriente nominal del circuito por consiguiente se toma como ajuste mínimo este valor. En los casos en las cuales la corriente de corto circuito mínima por falla entre fases al final del circuito fuese menor que el valor fijado (2.5 In) se recomienda la instalación de reconectadores en el troncal específico de dicho circuito. En los casos en que el 40% de la corriente minima de falla entre fases al final de un troncal de circuito, fuese menor que 2,5 veces la corriente nominal se recomienda la instalación de un reconectador en dicho troncal. En estos casos, el ajuste del relé instantáneo debe cubrir como minimo el 80% de la distancia existente entre él y equipo de protección (reconectador) colocado aguas abajo el mismo.

Este criterio de ajuste del instantáneo de fases (2,5 veces la corriente nominal del circuito) no es aplicable a circuitos que suplen cargas de alta densidad de motores o con motores de gran capacidad, ya que la elevada corriente de arranque de los mismos pueden provocar disparos no deseados del instantáneo. Referente al criterio de ajustes de los relés de tierra, tanto instantáneo como de tiempo inverso, se toman criterios diferentes:

- Relé de tiempo Inverso de de Tierra, se ajusta aproximadamente a un 60% de la corriente nominal del circuito; ajustes más bajas del 60% de la corriente nominal, causan serios problemas de coordinación con fusibles y reconectadores.

- Para el ajuste del relé instantáneo de tierra, se toma un ajuste que permita la mejor coordinación con fusibles ramales y reconectadores y que al mismo tiempo detecte fallas a tierra al final del circuito (en el caso que no se instalen reconectadores), en todo caso el relé instantáneos de tierra debe asegurar un despeje seguro de falla a tierra al final del circuito.

En cuanto a los ajustes de los ciclos de reenganche de los interruptores, se proponen (3) posibilidades de esquemas de reenganche en función al tipo de circuito. Para los circuitos rurales y urbanos con mucha vegetación se toma:

Para fallas permanentes, 0 -- 0,3 "--C O - 15" - CO- 35 -" - C O (abre - espera 0,3 [s]- cierra y abre- espera 15 [s] - cierra y abre - espera 35 [s] - cierra y abre). Para circuitos urbanos atraviesan zonas de escasa vegetación se toma:

0 - 0,3" - CO - 35" - CO. Para circuitos que alimentan cargas con alta densidad de motores, en la mayoría de los casos habría que desconectar el instantáneo, solo se ajusta en los casos en que el relé permite graduación entre 400% y 1000%.

2.5.1.2.- Instalacion de Reconectadores

Para circuitos de ciertas longitud (mayores de 15 Km) La protección del interruptor de salida no cubre satisfactoriamente la totalidad del mismo; por consiguiente se recomienda la instalación de reconectadores para dividir dicho circuito en dos o más zonas de protección, teniendo así un despeje más rapido, seguro y selectivo de los distintos tipos de fallas.

En algunos circuitos no es necesario su instalación de acuerdo con el criterio anterior, sin embargo, se recomienda su uso debido a la importancia de la carga y con el fin de dar mayor selectividad al sistema de protección.

Adicionalmente hay que tener en cuenta que la instalación de reconectadores disminuye apreciablemente el trabajo de mantenimiento de los interruptores de salida de la subestación. En circuitos de gran longitud, los niveles de falla a tierra son muy bajos, por consiguiente en estos casos se recomienda la instalación del dispositivo de disparo por falla a tierra en los reconectadores, asegurando así un despeje más rapido y seguro de este tipo de fallas.

Cuando ocurre una falla en la zona de protección del reconectador, este detecta la sobrecorriente e interrumpe el flujo de corriente de falla, después de transcurrido el intervalo de tiempo de reconexión, el reconectador reconecta automáticamente la línea. Si la falla persiste el reconectador repite la secuencia anterior hasta tres veces, si luego de la tercera operación la falla aún está presente se produce la apertura definitiva del dispositivo.

Clasificación de los Reconectadores.

Están clasificados en monofásicos y trifásicos, con control hidráulico o electrónico y con interruptores de aceite o de vacío.

Los reconectadores monofásicos son utilizados para protección de líneas monofásicas y los reconectadores trifásicos son utilizados cuando se requiere la apertura de las 3 fases por causa de una falla permanente en cualquiera de ellas, para prever un desbalance de cargas trifásicas.

Aplicación de los Reconectadores.

Los reconectadores son utilizados en cualquier parte de un sistema de distribución donde la capacidad de los mismos sea adecuada para los requerimientos del sistema.

La localización más usada es:

1.- Colocado en la salida de la subestación como protección de un alimentador.

2.- Sobre líneas, colocado a la mitad de un alimentador.

3.- Como respaldo de otras protecciones ubicadas a lo largo de un alimentador.

Criterios de aplicación.

Para la conveniente aplicación de los reconectadores hay varios factores que deben ser tomados en consideración:

1.- Sistema de tensión

2.- Corrientes de falla máxima y mínima en la zona de protección del reconectador.

3. Corriente máxima de carga.

4. Coordinación con los demás dispositivos de protección.

El sistema de tensión es conócido, y el reconectador debe tener una capacidad de tensión igual o mayor que la del sistema de tensión.

2.5.1.3.- Instalacion de Seccionalizador

A fin de hacer más selectivos los sistemas de protección para los circuitos eléctricos de distribución, se recomienda la aplicación de seccionalizadores en algunas ramales. Los seccionalizadores. Se instalan para proteger ramales de cierta longitud (mayores de 3 Kms) preferiblemente alimentando cargas trifásicas. De igual forma se recomienda instalarlos en circuitos que tengan posibilidades de interconexión con otros circuitos.

El seccionalizador no posee capacidad de interrupción y no está diseñado para interrumpir corrientes de falla; por lo tanto necesita ser respaldado por otro dispositivo que posea capacidad de interrupción. En el intervalo de reconexión del respaldo mientras éste se encuentra abierto, el seccionalizador puede abrir sus contactos.

Operación del seccionalizador.

El seccionalizador no interrumpe corrientes de falla pero su mecanismo de conteo le permite contabilizar las operaciones de interrupción del respaldo y luego del número de conteos para el cual fue calibrado, el seccionalizador abrirá sus contactos.

Ventajas de la utilización de seccionalizadores.

La función del seccionalizador automático de linea en un sistema de distribución, es análoga a del fusible seccionador de linea, pero presenta várias ventajas de utilización sobre él.

Dichas ventajas proporcionan una mayor confiabilidad del sistema y un menor tiempo de reposición en el caso de ocurrencia de fallas permanentes.

Estas ventajas son:

1.- La coordinación del seccionalizador con otros dispositivos de protección puede hacerse más fácilmente y la posibilidad de error en la elección del tipo de fusible es eliminada.

2.- En todo circuito de distribución ocurren sobrecargas o condiciones transitorias de sobrecorriente que aunque nò llegan a fundir los fusibles pueden causar fatiga en los mismos y de esta forma alterar su tiempo de mínima fúsión y cambiar el esquema de coordinación de las protecciones. Con la utilización de seccionalizadores se evita totalmente este inconveniente.

3.- Cuando ocurre una falla permanente en la zona de proteción de un fusible, éste lógicamente se funde y debe ser cambiado, lo cual se traduce en pérdida de tiempo. Con la utilización de seccionalizádores este inconveniente queda eliminado debidó a que para reenergizar nuevamente la línea luego que el seccionalizador ha actuado, solamente es necesario cerrarlo manualmente. Esto quiere decir que el servicio eléctrico puede ser restaurado más rápido y se disminuyen las molestias a los consumidores.

Factores a tener en consideración para la aplicación de seccionalizadores.

1. Voltaje del sistema.

El seccionalizador debe tener una tensión nominal igual o mayor que el sistema de tensión.

2. Corriente de carga máxima.

La capacidad de corriente de carga del seccionalizador debe ser sèleccionada mayor que la corriente de carga máxima en el punto donde se encuentra ubicado.

3. Corrientes máxima y minima de falla.

Efectos de las sobrecorrientes transitóriãs en la utilización del seccionalizador.

Una de las principales causas de operación indeseada e inesperada de los seccionalizadores es la sobrecorriente transitoria, la causa principal que produce esta sobrecorriente es la conexión de carga.

Para determinar si esta sobrecorriente excederá la minima corriente actuante del seccionalizádor, debe realizarse la siguiente operación:

1.- Se calcula la relación entré la capacidad mínima actuante del seccionalizador y la máxima corriente de carga en el punto de localización del seccionalizador.

$$\frac{I}{Icmax}$$

2. Para relaciones mayores que 10, la sobrecorriente transitoria no excederá a la mínima actuante del seccionalizador.

3. Para relaciones entre 10 y 5, la sobrecorriente transitoria puede ser un factor determinante y debe hacerse otra selección de la capacidad del seccionalizador para evitar que su corriente mínima actuante sea excedida por la sobrecorriente transitoria.

4. Para relaciones de 5 o menos, la sobrecorriente transitoria tiene todas las posibilidades de exceder la mínima corriente actuante del seccionalizador y su operación será inesperada.

Por el método anterior puede determinarse si el mínimo nivel actuante del seccionalizador es el adecuado, pero debe llevarse un registro de las corrientes de carga en los puntos de localización de los seccionalizadores, ya que el crecimiento inesperado de sectores y por consiguiente de carga, puede ocasionar el funcionamiento inadecuado del seccionalizador.

2.5.1.4.- ESQUEMAS DE PROTECCION SUPLEMENTARIA

Cuando se conoce los criterios de selección y ajustes de los diferentes equipos de protección, se pasa a analizar los esquemas de protección suplementaria.

Cuando se hace el diseño de un esquema de protecciones; el requisito más importante que debe estar plenamente satisfecho, es la coordinación de los equipos de protección. Por medio de la coordinación se logra que el sistema de protección sea más selectivo, de tal manera que aisle la falla a la sección más corta del circuito eléctrico. En el estudio se hace lo posible para que la coordinación sea la indicada, pero pueden presentarse situaciones donde sea necesaria la pérdida de coordinación (bajo determinado esquema de protección). En estos casos específicos se ajustan los parámetros de las protecciones hasta donde la perdida de coordinación sea la mínima (disparos no selectivos de los equipos de protección).

Para la protección de circuitos eléctricos de distribución existe una gran variedad de esquemas de protecciones, siendos los más importantes:

- DISYUNTOR - RECONECTADOR - SECCIONALIZADOR - FUSIBLE.
- DISYUNTOR - RECONECTADOR - FUSBILE.
- DISYUNTOR - RECONECTADOR
- DISYUNTOR - SECCIONALIZADOR
- DISYUNTOR - FUSIBLE
- RECONECTADOR - SECCIONALIZADOR - FUSIBLE
- RECONECTADOR - SECCIONALIZADOR
- RECONECTADOR - FUSIBLE
- RECONECTADOR - RECONECTADORES
- FUSIBLE - FUSIBLE

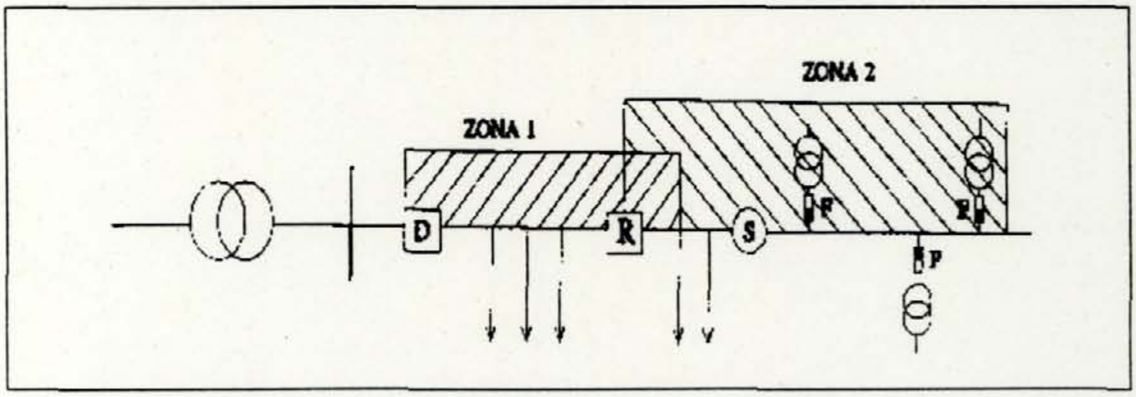

FIGURA 2.2. Esquema de protección Disyuntor-Reconectador-Seccionalizador-Fusible.

Como puede observarse existe una gran variedad de esquemas de protecciones, los mismos obedecen a la diversidad en las caracteristicas técnico - económica de los circuitos eléctricos de distribución. De todos los esquemas antes señalados, el más común es el DISYUNTOR - RECONECTADOR - SECCIONALIZADOR - FUSIBLE (ver figura 2.2).

2.5.2.1.- COORDINACION RECONECTADOR SECCIONALIZADOR

Como los seccionalizadores no poseen curvas de operación tiempo - corriente, esta coordinación no requiere estudio, ya que la misma depende del régimen de operación del reconectador. La máxima capacidad de corriente actuante del seccionalizador debe ser aproximadamente el 80% de la minima capacidad de disparo de reconectador.

2.5.2.2.- COORDINACION RECONECTADOR - FUSIBLE

Para la conveniente aplicación de los reconectadores y fusibles, deben ser coordinados por medio de sus curvas caracteristicas de operación. Para determinar el tipo de fusible a utilizar y el ajuste tipo de coordinación dependiendo de la ubicación de ambos dispositivos en el sistema de distribución eléctrica.

Si el fusible se encuentra aguas abajo del reconectador, el reconectador debe detectar todas las corrientes de fallas que puedan originarse en su zona de protección y en la de los fusibles.

TIEMPO TOTAL ACUMULADO

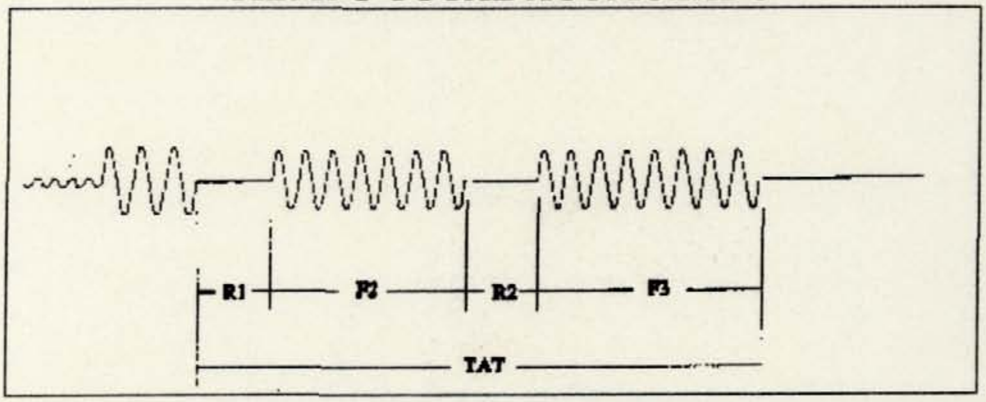

Figura 2.3. Tiempos de fallas y reconexión del reconectador.

La curva de operación rápida del reconectador debe ser ajustada por medio de un factor multiplicador (k) obtenido a patir de la tabla el cuál debe corresponder a la secuencia de operación del reconcetador y al tiempo de reconexión del mismo. Se deben obtener los puntos de coordinación mínimo y máximo.

TABLA No. 2.4. Factores de multiplicación o "K" para elementos fusibles del lado de carga.

TIEMPO DE RECONEXION (seg.)	FACTORES DE MULTIPLICACION	
	UNA OPERACION RAPIDA	DOS OPERACIONES RAPIDAS
0.5	1.2	1.80
1.0	1.2	1.35
1.5	1.2	1.35
2.0	1.2	1.35

El punto mínimo se determina por el valor de corriente en la intersección de la curva de máximo despeje del fusible con la curva retardada del reconectador. El punto máximo se determina por el valor de corriente en la intersección de la curva de minima fusión del fusible con la curva rápida ajustada del reconectador. En la figura 2.5 se ilustra el procedimiento anterior, donde la máxima coordinación entre ambas protecciones se obtiene para una secuencia de operación del reconectador, de dos (2) operaciones rápidas, seguidas de dos (2) lentas. Para fallas agua abajo del fusible, la primera operación rapida del reconectador permite despejar cerca del 80% de las fallas temporales, la segunda operación permite despejar otro 15% y antes de la primera operación retardada del reconectador el fusible debe actuar aislando la sección para fallas permanentes.

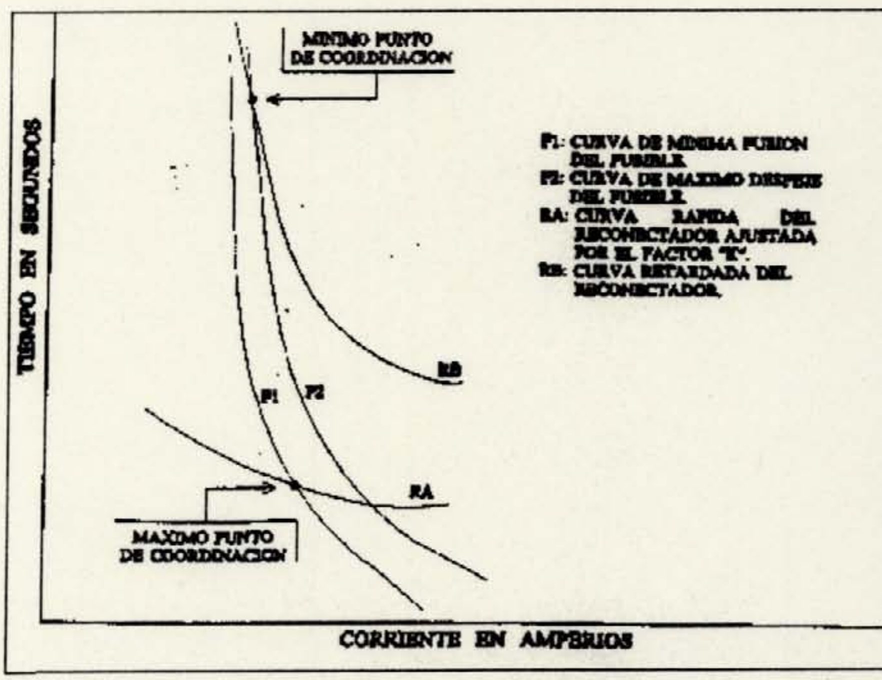

Figura 2.5. Puntos mínimo y máximo para la coordinación de Reconectador-Fusible.

2.5.2.3.- COORDINACION DISYUNTOR - RECONECTADOR

Para analizar y realizar la coordinación de estos equipos, hay que tener presente que existe un tiempo entre el momento en que se abre el disyuntor y el momento en que el relé de sobrecorriente da la orden de apertura (este tiempo es de varios ciclos). En los ajustes de tiempos de los relés de los disyuntores, se debe tomar en cuenta el tiempo total en que el reconectador despeja la falla, para evitar operaciones erróneas del disyuntor. Lo anteriormente dicho, se basa en que si los relés son electromecanicos, lo tiempos de reposición de los mismos, son normalmente largos y si se detecta una nueva corriente de falla antes que el relé se reponga completamente, se provocará un avance del disco desde el punto de reposición incompleta, pudiendo producirse la operación del mismo. Por lo tanto en este tipo de coordinación deben tenerse presente los tiempos de operación del reconectador y el relé del disyuntor, para evitar que el disyuntor se dispare antes que el reconectador termine su secuencia de operación (ver fig. 2.6). Este fenómeno no ocurre con relés eléctronicos.

Dada una secuencia de operación del reconectador, se suman los tiempos de las caracteristica tiempo - corriente obteniéndose la curva acumulativa; si ésta se encuentra por debajo de la curva caracteristica del relé entonces se asegura la coordinación del disyuntor con el reconectador.

Si la curva acumulativa del reconectador sobrepasa la caracteristica tiempo corriente del relé en algún punto, la coordinación se puede lograr determinando los porcentajes de avances y de reposición del disco del relé (para relés electromécanicos) para cada operación del reconectador considerando positivo (+) el porcentaje de avance y negativo (-) el porcentaje de reposición. Si la suma algébraica de estos porcentajes es mayor del 100% no se asegura coordinación de estos equipos, debido a que el disyuntor se abrirá antes que el reconectador termine su secuencia de operación. Para realizar la coordinación de cualquier esquema de protección, es necesario este tipo de analisis.

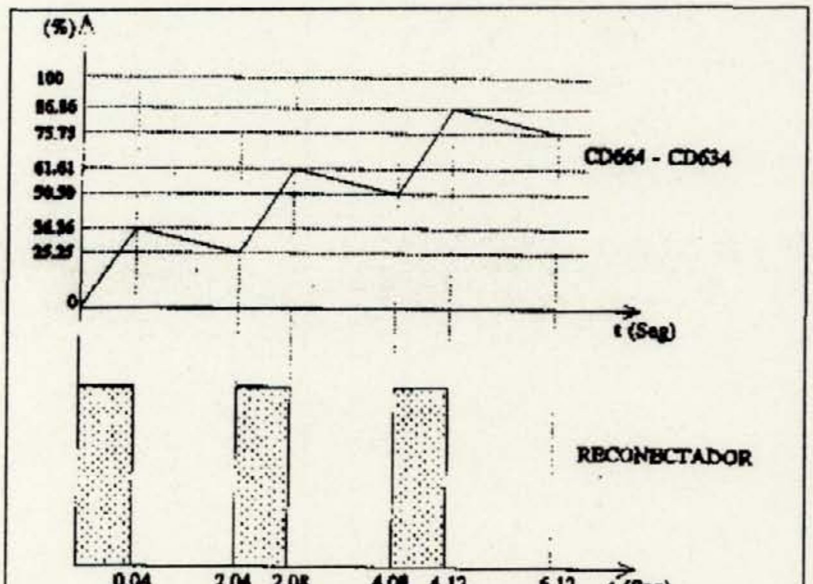

Figura 2.6. Sobrerecorrido de un relé electromecanico.

Todos los esquemas de protección puede plantearse en cualquier tipo de circuito (industriales, urbanos, rurales o cualquier combinación de estos), que tenga un marcado número de fallas y se desee mejorar la calidad de servicio.

2.5.2.4.- Ventajas y Desventajas de los Esquemas de Protección Suplementaria.

Ventajas: Permiten despejar el 95% de las fallas temporales (r1) ofrecen selectividad al sistema de distribución al despejar fallas; en caso de presentarse fallas permanentes el equipo sacará de servicio una sección mínima del circuito, ofrecen puntos de seccionamiento adicionales al sistema y localizan inmediatamente la falla.

Desventajas: Pertubaciones causadas por las operaciones de los equipos de protección suplementaria.

2.6.- CRITERIOS DE SELECCION Y COLOCACION DE EQUIPOS INDICADORES DE FALLAS.

Estos equipos necesitan que circule una minima corriente a través del conductor donde son colocados, para hacer cambiar la bandera indicadora. Este mínimo valor de corriente que activa ak dispositivo, se denomina corriente de disparo. Para la adquisición de estos aparatos se

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Si se desea detectar todo tipo de falla (3Ø 2Ø 2ØT 1Ø 1ØT) con estos aparatos, es necesario instalarlos en las tres fases del punto escogido.

Repecto a los puntos de colocación, se toma como criterio que estos aparatos deben ser instalados en puntos de seccionamientos estratégicos, de manera tal que puedan cubrirse los principales ramales y troncales del circuito asi a la hora de una falla poder localizarla en el menor tiempo posible, seccionar para realizar mantenimiento. Estos equipos pueden ser instalado aguas abajo de los equipos de protección suplementaria sin ningún problema, puesto que su tiempo de respuesta es mínima. (Ver anexo C).

CAPITULO III

CAPITULO III

ANALISIS DE FLUJO DE CARGA Y CORTO CIRCUITO, Y COORDINACION DE PROTECCIONES

3.1.- CALCULO DE FLUJO DE CARGA Y NIVELES DE CORTOCIRCUITO:

El cálculo de flujo de carga y los niveles de cortocircuito se pueden realizar manualmente (Ver Anexo A) o con la ayuda de microcomputadoras (Software). En este trabajo se hizo dicho cálculo con la ayuda de un programa digitalizado llamado MICROSAD.

Para el manejo de este programa es necesario conocer a cabalidad el sistema de distribución actual, su configuración, sus características de operación y sus límites de operación.

3.2.- DIGITALIZACION Y USO DE PROGRAMAS.

Para realizar un análisis de las condiciones de operación de las redes de distribución se requiere el uso de un paquete de programas que faciliten el manejo de los abundantes datos del sistema, asi como el cálculo de los parámetros eléctricos en forma flexible y rápida, amoldándose a las cambiantes condiciones de la red.

El paquete usado para este fin es el MICROSAD. Este paquete permite la simulación del comportamiento de la red de distribución en diferentes condiciones de operación.

Esta simulación consiste en reducir los circuitos de la red de distribución a un conjunto de valores alfanuméricos que conformen un banco de datos en el computador, realizando un proceso que se llama digitalización.

3.3.- BANCO DE DATOS DE LA RED.

La estructura de la red es simulada en el computador mediante elementos ficticios denominados nodos y secciones.

- NODO: Punto de la red donde se concentra un número determinado de cargas distribuidas en un sector de un circuito de distribución primaria (Ver figura 3.1).

- SECCION: Representa el tramo de conductor que une dos nodos.

Los archivos que contienen los datos de nodos secciones y alimentadores conforman el banco de datos de la red, que posteriormente requieran los programas de aplicación.

3.4.- DESCRIPCION DE LOS PROGRAMAS.

Este paquete de programas tiene como objetivo principal el estudio del comportamiento de las redes de distribución sus funciones principales son:

- Creación y actualización de bancos de datos de redes de distribución.

- Análisis del comportamiento de las redes de distribución.

Para realizar estas funciones el paquete está formado por 2 subsistemas:

- Manejo de datos.

- Subsistema de análisis.

3.4.1.- SUBSISTEMA DE MANEJO DE BANCO DE DATOS.

Se encarga de la creación y actualización del Banco de datos que contiene la información de la red de distribución.

Esta formado por los siguientes programas:

- CREABD: Crea e inicializa el banco de datos de la red de distribución.

- NODSEC: Realiza la captura, validación y actualización de datos de nodos y secciones. Con este programa se realiza las siguientes funciones:

    - BS: Buscar y modificar sección.
    - CN: Crear nodo.
    - BN: Buscar y modificar nodo.

- ALIMEN: Realiza la captura, validación y actualización de datos de alimentadores. Realiza las siguientes funciones:

    - CA: Crear alimentador.

- BA: Buscar alimentador.
- FN: Finalizar programa.

- CHECK: Chequea las interrelaciones entre nodos y secciones, informando al usuario los errores cometidos.

- OPERA: Realiza la captura, validación y actualización de datos de seccionadores. Adicionalmente, se pueden simular operaciones sobre los seccionalizadores que posee la red. Las posibles funciones que el usuario puede seleccionar son:

  - CS: Crear y modificar seccionador.
  - BS: Buscar seccionador.
  - CE: Cerrar seccionador.
  - OP: Realizar operaciones.
  - RS: Restaurar sistema.
  - FN: Finalizar programa.

3.4.2.- SUBSISTEMA DE ANALISIS.

Este subsistema proporciona información relativa al comportamiento de la red de distribución que se halla en estudio.

- LOCCAR: Este programa calcula y almacena las cargas en los nodos y distribuye la demanda del circuito en los nodos en proporción a los KVA conectados. Este programa proporciona el siguiente listado:

  - Nombre del alimentador
  - S/E a la que pertenece
  - Número de identificación
  - Factor de utilización de las cargas conectadas.
  - Factor de potencia
  - Carga total conectada en KVA.
  - Demanda localizada total en KVA.
  - Carga puntual conectada total en KVA
  - Factor de diversidad de las cargas puntuales.
  - Demanda especial total.

- ANARED: Este programa calcula las caidas de tensión y capacidad de carga de los conductores en cada sección, determinando las pérdidas en KW y KVAR. Este programa produce un listado con los siguientes datos:

Por Nodo:

- Carga conectada.
- Demanda total de nodo.
- Nodos en los cuales comienza un ramal.

Por sección:

- Longitud.
- Tipo de conductor.
- Número de fases.
- Resistencia y reactancia.
- Porcentaje de carga.
- Carga a través de la sección.
- Tensión final de la sección y porcentaje respecto a la de la S/E.

- LOCCAP: Este programa ubica condensadores en la res de distribución siguiendo dos posibles criterios, a conveniencia del usuario:

  - Mínimas pérdidas.
  - Mínimas caidas de tensión.

- CORCIR: Calcula corriente de falla en cada uno de los nodos de la red de distribución.

Para la obtención de los niveles de cortocircuito a través de este programa se necesita como dato principal los MVA trifásicos obtenidos por el programa de cortocircuito llamado ATENEA.

Este programa previo (ATENEA) tiene por objetivo determinar las corrientes de falla por las ramas (Lineas, cables y tranformadores) y los niveles de cortocircuito en las barras del sistema eléctrico.

Las características principales de este programa son:

- Solución de las ecuaciones de cortocircuito mediante el uso de las matrices de admitancia en las redes de secuencias positiva, negativa y cero.

- Resultados de corrientes de falla en amperios de secuencias positiva, negativa y cero y en fases A, B y C, por cada línea ó transformadores del sistema ó en forma selectiva.

- Resultados de los niveles de cortocircuito trifásicos y monofásicos en barras del sistema. Reporte de aquellas barras donde sean excedidos los niveles de cortocircuito máximos.

- Resultados de voltajes durante la falta por fase y secuencia.

- Capacidad de simular fallas trifásicas, monofásicas, bifásicas a tierra con o sin resistencia de falla.

- El sistema puede resolverse en vacío o bajo carga.

- Capacidad para representar acoplamientos mutuos en secuencia cero entre lineas de transmisión cuyas barras terminales no sean necesariamente las mismas.

- El usuario especifica directamente al programa las conexiones de los transformadores en los lados primario, secundario y terciario, sean estas estrella o neutro o delta o estrella aislada y automáticamente el programa hace las conexiones correspondientes en la red de secuencia cero.

- Modela los desfasajes introducidos por transformadores delta-estrella.

- Un tiempo de 1/2 ciclo se utiliza para obtener niveles de cortocircuito momentáneos y corrientes de falla para ajuste de protecciones instantáneas.

3.4.3.- DIGITALIZACION DE LA RED.

El proceso de digitalización de la red persigue el objetivos de disminuir apreciablemente el número de datos que deben introducirse al computador, convirtiéndolos en un conjunto de datos alfanuméricos que sean accesibles al computador y sin perder la precisión de los resultados obtenidos.

3.4.4.- REGLAS PARA LA DIGITALIZACION DE LA RED.

Para efectuar la digitalización de la red se deberá observar un conjunto de reglas que garanticen los resultados con una precisión aceptable de los programas de análisis, estas reglas se clasifican:

- Reglas para uniformización y comprensión de los datos.

- Reglas para la asignación y ubicación de los nodos en los diferentes puntos de la red.

- Reglas aconsejables para asegurar la convergencia del algoritmo usado en el programa de localización de carga (LOCCAR).

3.4.5.- REGLAS PARA LA UNIFORMIZACION Y COMPRESION.

a) Los planos a usar para la asignación de nodos y secciones serán de las siguientes escalas:

- 1:5000 en áreas urbanas

- 1:10000

  en areas rurales

- 1:25000

- 1:100000 subtransmisión

b) Los nodos se representan mediante una flecha y se les identificará con un número como se muestra en la figura 3.1

c) Las secciones se representarán mediante un óvalo y se les identificará con un número en su interior (Ver figura 3.1.)

d) Para identificar los nodos y las secciones se usarán números en forma consecutiva finalizada la digitalización se recomienda dejar 20 números libres o vacantes, antes de digitalizar el siguiente circuito, para el caso en que se detecte algún error en la digitalización o se desee incorporar una nueva carga.

e) A fin de evitar posibles confusiones deberán encerrarse dentro de un anillo las cargas que abarca cada nodo delimitando asi su area de influencia.

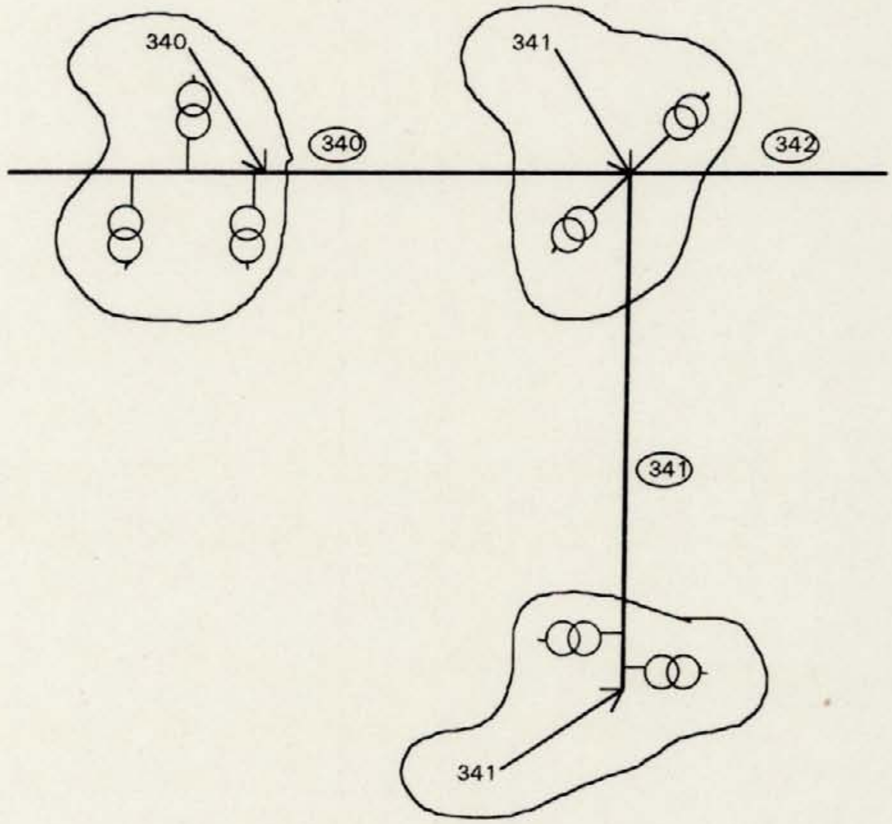


FIGURA 3.1: Notación a usarse para la identificación de nodos y secciones.

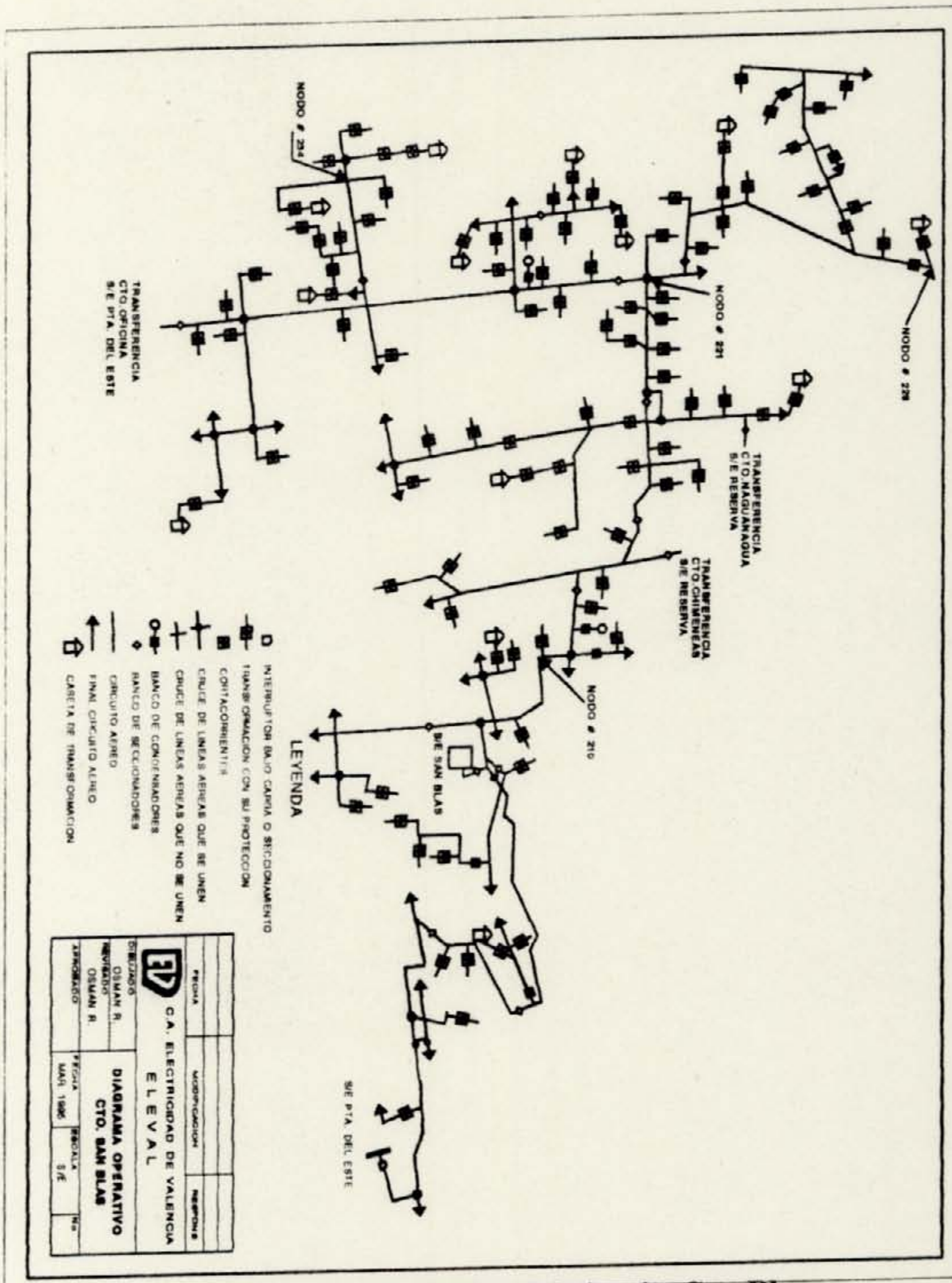


Diagrama operativo del circuito San Blas.

3.4.6.- REGLAS DE APLICACION Y UBICACION DE LOS NODOS EN LOS DIFERENTES PUNTOS DE LA RED.

a) Se ubicarán los nodos en el punto donde se encuentren los centros de carga de los transformadores agrupados.

b) Se tratará de ubicar (1) un solo nodo en cada cuadrícula de carga haciendo la excepción de esta regla para los siguientes casos:

- Existe más de un circuito alimentando la cuadrícula
- Cuando de acuerdo a estas reglas ello no sea posible.

c) Deberá colocarse un nodo en aquellos puntos de la red que presenten algunas de las siguientes características:

- Cambio de calibre de conductor
- Paso de aérea a subterráneo o viceversa
- En ramificaciones de importancia
- En aquellos casos en que se conoce su consumo de KW y KVAR.
- En los puntos de transferencia de carga entre circuitos.
- En reguladores de tensión.
- En equipos de protección que sean de interés tales

como reconectadores, seccionalizadores, etc.

- En banco de condensadores.

3.4.7.- INTRODUCCION DE DATOS.

Para la introducción de datos en el programa digitalizado MICROSAD, con el fin de obtener los valores de flujo de carga y los niveles de cortocircuito, se utilizaron 2 subprogramas internos: ALIMEN y NODSEC.

El programa ALIMEN se utiliza para crear el alimentador, mientras que el programa NODSEC es utilizado para la creación de las secciones y los nodos.

Ambos programas cumplen con los siguientes formatos:

NODSEC

- Creación de Nodos:

FORMATO: CN IN S1 S2 S3 S4 KWP KVARP E/P REG
RS

- ID Identificación del nodo

- S1,2,3,4	Secciones conectadas
- KVA	KVA Totales conectados
- KWP	KW Puntuales totales
- E/P	Especial/Puntual
- REG	Porcentaje de regulación por fase
- RS	Sección donde colocar los reguladores

- Creación de Sección:

FORMATO: CS ID LONG COND NODO1 NODO2
FACTS NFASES

- ID	Identificación de sección
- LONG	Longitud en metros sin decimal
- COND	Código de conductor
- NODO1,2	Nodos conectados
- FACTS	Factor de esparcimiento. Opcional Valor asumido: 1.37
- NFASES	Número de fases. Opcional Valor asumido: 3

ALIMEN

- Crear alimentador:

FORMATO: CS ID SEC FP KVLL AMPF1 AMPF2 AMPF3
FDIV PBAR NEUT

- ID	Identificación del alimentador
- SEC	Sección de comienzo
- FP	Factor de potencia. Opcional
	Valor asumido: 1.0
- KVLL	Voltaje línea a línea. Opcional
	Valor asumido: 13.8
- AMPF1,2,3,	Amperios por fase
- FDIV	F. diversidad de C. Punt. Opcional
	Valor asumido: 1.0
- PBAR	% de voltaje en la barra opcional
	Valor asumido: 105%
- NEUT	Neutro del sistema opcional
	Valor asumido: 0 (NO)

3.4.8.- OBTENCION DE RESULTADOS.

Se obtuvieron los valores de flujo de carga y los niveles de cortocircuito de los diferentes tipos de fallas en cada uno de los nodos (Ver anexo E).

Estos resultados junto con la topología del circuito en estudio, permitieron elegir los sitios adecuados para la ubicación de los equipos de protección suplementaria e indicadores de falla.

3.4.9.- CRITERIOS TOMADOS

Los siguientes criterios se definirán para seleccionar los lugares donde deberían colocarse los equipos de protección suplementaria e indicadores de falla:

- Máxima pérdida de carga (7.779 KVA).
- Despejes selectivos de fallas.
- Minimizar el tiempo para localización de fallas
- Respaldo del circuito sin desconexión de cargas
- Colocación de equipos indicadores de fallas al lado de seccionadores.

3.5.- SELECCION DE LUGARES PARA COLOCACION DE EQUIPOS DE PROTECCION SUPLEMENTARIA E INDICADORES DE FALLA.

Para seleccionar los lugares donde colocar estos equipos, se tomaron en cuenta los cinco (5) criterios antes mencionados:

El criterio de máximo diferimiento de carga, hace que se divida el circuito en dos (2) zonas de protección. Esta idea es reforzada al observar la topología del circuito. El punto de colocación del reconectador maneja una carga instalada de 7.779 KVA la cual se divide en dos ramales donde cada ramal tiene una carga de 3.507 y 4272 KVA. Para solucionar este problema se decidió colocar un seccionalizador en cada ramal, que divida la carga en dos puntos casi iguales.

Si se analizan los resultados obtenidos del programa (flujo de carga y corriente de cortocircuito).

En todos y cada uno de los ramales existe una diferencia entre la máxima corriente de carga y la mínima corriente de corto circuito (para cada una de las zonas de protección establecidas).

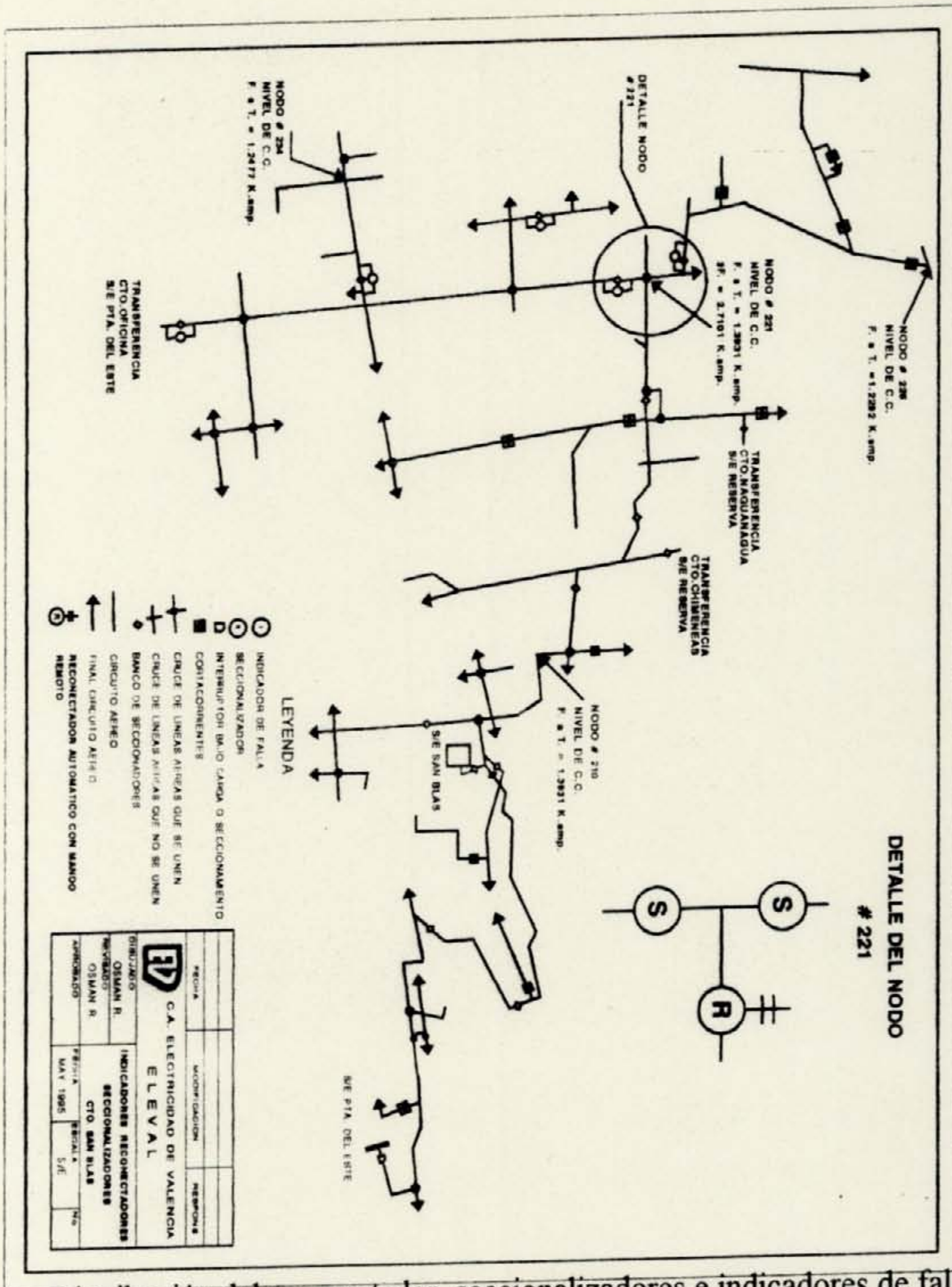
Desde el punto de vista operativo, esta distribución de equipos de protección tiene grandes ventajas, debido a que no sería necesario abrir el interruptor principal del circuito en la S/E al realizar maniobras de mantenimientos en algunos de estos ramales.

Los seccionalizadores facilitarían la transferencia de carga del circuito con otros; al momento de una falla al lado de los seccionadores (todos los del circuito en estudio), a excepción de aquellos que se encuentren en comienzo de la troncal, es importante, ya que al presentarse una falla permanente, esta podrá ser corregida rápidamente, debido a que la cuadrilla de mantenimiento podrá llegar a la misma guiada por dichos aparatos en menor tiempo. Asi mismo se colocarán en sub-ramales pequeños, donde la accesibilidad sea difícil. En la Fig. 3.2 se puede observar la distribución final de estos equipos (reconectador, seccionalizadores e indicadores de falla)

3.6.- COORDINACION Y AJUSTE DE LOS EQUIPOS DE PROTECCION.

3.6.1.- ZONAS DE PROTECCION.

Concluida la selección de los lugares adecuados para colocar los equipos de protección suplementaria e indicadores de falla, se tiene dos (2) zonas de protección(Ver Fig. 3.3), la primera es la que abarca el relé del interruptor principal que comprende la totalidad del circuito, y la segunda protegida por el reconectador hasta las respectivas cargas. Existen dos ramales con seccionalizadores, pero este dispositivo no requiere coordinación.



Distribución del reconectador, seccionalizadores e indicadores de fallas

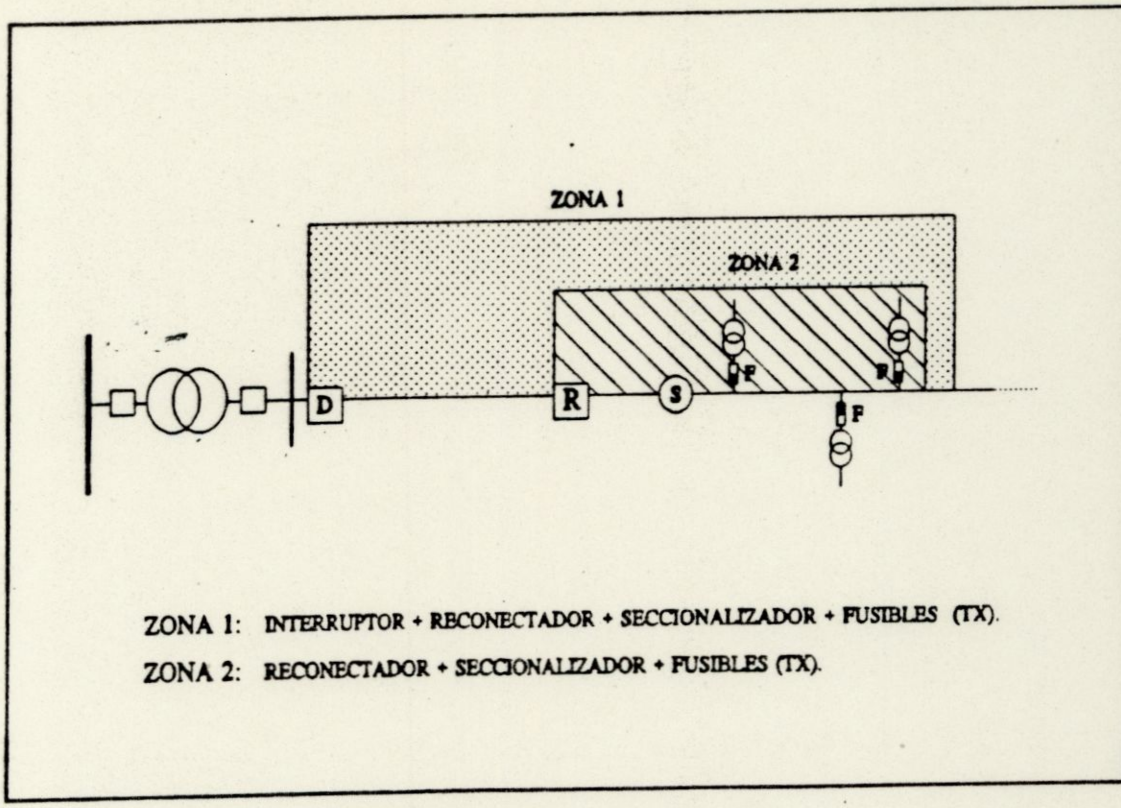


FIGURA 3.3: Esquema de protección.

3.6.2.- SELECCION DE LA PROTECCION DE LOS TRANSFORMADORES DE DISTRIBUCION.

Una protección de sobrecorriente para transformadores debe cumplir con las siguientes funciones:

- Proteger el sistema cuando hay fallas en el transformador.
- Proteger al transformador contra sobrecargas severas.
- Desconectar al transformador tan rápido como sea posible, limitando la energía de falla.
- Permitir sobrecarga de corta duración.

- Soportar corrientes magnetizantes anormales y las corrientes de carga fria. (cold load inrush)
- Ser poco sensible a los efectos transitorios producidos por las descargas atmosféricas.

Entre los dispositivos disponibles para protección de sobrecorriente de transformadores se encuentran: fusibles interruptores y reconectadores. La protección a escoger es generalmente la que sea más económica y que cumpla con las funciones deseadas.

Cuando se va a proteger un transformador con fusible es necesario buscar un punto de equilibrio considerando los siguientes factores, que a continuación entran en conflicto:

- Continuidad de servicios.
- Disminución de la vida útil del transformador por sobrecargas.
- Coordinación de los fusibles del transformador con dispositivos de seccionalización.
- Efectos de corrientes magnetizantes transitorias y carga fria, etc.

Por eso es que para escoger un fusible sea necesario considerar los puntos que se mencionan a continuación:

- Las corrientes magnetizantes transitorias se producen al energizar un transformador. Esta corrientes dependen del valor residual del núcleo y del valor instantáneo del voltage en el momento de la energización. Para no operar con estas corrientes un fusible debe, típicamente, ser capáz de soportar 25 veces la corriente de plena carga durante 0,01 seg. y 12 veces la corriente de plena carga durante 0,1 seg.

- La corriente de carga fría es la corriente que se presenta cuando se reenergiza un circuito después de una interrupción prolongada de servicio.

Esta corriente varía dependiendo del sistema, y la curva del fusible debe ser más lenta que la curva de carga fría (si es que ésta se conoce).

- Los sobrevoltages producidos por descargas atmósféricas pueden saturar al núcleo produciendo corrientes magnetizantes transitorias.

Al presentarse daños en los fusibles originados por sobre voltage la solución es usar fusibles de mayor amperaje.

3.6.2.1.- Determinación de la Curva de Daño.

Para una mejor selección de los fusibles, a partir de una edición reciente de la norma ANSI C.57.109 (Ver Ref R2), ilustra las técnicas usadas para construir la curva de daños de los transformadores con el objeto de lograr una efectiva protección de los mismos. (Ver anexos F y G).

En la Tabla 3.1 (Ver Ref R2) se indican las categorías de los transformadores de acuerdo a su capacidad.

TABLA 3.1.

Clasificación de los transformadores según norma ANSI C.57.109

POTENCIA NOMINAL (KVA) MINIMA DE PLACA (REGIMEN OA)		
CATEGORIA	**MONOFASICO**	**TRIFASICO**
I	5 - 501	15 - 501
II	502 - 1667	502 - 5000
III	1668 - 10000	5001 - 30000
IV	MAYOR QUE 10000	MAYOR QUE 30000

Dependiendo de la categoría del transformador y a partir de la Tabla 3.1 (Tomada de la Ref. R2) se obtuvieron los puntos de la curva de daños termomecánicos del trasnformador.

TABLA 3.2.

Curva de daño tiempo-corriente para TX según normas

ANSI C.57.109

Punto de cálculo	**Categoría del transformador**	**Tiempo (seg.)**	**Corriente (Amp.)**
1	I II III, IV	$t = 1250 * (Zt)^2$ $t = 2$ $t = 2$	I = IN(OA)/Zt I = IN(OA)/Zt I = IN(OA)/(Zt+Zs)
2	II III, IV	t = 4,08 t = 8,00	I = 0.7 IN(OA)/Zt I = 0.5 IN(OA)/(Zt+Zs)
3	II III, IV	$t = 2551 * (Zt)^2$ $t = 5000 * (Zt+Zs)^2$	I = 0.7 IN(OA)/Zt I = 0.5 IN(OA)/(Zt+Zs)
4	I, II, III, IV	t = 50	I = 5*IN(OA)

donde;

Zt = Impedancia del transformador en por unidad en la base OA del transformador.

Zs = Impedancia del sistema en por unidad en la base OA del transformador.

OA = Inmerso en aceite, enfriado por aire (no forjado).

De la Tabla 3.2 se observa el número de puntos que tienen las curvas de daños de los transformadores según su categoría:

CATEGORIA 1	2 PTS. (1,4)
CATEGORIA 2	4 PTS. (1,2,3,4)
CATEGORIA 3	4 PTS. (1,2,3,4)
CATEGORIA 4	4 PTS. (1,2,3,4)

Para la categoría I que corresponde con las capacidades instaladas en el circuito San Blas de acuerdo con esta tabla, para la Categoría I:

$$I1 = In\ (OA)/Zt \qquad \text{(Ec. 3.1)}$$

$$T1 = 1250 * (Zt)^2 \qquad \text{(Ec. 3.1)}$$

donde;

In = Corriente nominal del primario del Tx

Z(t) = Impedancia en por unidad del Tx.

Siendo la corriente nominal del primario del Tx:

$$In = \frac{Sn}{\sqrt{3} * Vn} \qquad \text{(Ec. 3.3)}$$

Por ejemplo:

Para un banco de 500 KVA

$S = 3 * 167 = 500\ KVA$

$Zt = 2{,}8\% * 500\ KVA = 8{,}4\%$

A partir de la Ec. 3.3 $In = \dfrac{Sn}{\sqrt{3} * Vn}$

$$In = \frac{500 * 10^3}{\sqrt{3} * 13.800} = 20{,}96\ Amp$$

Sustituyendo los valores de Zn y Zt en las Ec. 3.1 y Ec. 3.2.

$I1 = 20{,}96\ (OA) / 0{,}084 = 249{,}5\ Amp$

$T1 = 1250 * (0{,}084)^2 = 8{,}82\ seg.$

Siguiendo un procedimiento similar y utilizando la tabla anterior, se obtiene el punto restante (Ver Tabla 3.2)

TABLA 3.3

Puntos ANSI para curva de daño

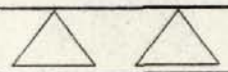
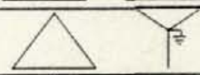
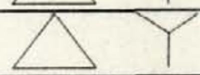
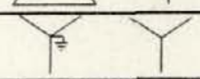
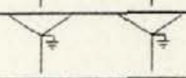
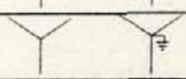
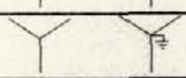
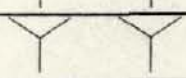
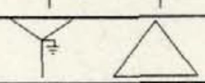
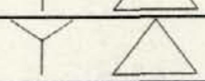
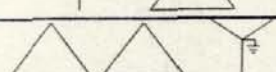
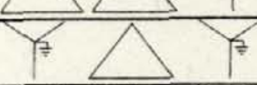
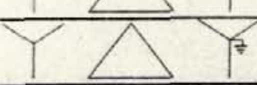
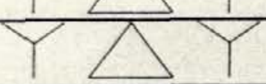
Punto ANSI	Tiempo [S]	Corriente [A]
No. 1	8.82	249.5
No. 2	50	104.8

Dependiendo de la conexión de los transformadores y conforme a la norma C.57.109 (Ver Ref R2) hay que multiplicar los valores de la curva de daños por un factor de corrección para garantizar que el dispositivo primario de protección sea capaz de detectar las corrientes de falla y pueda proteger las arrolladas del transformador contra fallas externas.

Por ejemplo en la conexión delta-delta la máxima coriente que aparece en el primario para una falla trifásica en el secundario, es la corriente de falla del secundario dividida por la relación de transformación, pero esto no ocurre para una falla bifásica, caso para el cual la corriente en el primario toma un valor de 0.87 veces la corriente de falla en el secundario por el inverso de la relación de transformación. Esto sugiere que para los fusibles protegan adecuadamente el transformador, su curva de tiempo total de despege, debe ser más rápida que la curva de daños del Tx reducida en corriente 0.87 veces.

TABLA 3.4

Factores de corrección para la curva de daño

Conexión del Tranformador	TRIFASICA	BIFASICA	MONOFASICA	FACTOR ANSI
	1.0	0.87	-	0.87
	1.0	1.15	0.58	0.58
	1.0	1.15	-	1.0
	1.0	1.0	-	1.0
	1.0	1.0	1.0	1.0
	1.0	1.0	0.67	0.67
	1.0	1.0	-	1.0
	1.0	1.0	-	1.0
	1.0	1.0	-	1.0
	1.0	1.0	-	1.0
	1.0	1.15	1.0	1.0
	1.0	1.0	0.67	0.67
	1.0	1.0	0.67	0.67
	1.0	1.0	1.0	1.0

La Tabla 3.4 (Tomada de Ref. (2)) muestra la relación entre la corriente del lado primario del transformador (en PU) y la corriente del arrollado secundario del transformador (en PU) para diferentes conexiones y para diferentes tipos de fallas. Los transformadores, circuitos en estudio, son de conexión delta-estrella aterrado por lo que el factor ANSI es 0.58

por lo tanto, la nueva curva de daño ANSI está definida ahora por los puntos indicados en la Tabla 3.5.

TABLA 3.5.

Puntos ANSI corregidos para curva de daño del transformador

Punto ANSI	Tiempo [S]	Corriente [A]
No. 1	8.82	144.71
No. 2	50	60.78

3.6.2.2.- Determinación de la curva Inrush del transformador.

Las corrientes magnetizadas transitorias se producen al energizar un transformador. Estas corrientes dependen del flujo residual en el nucleo y del valor instantáneo del voltaje en el momento de la energización (Ver Anexo H).

Para no operar con estas corrientes un fusible debe, tipicamente, ser capaz de soportar 25 veces la corriente de plena carga durante 0,01 seg y 12 veces la corriente de plena carga durante 0.1 seg.

La curva Inrush o curva de energización del transformador, se obtiene a partir de los puntos que a continuación se calculan:

- Punto 1:

Pata T1 = 0,01 seg.

I1 = 25 * In Ec. 3.4

I1 = 25 * (20,96) = 524 Amp.

- Punto 2:

Para T2 = 0,1 seg.

I2 = 12 * In Ec. 3.5

I2 = 12 * (20,96) = 251,5 Amp.

En resumen, ver Tabla 3.6

TABLA 3.6.

Puntos ANSI para curva de Inrush

Punto ANSI	**Tiempo [S]**	**Corriente [A]**
No. 1	0,01	524
No. 2	0,1	251.5

3.6.2.3.- Selección del Fusible.

Para seleccionar el fusible de protección del transformador de distribución, se deben tomar en cuenta las dos (2) curvas anteriormente halladas. La curva del fusible debe estar por debajo de la curva de daño y por encima de la curva de Inrush del transformador que se va a proteger para evitar que este se dañe y que actúe el fusible al energizar al mismo (Ver Ref R2).

El fusible a utilizar es el del tipo K, y el valor límite superior normalizado según el código eléctrico nacional, sección 450-3 (300% de la corriente nominal primaria para una impedancia del transformador no mayor de 10%).

En la figura 3.4 se muestra la curva característica del fusible tipo 25-K y las curvas de daño e Inrush del transformador.

A continuación se muestra en la Tabla 3.7 los fusibles recomendados para los bancos de transformador de acuerdo a sus capacidades (KVA).

TABLA 3.7

Fusibles según capacidad de los transformadores

Banco Trifásico (KVA)	Corriente (Amp) AT 13.8 KV	Impedancia (%)	Fusible (A)
3 * 5	0.63	5.4	1 - k
3 * 10	1.26	5.4	2 - k
3 * 15	1.88	5.4	3 - k
3 * 25	3.14	5.4	5 - k
3 * 37,5	4.71	6.0	6 - k
3 * 50	6.28	6.0	8 - k
3 * 75	9.41	6.0	12 - k
3 * 100	12.55	7.5	15 - k
3 * 167	20.96	8.4	25 - k

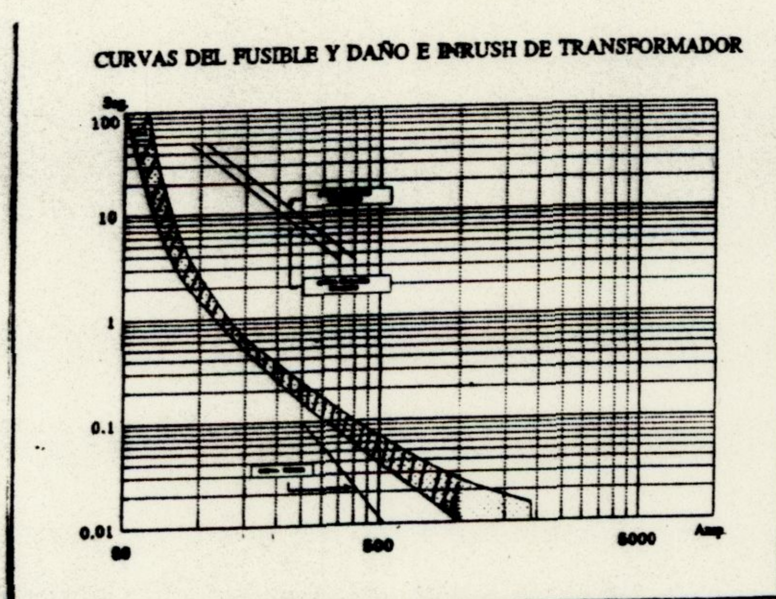


FIGURA [illegible]: Comparación entre curvas de daño e inrush del transformador y las curvas características del fusible 25K.

3.6.3.- ESCOGENCIA Y AJUSTE DE LOS RECONECTADORES

3.6.3.1.- ESCOJENCIA DEL TIPO DE RECONECTADORES

Como ya se mencionó, Eleval C.A. Posee en los actuales momentos ocho (8) reconectadores automaticos PMR 15 Marca Hawker Siddeley Switchgear. Estos reconectadores tienen las siguientes caracteristicas.

Designación de la unidad.	PMR 15
- Tensión nominal (kv)	14,4
- Tensión más alta de sistema en kv	15,5
- Intensidad nominal (a)	560
- Intensidad de Interrupción (ka)	12
- Poder de cierre (ka)	35
- Tensión nominal de ensayo a impulso (bil)(kv)	110
- Tensión de ensayo a frecuencia industrial en seco / humedo (kv)	50/45
- Presión normal del gas en bares (relativa)	1,5
- Presión minima del gas en bares (relativa)	1,0

3.6.3.2.- AJUSTE DEL DISPARO DE FASE DEL RECONECTADOR

Mediante este ajuste se puede detectar las corrientes de fallas del sistema y ademas ofrecer seguridad y sensibilidad para desconectar parte del mismo cuando ocurra una falla de cualquier naturaleza que involucre dos (2) o más fases. El disparo de fase depende de la maxima corriente de carga y la corriente de corto circuito fase-fase al final de la zona de protección considerada. En la ecuación (3.6) se muestra el rango de valores para la escogencia de la corriente de ajuste Ec (3.6)

$$\boxed{I\,carga_{Max} * 1.4 < I\,aguste \leq \frac{Icc\,øø}{1,5}}$$

donde;

1,5 : Factor de seguridad

1,4 : Factor de seguridad

Al definir el valor del disparo de fase, se debe ajustar al mínimo valor posible, de esta manera la operación del reconectador será más rapida para las corrientes de fallas, reduciendo la probabilidad de daños o componentes del circuito y extendiendo la zona de protección.

Para el calculo de la corriente nominal en el punto de instalacción del reconectador, se hizo a las 3:30 p.m. donde se presentó máxima demanda, información suministrada por el departamento de planificación, mediante el uso de kilo amperimetro (hola) el valor de las corrientes en cada una de las fase.

R = 157 Amp.

S = 150 Amp.

T = 155 Amp.

$$\left(157 * 1{,}4 < I \text{ ajuste} \leq \frac{2055}{1{,}5} \right) \text{amp}$$

$$(220 < I \text{ ajuste} \leq 1370) \text{ amp}$$

Tc 300:1

Para determinar el porecentaje de disparo mínimo se forma :

$$\frac{\text{Iajust}}{} = \frac{230}{300/1} = 0{,}76$$

En los ajustes del mínimos disparos por fase (%) no se dispones 76% por lo que se toma 80% que es el inmediato superior.

Por lo tanto tenemos: 0,8 * 300 amp = 240

El disparo minimo estará en 240 amp.

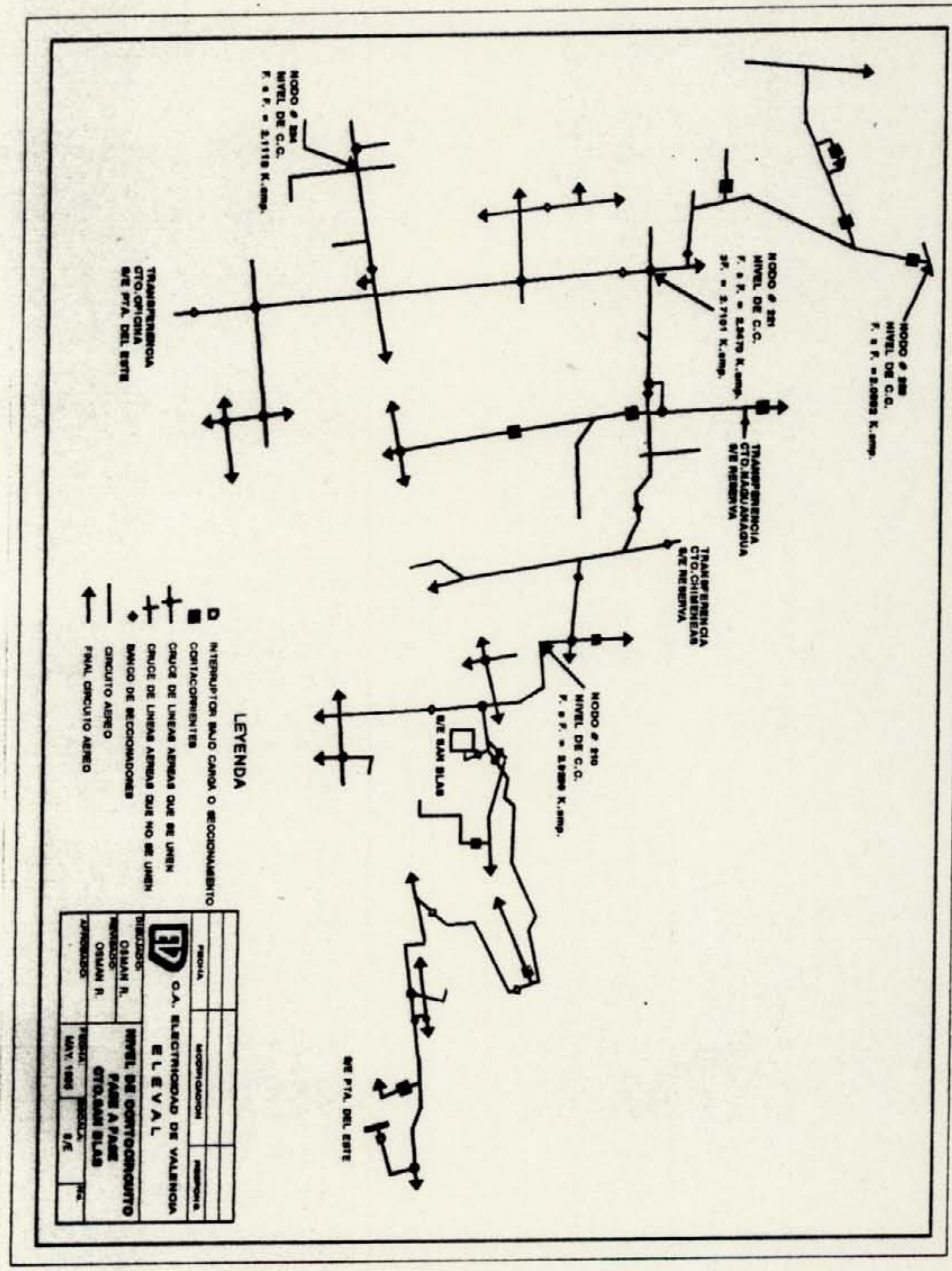


Fig. 3.5.: Corriente de cortocircuito de fase - fase del circuito San Blas.

3.6.3.3.- Ajuste del Disparo de Tierra del Reconectador

Una vez calculado el disparo de fase del reconectador se procede a calcular los valores de corrientes para el disparo de tierra del reconectador.

Mediante este ajuste se puede ofrecer seguridad y sensibilidad para desconexión de una parte del sistema bajo la ocurrencia de una falla del cualquier naturaleza que involucre cualquier fase y tierra o cualquier combinación de fase y tierra. El disparo de tierra depende del desequilibrio de las corrientes máxima de cargo y de la corriente de corto circuito al final de la zona de protección considerada.

Para el ajuste del valor de la corriente de disparo por fallas a tierra del reconectador se toman en cuenta los valores de corrientes mostrados en la figura (3.6). En la ecuación (3.7). se muestra el rango para tal ajuste.

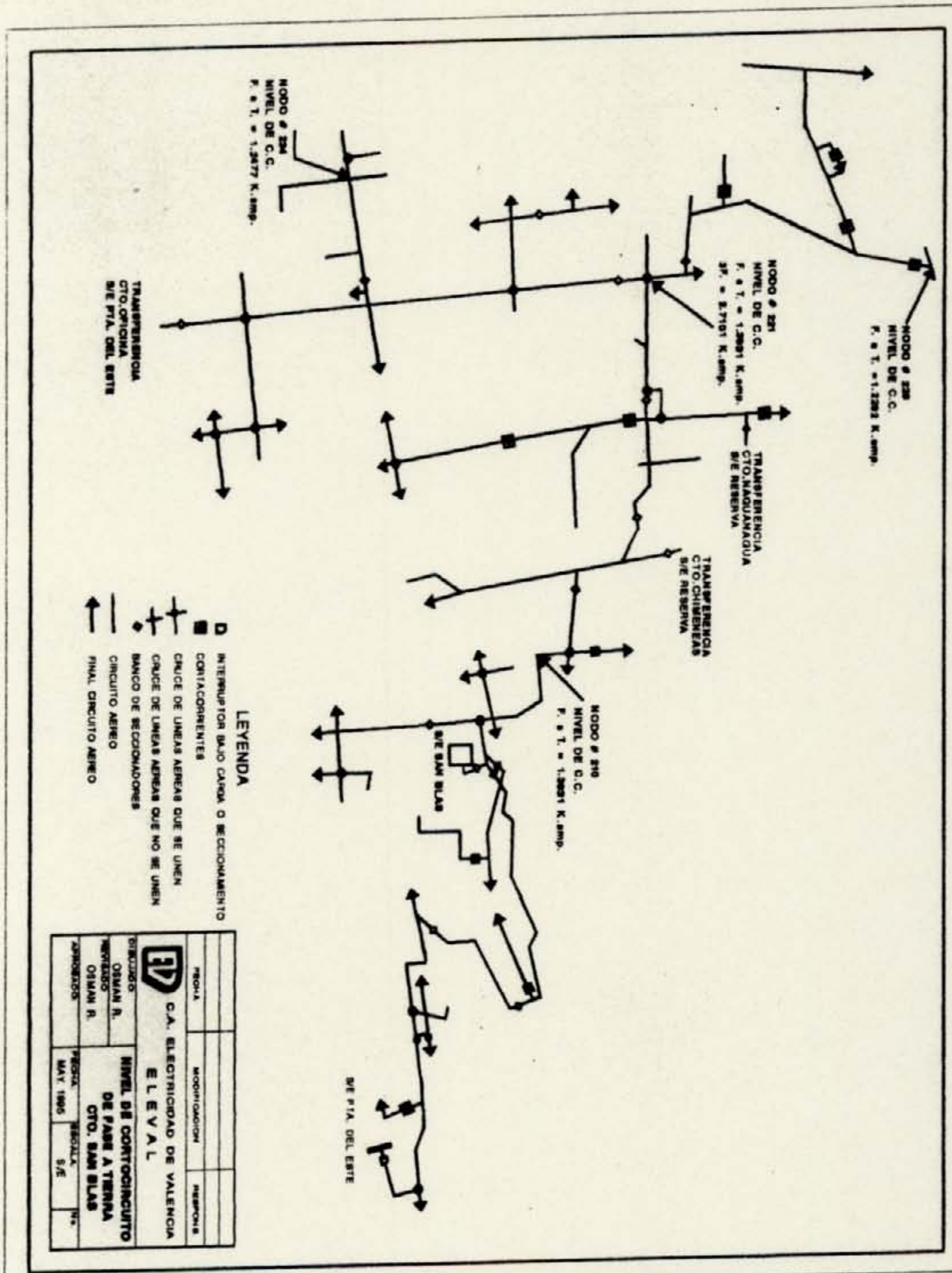


Figura 3.6 Corrientes de Corto Circuito Fase - Tierra del Circuito San Blas.

E.c. (3.7)

$$(0{,}1 \text{ a } 0{,}3)\ I_{carga\ max} < I\ ajuste < \frac{Icc\varnothing T}{1{,}5}$$

1,5 Factor de seguridad

(0,1 a 0,3) porcentaje de desequilibrio permitido para el cálculo se asume un desbalance del 20 %

Este valor de ajuste debe estar lo más cerca del limite inferior, para la mejor operación del reconectador y causar la menor cantidad de daños de los elementos que conforman el sistema.

$$157 * 0{,}2 < I\ ajuste \leq \frac{1229}{1{,}5}$$

$31{,}4 < I\ ajuste \leq 814$

Tc 300 : I

Para determinar el porcentaje de disparo minimo se toma:

$$\frac{I\ ajuste}{Tc\ \ 300{:}1} = \frac{40\ \ amp}{Tc} = 0{,}13$$

En los ajuste del mínimos disparo de tierra (%) no se dispone de 13% por lo que se toma 20% que es el inmediato superior.

Por lo tanto tenemos: $0{,}2 * 300 = 60$

El disparo mínimo estara en 60 amp.

3.6.3.4.- Bloqueo del Reconectador

los reconectadores poseen la característica de evitar una subsecuente reconexión, despues de haber ocurrido un determinado número de disparo del reconectador.

El número máximo de disparo para bloqueo en en la mayoria de los reconectadores en el mercado; en cuatro (4). El bloqueo depende de las características de la carga y la coordinación con los demás equipos de protección.

los reconectadores escogidos en este estudio, estan ajustados en 3 operaciones para el bloque, para fase y tierra y una sola operación para el bloqueo para ajuste por alta intensidad de corriente y falla sensitivas a tierra.

3.6.3.5.- Número de Operaciones Rapidas y Retardadas del Reconectadores.

La operación rápida elimina la gran mayoria de las fallas transitorias, estadísticamente se ha demostrado, elimina el 95% de las fallas transitorias, proporcionando así coordinación con los fusibles instalados en serie y evitando que el fusible tenga que operar innecesariamente garantizando la continuidad del servicio en el trecho ajustes más sencibles; con un número de operaciones hasta bloqueo ajustable individualmente.

Este ajuste se muestra en la Ec. 3.8

$$SEF \leq (0,1 \text{ a } 0,3)\ Icarga_{max}$$

Este ajuste será bloqueado debido a que, al tomar una impendancia de falla de 30 Ω los valores de corrientes son muy elevados inclusive mayor que el ajuste de disparo mínimo 240 Amp (Ver Anexo E).

Este ajuste será desactivado porque no se justifica su activación, ya que con una alta impedancia de falla, el programa de cálculo de flujo de carga y niveles de cortocircuito arroja valores de corriente muy altos.

3.6.3.7.- Ajustes por Alta Intensidad del Reconectador.

Este ajuste se realiza para protección del equipo en si, los elementos que conforman al sistema aguas abajo del reconectador.

Este valor de ajuste es el de nivel de corto circuito trifásico (3Ø) en el punto donde se instala el reconectador, en este caso es:

Icc(3Ø) = 2,71 KAmp. y de fase a tierra Icc(2ØT) = 2,393 KAmp.

En virtud que el equipo está diseñado para un nivel de cortocircuito de 12 KAmp; se hace el ajuste antes mencionado debido que al ocurrir un cortocircuito cerca del reconectador podría ocasionarle daños como dañar los bushin o que la línea pueda caer sobre el reconectador y causar daños a las partes externas del equipo. Los múltiplos del mínimo disparo para fase y para fase a tierra son:

$$\text{Fase} = \frac{2710}{240} = 11.3$$

$$\text{Fase-tierra} = \frac{2393}{60} = 40$$

Como se puede ver los ajustes por alta intensidad para la fase es: 11,3 pero este valor no se encuentra en la característica por alta intensidad por lo que se toma 12 como múltiplo de mínimo disparo por fase, para el ajuste por alta intensidad para fase tierra se toam 20 como múltiplo del mínimo disparo por tierra. (Ver Anexo J).

3.6.3.8.- Ajuste de los Tiempos Muertos del Reconectador.

Es el tiempo comprendido entre una operación de apertura y la subsecuente operación de cierre del reconectador también llamado intervalo de reconexión, se define en función de la coordinación de los demás equipos de reconexión y las características de la carga.

Consumidor residencial generalmente los tiempos muertos no son incovenientes grave para este tipo de consumidor porque el beneficio de tener reconexión es mucho mayor.

Consumidor industrial este requiere especial atención principalmente en las vias de trafico pesado, más de diez (10) segundos es considerado peligroso e intervalos entre uno (1), y dos), segundos son considerados sastifactorios.

Los tiempos muertos	Fase:	2 Sg -20 Sg
	Neutro:	2 sg -20 Sg

3.6.3.9.- Ajuste del Tiempo de Alerta (Rearme) del Reconectador.

Es el tiempo requerido para que el reconectador retorne a su secuencia inicial de operación.

Cuando es ajustable, se debe conocer la filosofía de construcción del reconectador en lo que se refiere al inicio del conteo de la unidad de rearme.

En lo reconectadores hidráulicos el tiempo de rearme no es seleccionable, depende del tiempo del mecanismo hidráulico que varía aleatoriamente alrededor de los 90 segundos por cada operación.

En los reconectadores con control electrónico el conteo de tiempo de esta unidad parte con el comienzo de la operación del primer disparo.

De esta forma el tiempo de rearme está dado por la siguiente ecuación:

$$\boxed{T_{REARME} \geq 1{,}1 * (\Sigma \text{tiempo máximo de disparo}) + 1{,}5\ (\Sigma \text{intérvalos de reconexión})}$$

En el caso de los reconectadores que tienen eleval C.A., reconectadores microprocesadores PMR, el conteo de tiempo de iniciar a partir de la primera operación exitosa del reconectador o sea, despues del primer recierre, de esta forma el tiempo de alerta está dado por la siguiente ecuación.

Ec. 3.10

$T_{REARME} \geq$ (máximo tiempo de disparo después del primer recierre + el máximo tiempo muerto después del primer recierre).

T_{REARME} = 6.8 seg + 20 seg. = 26.8 no se dispone de este tiempo se toma el inmediato superior T_{REARME} = 30 seg.

3.6.3.10.- Ajuste para la conexión de carga en frio

Cuando se realiza el disparo de un dispositivo de protección generalmente se retira el servicio una cierta cantidad de carga que luego se pone en servicio al cerrar el dispositivo de protección nuevamente. Este reestablecimiento de servicio involucra grandes corrientes iniciales especialmente en las cargas por enfriamiento han llegado a temperatura o estado frio.

En los circuitos de distribución típicos como es el caso de los circuitos de ELEVAL, C.A.

El valor de la corriente de conexión de carga en frio en los circuitos de ELEVAL, esta cubre 3 y 6 veces la corriente nominal en el caso del circuito San Blas, el valor de la corriente de conexión de carga en frio es 6 veces la corriente nominal.

Esta corriente es: 6 * 157 Amp. = 942 Amp.

3.6.3.11.- Relación del Transformador de Corriente (CT) del Reconectador.

El C.T. es uno de los principales componentes en un reconectador, pues es el que alimenta el circuito de inteligencia.

La relación adecuada depende de la máxima corriente de carga y de la corriente máxima de cortocircuito en el punto de instalación del reconectador la cual se muestra en la Ec. 3.10

$$\boxed{Icarga_{max} * K \leq IP < \frac{Icc\ Max}{Fs}}$$

$$157 * 1{,}5 \leq Ip < \frac{2710}{15}$$

$$235{,}5 \leq Ip < 181 \text{ Amp.}$$

El Tc elegido es de 300:1 que es una de las relaciones de los transformadores de intensidad (Ver anexo J).

Ip = Corriente primaria del CT.

Fs = Factor de sobrecorriente

K = 1,5

Tc = 300/1

Fs = 15

Los transformadores de corriente que tienen los reconectadores de ELEVAL C.A. son 5.P. 64 esto quiere decir que tiene un cinco 5% de error cuando circular por ellos 64 veces la corriente nominal.

3.6.4.- COORDINACION RECONECTADOR FUSIBLE DEL TRANSFORMADOR DE DISTRIBUCION (T X)

3.6.4.1.- Caracteristicas Tiempo - Corriente de Fase de los Reconectadores

Esta define el tiempo de apertura del reconectador en función de la intensidad de la corriente de corto circuito, y de la corriente de disparo de fase.

Se sabe que los reconectadores PMR que tiene ELEVAL C.A. tienen una familia de cuarenta 40 curvas (Ver Anexo J).

Las curvas son escogidas en función de los criterios de coordinación y selectividad a través del coordenograma y los estudios de coordinación de los equipos de protección instalados aguas abajo y aguas arriba del reconectador; para justificar la elección de las respectivas curvas, se ilustra y se explica a través de un ejemplo para fallas en diferentes puntos.

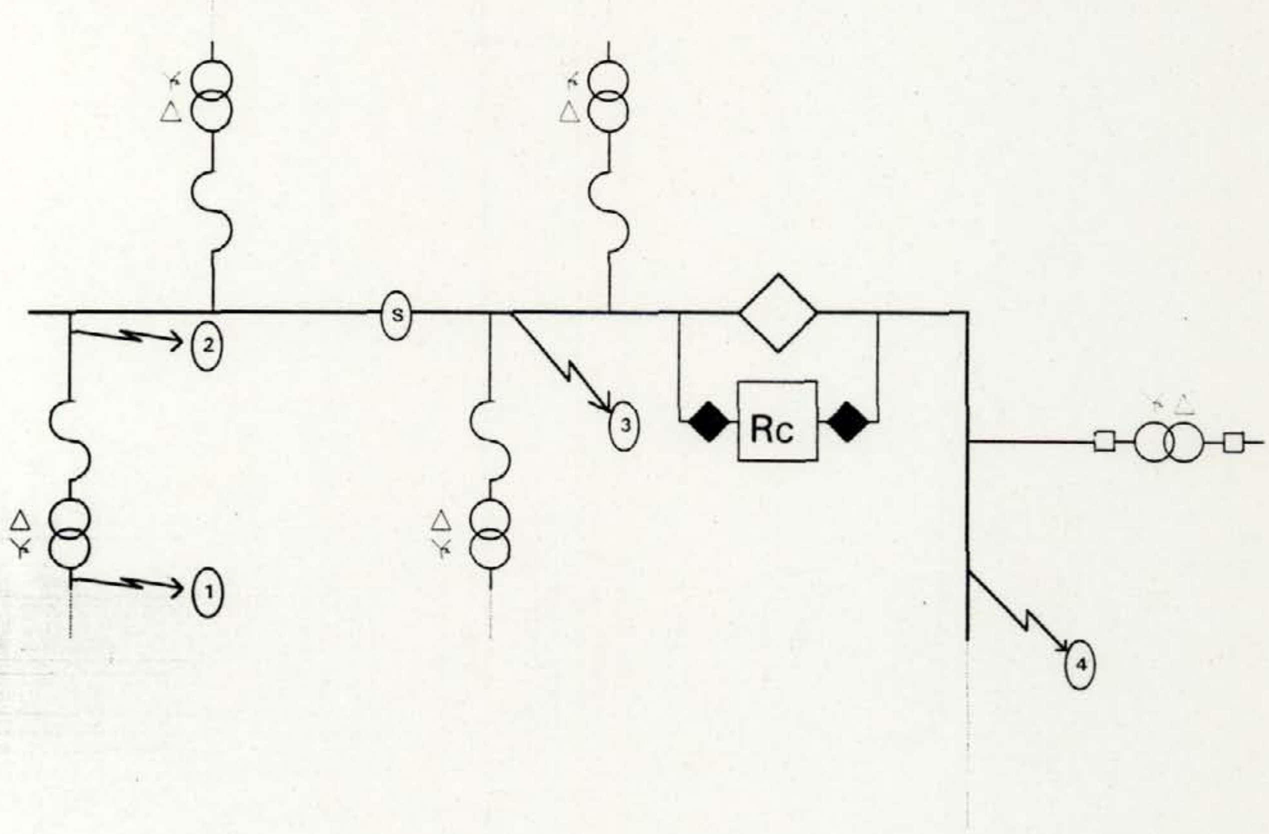


Fig 3.7. Diagrama unifilar con diferentes puntos de Fallas.

Para una falla en el punto (1) como se define en la figura 3.7, debe fundirse los fusibles del primario del transformador, sin que el reconectador opere, para fallas en el punto (2), el análisis dependerá de si es una falla temporal o permanente. Si son fallas temporales, el reconectador operará y despejará el 95% de dichas fallas en la primera operación, si no es despejada en esta operación, entonces lo hará en la segunda operación. El reconectador abrirá de nuevo sus contactos (segunda operación), y en ese lapso operará el seccionalizador aislado la parte fallada del ramal. Luego el recierre del reconectador es exitoso para una falla en (3) siendo fugas, el reconectador despejará la misma, en la primera o segunda operación, pero para fallas permanentes el trocal será aislado en la tercera operación del mismo, y como respaldo a este se encuentra aguas arriba el relé en la salida de la s/e, por tal razón la curva de despege del relé debe estar por encima de las curvas del reconectador para falla en (4), debe actuar el interruptor de la s/e.

3.6.4.2.- Características Tiempo Corriente de Tierra.

Esta característica define el tiempo de apertura del reconectador en función de la intensidad de corrientes de falla a tierra ($I_{2\varnothing T}$, $I_{1\varnothing T}$) y de la corriente de disparo de tierra. La elección de la curva se define en función de los criterios de coordinación y selectividad a través del coordenograma y de los estudios de coordinación, con los equipos de protección instalados aguas arriba y aguas abajo del reconectador.

El resto de las consideraciones son similares a la característica tiempo-corriente de fase.

3.6.5.- SELECCION DEL TIPO DE RELE.

La alternativa de escoger un relé está descartada debido a que ELEVAL, C.A., ya los tiene instalados en la S/E las características de estos reles son las siguinetes: (Ver Anexo K)

- Relé General Electric.
- Tipo IFC77B
- Relé monofásico de sobrecorriente, con arranque retardado y/o instantáneo.
- Relé sobrecorriente de tierra, con arranque instantáneo y/o retardado
- Características del tiempo extremadamente inversa para los relés de fase y para los relés de tierra.

3.6.5.1.- Ajuste de la Corriente de Arranque de Fase de los Relés.

Estos relés instalados en la S/E serán ajustados de la siguiente manera:

$Is = I_{carga} * 1,4 = 300$ Amp $* 1,4 = 420$ Amp. primaria

La relación de los transformadores de corrientes usados para protección 600/5 Amp.

Is = 3,5 Amp. secundario

TAP = 4 Amp   Is = 480 Amp. primario

Por razones de coordinación se toma el TAP: 5

3.6.5.2.- Ajuste de la Corriente de Arranque de Tierra de Relé.

Este ajuste se toma para un desequilibrio de 10 a 30 por ciento de la corriente de carga máxima.

Is = (0,1 a 0,3) $Icarga_{max}$

Luego se colocan las corrientes asumiendo el 20% de desbalance.

Is = 0,2 * 300 = 60 Amp. primario

Is = 0,5 Amp. secundario

TAP = 0,5 Amp Is = 60 Amp primario

Por razones de coordinación se toma el TAP: 1,2

Por tanto la $I_{arranque}$ = 600/5 * 1,2 Amp. = 144 Amp.

3.6.5.3.- Ajuste de la Unidad Instantánea del Relé de Fase y de Neutro.

Se ajustará el nivel de disparo de manera tal que no sea sensible a cortocircuito localizados aguas abajo del subsiguiente equipo de protección suplementario (reconectador) generalmente se protege el 80% de la distancia comprendida entre el relé y el equipo de protección suplementario. La unidad instantánea del relé de fase no deberá ser sensible a las corrientes de energización del circuito.

$Ins \geq (3 \text{ a } 6)\ Icarga_{max}$

Este problema se minimiza con el arranque temporizado de las cargas. Cuando se hace un ajuste, éste debe hacerse para el reconectador más cercano a la S/E.

Esto se debe a la imposibilidad de fijar a los equidistantes de la S/E. Esta idea trae como consecuencia que cierta zona aguas arriba de los reconectadores más lejanos, queda desprotegido en lo que a protección instantánea se refiere.

RECONECTADOR	DISTANCIA A LA BARRA (MTS)	Icc [Amp.] Ø-Ø Ø-T
A	3920 Nodo 210	2929 1740

Para el relé instantáneo de fase se toma como ajuste, se asume 6 veces $I_{carga_{max}}$

$Is \geq 6\ I_{carga_{max}}$ [A] primario

$Is \geq 6 * 300$ [A]

$Is \geq 1800$ [A] primario

Pero la otra limitante es la corriente de cortocircuito en los alrededores del reconectador el ajuste debe ser mayor o igual a dicha corriente.

$Icc2\varnothing = 2929$ [A]

Is = 2929 [A] primario

Is = 24,4 [A] secundario

Por lo que el ajuste será:

Ajuste unidad instantánea (Amp)	**Posición**	**Rango en Amp.**
(6-150)	L	6-30

Para el relé instantáneo de tierra

$Icc_{\varnothing T} = 2700$ [A]

Is = 2700 [A] primario

Is = 22,5 [A] secundario

Ajuste unidad instantánea (Amp)	**Posición**	**Rango en Amp.**
(2-50)	H	10-50

3.6.6.- SELECCION DEL SECCIONALIZADOR.

Se escogen a los seccionalizadores de tipo de control electrónico, debido a que van a ser instalados despues del reconectador los puntos escogidos se encuentran a ambos lados del nodo 221 (Ver figura Página 82).

De acuerdo a los resultados dados mediante mediciones hechas en horas pico, las corrientes máximas de carga son 86 Amp. y 65 Amp. y los valores de corriente de falla son:

	Icc3Ø	Icc2Ø	Icc2ØT	Icc1ØT
Nodo 225	3,27 Kamp	2,11 Kamp	2,15 Kamp	1,27 Kamp
Nodo 234	2,33 Kamp	2,02 Kamp	2,06 Kamp	1,22 Kamp

Por criterio, la máxima corriente actuante del seccionalizador es de 80% de la corriente de disparo del reconectador, es decir:

$$I_{DIS\ RR} = 240 \text{ Amp} \Rightarrow IA \leq 0,8 * 240 = 192 \text{ Amp}$$

las corrientes actuante de este seccionalizador son: 8, 16, 24, 40, 56, 80, 112, 160, 224, 225, 296, 320 Amperios se elige una corriente actuante de 160 amp.

Ahora se calcula la relación entre la capacidad mínima actuante de ambos seccionalizadores y la máxima corriente de carga que debe estar entre 5 y 10

$$5 < \frac{I_A}{I_{CMAX}} < 10$$

$$\frac{Ia}{Icmax} = \frac{129}{65} = 2.9$$

Es de notar que la relación Ia/Icmak es menor que cinco (5), por lo que la sobrecorriente transitoria tiene todas las posibilidades de exceder la mínima corriente actuante del seccionalizador y su operación sera inesperada.

Por lo tanto hay que ajustar los seccionalizadores GN3E (Ver Anexo L) para estas sobrecorriente transitoria cuando se produce la conexion de carga, este ajuste es:

- CORRIENTE $4*I_A = 4 * 160 = 640$ Amp.
- CICLOS 10 CICLOS DE DURACION.

Para el neutro :

$I_{RCDIS} = 60$ Amp.

$I_A = 0,8 * 60 = 48$

Las corrientes actuantes de neutro disponible para el seccionalizador elegido son : 3.5, 7, 16, 28, 40, 56, 80, 112, 160, 224, y 320 amperios. Se elige una corriente actuante de 56 [A]

3.6.6.- CONTEO PARA LA APERTURA DEL SECCIONALIZADOR.

Para el ajuste del número de conteo, existen unos taps. para la selección adecuada y con las siguientes características:

- Tipo: GN3E
- Tensión nominal : 14,4 [Kv]
- Corriente nominal : 200 [A]
- Maxima capacidad de interrupción : 440 [A]
- I_A fase 160 Amp.
- I_A neutro 56 Amp.
- Número de conteos 2.

3.6.7.- AJUSTES FINALES DEL RECONECTADOR Y RELE Y SUS CURVAS DE COORDINACIÓN

Rele IFC77B Fase Tap 5 RT 600: 5 dial # 2

Rele IFC77B Neutro Tap 1,2 RT 600: 5 dial # 9

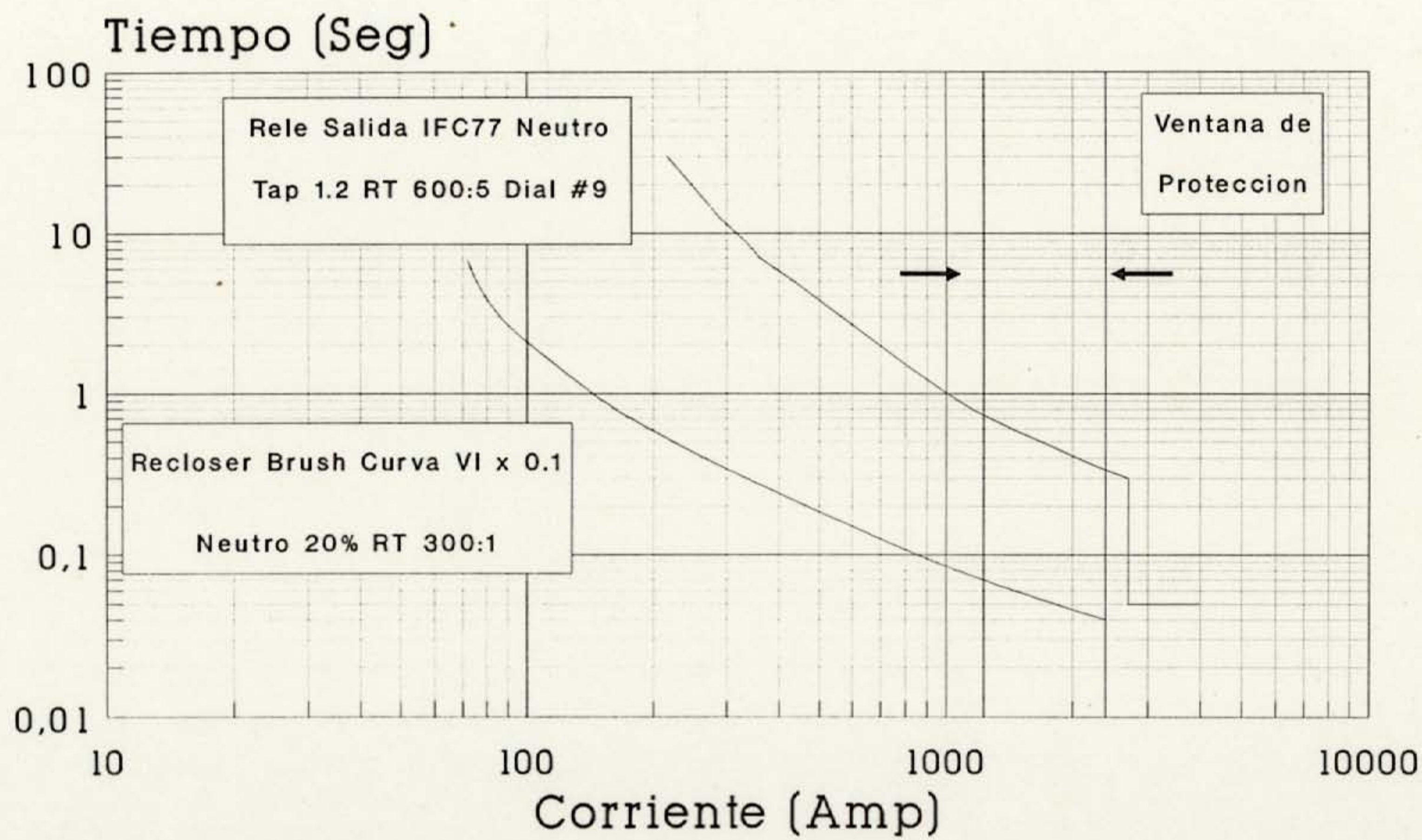
Reconectador Brush Curva VI*0.1 Fase 80% RT 300 : I

Reconectador Brush Curva VI*0.1 neutro 20% RT 300 : I

0.1 = Factor multiplicador (Ver Anexo J)

Para la coordinación de los fusibles de los TX- Reconectador se toma como referencia el fusible de mayor capacidad, ya que este representa la situacción más crítica en lo que a tiempo de operación se refiere.

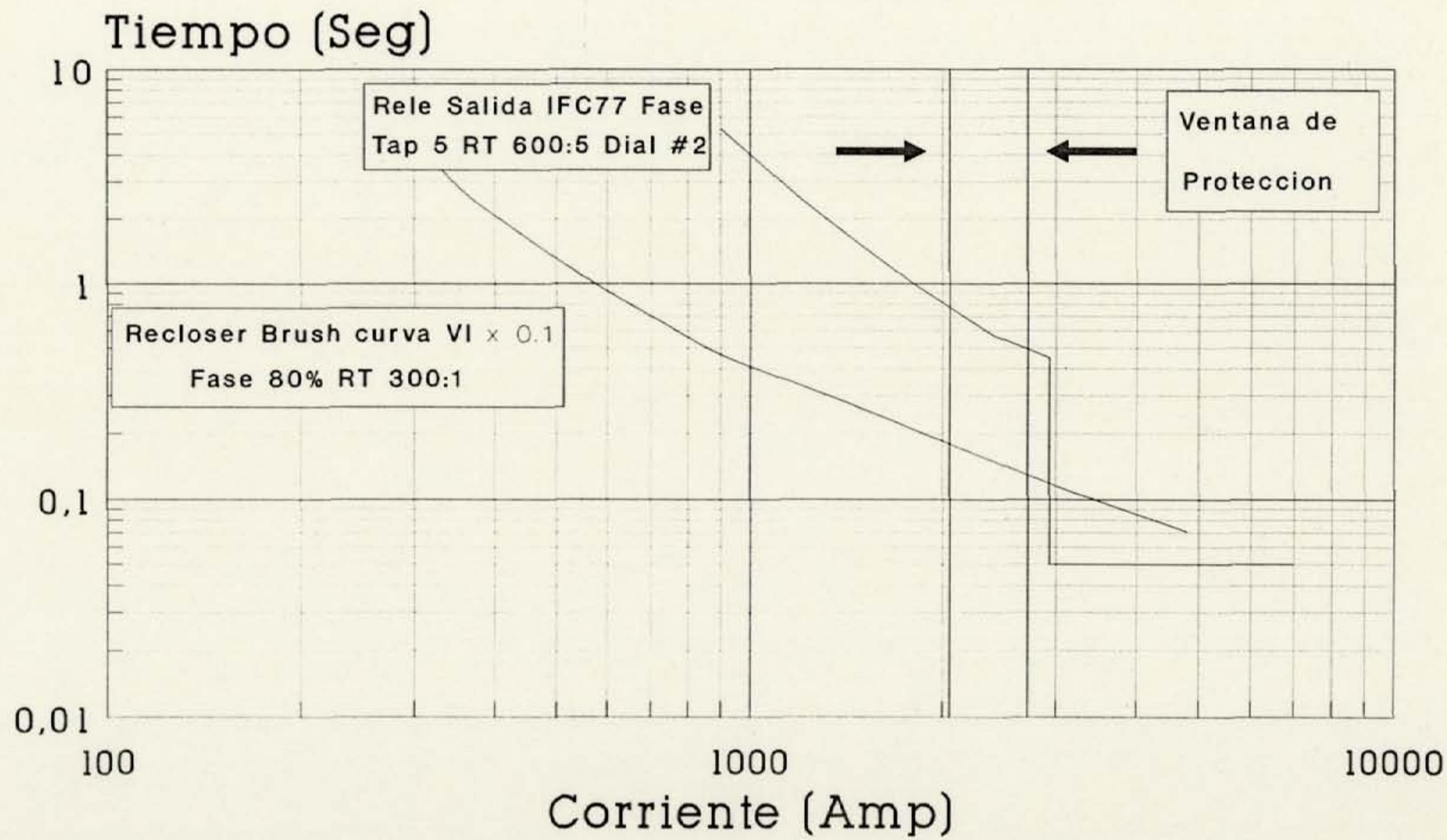
Coordenograma de Neutro
Salida San Blas
IFC77, Reconectador Brush



Coordenograma de Fase

Salida San Blas

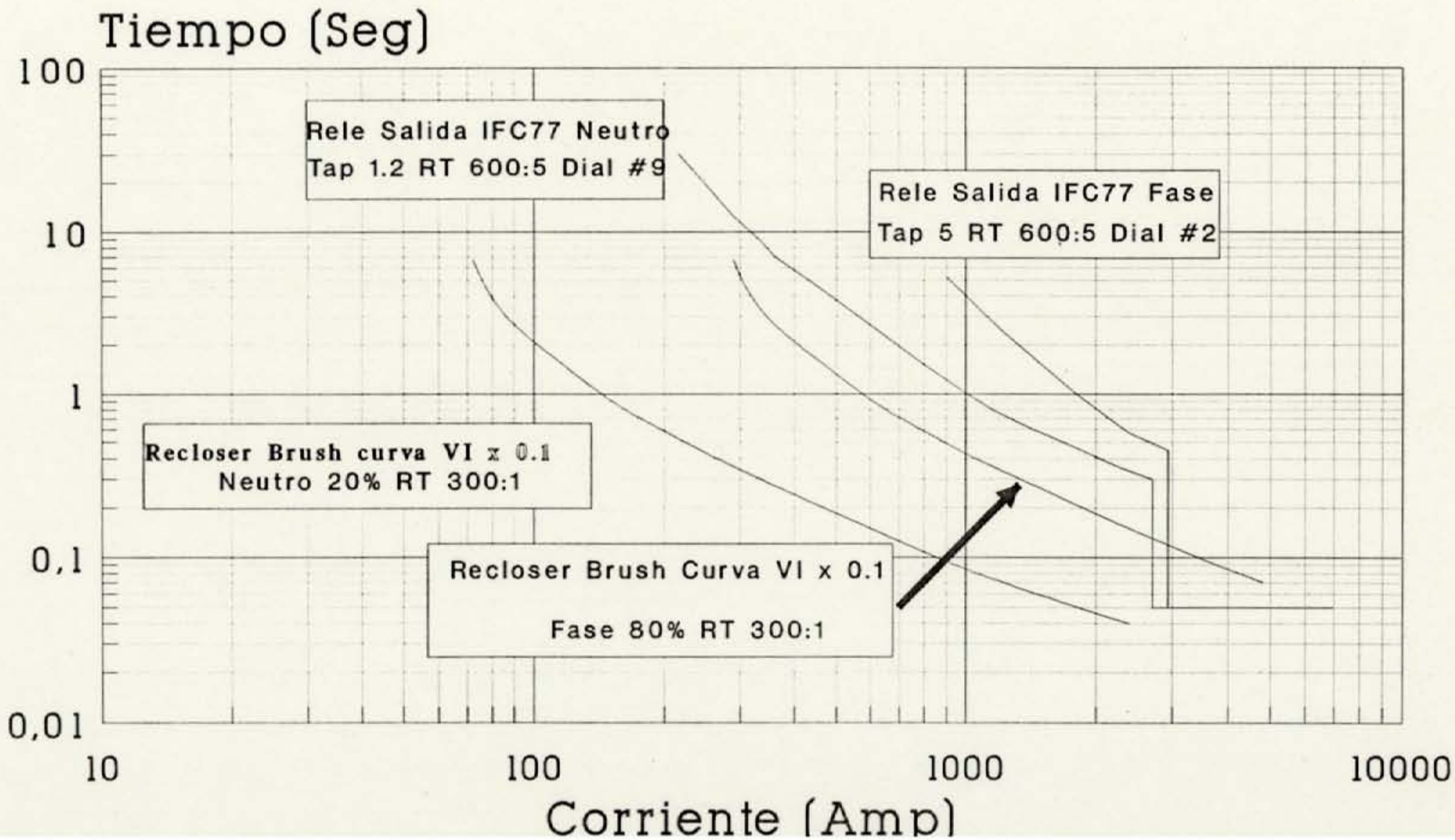
IFC77, Reconectador Brush



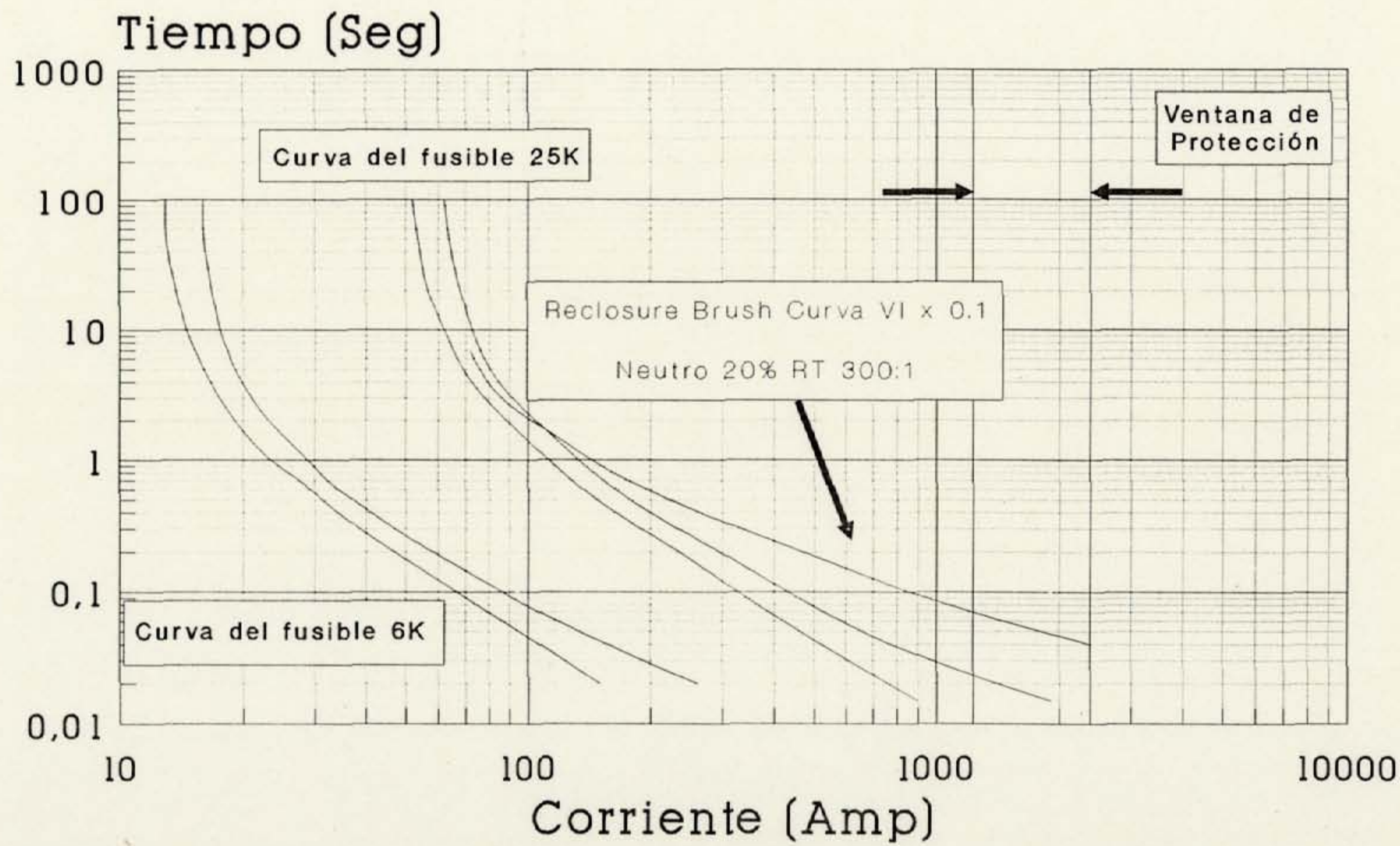
Coordenograma de Fase, Neutro

Salida San Blas

IFC77, Reconectador Brush



Coordenograma del fusible de 25 K de los tx 3*167.5 (KVA) y el Reconectador Brush



CAPITULO IV

CAPITULO IV

SISTEMA DE CONTROL Y SUPERVISION

4.1.- REQUERIMIENTOS DEL SCADA PARA OPTIMIZAR EL FUNCIONAMIENTO DE LOS SISTEMAS DE PROTECCION SUPLEMENTARIA.

A medida que los sistemas electricos crecen, el número de puntos de supervisión y control se hace númeroso. Esto trae como consecuencia cierto descontrol a la hora de supervisar los circuitos.

Como se puede observar esto no sería muy complicado si el sistema contara con pocas S/E, pero cuando se habla de decenas de ellas, la situación se hace complicada.

Es por ello que es importante adaptar al sistema eléctrico de Eleval C.A., un sistema de control (SCADA), que permita supervisar y controlar a distancia instalaciones de cualquier tipo, así como tambien los parametro físicos (tales como: corriente, voltaje, potencia y otros), en puntos estratejicos a supervisar.

4.2.- DEFINICION DE SCADA

La expresión SCADA es la abreviación por sus siglas en ingles (supervisor, control an data aquisition). Es un sistema de control y adquisición de datos, el cual permite supervisar y controlar a distancia instalaciones de cualquier tipo. Cuando se habla de supervisión en sistemas electricos, se hace referencia a medidas de parámetros físicos (tales: corriente, tensión, potencia y otros).

El SCADA solo tiene acceso a esta información y en algunos casos puede deducirse algún otro parámetro que se pueda calcular a partir de las medidas realizadas. De igual manera, sólo tiene la posibilidad de gobernar los interuptores que estén bajo su control.

El propósito de un sistema de supervisión y control es adquirir y procesar información en "tiempo real", es decir procesar data que refleje en información los fenomenos y sucesos que se producen sobre las variables supervisadas, en el mismo momento en que ocurren.

Ademas de acciones de telecontrol o telemando sobre dispositivos que modifican las variables de estado de un sistema. (en este caso eléctrico de potencia).

El hecho de poder realizar controles a distancia, es muy importante en instalaciones que cobran áreas extensas, tal es el caso de : lineas de trasmisión eléctrica oleoductos y otros. El principio fundamental se basa en concentrar en una sala de control, todas las informaciones provenientes del campo y toda la generación de control sobre el mismo. Evidentemente, deben existir medios de recolección de información y generación de control en el campo y ésta es la tarea de las estaciones remotas. Por otro lado se deben tener sistemas de comunicación, para el envio de mensajes entre la estación central y el campo.

4.3.- ESQUEMA BASICO DE UN SISTEMA SCADA DENTRO DE LA EMPRESA ELECTRICA.

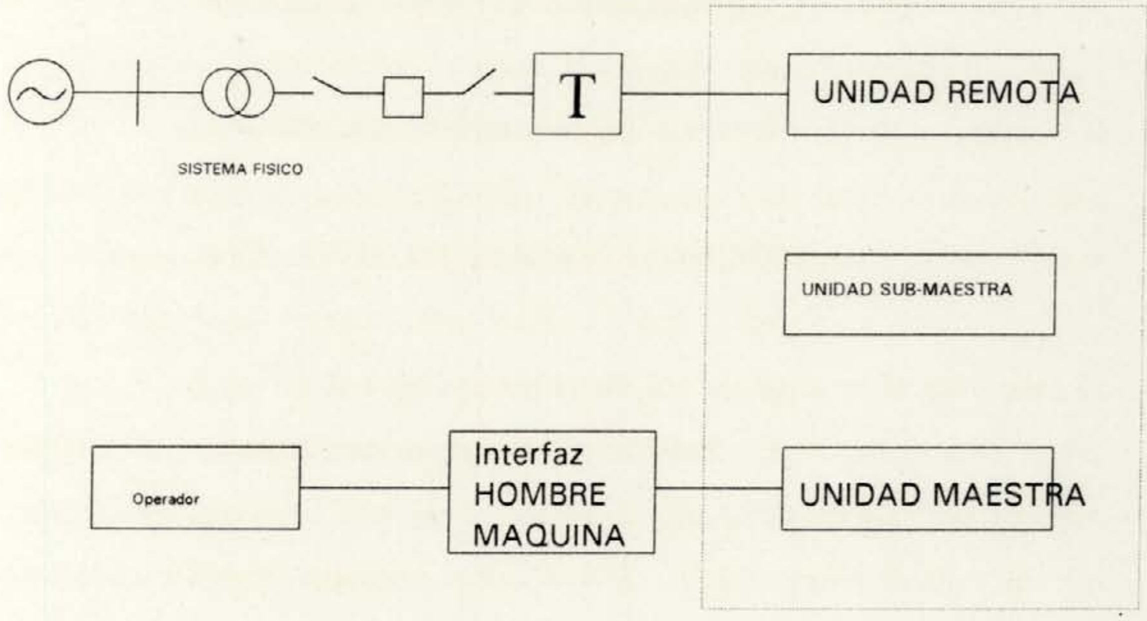


FIG. 4.1

4.3.1.- SISTEMA FISICO

Es el sistema que para nuestro caso será supervisado por SCADA. Este sistema se conforma por los dos circuitos a estudiar dentro de ELEVAL.

4.3.2.- TRADUCTOR

Este elemento se encarga de convertir un fenomeno físico en una señal electrica equivalente y manejable por las unidades remotas de procesamiento. Estas pueden ser:

- Corriente, Tensión, Potencia, Energia, Frecuencia, etc.
- Temperatura, Tensión, Humedad, Flujo, Velocidad, Aceleración, Torque, Angulos, etc.

4.3.3.- UNIDAD TERMINAL REMOTA

Esta unidad se conforma de los equipos utilizados para la adquisición y control directo de la información.

Estos equipos procesan la señal proveniente de los transductores y la envian a la unidad maestra o sub-maestra a través del sistema de la comunicación.

4.3.4.-SISTEMA DE COMUNICACION

Este sistema de comunicación está compuesto principalmente por 4 elementos:

- El Mensaje : Conjunto de datos a trasmitir.
  (Data, Variables, Voltios, Presión, KW)

- El Trasmisor : fuente de la señal (modulador)
  (Moden, Trasmisor Optico, Generador de Microonda).

- El Receptor : Destino de la señal (demodulador)
  (Receptor, Optico de Microonda)

- El Medio : Canal físico de transmición.
  (Cable de cobre, fibra óptica, el espacio libre)

4.3.5.- UNIDAD MAESTRA:

Constituye el centro de procesamiento principal.

Está conformado por un conjunto de computadores que son capaces de realizar múltiples procesamientos. Reciben la información, la procesan e interactúan con la interfaz hombre-máquina.

Algunas ejercen acciones de control respondiendo a secuencias establecidas por medio de un programa (software). Se encuentran ubicados en un centro de control.

4.3.6.- UNIDAD SUB-MAESTRA:

Esta unidad posee las mismas características que la unidad maestra pero con una menor capacidad de procesamiento de información y en la mayoría de los casos, monitorean a un conjunto de unidades remotas. (Estas unidades se utilizan para disminuir la dependencia de la variable supervisada del centro de control).

También se encarga de distribuir los procesos y aumentar la efectividad del proceso del sistema.

Es una herramienta típica en sistemas de control muy complejas donde es necesaria la distribución de los procesos.

4.3.7.- INTERFAZ HOMBRE-MAQUINA:

Es el punto de comunicación entre el operador y la máquina a través del cual se visualiza el estado del sistema, asi como también realiza acciones que modifiquen el comportamiento de este.

Está constituido por cónsolas de control (teclado), tableros de control óptico (Mímico), pantalla, impresoras.

4.3.8.- CENTRO DE CONTROL

El centro de control esta constituido además del control maestro, por otros dispositivos como por ejemplo:

- Computador Maestro
- Diversas impresoras a las cuales se envían determinado tipos de mensaje.
- Teletipos remotos ubicados en diversas dependencias, a las cuales se envían mensajes clasificados.
- Mímico en el cual se visualizan las partes más importantes del sistema.
- Cónsolas gráficas para operadores desde las cuales se solicita información y se originan comandos.

4.3.9.- OPERADOR.

Las fallas o anormalidades que ocurren en el sistema son reportadas al operador de la siguiente manera:

- Mensaje de advertencia por impresora y cónsola

- Mensaje de alarma visual y/o sonora.

Mediante cónsolas gráficas (entrada de las funciones a ejecutar al tocar físicamente la pantalla de la misma) el operador puede interactuar con el sistema para:

- Solicitar información de campo

- Sacar reportes del sistema por impresoras o teletipos remotos

- Ejercer acción en el campo, sobre el proceso que se supervisa y/o controla mediante comandos enviados a las estaciones remotas.

- Ejecutar programas de aplicación del sistema y otras.

4.4.- APLICACIONES DEL SCADA EN UN SISTEMA ELECTRICO DE POTENCIA.

Recolección periodica, procesamiento y monitoreo del sistema, tales como:

- Corriente, tensión, potencia, frecuencia, energía.

- Velocidad de rotación, temperatura, presión.

- Control remoto de dispositivos de maniobras y protección tales como: interruptores y seccionadores.

- Control de monitoreo de alarmas.

- Obtención de indicaciones del estado de operación de dispositivos de maniobra y protección del sistema eléctrico.

4.5.- SISTEMA DE GESTION DE ENERGIA.

Un sistema de gestión de energía, es un conjunto de paquetes de aplicaciones asociadas a un SCADA diseñado para el control y la supervisión de las redes eléctricas.

En la mayoría de los casos las funciones de un sistema de gestión de energía son:

- Control de la Red:

Mantiene constante la frecuencia en los puntos de intercambios, independientemente de las condiciones actuales de la carga.

- Supervisión de la Red:

Proporciona al operador las condiciones actuales del sistema, asi como los mejores esquemas posibles del sistema.

- Mejoras de la Operación:

Facilita al operador los cálculos que permitan aumentar a rendimiento y explotación del sistema.

- Planificación de Energía:

Métodos estadísticos permiten la programación óptima de las unidades de generación para atender las futuras demendas del sistema.

- Automatización de la Distribución:

Incluye funciones de supervisión de la red para el mapeado geográfico e integra la gestión de carga.

- Simulador de Entrenamiento:

Proporciona entrenamiento del operador a diferentes niveles de autoridad.

4.6.- ESTRUCTURA GENERAL DEL SCADA Y LOS CIRCUITOS DE DISTRIBUCION.

Debido a la necesidad que tiene la Electricidad de Valencia, C.A., de llevar a cabo la supervisión y obtención de la información de la red, ha evaluado la posibilidad de adoptar un sistema de supervisión y adquisición de datos (SCADA), cuya estructura general consta de un centro de control, estaciones remotas, un sistema de medición y protección y un sistema de comunicación entre el centro de control y las estaciones remotas, (Ver Fig. 4.2).

Para la estructuración del SCADA, ELEVAL, C.A., ha evaluado ciertos grupos de equipos con la finalidad de obtener medición, ejercer el control y ser capaz de transmitir y recibir datos que se relacionen con sus funciones.

ESQUEMA GENERAL DEL SCADA DE DISTRIBUCION
(UTILIZANDO RECONECTADORES)

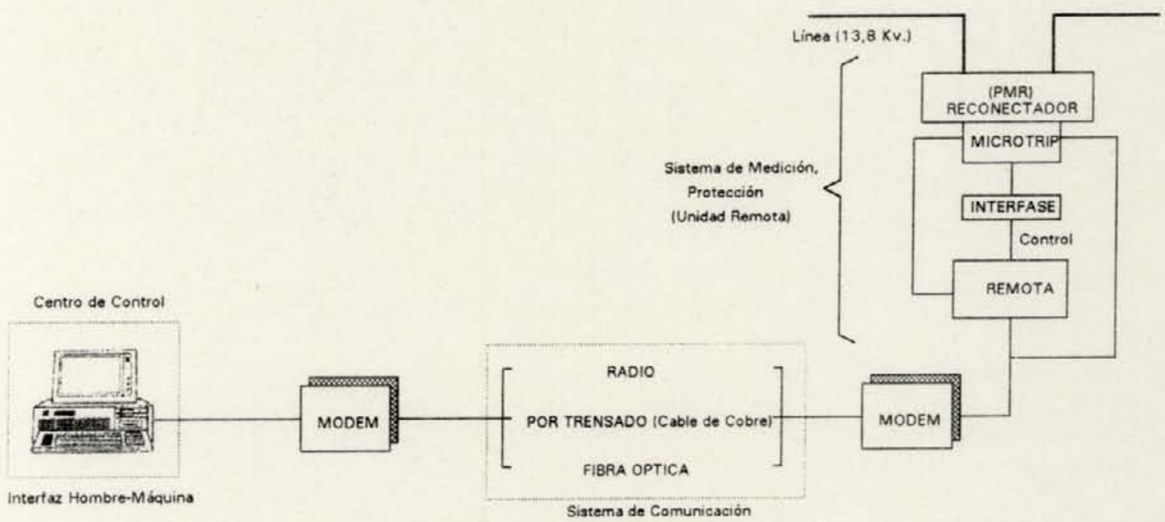


FIG. 4.2

4.6.1.- SISTEMA DE PROTECCION Y MEDICION.

Tal como se muestra en la Figura 4.2, este sistema está conformado por el reconectador.

El Reconectador, como fue descrito anteriormente es escencialmente un disyuntor con las funciones necesarias para detectar sobreintensidades, medir la duración e interrumpir las fallas, y si se selecciona para que lo haga asi, reconectar automáticamente restaurando el suministro a la linea aerea.

En el reconectador automático PMR, la capacidad de detección se obtiene de un modulo de control electrónico (Microtrip), alojado en una caja de control separada resistente a la interperie, la cual va a estar conectada a una remota de control y a un sistema de comunicación, tal como se muestra en la Figura 4.2.

El mismo consta de un panel frontal donde se maneja los diferentes controles e indicadores (Microtrip), los cuales se describen a continuación:

4.6.1.1.- Controles del Disyuntor.

- Cierre.

Una presión sobre el pulsador "close" envía una señal de cierre al disyuntor y activa la protección, si se ha seleccionado la conexión de carga fria como activada y se mantiene pulsada la tecla "close", el relé permitirá solamente un disparo para el bloqueo de acuerdo a las características de conexión de carga fría programada.

La liberación del pulsador "close" devuelve el relé a la secuencia automática/no automática según corresponda.

Si se oprime el pulsador "Trip" se envía una señal de disparo al disyuntos y se desconecta el relé. Si el Microtrip está realizando una secuencia ésta se termina.

4.6.1.2.- Controles de Protección e Indicación de Estado.

- Estado de Control.

Bajo demanda la indicación de estado de los controles siguientes se obtiene oprimiendo el pulsador Control Estatus.

Esta indicación no resulta afectada por la selección de control local o remota.

- Control Local/Remoto.

Cuando se selecciona el control local las funciones del relé y del disyuntor se pueden controlar mediante los pulsadores. La selección de control remoto desactiva los pulsadores y el control se transfiere a la posición remota.

- Control de Reconexión Automática
  Activado / Desactivado.

Cuando se activa el control automático, una condición de falla hará que el Microtrip realice un secuencia programada de reconexión en un máximo de 4 disparos hasta el bloqueo. Cuando se selecciona el control automático como desactivado, el Microtrip realizará un solo disparo para el bloqueo. La característica de disparo no automática se selecciona de forma exclusiva.

- Control de Disparo por Fallas a Tierra
  Activado/Desactivado.

Cuando se selecciona la protección a tierra como activada, el Microtrip responderá a la falla de tierra de acuerdo con la programación. Cuando se seleckiona la protección a tierra comno desactivada, el Microtrip no responderá a las fallas a tierra.

- Control de Fallas Sensibles a Tierra
  Activadas/Desactivadas.

Cuando se selecciona como activada, la protección contra fallas sensibles a tierra (SEF) se activa, pero solamente si también está activada la protección contra fallas a tierra. Cuando se selecciona como desactivada, el Microtrip no responderá a las fallas sensibles a tierra.

- Control Activado/Desactivado de la Protección.

La desactivación de la protección corta la tensión a relé Microtrip e impide que el relé responda a ninguna condición de falla.

- Indicación de Tensión en el Control (Control Power).

Este led indica que el Microtrip está bajo tensión y es independiente del pulsador Control Status.

- Indicación de Fin de Secuencia. (Sequence Lockout)

Este led se ilumina para indicar que el relé ha alcanzado el final de su secuencia programada y que se ha bloqueado dejando abierto el disyuntor. La indicación de bloqueo se inicializa oprimiendo el pulsador "close".

4.6.1.3.- Funcionamiento del Relé Microtrip.

Es una unidad basada en un microprocesador alimentada mediante una pila de litio. Mediante el uso de transformadores de intensidad interpuestos es capaz de vigilar las corrientes de fase, las corrientes de tierra y las corrientes sensibles de tierra. Si cualquiera de éstas supera los valores programados en el Microtrip, éste responde a una secuencia de hasta 4 operaciones de disparo.

Bajo circunstancias normales el relé se encontrará en el modo de baja potencia o de espera vigilando estos niveles de intensidad. Si cualquiera de estos niveles preseleccionados de falla se superan los circuitos internos activa al relé y da comienzo a la secuencia de protección.

A lo largo de la secuencia, el Microtrip consulta la memoria interna para establecer los parámetros de protección y responde de acuerdo con ellos. Estos parámetros introducidos previamente utilizando la pantalla integral o el programador portátil, y grabados dentro del microtrip, determinan el número de disparos en la secuencia, los tiempos de disparos, los intervalos entre reconexiones (tiempos muertos) y el tiempo de alerta, etc.

Una vez iniciado una secuencia se puede terminar de dos maneras distintas:

- Si la falla es permanente. El microtrip ejecutará la secuencia programada de operaciones de disparos y cierre y se desconectará dejando el reconectador en posición abierta. Esta condición se conoce con el nombre de bloqueo y el reconectador tendrá que cerrarse manualmente (local o remotamente) para volver a reestablecer el circuito.

- Si la falla se elimina antes de alcanzar el bloqueo, el reconectador permanecerá cerrado y el Microtrip comenzará la reinicialización, sin embargo si la falla se vuelve a producir antes del final del tiempo de alerta la secuencia de protección continuará hasta el bloqueo. (Ver Anexo J)

4.6.1.4.- Control Remoto.

Los controles remotos solamente están activados cuando se ha seleccionado control remoto desde el panel frontal.

Para hacer que actúe una función del control remoto, es necesario aplicar un impulso de 5 voltios, con una duración entre 50 mseg. y 5 seg. a la entrada adecuada. Los reconectadores se pueden suministrar de tal manera que los 5 voltios se tomen de una pila de litio de 24 voltios interna, utilizando una resistencia limitadora adecuada y que exige el uso de contactos limpios en los circuitos externos.

Las funciones siguientes actúan exactamente de la misma manera que sus controles locales equivalentes.

a) Cierre.	
b) Disparo.	
c) Reconexión automática.	Activada/Desactivada
d) Fallas a tierra.	Activada/Desactivada
e) SEF	Activada/Desactivada
f) Protección	Activada/Desactivada

4.6.2.- UNIDAD REMOTA.

Tal como se muestra en la figura 4.2 el esquema general del SCADA de distribución consta de una unidad remota la cual se encarga de comunicarse con un computador (Centro de Control) a través del canal de comunicación.

La unidad remota debe controlar completamente al reconectador y para ello es necesario que esta unidad disponga de 11 contactos secos y 11 entradas analógicas, las cuales interactuarán con l;a regleta de control del reconectador.

Los contactos auxiliares se conectarán en los puntos de la unidad remota que le permitan registrar en que estado se encuentra el reconectador. Estos contactos auxiliares eventualmente podrían funcionar como posibles señales de alarma.

El computador contiene un programa que se encarga de interpretar las señales provenientes de la unidad remota y las presenta al operador.

4.6.3.- SISTEMA DE COMUNICACION.

En estos momentos la empresa Electricidad de Valencia, C.A., está realizando un estudio para el diseño del sistema de comunicación con el fin de optimizar el desempeño del sistema eléctrico incluyendo principalmente el sistema de protección.

Tal como se muestra en la Fig. 4.2 este sistema representa el canal o vía de comunicación para el intercambio de la misma entre el centro de control (computador) y la unidad remota la cual envía la orden al reconectador.

Los canales o vías de comunicación pueden ser enlace de radios modems, pares telefónicos y/o fibra óptica.

4.6.4.- CENTRO DE CONTROL.

Este se encarga de recibir y manejar los datos que envía la unidad remota a través del sistema de comunicación.

Mediante un computador, el centro de control programa al Microtrip del reconectador para que cumpla funciones específicas dentro del sistema, asi como también se encarga de programar a la unidad remota, para que ejerza control directo sobre el reconectador.

4.7.- POSIBLE ESQUEMA DE CONEXION DEL PMR3 A UN DISPOSITIVO DE CONTROL ELECTRONICO

Después del análisis realizado al sistema de control remoto que presenta el PMR3 (reconectador), es posible lograr la conexión del mismo a un dispositivo electrónico de control (Ver Anexo J), el cual se utilizaría en el SCADA como unidad de control remoto.

En el esquema que se presenta en la Electricidad de Valencia, C.A. se puede observar un módulo de control el cual permite el mayor aprovechamiento de los contactos secos del PMR3 conectados al 3720. Este módulo de control tal como se muestra en la Fig. 4.3. Consta de un conjunto de relés temporizados y/o relés biestables (Latch) los cuales a través de un funcionamiento en conjunto logran conectar un contacto seco del 3720 con dos contactos secos del reconectador PMR3 a fin de utilizar 6 contactos secos del mismo.

El equipo 3720 ACM descrikto en el anexo X es utilizado como unidad remota y su conexión conjuntamente con el módulo de control y la línea se muestra en la figura Fig. 4.4 donde se identifican las disposiciones de las líneas de corriente, de potencial y alimentación, los contactos secos que gobiernan el funcionamiento PMR 3 y las señales de Status del mismo.

Los puntos de conexión de 3720 ACM con el PRM3 se muestra en la fig. 4.5 donde se muestran las referencias hacia donde se dirigen cada una de las funciones del 3720 ACM.

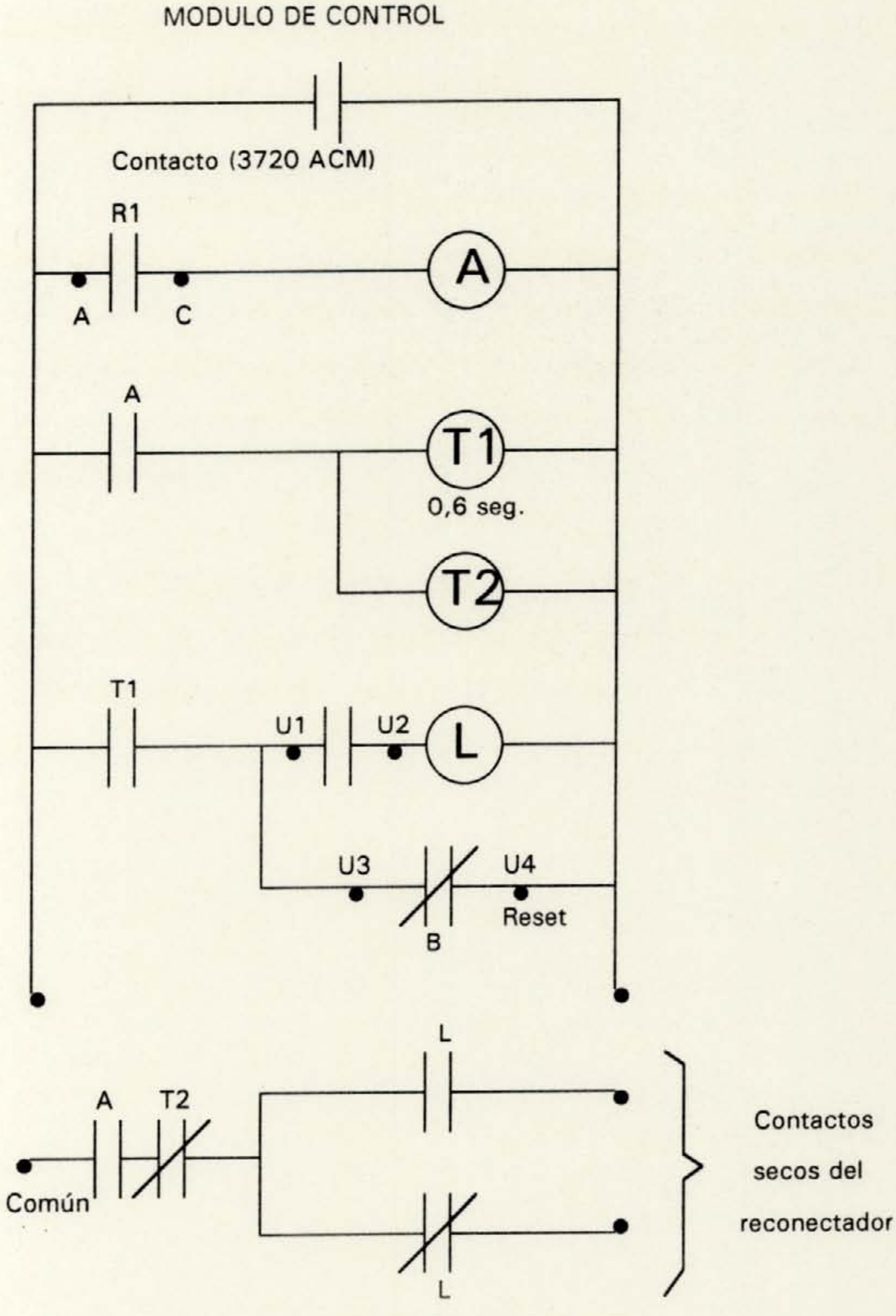

MODULO DE CONTROL
Contacto (3720 ACM)
R1
A
C
A
A
T1
0,6 seg.
T2
T1
U1
U2
L
U3
U4
Reset
B
L
A
T2
Común
L
Contactos
secos del
reconectador

Fig. 4.3

R1 = Contanto seco del equipo 3720 ACM (Pulso en seg.)

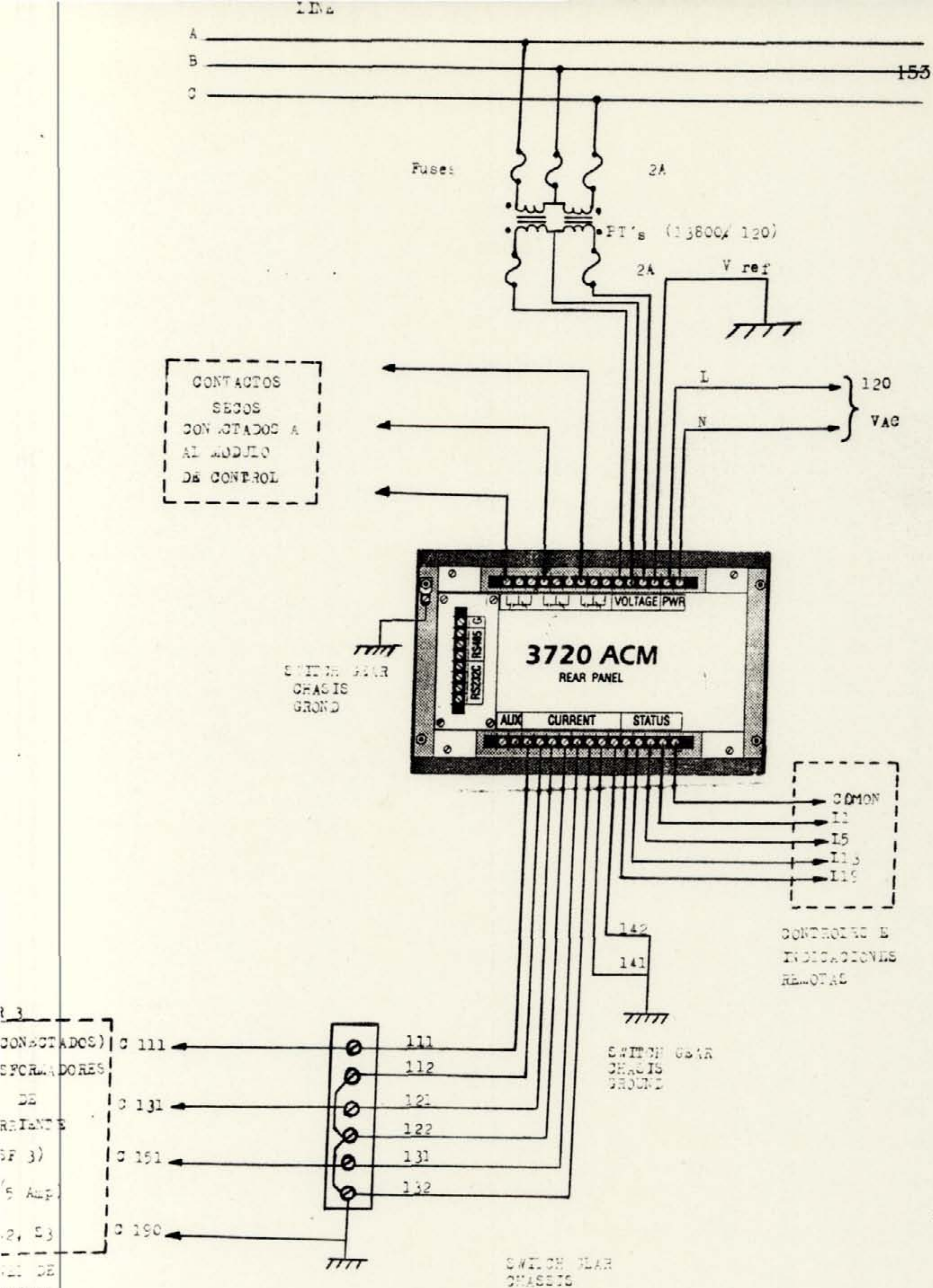
T1 = Relé temporizado al cierre (0 - 1 seg.)

T2 = Relé temporizado al cierre (0 - 1 seg.)

B = Contactos auxiliares del Brush.

L = Relé bi-estable (Latch)

A = Relé Auxiliar.



* DIAGRAMA DE CONEXION DE LAS UNIDADES REMOTA (FIGURA 4.4

DIAGRAMA DEL MICROTRIP (BASICO)

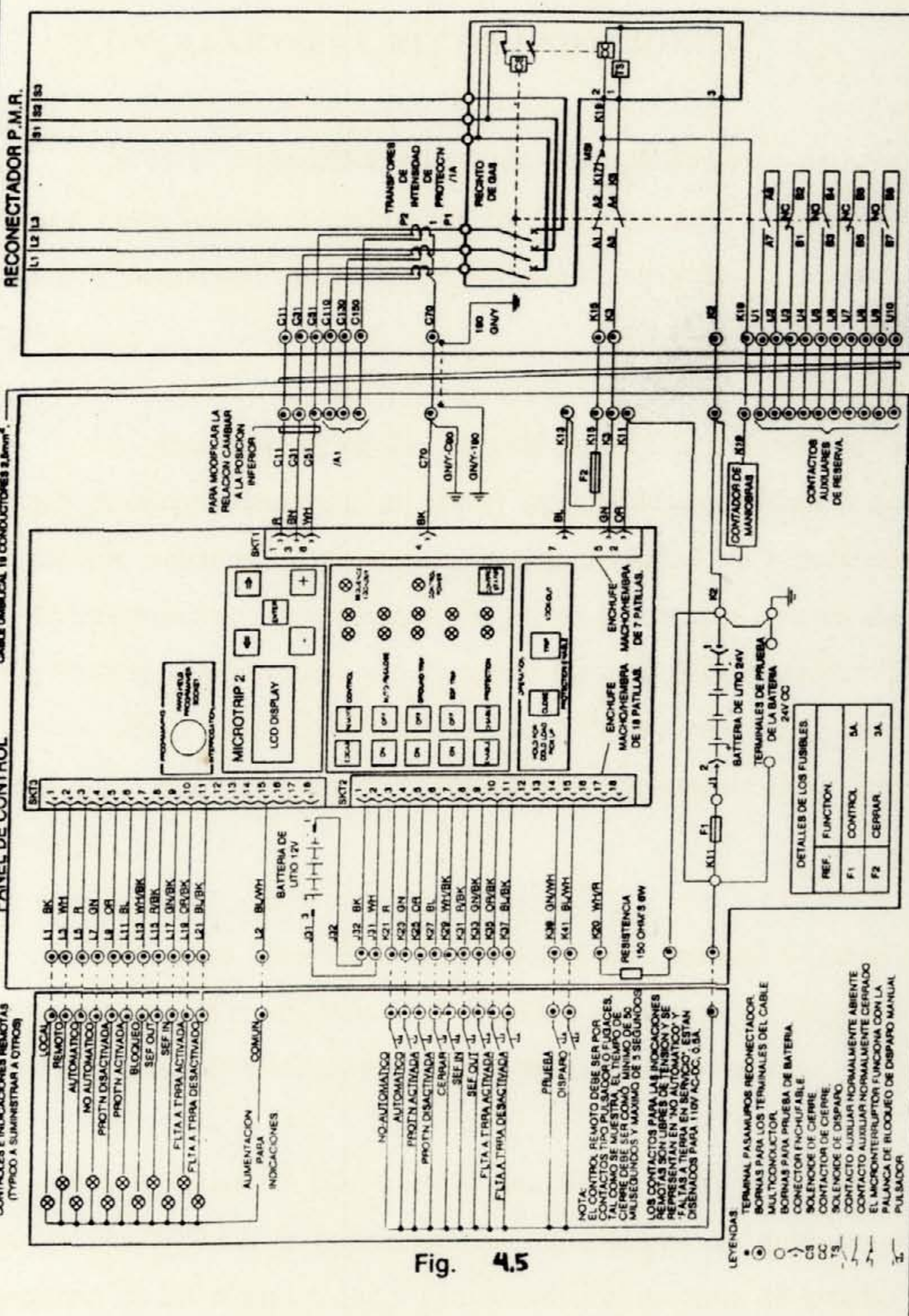


Fig. 4.5

CONCLUSIONES Y RECOMENDACIONES

Las ideas expuestas a lo largo de este trabajo sirven de base para futuros estudios de coordinación de protecciones a nivel de distribuciones, ya que actualmente se les ha dado la importancia necesaria a los mismos.

Los objetivos principales de toda empresa encargada de la distribución de energía deben ser, en primer lugar la de modernizar la de modernizar sus sistemas de protección, con la finalidad de reducir el número de interrupciones permanentes y construir un sistema coordinado que haga mínima la dependecia del elemento humano para mantener la coordinación, sobre todo la confiabilidad del sistema sería mejorada e igualmente, sería más fácil y rápido el reestablecer nuevamente el servicio a los usuarios.

Esto debe hacerse de una manera más técnica y menos empírica como sucede en diversas oportunidades; ya que de ello depende la calidad del servicio prestado y por ende el prestigio de la empresa.

A lo largo de este trabajo, que fijarán las bases para la proyección planificación e instalación de los equipos de protección suplementaria en los circuitos que así lo ameriten en la zona de estudio.

Dichas recomendaciones y conclusiones acá mencionadas se basarón en informaciones obtenidas, calculadas y estudios realizados.

- Se recomienda, para la instalación de un equipo de protección suplementaria en un determinado circuito, se realicen estudios y adaptar estos resultados al sitio de ubicacción del equipo, de acuerdo a los criterios generales sobre la ubicación de estos equipos

- Los equipos de protección deben poseer la capacidad suficiente para interrumpir las corrientes de falla máxima en el sitio de su instalación. De no ser así, reubicar el equipo.

Los reconectadores son herramientas muy valiosas en los esquemas de protección por sobre corriente requeridas para líneas de distribución y subestaciones. Pueden ser instalados en cualquier parte sobre un sistema, sin inversión adicional para equipo auxiliar.

Además son dispositivos sumamente duraderos y confiables, poseen largos ciclos de trabajo y requieren muy poco mantenimiento.

Los procedimientos para aplicarlos y coordinarlos són muy sencillos y poseen la ventaja de que pueden eliminar hasta un aproximado un 95% de corte, en sistemas cerca de distribución, esto significa más clientes satisfechos, mayores ingresos y significativa reducción de los costos de mantenimiento.

Los seccionadores automáticos de línea también traen grandes ventajas y una de la más inportante es la economía. Pueden instalarse para proveer puntos adicionales con el objeto de seccionalizar automáticamente circuitos de distribución.

Su instalación es sencilla, ya que pueden utilizarse sobre partes y operados con un pértiga común y aunque el seccionalizador no interrumpe la corriente de falla, puede interrunpir la corriente de carga normal y por lo tanto puede usarce como interruptor de carga para seccionalización de línea manual.

- Debe tomarse mensualmente, las lecturas de los contadores de operación registradas de los reconectadores con la finalidad de realizar programas de mantenimiento en los equipos y en las redes de distribución.

- Organizar diferentes tipos de charlas, cursos y conferencias sobre los distintos equipos, al personal para que se familiaricen con los mismo.

- Para lograr una protección rápida, segura y selectiva, la selección, ajustes y coordinación de los equipos de protección suplementaria debe ser realizada por un personal altamente calificado y especializado .

- De acuerdo a los estudios realizados ; elegir la secuencia de operación del equipo, más adecuada de acuerdo al caso.

- Forma un archivo, clasificado por S/E y circuito, todas las corrientes de operación de los equips de protección instalados en la zona, así como también enumerar para su total indentificación, las carpetas con los diagramas unifilares actualizado de cada S/E y circuitos; boletines de información, instalación, operación y mantenimiento de los equipos; en fin catalogos en general relacionados con la materia. Mantener el día toda esta información y notificar los cambios realizados.

- A fin de ser más selectivos el sistema de protección para alimentadores, se recomienda aplicar seccionalizadores en aquellos ramales de cierta longitud e importancia para reducir así el número de clientes afectados en caso de una falla permanente en ese ramal.

- En aquellos casos en que se instale un seccionalizador despues de un reconectador, se recomienda que éste sea del tipo eléctronico, para garantizar la coordinación entre este dispositivo de disparo por tierra.

- En la selección y remplazo de los elementos fusibles deben procuparse que sean los indicados en cada caso, este punto es de vital importancia para lograr y mantener una buena coordinación de protecciones. No se recomieda la instalación de fusibles, ramales en aquellos casos que se alimenten cargas trifásicas por los problemas que ocasionarían la operación de una fase en caso de que se funda un solo fusible.

- Para el ajuste de los equipos de protección deben conocerse; entre otras cosas; los niveles de falla, las corrientes de carga normal etc, en los puntos de interés. Estos valores deben obtenerse de una manera precisa.

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GLOSARIO

Aguas abajo: Hacia la carga (sólo en sistemas radiales).

Aguas arriba: Hacia la generación (sólo en sistemas radiales).

Cold Load Píck-up: Corriente de reestablecimiento en frio.

Set point: Valor de fijacíón de una variable.

Software: Programas de aplicación en computadoras.

Modem: Dispositivo que permite la trasmisión de datos (digitales) entre dos (2) puntos o computadores comunmente usado en líneas telefónicas para comunicar computadores.

Traductor: Dispositivos que convierten un tipo de parámetro físico a una señal electrónica manejable por un equipo de medición.

ANEXO A

AUTOMATIC CIRCUIT RECLOSERS: CHARACTERISTICS AND APPLICATION FACTORS

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Abstract

Automatic circuit reclosers are self-contained fault interrupting and reclosing devices, specifically designed for the overcurrent protection of distribution systems. Present-day reclosers have dual timing characteristics which facilitate temporary and permanent fault protection for all areas of the distribution system. The proper application of automatic circuit reclosers depends on system electrical parameters, protection philosophy, and coordination with other protective equipment.

4.1 Introduction

Due to the transient nature of faults on overhead distribution systems, such as could be caused by lightning, switching surges, wind, and animal or tree contact, a large percentage of faults are temporary or nonpersistent as opposed to permanent (persistent). Naturally, the percentage of temporary faults occurring on a particular system varies according to design and local environmental conditions, however, it is generally agreed that 50-90 percent of all faults on overhead systems are temporary or initially so. Early recognition of this fact led to the development of protective devices capable of sensing and interrupting fault current and automatically reclosing a number of times to reenergize the circuit before ultimately opening the circuit permanently.

Historically, the first automatic reclosing device developed was the repeater fuse. It consisted of two or three expulsion fuses mechanically ganged together allowing automatic reclosing when the one in-circuit fuse operated in response to an over-current. The success of that device led to the introduction of the first automatic circuit recloser in 1939. This recloser offered quite an improvement in operation over the repeater fuse in that it was self-resetting (prior to the last operation) and fast enough to prevent some transient faults from turning into permanent faults. However, it was so fast that no coordination with other downline devices (either fuses or reclosers) was possible. Then, in 1944, the recloser, as it is known today, was introduced. This device had "dual" time-current characteristics (fast and delayed) to allow protection against temporary faults yet permit coordination with other downline devices.

Early reclosers were single phase, hydraulically controlled, utilizing interruption in oil. They had low continuous current carrying and interrupting capacities and were generally applied out on lines in place of fuses. Later, three-phase reclosers were developed, which were essentially three, single-phase reclosers placed in a common tank and mechanically ganged together to provide single phase trip, three-phase lockout. Still later, three-phase trip, three-phase lockout reclosers were developed.

The original three-phase reclosers utilized hydraulic control and oil interruption; later versions made use of electronic controls and either oil or vacuum interruption. As time went on, interrupting and continuous current carrying capacities of both single- and three-phase reclosers were greatly increased, allowing their use as feeder sectionalizing devices and, ultimately, in the distribution substation as main feeder protective devices.

Today there is a great number of reclosers produced by various manufacturers in terms of voltage, continuous current, and interrupting current ratings; some with capabilities rivaling those of circuit breakers.

4.2 Types of Reclosers

Reclosers may be classified in a number of ways: (1) by their interrupting medium, (2) by their means of control, or (3) by their number of phases.

4.2.1 Interrupting Media

At the present time, reclosers are designed to interrupt fault currents utilizing either oil or vacuum interrupters. Those reclosers that utilize oil as the interrupting medium also make use of the same oil for insulation against impulse and low-frequency voltages; those that utilize vacuum as the interrupting medium may use either oil or air for insulation against impulse and low-frequency voltages.

As mentioned previously, reclosers first utilized oil interrupters; however, in the early 1960's, reclosers utilizing vacuum interruption, a technology transferred from circuit breakers, were introduced. After an initial acceptance period, their use became well established, due in large part to their demonstrated longer life and reduced maintenance requirements.

4.2.2 Control Systems

Reclosers are controlled, as far as their timing, counting, and reclosing characteristics are concerned, by means of one of two methods: hydraulic control or electronic/relay control. The former control system is associated with series (trip) coil reclosers, the latter system is associated with nonseries coil (shunt trip) reclosers.

Hydraulically controlled reclosers utilize the insulating oil in conjunction with a hydraulic mechanism contained within the device, consisting of various pumps, orifices, and valves, to achieve their time-current trip characteristics, counting, and reclose interval timing functions. A variation of this design occurs in some larger three-phase reclosers where a second and separate hydraulic system is used for the time-current trip characteristics only. A special silicone oil with relatively constant viscosity over normal operating temperature range is used in this second hydraulic system to provide better timing versus temperature characteristics. In all hydraulically controlled reclosers, overcurrents are sensed by a series solenoid coil.

Electronic/relay controlled reclosers, first developed in 1960, utilize a separately mounted electronic control or set of overcurrent and reclosing relays to provide trip timing, counting, and reclose interval timing characteristics. Since these operating characteristics are controlled by nonhydraulic mechanisms located external to the recloser tank, it is generally agreed that these devices are more accurate, repeatable, and flexible than their hydraulic counter parts. All electronic/relay controlled reclosers sense overcurrents by means of internally mounted bushing current transformers.

4.2.3. Number of Phases

Automatic circuit reclosers are designed as single- or three-phase devices. The three-phase types may have either of two modes of operation: (1) single-phase trip, three-phase lockout; (2) three-phase trip, three-phase lockout. The smaller three-phase units employ mode 1, wherein each phase trips independently of the other; when any one phase goes to lockout, the other two are simultaneously locked out. Larger three-phase reclosers employ mode 2, in which all three phases trip simultaneously, regardless of which phase is sensing an overcurrent (similar to the operation of a circuit breaker).

Although it is conceivable that a given recloser may be designed with any combination of interrupting media, insulation, control systems, and phases, the following indicates the seven combinations presently produced:

- single phase with hydraulic control, oil interrupters and oil insulation;
- single phase with hydraulic control, vacuum interrupters, oil insulation;
- three phase with hydraulic control, oil interrupters, oil insulation;
- three phase with hydraulic control, vacuum interrupters, oil insulation;
- three phase with electronic control, oil interrupters, oil insulation;
- three phase with electronic control, vacuum interrupters, oil insulation;
- three phase with electronic control, vacuum interrupters, air insulation.

Typical single-phase hydraulic and three-phase electronic reclosers are shown in Figure 4.1.

4.3 Theory of Operation

An automatic circuit recloser is defined by American National Standard ANSI C37.60-1974 as "a self-controlled device for automatically interrupting and reclosing an alternating-current circuit with a predetermined sequence of opening and reclosing followed by resetting, hold-closed, or lockout." As such, there are two basic types of operation: lockout and hold-closed.

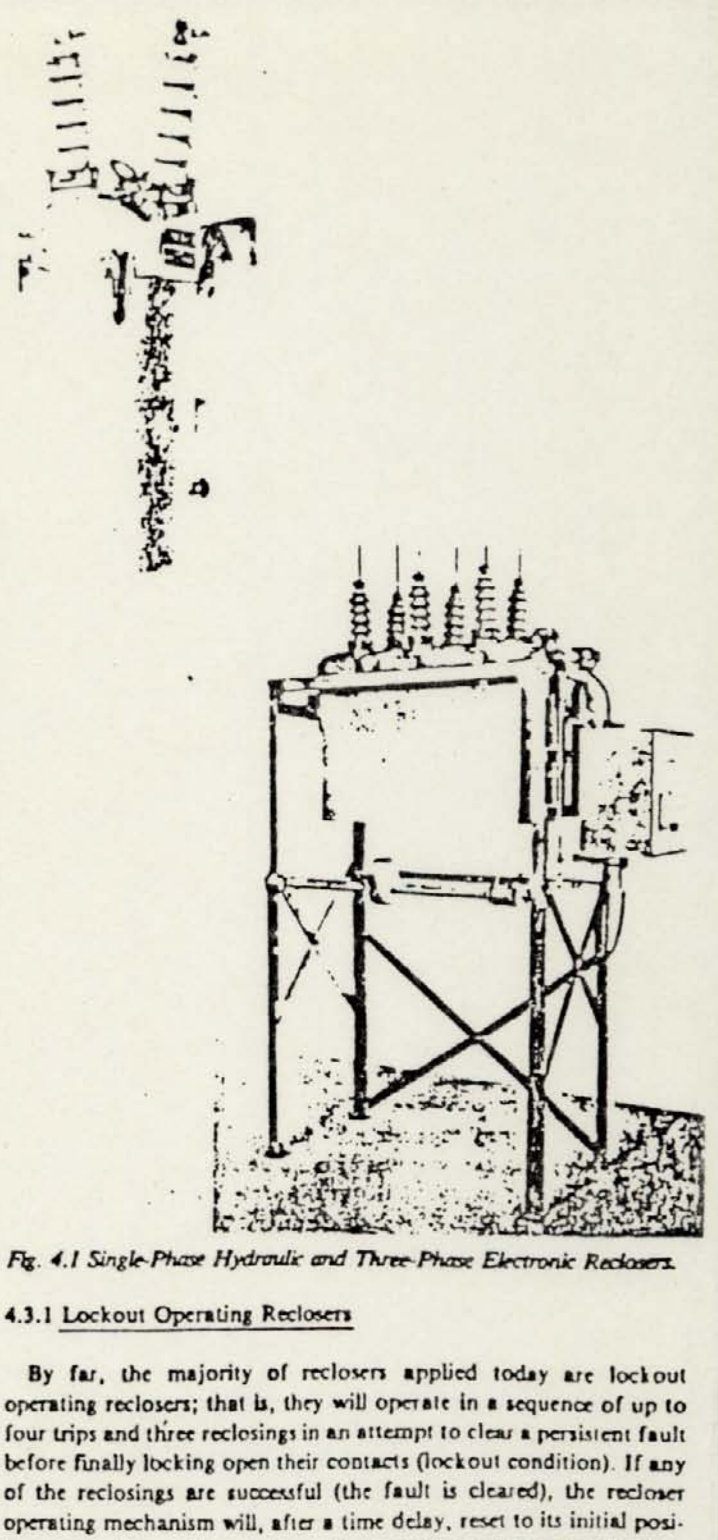


Fig. 4.1 Single-Phase Hydraulic and Three-Phase Electronic Reclosers.

4.3.1 Lockout Operating Reclosers

By far, the majority of reclosers applied today are lockout operating reclosers; that is, they will operate in a sequence of up to four trips and three reclosings in an attempt to clear a persistent fault before finally locking open their contacts (lockout condition). If any of the reclosings are successful (the fault is cleared), the recloser operating mechanism will, after a time delay, reset to its initial position, ready for another predetermined number of trips to lockout sequence. Figure 4.2 shows a typical four trip to lockout recloser operating sequence.

In Figure 4.2, reference is made to "fast" and "time-delayed" operations. These are the so-called dual time-current characteristic tripping operations that have come to be associated with reclosers. Figure 4.3 indicates how these characteristics are usually given in terms of time and current. Note that the curves are identified by letters, which is often the case. Here Curve A is the fast (sometimes called instantaneous) curve, while Curves B and C are the time-delayed curves.

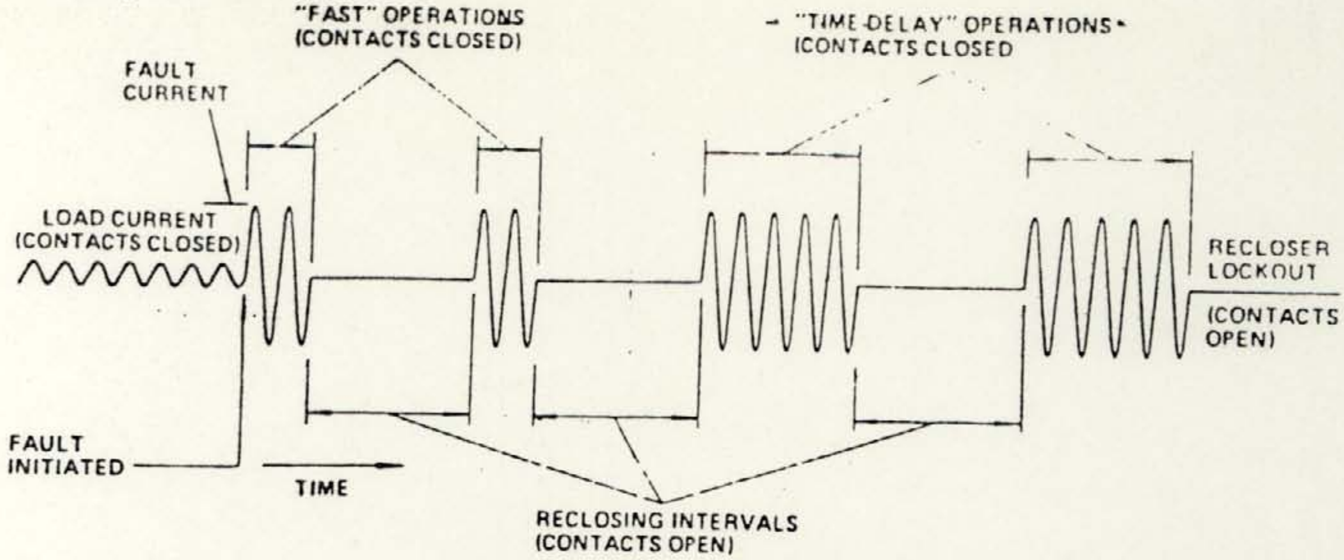


Fig. 4.2 Typical Four Trip to Lockout Operation Sequence.

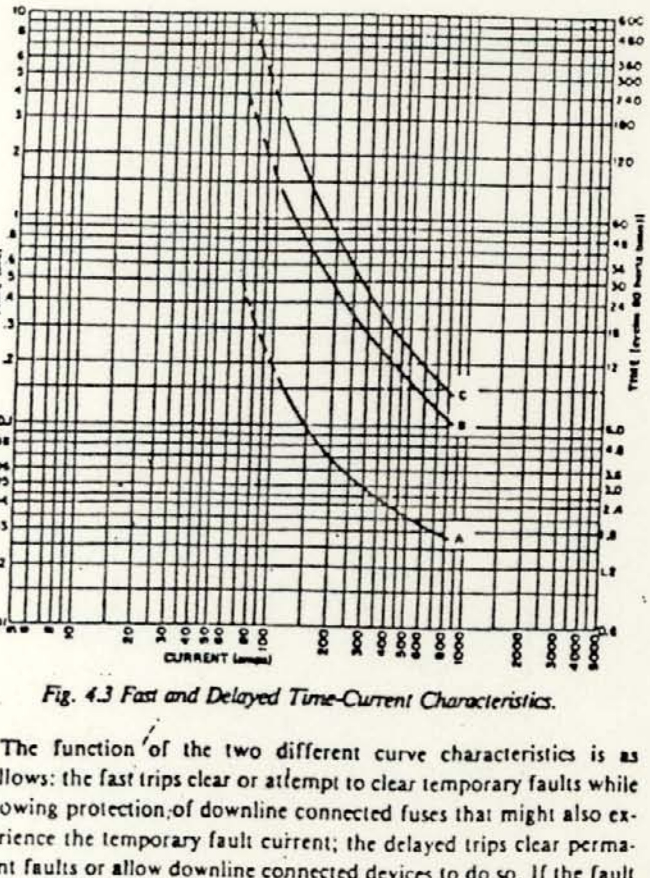


Fig. 4.3 Fast and Delayed Time-Current Characteristics.

The function of the two different curve characteristics is as follows: the fast trips clear or attempt to clear temporary faults while allowing protection of downline connected fuses that might also experience the temporary fault current; the delayed trips clear permanent faults or allow downline connected devices to do so. If the fault is not cleared before the last trip timing, the recloser considers it permanent and locks out the circuit.

The reclosing interval times are those times in the operating sequence when the reclosers contacts are open. These times are fixed on some reclosers - on the order of 1 to 2 seconds, and adjustable on others. The purpose of the open time is to give self-restoring insulation a chance to regain its dielectric strength.

4.3.2 Hold-Closed Operating Reclosers

Some use has been made of reclosers operating to a "hold-closed" position rather than a lockout position. A typical operating sequence might be two operations on a fast curve to clear temporary faults and protect downline fuses, followed by hold-closed. As long as fault current continues to flow through the recloser, the contacts will be held closed, during which time a downline device will operate and clear the fault. Once this occurs, the recloser resets. The limitation on the recloser during the hold-closed operation is the thermal time-current characteristics of its series elements. Since the vast majority of reclosers fall into the lockout operating category, no further reference will be made to the hold-closed types.

Standards recognize two generic types of reclosers: the series coil type and the nonseries (shunt) coil type. A brief description of operation is given for each type.

4.3.3 Series Coil Type Operation

When an overcurrent occurs on a circuit protected by this type of recloser, it is sensed by the internal series solenoid coil. Tripping energy is derived from the primary circuit by the series coil and trip timing is initiated. Timing functions are then controlled by the hydraulic system. Contact opening force is supplied by springs charged from a previous closing operation or during a reclosing operation. Contact closing force is supplied by springs charged after a trip operation or by energy supplied from the primary (or auxiliary circuit) via a closing solenoid coil.

4.3.4 Nonseries Coil Type Operation

Nonseries coil reclosers sense overcurrents by means of internally mounted bushing current transformers in conjunction with externally mounted electronic controls or protective relays. Tripping energy is generally not supplied directly by the primary circuit, but rather from another source such as a battery. The battery, however, may be charged by the primary circuit via current or potential transformers. All timing functions are controlled by the electronic system or by the protective relay scheme. Contact opening force is provided by springs charged during a previous closing operation or during a reclosing operation. Contact closing force is provided by springs charged by a motor or by energy supplied from the primary (or auxiliary circuit) via a closing solenoid coil.

4.3.5 Unit Operation

The basic unit operation of a recloser as defined by ANSI C37.60 1974 is shown in Figure 4.4. This is the operation on which the duty cycle performance characteristic is based and which will be discussed in the next section.

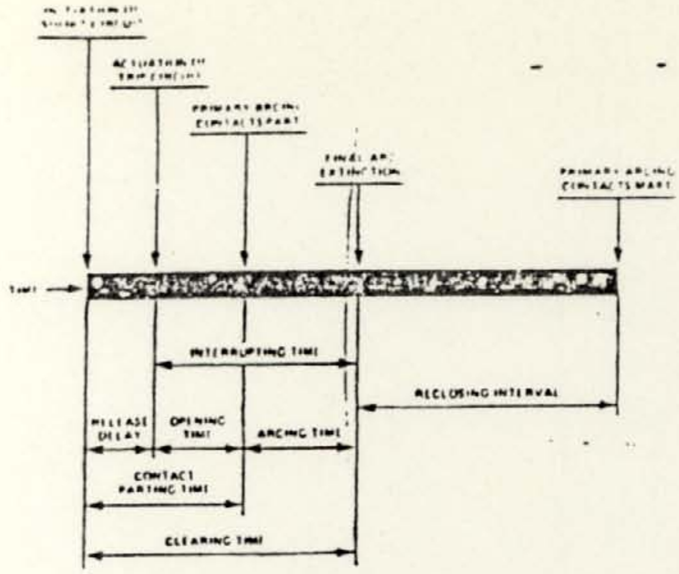


Fig. 4.4 Unit Operations

4.4 Ratings and Definitions

Reclosers are rated according to the following parameters: maximum voltage, frequency, continuous current, minimum tripping current, symmetrical interrupting current, making current, and impulse withstand voltage. For reference, Tables 2A and 2B from C37.60 are reprinted as Table 4.1 and 4.2, respectively.

4.4.1 Maximum Voltage

This is the maximum 60 hertz rms voltage to which the recloser should be subjected. Voltages from 15.0 kV to 72.5 kV are recognized.

4.4.2 Frequency

60 hertz is the recognized rated frequency.

4.4.3 Continuous Current

This is the maximum continuous current that the recloser is capable of carrying, with hot-spot temperatures of various parts not exceeding the established rises above ambient of 40 °C. This rating is sometimes termed the frame size for series coil reclosers, because these types have their continuous current carrying capability limited by their series coil rating. For example, A line 1 recloser rated 50 amps continuous with a 35 amp coil (Table 4.2) is limited to operation at continuous currents of 35 amps or less.

4.4.4 Minimum Tripping Current

This rating applies to the series coil type reclosers only. For these reclosers, the minimum trip current is defined to be two times the continuous current rating, plus or minus a ten percent tolerance. Some reclosers are available with alternate coils that have a minimum trip current of 1.4 times continuous current rating. Of course, nonseries coil reclosers have an associated minimum trip current also, but it has no relation to the continuous current carrying capability.

Table 4.1
Rated Maximum Voltage, Rated Continuous Current, Rated Interrupting Current, Rated Impulse Withstand Voltage, and Performance Characteristics of Oil Reclosers

Line No	Nominal System Voltage kV rms	Rated Maximum Voltage kV rms	Rated Impulse Withstand Voltage* kV Crest	Low-Frequency Insulation Level Withstand Test* kV rms		Current Ratings, Amperes		Standard Operating Duty* — Percent of Interrupting Rating						Total Number of Unit Operations
				1-minute Dry	10-second Wet	Continuous, 60 Hz	Symmetrical Interrupting† at Rated Maximum Volts	15-20		45-55		90-100		
								Minimum X / R	Number of Unit Operations	Minimum X / R	Number of Unit Operations	Minimum X / R	Number of Unit Operations	
(Col 1)	(Col 2)	(Col 3)	(Col 4)	(Col 5)	(Col 6)	(Col 7)	(Col 8)	(Col 9)	(Col 10)	(Col 11)	(Col 12)	(Col 13)	(Col 14)	(Col 15)
						SINGLE-PHASE RECLOSERS								
1	14.4	15.0	95	35	30	50	1 250	2	40	4	40	8	20	100
2	14.4	15.5	110	50	45	100	2 000	2	32	5	24	10	12	68
3	14.4	15.5	110	50	45	280	4 000	3	32	6	20	12	12	64
4	14.4	15.5	110	50	45	560	8 000	3	28	7	20	14	10	58
5	24.9	27.0	150	60	50	100	2 500	2	32	5	24	12	12	68
6	24.9	27.0	150	60	50	280	4 000	3	32	6	20	13	12	64
7	34.5	38.0	150	70	60	560	8 000	4	28	8	20	15	10	58
						THREE-PHASE RECLOSERS								
8	14.4	15.0	95	35	30	50	1 250	2	40	4	40	8	20	100
9	14.4	15.5	110	50	45	100	2 000	2	32	5	24	10	12	64
10	14.4	15.5	110	50	45	280	4 000	3	32	6	20	12	12	64
11	14.4	15.5	110	50	45	400	4 000	3	32	6	20	12	12	64
12	14.4	15.5	110	50	45	560	8 000	3	28	7	20	14	10	58
13	14.4	15.5	110	50	45	560	16 000	4	16	8	8	16	4	28
14	14.4	15.5	110	50	45	560	16 000	4	28	8	20	16	10	58
15	14.4	15.5	110	50	45	1120	16 000	4	28	8	20	16	10	58
16	24.9	27.0	150	60	50	100	2 500	2	32	5	24	12	12	68
17	24.9	27.0	150	60	50	560	8 000	4	28	8	20	15	10	58
18	24.9	27.0	150	60	50	1120	8 000	4	28	8	20	15	10	58
19	24.9	27.0	150	60	50	560	12 000	4	28	8	20	15	10	58
20	34.5	38.0	150	70	60	400	6 000	4	28	8	24	15	10	62
21	34.5	38.0	200	80	70	560	12 000	4	28	8	20	15	10	58
22	34.5	38.0	200	80	70	1120	12 000	4	28	8	20	15	10	58
23	46.0	48.3	250	105	95	560	10 000	4	28	8	20	15	10	58
24	69.0	72.5	350	160	140	560	8 000	4	28	8	20	16	10	58

*These are performance characteristics specified as test requirements in the standard.

†See Table 4.2 for complete data on rated interrupting currents for reclosers using smaller series coil sizes or reduced minimum trip settings.

Table 4.2

Continuous Current and Interrupting Current Ratings of Oil Reclosers

Continuous Current Rating, Amperes	Interrupting Current Rating in Amperes at Rated Maximum Voltage: Single-Phase Series Coil Reclosers							Three-Phase Series Coil Reclosers						
Recloser Line No	1	2	3	4	5	6	7	8	9	10	11	12 17	16	20
Rated Maximum Voltage, kV	15.0	15.5	15.5	15.5	27.0	27.0	38.0	15.0	15.5	15.5	15.5	15/27	27.0	34.0
5	125	200	—	—	200	—	—	125	200	—	—	—	200	—
10	250	400	—	—	400	—	—	250	400	—	—	—	400	—
15	375	600	—	—	600	—	—	375	600	—	—	—	600	—
25	625	1000	1500	—	1000	—	—	625	1000	1500	1500	—	1000	1500
35	875	1400	2100	—	1400	—	—	875	1400	2100	2100	—	1400	2100
50	1250	2000	3000	—	2000	3000	—	1250	2000	3000	3000	—	2000	3000
70	—	2000	4000	—	2500	4000	—	—	2000	4000	4000	—	2500	4200
100	—	2000	4000	6000	2500	4000	6000	—	2000	4000	4000	6000	2500	6000
140	—	—	4000	8000	—	4000	8000	—	—	4000	4000	8000	—	6000
200	—	—	4000	8000	—	4000	8000	—	—	4000	4000	8000	—	6000
280	—	—	4000	8000	—	4000	8000	—	—	4000	4000	8000	—	6000
400	—	—	—	8000	—	—	8000	—	—	—	4000	8000	—	6000
560	—	—	—	8000	—	—	8000	—	—	—	—	8000	—	—

Minimum Trip Setting, Amperes	Three-Phase Nonseries Coil Reclosers												
Recloser Line No	11	12	13	14	15	17	18	19	20	21	22	23	24
Rated Maximum Voltage, kV	15.5	15.5	15.5	15.5	15.5	27.0	27.0	27.0	38.0	38.0	38.0	48.3	72.5
100	3000	—	—	—	—	—	—	—	3000	3000	—	3000	3000
140	4000	—	—	—	—	—	—	—	4200	4200	—	4200	4200
200	4000	6000	6000	6000	—	6000	6000	6000	6000	6000	6000	6000	6000
280	4000	8000	8400	8400	—	8000	8000	8400	6000	8400	8400	8400	8000
400	4000	8000	12000	12000	12000	8000	8000	12000	6000	12000	12000	10000	8000
560	4000	8000	16000	16000	16000	8000	8000	12000	6000	12000	12000	10000	8000
800	4000	8000	16000	16000	16000	8000	8000	12000	6000	12000	12000	10000	8000
1120	—	8000	16000	16000	16000	8000	8000	12000	—	12000	12000	10000	8000
1600	—	—	—	—	16000	—	8000	—	—	—	12000	—	—
2240	—	—	—	—	16000	—	8000	—	—	—	12000	—	—

4.4.5 Symmetrical Interrupting Current

This rating gives the maximum symmetric current that the recloser is capable of interrupting. For series coil reclosers, the symmetric interrupting rating is based in some cases on the continuous current rating of the series coil. Returning to the example of the line 1 recloser, Table 4.2 indicates that with a 35 ampere rated coil, the interrupting current at maximum rated voltage is 875 amps, while with a 50 ampere rated coil, the interrupting current at maximum rated voltage is the full 1250 amps. This limitation on interrupting current arises in the lower ampere rated coils because of the opening forces they develop under high fault conditions. Without this limitation, it is possible for the small ampere size coils to develop enough opening force to damage the operating mechanism of the recloser. As indicated in Table 4.2, some nonseries coil reclosers have their interrupting ratings based on their minimum trip setting. This is not a mechanical limitation as described previously, but a limitation on the amount of energy that may be supplied to electronic controls during the fault. Accessories are available to overcome this limitation for nonseries reclosers to make their maximum interrupting current capability independent of minimum trip current.

Although not called out as a separate rating, reclosers are tested to interrupt the maximum asymmetric current that results from operation on a circuit having an X/R ratio given in Column 13 of Table 4.1. Therefore, when a recloser is applied within the maximum symmetric fault current rating on a circuit having an X/R ratio no greater than the maximum test, it is capable of interrupting any degree of asymmetry that may occur.

One final note on interrupting capability: Although reclosers are not generally constant kVA interrupting devices, some increase in interrupting current capability at voltages lower than maximum rated is exhibited by some recloser designs.

4.4.6 Making Current

This value is the same as that given by the rated symmetrical interrupting current and includes the possible asymmetry.

4.4.7 Impulse Withstand Voltage (BIL)

This value indicates the insulation is capable of withstanding the application of an impulse voltage wave having the listed crest value and 1.2 x 50 microsecond shape.

4.4.8 Standard Operating Duty

The standard operating duty (duty cycle), although not a rating, is a performance characteristic. It establishes the capability of a recloser to interrupt a relatively large number of faults at three different percentage values of rated interrupting current and minimum circuit X/R ratios. For the operating duty test, the recloser is adjusted to give the maximum possible number of unit operations (Figure 4.4) before lockout, with the minimum reclosing intervals for which the recloser is designed. Additionally, at least one fast trip followed by one delayed trip operation must occur at a value not less than the rated interrupting current. For example: a line 11 recloser, with a total number of unit operations of 64, would be tested for 16, 4 trip operations to lockout. It might be tested with the following sequence: 0 + instantaneous + CO + 2 sec + CO + 2 sec + CO.

The operating duty test for vacuum reclosers is the same as that for oil reclosers with the exception that the total number of unit operations represents half-life as measured by contact erosion. The standards allow manufacturers to test only to half-life because of the expense and time required for a test of the full duty cycle of a vacuum recloser.

No maintenance is allowed on the recloser during the operating duty test and at the end of the test, the recloser must be in substantially the same mechanical condition as when the test was begun. In addition, the recloser must be capable of withstanding the rated maximum voltage with contacts in the open position and must be capable of carrying rated continuous current, at rated maximum voltage, although not necessarily without exceeding rated temperature rise.

4.4.9 Definitions

The following terms associated with reclosers and recloser operation should be defined since they were not covered as ratings: reclosing interval and reset time.

Reclosing Interval — is defined as that time from the moment of fault current interruption until the recloser main contacts reclose (Figure 4.4). This time is independent of fault current magnitude.

Reset Time — is defined to be the amount of time required for the recloser control mechanism to return from some intermediate position in its operating sequence to its starting position; i.e., the time required "to forget" that a previous fault or series of faults has occurred.

4.5 Application Factors

Correct application of reclosers to the protection of distribution systems requires consideration and selection of the following recloser ratings and characteristics: voltage and impulse withstand (BIL) ratings, continuous current, interrupting current, minimum trip current, time-current operating characteristics, operating sequence, reclosing intervals, and reset timing.

4.5.1 Voltage and BIL Ratings — must be selected to be compatible with the system. The voltage ratings of either single- or three-phase reclosers must be greater than or equal to the maximum anticipated system line-to-line voltage. An exception to this rule allows the choice of single-phase reclosers having voltage ratings greater than or equal to the maximum anticipated line to neutral voltage of single-phase taps, provided the BIL and RIV requirements are satisfied.

4.5.2 Continuous Current Rating — must be selected to be greater than or equal to the expected peak load current through the recloser. Allowance should be made for anticipated load growth, possible load transfer, and effect of cold-load inrush. For series coil reclosers, some operating companies account for the effect of cold-load inrush by multiplying the peak load by a factor of 1.25-1.5 and choose a coil having a continuous current rating closest to and larger than the resulting current. This results in a minimum trip current of 2.5-3.0 times peak load current.

4.5.3 Interrupting Current Rating — must be greater than the maximum expected symmetrical fault current at the recloser's point of application. The X/R ratio at that location must be equal to or less than that at which the recloser is tested, at the maximum interrupting current, during the operating duty test. No uprating for symmetrical fault currents occurring at X/R ratios less than these maximums for which the recloser is tested should be allowed without approval from the manufacturer. Some allowance for increase in system fault current should be considered.

4.5.4 Minimum Trip Current — must be selected to be lower than the minimum expected fault current at the end of the recloser's zone of protection. Naturally, the lower limit of minimum trip selection is the peak expected load current, including factors for load growth and cold-load inrush. The minimum trip current for series coil reclosers is automatically fixed by selection of the continuous current rating.

For nonseries coil reclosers, a minimum level of minimum trip current could be selected by multiplying the peak expected load current by a factor of 2.5-3.0. It would be possible to set the minimum trip of a nonseries coil recloser exactly at the calculated level. If desired, the next larger available standard setting could be used.

4.5.5 Time-Current Operating Characteristics — usually must be chosen to coordinate with both upline and downline protective devices. The procedures to be used are covered in depth in other sections of this tutorial. For the purposes of use in the section on coordination, it should be noted that the fast curves are generally plotted to maximum test values and that the delayed curves are plotted to average test values with a tolerance of ten percent on time or current, whichever is greater. Figure 4.5 shows typical time-current clearing characteristics for series coil reclosers. Figures 4.6 and 4.7 show typical time-current response and clearing characteristics, respectively, for nonseries coil reclosers. Response curves indicate the amount of time after initiation of fault current before the trip circuit of the recloser is actuated (release delay). Clearing curves are made up of response (release) time plus interrupting time. Both response and clearing curves for nonseries coil reclosers are often published in terms of time versus current in percentage of minimum trip since these characteristics are generally independent of minimum trip current.

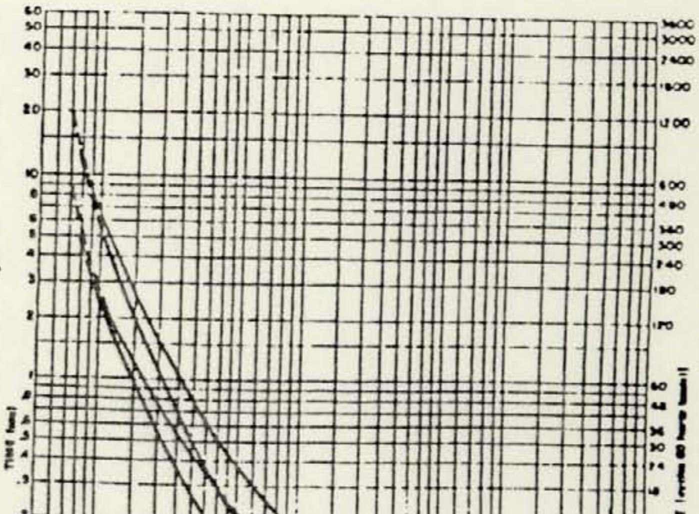


Fig. 4.5 Typical Series Coil Recloser Clearing Characteristics

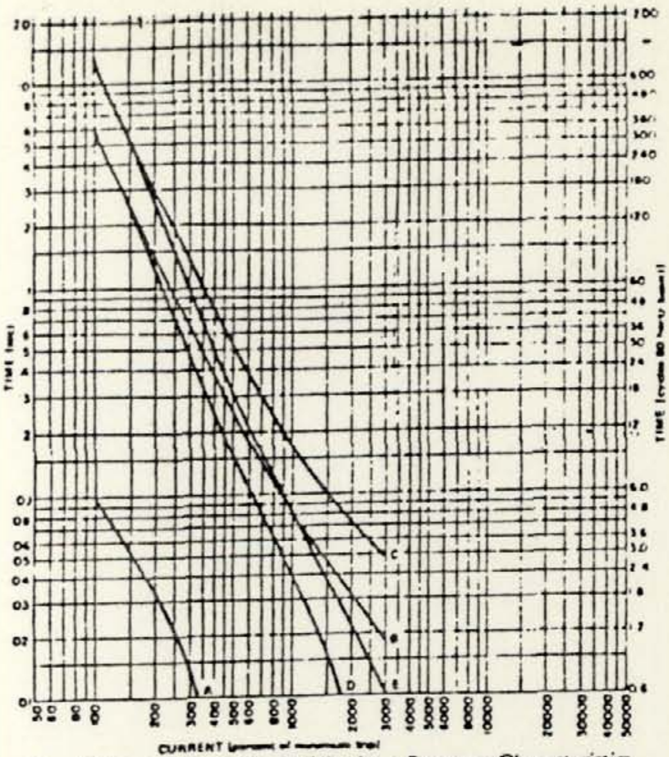


Fig. 4.6 Typical Nonseries Coil Recloser Response Characteristics.

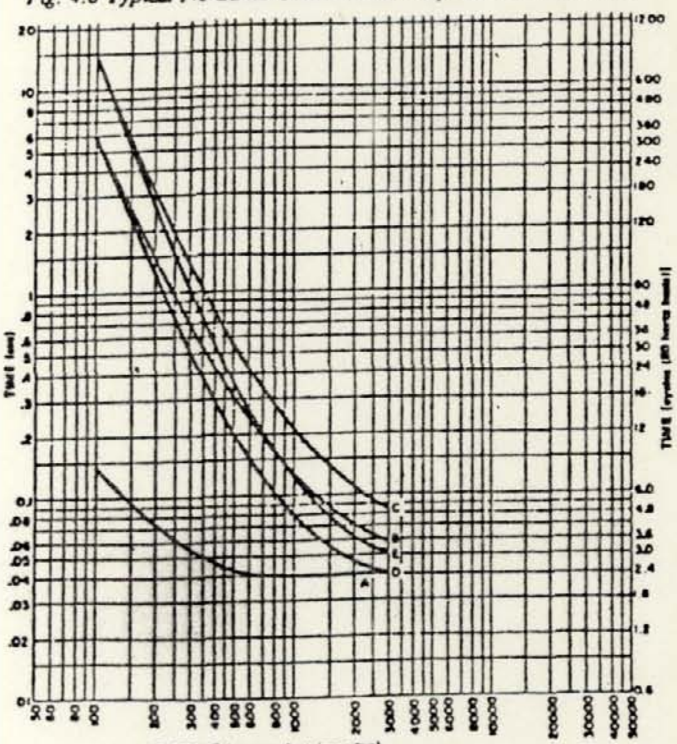


Fig. 4.7 Typical Nonseries Coil Recloser Clearing Characteristics.

4.5.6 Operating Sequences — for reclosers are chosen primarily on the basis of providing temporary fault protection and coordination with other protective devices. Typical sequences are: two fast — two delayed; one fast — three delayed, one fast — two delayed and two fast — one delayed operations. Although it is possible to select recloser operating sequences that are either all fast or all delayed, it is generally not done except in unusual circumstances because of the difficulties a choice such as that imposes on coordination. For the relative merits of various operating sequences (Table 4.3).

4.5.7 Reclosing Interval Timings — when selectable, may be chosen on the basis of aiding coordination with other protective devices and limiting the dead time of the circuit. As a practical minimum, the

Table 4.3

Relative Merits of Various Recloser Sequences

Sequence	Advantages	Disadvantages	Comments
2A2B (two fast two delayed)	[illegible] with fuse links		[illegible]
	Excellent for coordination with backup [illegible] breaker relays		
	Good for coordination with sectionalizers		
		Possibility of [illegible] cascading	[illegible] cascading can occur when two adjacent reclosers are coordinated in series and each is set for two fast two delayed operations
		Poor for reclosers on [illegible] coordination	Sectionalizers would [illegible] at third operation
2A3C (two fast [illegible])	Coordination range with fuse links wider than possible with 2A2B sequence		[illegible]
		Possibility of [illegible] cascading	[illegible] cascading can occur when two adjacent reclosers are coordinated in series and each is set for two fast two delayed operations
		Total operating time greater than 2A2B sequence	[illegible] relays have to be set higher
2A2D (two fast two delayed)	Excellent for coordination with fuse links		[illegible]
			[illegible] than 2A3C sequence
		Possibility of [illegible] cascading	[illegible] cascading can occur when two adjacent reclosers are coordinated in series and each is set for two fast two delayed operations
1A3B 1A3C 1A3D (one fast/three delayed)	Excellent for recloser/sectionalizer/fuse link series coordination		Fuse melts and clears on first time delay operation. Sectionalizer set for three counts remains closed
		Increased fuse link clearing	Fuse melts and clears on first time delay operation and recloser clears [illegible] of faults during fast operation
		Total operating time greater than two fast two delayed sequence	[illegible]
A4 (four fast)	Good for coordination with backup oil circuit breaker relays		[illegible] relays
	Fast clearing time for all faults		Maximum protection against arc damage
		No fuse link coordination possible	Fuse link would not be given adequate time to melt during all fast operations but could melt because of cumulative heating
B4 C4 D4 (four delayed)	Good recloser/fuse link series coordination		[illegible]
	Prevents [illegible] cascading		No fast curve to allow [illegible] cascading
		No fuse link coordination possible	Fuse melts and clears during first recloser operation
		Total operating time greater than 2A2B sequence	Oil circuit breaker relays have to be set higher than for 2A3C sequence
			Possible arc damage [illegible]

time should be long enough to allow any arc paths to deionize. The fastest reclosing interval times are often called instantaneous and are on the order of 0.5 seconds. Generally speaking, timings of instantaneous and two seconds are used after fast trip operations, timings longer than 2 seconds, e.g., 5, 10 seconds, after delayed trip operations. The faster timings limit the amount of load such as motors that may be dropped off line due to loss of voltage, although even instantaneous timings may not be fast enough to prevent loss of some computer or highly autmomated process loads. The longer timings allow better coordination with source-side devices such as fuses and induction overcurrent relay controlled circuit breakers. On series coil reclosers, the reclosing interval time is generally not selectable and runs in the range of 1 to 2 seconds.

4.5.8 Reset Timing — is generally selectable on nonseries coil reclosers and not selectable on series coil reclosers. When selectable, it may be timed from the first fault interruption or from successful reclose. If timed from first fault interruption, the reset time must be selected to be greater than the sum of all reclosing interval times, plus the sum of the longest clearing times for all operating curve characteristics with applicable tolerances accounted for. When timed from successful reclose; i.e., the recloser is closed with current below minimum trip, the reset time may be quite short - on the order of 5 to

10 seconds. The only limitation in this case is that the reset time must be longer than the longest reclosing interval of any downline or upline protective device with which the recloser might trip simultaneously.

The selection of short reset times can result in a failure to clear a "swinging fault", allowing a number of trip operations to accumulate; conversely, selection of long reset times may allow a series of temporary faults to lockout the recloser.

4.6 Phase Selection

The choice of whether to apply one, three-phase recloser or three, single-phase reclosers to the protection of a three-phase circuit depends largely on the connection of loads to be protected. However, other factors such as reliability and specific recloser protective characteristics required should be considered.

Three, single-phase reclosers can be used to protect a three-phase system when loads are predominantly single phase; when any three-phase connected loads, such as motors, have their own unbalance protection; and when the effects of backfeed current through grounded wye-delta connected transformers are not objectionable. With this scheme of protection, if a ground fault occurs on one phase (either temporary or permanent), the other two-thirds of the system will remain in service. If the load is predominately three-phase, then three-phase reclosers, which may be either single-phase trip, three-phase lockout, or three-phase trip and lockout, should be considered. Table 4.4 indicates the relative merits of applying the various reclosers to systems having different transformer connections.

In some cases, it may be possible to use three, single-phase reclosers or one, three-phase recloser with single-phase trip, three-phase lockout; however, because of high available fault current, special coordination requirements involving ground trip, unusual operating curves or extended reclose interval timing, it may be necessary to apply a three-phase trip and lockout type recloser.

4.7 Extended Application

The application of reclosers can be extended by use of different accessories available from the manufacturers. Commonly applied accessories are: ground trip, nonreclosing, instantaneous trip and lockout, sequence coordination and remote close-open functions.

4.7.1 Ground Trip — may be used with all three-phase reclosers having three-phase trip and lockout operation. This function is used when one desires to sense high impedance ground faults that may have magnitudes less than peak load currents. The accessory monitors the unbalance or zero sequence current that flows in the neutral of residually connected current transformers under ground fault conditions. Series coil reclosers must be provided with three externally or internally mounted current transformers; nonseries reclosers generally employ the current transformers used for normal phase sensing.

Ground trip has a minimum trip level and time current operating curve characteristics associated with it similar to the normal phase sensing. Selection of minimum trip for ground fault sensing on multigrounded systems is limited by the fact that there is load connected from line to neutral and, therefore, some neutral current flows even when no fault condition exists. Another consideration that must be taken into account is the possibility of losing a large single-phase tap or load within the recloser's zone of protection, which can result in neutral current flow. Finally, consideration of the possibility of sympathetic tripping may place a lower bound on minimum trip selection. All of these factors must be taken into account and then minimum trip may be chosen to be greater than the worst case unbalance. A typical level of minimum trip setting for a recloser protecting a multigrounded neutral system is 30 to 50 perce[nt] of the phase minimum trip setting. As with phase trip, ground tr[ip] operating curves should be selected to provide coordination wi[th] both upline and downline devices. Generally, both fast and delaye[d] curves are used, with the operating sequence being the same for bo[th] ground and phase fault tripping.

4.7.2 Nonreclosing — is an accessory available on most reclose[rs] regardless of type. This function, which is actuated by mechanical o[r] electrical means, modifies the preprogrammed number of trip opera[-]tions to lockout sequence so that there is only one trip operatio[n] before the recloser locks out. This function is useful when closing [a] recloser back onto a line which previously had a fault that still ma[y] not be cleared. This function may also be used when lines within the recloser's zone of protection are being maintained while energized.

4.7.3 Instantaneous Trip and Lockout — are accessories that are used singly or together on some three-phase nonseries coil reclosers. Above preselected current levels, these functions modify the normal preprogrammed series of fast and delayed timing operation; below the preselected levels, no modification occurs. Use of these functions can increase the margin of coordination between so equipped reclosers and upline protective devices. They also can cut down on the short-circuit duty experienced by substation transformers. Setting of these functions would normally be some hundreds of percent of the minimum trip of the recloser.

4.7.4 Sequence Coordination — is an accessory that is available on nonseries coil reclosers which limits possible cascading of two series reclosers having overlapping zones of protection. This function is applied to the backup recloser and is in operation only during the fast trip timings. In essence, it senses the operation of the downline recloser in response to a fault, sequences the backup recloser to its delayed curves in step with the downline recloser, and thus prevents unnecessary fast trip operations of the backup recloser for faults cleared by the downline recloser. The use of this function does not nullify the requirement for time-current coordination between the two reclosers, nor does it change the operating characteristics of the so equipped recloser for faults between it and the downline recloser.

4.7.5 Remote Close-Open Functions — such as remote trip, remote close, remote lockout, and reclose blocking are available on most three-phase reclosers. These functions are of use in load transfer, loop sectionalizing, and supervisory schemes to increase the reliability of the distribution system.

The foregoing points out the considerations necessary for correct application of reclosers to the protection of the distribution system. Ultimately, the selection of characteristics and settings is based on the recloser's location in the system; i.e., in substations, mains, or laterals.

4.8 Application Example

Consider the system shown in Figure 4.8. It is desired to select a recloser for locations A and B.

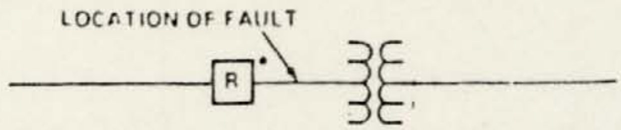
4.8.1 Ratings of Recloser at B.

a. The nominal voltage is 7.2 kV. Since the recloser will protect a single phase tap, tentatively pick any single-phase recloser described in lines 1 through 4 of Table 4.1.

b. Peak load current is 55 amps; this limits the applicable reclosers to those in lines 2, 3, or 4. To allow for expected high load growth and inrush, choose a coil having a continuous current rating equal

Table 4.4

Relative Merits of Applying Single- and Three-Phase Reclosers on Three-Phase Systems



Winding Conn.	Type of Fault	Consider-ations	Three Single-Phase Nonautointerconnected Reclosers	One Three-Phase Recloser: Single Phase Trip with Three Phase Lockout	One Three-Phase Recloser: Three Phase Trip and Lockout
Y-Δ with ungrounded neutral	Line-to-ground	Service Continuity	Two unaffected phases remain in service	All phases interrupted except on transient faults	All phases tripped and locked out simultaneously
		Single phasing of Load	Single phase service supplied to secondary with one phase locked out	No single phase service possible after lockout	No single phase service possible
		Back-feed Current	Interrupted phase and neutral above ground. Some back feed through winding capacitances with possibility of voltage hazard	All phases locked open, thereby removing potential and hazards	No hazard because possibility of capacitive back feed eliminated
		Distribution Transformer Burn-out	Unlikely because back feed current through capacitances will be small	No possibility	No possibility. Also resonant overvoltages cannot occur to damage transformers
	Line-to-line	Service Continuity	Two phases locked out and all service removed	Three phases locked out	All phases tripped and locked out simultaneously
		Single-phasing of Load	Except for possible induction due to series inductance-capacitance circuit, none	No possibility	No possibility
		Back-feed Current	One phase energized with possible resonant overvoltage	No hazard after lockout	No hazard
	Three-phase		Three-phase faults on wye-delta systems cause reclosers to interrupt in all phases at approximately the same time under normal conditions. However, a possibility exists for three line currents to be unbalanced, which can cause two phases to be cleared before the remaining phase is tripped. In this case, single-phase reclosers will behave as outlined under the line-to-line fault conditions and three-phase reclosers will lock out all phases, as during line-to-line faults.		
Y-Δ with grounded neutral	Line-to-ground	Service Continuity	Two unaffected phases remain in service. However, the faulted phase may lock out even on transient faults because of possible back feed to faulted section from delta secondary. See note 1.	All phases are locked out possibly even on transient faults because of back-feed currents maintaining an arc. See note 1.	All phases are locked out. No possibility of back feed to cause lockout on transient fault.
		Single-phasing of Load	No single-phase service possible	No single-phase service possible	No single phase service possible
		Back-feed Current	Back-feed current and induced voltage from the secondary are a hazard when one phase is locked open.	Back-feed possibility and resultant hazard removed after lockout of all three phases	No hazard because possibility of back feed is eliminated
		Distribution Transformer Burn-out	Danger exists because back-feed current through interrupted phase and neutral can be quite high. See note 1.	After lockout on all three phases back feed cannot flow. Danger to transformers reduced	No possibility of back feed damaging transformers
	Line-to-line	Service Continuity	Two phases are locked out. Single-phase service to load.	Three phases locked out.	All phases tripped and locked out simultaneously.
		Single-phasing of Load	Single-phase service will occur after two phase lockout.	After lockout on all phases, no single-phasing can occur.	No single-phase service possible
		Back-feed Current	One phase energized to ground after two phases lock out.	No hazard after lockout	No hazard
	Three-phase		See three-phase faults under wye-delta with ungrounded neutrals.		
Δ-Δ	Line-to-line	Service Continuity	Two phases are opened. Service interrupted on all three phases.	All phases are interrupted and service is removed.	Service is removed
		Single-phasing of Load	Not possible when two phases lock out. See note 2.	All phases interrupted with two phases interrupted on transient	Not possible.
		Back-feed Current	Two phases interrupted. Remaining phase energized to ground through capacitances only. No hazard.	No hazard with all phases open	Hazard eliminated
		Distribution Transformer Burn-out	No possibility.	No possibility	No possibility.
	Three-phase	Service Continuity	All phases locked out	All phases interrupted	All phases interrupted
		Single-phasing of Load	No possibility.	No possibility	No possibility
		Back-feed Current	No hazard when all phases locked out. See note 3.	No hazard after lockout	No hazard

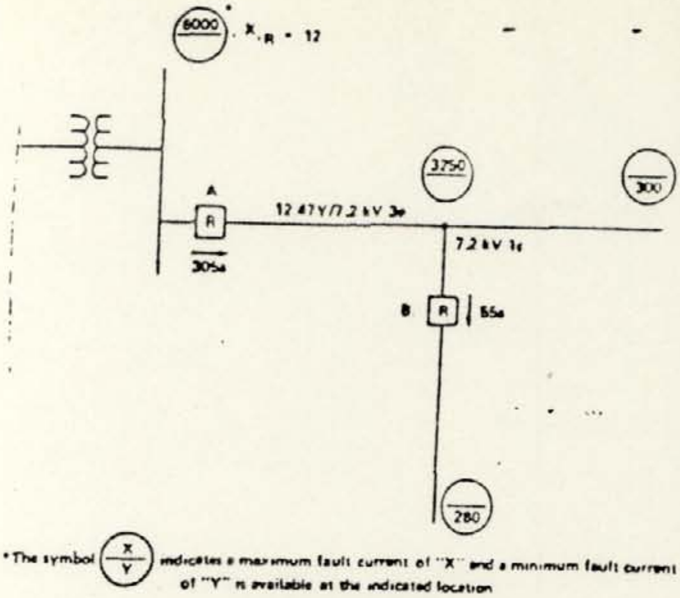
(*Three, single-phase or one, three-phase recloser bank. Fault considered permanent unless otherwise noted.)

NOTE 1: Back-feed current to a single-phase-to-ground fault occurs when the delta secondary, energized from the primary on two phases, induces a voltage in the opened primary on the remaining phase. This voltage is applied to the fault after the recloser in that phase opens, with the result that current can flow through the fault to the neutral to complete the circuit. If the fault is an arcing ground, the back-feed current may be sufficient to maintain the arc. Then, when the recloser contacts close after interrupting, the fault is still present. This causes unnecessary lockouts due to what would ordinarily be transient faults.

If the recloser is of the type which breaks all three phases simultaneously, the energy to the arc is removed and it is cleared. The proportion of temporary to permanent phase-to-ground faults varies on different systems. The average ratio is about nine temporary faults to one permanent fault, so in most cases a great improvement in service continuity can be achieved on grounded wye-delta systems by the use of reclosers which interrupt all phases simultaneously.

NOTE 2: Because two reclosers sense current during a line-to-line fault, both reclosers should open approximately at the same time. This is the most general case, but single-phase service could be supplied when single-phase reclosers are used and one clears the fault before the other trips.

NOTE 3: All reclosers normally open simultaneously on a three-phase fault. However, should two reclosers open before the third trips, one line could still remain energized, with a possible hazard because of capacitive currents.



*The symbol (X/Y) indicates a maximum fault current of "X" and a minimum fault current of "Y" is available at the indicated location

Fig. 4.8 Example System.

to or next size greater than 1.5 x 55 = 82.5 amps. Choose 100 amps.

c. Maximum fault current at B is 3250 amperes. Therefore, only line 3 or 4 reclosers are applicable. Check interrupting capacity of a line 3 recloser with a 100 amp coil from Table 4.2 - 4000 amps, therefore, the line 3 recloser is adequate.

d. Minimum fault at the end of the single phase line is 280 amps. Since the minimum trip of 100 amp recloser is 2 x 100 = 200 plus ten percent tolerence = 220 amps, this recloser can protect the entire tap, assuming fault impedance is no greater than 20 ohms.

The final selection for the recloser at B results in a line 3 device having 15.5 kV maximum design voltage, continuous current rating of 100 amps, frame size of 280 amps and symmetrical interrupting current of 4000 amps.

4.8.2 Ratings of Recloser at A

a. The nominal voltage is 12.47 kV. Since the recloser will protect a three-phase line emanating from a substation, it is desired to use a three-phase nonseries coil recloser. Tentatively, pick any recloser described in lines 11 through 13 of Table 4.1.

b. Peak load current is 305 amps. This still allows use of reclosers in lines 11, 12, or 13. For the nonseries coil recloser, choose a continuous current rating, to allow for load growth, equal to or next size larger than 1.25 x 305 = 381 amps. Tentatively choose 400 amps. The minimum trip setting should be equal to or greater than 2.5 x 305 = 763. Choose 800.

c. Maximum fault current at A is 6000 amps at X/R = 12. Therefore, only line 12 or 13 reclosers are applicable. Check interrupting capacity of a line 12 recloser with an 800 amp minimum trip setting from Table 4.2 - 8000 amps, therefore the line 12, 560 amp rated recloser is adequate.

d. Minimum fault at the end of the three-phase line is 300 amps. Since the minimum trip of the selected recloser is 800 plus ten percent tolerance = 880 amps, this recloser cannot protect the entire length of line from high impedance faults. To increase sensitivity, ground trip may be added. Additional protective devices could be added to further sectionalize the three-phase line.

The final selection for the recloser at A results in a line 12 nonseries coil device having 15.5 kV maximum design voltage, continuous current rating of 560 amps, minimum trip setting of 800 amps and symmetrical interrupting capacity of 8000 amps.

Operating sequences and time-current curves for the reclosers at A and B must be selected before the entire application process is completed. The procedures for accomplishing this are covered in other sections of this tutorial. Because of coordination requirements, the final selection process could conceivably result in a change from the ratings previously specified.

4.9 Summary

The foregoing has covered a brief history, the various types, operation, ratings, and application factors of automatic circuit reclosers. It is hoped that the discussion will promote a better understanding of recloser characteristics and application to the protection of electric distribution systems.

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ANEXO B

AUTOMATIC LINE SECTIONALIZERS -- CHARACTERISTICS AND APPLICATION FACTORS

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Abstract

Automatic line sectionalizers are self-contained, automatically controlled circuit-opening devices which isolate a faulted portion of a distribution feeder after the circuit has been deenergized by a primary protective device, such as a recloser or reclosing circuit breaker. Sectionalizers, in essence, sense overcurrents and record counts when a fault interruption occurs. The device will open when a preselected number of counts has been recorded.

Sectionalizers have many distinct applications as a distribution protection tool. They may be applied between two protective devices where an additional step in coordination is not practical. Sectionalizers are oftentimes employed on densely loaded systems where an economical main line sectionalizing device is required. They are also used on close-in taps, where high available fault currents prevent coordination with fuses.

The proper application of automatic line sectionalizers is dependent upon system electrical parameters, as well as the operating characteristics of source- and load-side fault interrupting devices.

5.1 Introduction

American National Standards (C37.63) defines an automatic line sectionalizer as follows: "A self-contained circuit opening device that automatically opens the main electrical circuit through it after sensing and responding to a predetermined number of successive main current impulses of equal to or greater than a predetermined magnitude. It opens while the main electrical circuit is deenergized. It may also have provision to be manually operated to interrupt loads."

In other words, a sectionalizer is a protective device that, while working with a backup reclosing fault interrupter, isolates faulted sections of line from a distribution system. It counts the overcurrent operations of a backup device. After a preselected number of fault current interrupting operations, and while the backup device is open, the sectionalizer opens, isolating the faulted sections. This allows the source-side device to reclose, restoring the unfaulted line sections to service.

Sectionalizers, unlike most other distribution protective devices, do not have time-current characteristics. They are, therefore, commonly used between two protective devices having operating curves which are very close together, and where an additional step in coordination is not practical. Sectionalizers are also commonly employed on close in taps where high available fault current prevents coordination with fuses.

Sectionalizers are not fault current interrupters, and must be used with a backup device which has fault current interruption capability. Since fault current interruption is not a consideration, sectionalizers can be used in high fault current areas where small reclosers might not be adequate in terms of interrupting rating. They also serve as an economical sectionalizing device, since the additional equipment costs associated with fault interruption are not required.

Finally, sectionalizers have make and latch and load break ratings which allow them to serve as switching devices as well as automatic sectionalizing devices.

5.2 Types of Sectionalizers

Sectionalizers may be classified by their insulation and interrupting medium, or by their means of control. The insulation and interrupting medium may be either oil, air, or vacuum. Control may be series actuated in the case of hydraulic or dry type sectionalizers, or shunt actuated for electronic or electromechanical control. Sectionalizers may be further categorized into single-phase or three-phase versions and manual or motor operated versions. In practice, however, four definite varieties of sectionalizers can be identified: hydraulic, electronic, dry-type, and vacuum.

5.2.1 Hydraulic Sectionalizer — Figure 5.1 shows an external view of a single-phase and a three-phase hydraulic sectionalizer. Outwardly, the hydraulic sectionalizer has the appearance of an oil switch.

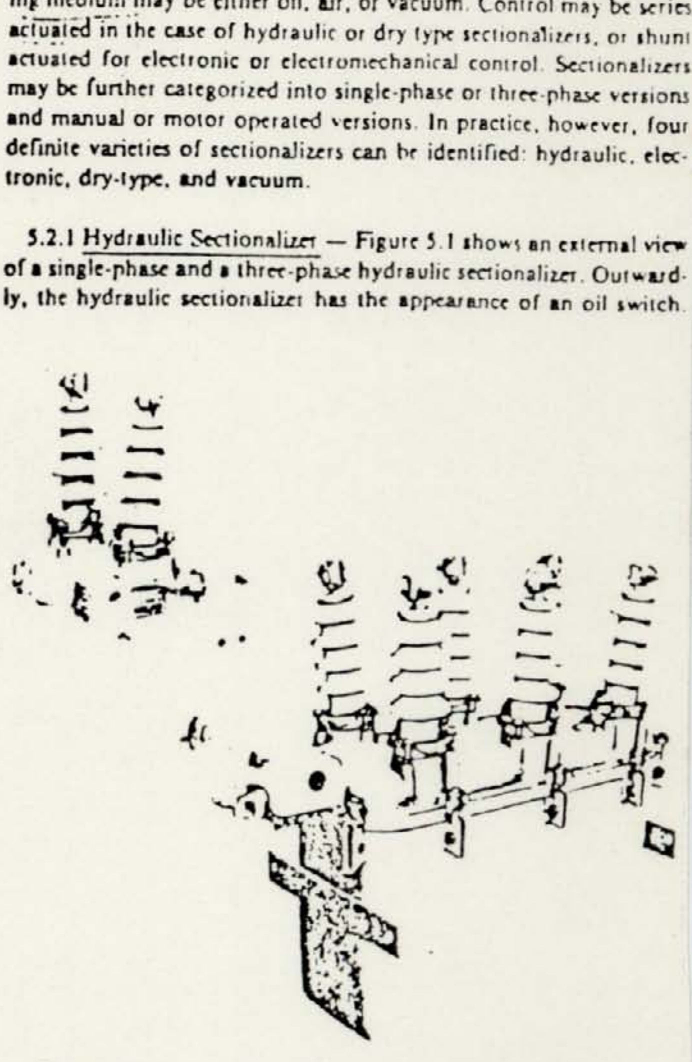

Fig. 5.1 Single- and Three-Phase Hydraulic Sectionalizers

Load current interruption and insulation is achieved through the dielectric properties of the oil, much the same as a conventional oil switch. The control is series actuated through an oil-immersed series coil; timing, counting, and control is achieved through hydraulics.

5.2.2 Dry-Type Sectionalizer — Figure 5.2 illustrates a single phase dry-type sectionalizer. The outward appearance is very similar to an open-type fuse cutout. Insulation is provided through air clearance; load current interruption may be achieved through the use of an arc extinguishing chute and snap action blade, similar to a load-break cutout operation. The sectionalizer is series-actuated through a dry-type series coil. The counting mechanism is mechanical, and timing is achieved through the use of silicon gum.

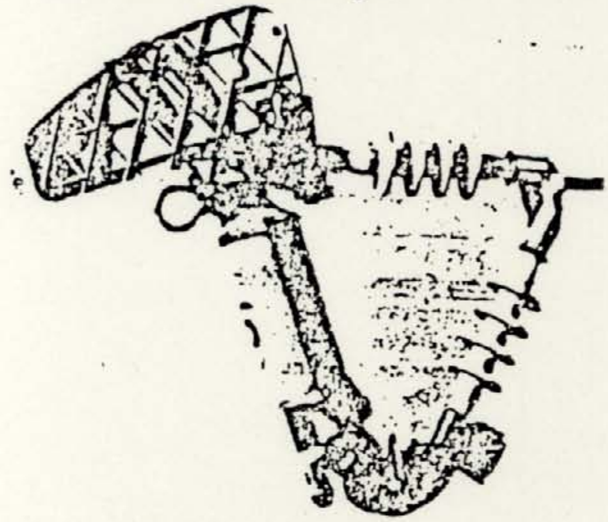

Fig. 5.2 Dry-Type Sectionalizer.

5.2.3 Vacuum Sectionalizer — Figure 5.3 shows an external view of a vacuum sectionalizer, which is similar in appearance to a three-phase vacuum switch. Air insulation and vacuum load interruption are employed. The sectionalizer is actuated through the loss of voltage and utilizes timers to control the trip, close, and lockout functions.

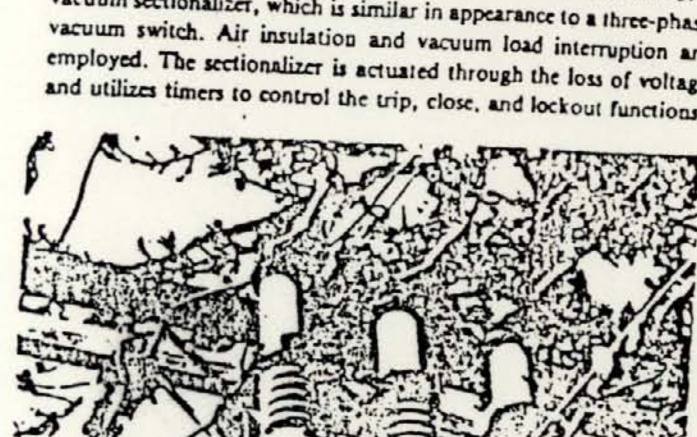

Fig. 5.3 Vacuum Sectionalizer.

5.2.4 Electronic Sectionalizers — Figure 5.4 illustrates electronically controlled sectionalizers. Externally, it appears similar to a three-phase hydraulic sectionalizer or oil switch, with the exception that an electronic control is mounted on the sectionalizer or remotely located and connected through a control cable. Insulation and load current interruption takes place within an oil medium. The control mechanism is shunt actuated through the use of current

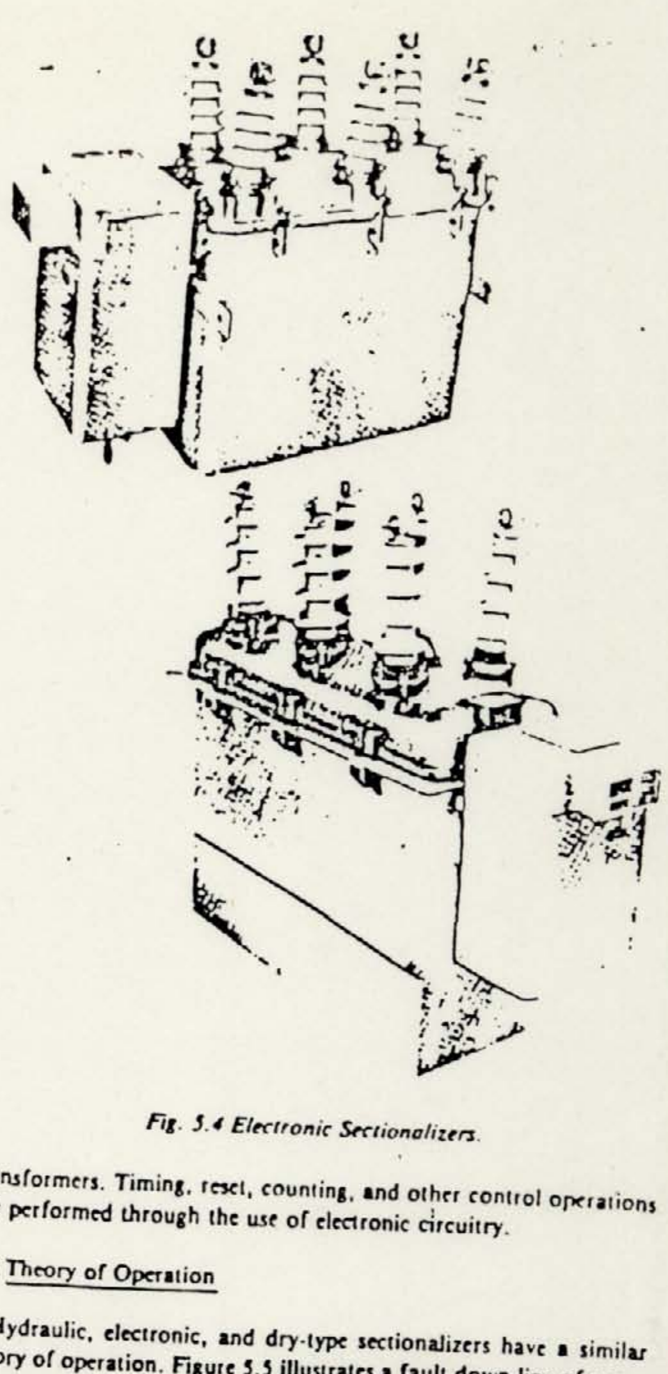

Fig. 5.4 Electronic Sectionalizers.

transformers. Timing, reset, counting, and other control operations are performed through the use of electronic circuitry.

5.3 Theory of Operation

Hydraulic, electronic, and dry-type sectionalizers have a similar theory of operation. Figure 5.5 illustrates a fault down-line of a sectionalizer. When a current flows through the sectionalizer, which is above its minimum actuating current level, the sectionalizer arms to count. That is, the series coil plunger is pulled down on hydraulic or dry-type sectionalizer, or a relay or electronic function is pulled in or energized on an electronic sectionalizer. This overcurrent is generally caused by a fault, but the sectionalizer may also arm to count during an inrush condition. The count is completed when the current through the sectionalizer falls below a drop out value, typically 40 percent of the sectionalizer's minimum actuating current. Ideally, the count is completed when the source-side device interrupts the fault current which actuated the sectionalizer. The sectionalizer may also complete a count when the inrush current decays below the drop out

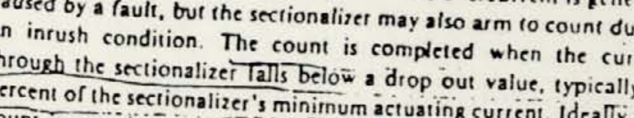

Fig. 5.5

value, or, it may complete its count when a downline device interrupts the fault current, if the remaining load current through the sectionalizer is below the drop out value. After a reclosing interval, the fault interrupting device will reclose. If the fault were temporary, no overcurrent should result, and both devices will reset. If the fault were permanent, an overcurrent will be reestablished, and the process will be repeated. After a preselected number of counts have been recorded by the sectionalizer, it will open during the reclosing (open) interval of the fault interrupting device, isolating the faulted section of line. The fault interrupter will then reclose and restore service to the unfaulted line sections on the source side of the sectionalizer.

5.4 Definition of Sectionalizer Terms

Automatic line sectionalizers have a uniquely associated group of terms which define their operation:

5.4.1 Minimum Actuating Current — This is the minimum current required to initiate a counting operation. Current through the sectionalizer above the minimum actuating current level will cause the sectionalizer to arm to count. Dry-type and hydraulic sectionalizers actuate at 160 percent of the series coil current rating. Electronic sectionalizer actuating currents are set independently of the continuous current rating of the sectionalizer.

5.4.2 Counting Operation — Each advance of the counting mechanism towards a lockout operation.

5.4.3 Counts to Trip — The number of counts the sectionalizer will initiate prior to opening its contacts and isolating the circuit. Most sectionalizers may be set at 1, 2, or 3 counts to trip.

5.4.4 Memory Time — The period of time the sectionalizer will retain a count. The memory time is usually specified as a minimum value, tolerances positive.

5.4.5 Reset Time — The time required after one or more counting operations for the counting mechanism to return to the starting position of that counting operation.

5.5 Sectionalizer Ratings

Table 5.1 lists the standard maximum voltage, impulse withstand voltage, continuous current, and interrupting current ratings for automatic line sectionalizers. These ratings are similar to ratings given to other distribution switchgear.

Table 5.2 lists the continuous current, minimum actuating current, and momentary and short time current ratings for the automatic line sectionalizers described in Table 5.1. Sectionalizers must be capable of closing into fault currents, latching, and carrying the fault current without thermal or mechanical damage, until a backup fault interrupting device clears the fault. Table 5.2 lists the limitations of sectionalizers for this type of duty.

Although most of the ratings such as nominal voltage class, rated maximum voltage, and impulse and low frequency test voltages are consistent with the ratings of automatic circuit reclosers discussed in the previous section, some of the ratings require further amplification.

5.5.1 Continuous Current Rating (Column 7, Table 5.1) — This is the maximum current the sectionalizer can carry without exceeding the established hot-spot temperature rises. As in reclosers, this rating is oftentimes termed the frame size for series coil sectionalizers, since the continuous current rating of a given sectionalizer is limited by the thermal limitations of the series coil. For example, a line 1 sectionalizer has a 200 ampere continuous current rating (frame size); However, if it is supplied with a 35 amp coil, the sectionalizer may only be used where peak load current is 35 amperes or less.

5.5.2 Symmetrical Interrupting Current (load break) (Column 8 from Table 5.1) — Most sectionalizers have a load-break rating, which allows them the dual purpose of serving as an automatic sectionalizing device as well as a manual or motor operated load-break switch. In addition, this load-break rating prevents an eventful failure should the sectionalizer open its contact under load, due to counting inrush current or fault current interruptions of downline devices.

Table 5.1
Rated Maximum Voltage, Rated Impulse Withstand Voltage, Rated Continuous Current, Rated Symmetrical Interrupting Current and Performance Characteristics of Automatic Line Sectionalizers

Identification		Rated Maximum Voltage kV rms	Rated Impulse Withstand Voltage kV Crest	Low-Frequency Insulation Level Withstand Tests* kV rms		60 Hz Current Ratings in Amperes†	
Line No.	Nominal Voltage Class kV rms			1 Min Dry	10 s Wet	Continuous	Symmetrical Interrupting (Load Break) rms
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Single-Phase Sectionalizers							
1	14.4	15.0	95	35	30	200	440
2	14.4	15.0	125	42	36	200	200
3	14.4	15.0	125	42	36	200	440
4	24.9	27.0	125	60	50	200	...
Three-Phase Sectionalizers							
5	14.4	15.5	110	50	45	200	440
6	14.4	15.5	110	50	45	400	880
7	14.4	15.5	110	50	45	600	1320
8	34.5	38.0	150	70	60	400	880

*These are performance characteristics specified as test requirements in this standard.

†On the basis of maximum continuous current rating only. See Table 5.2 for complete data on current ratings for all continuous current ratings.

Table 5.2
Rated Continuous Current, Rated Minimum Actuating Current,
Rated Asymmetrical Making Current, Rated Momentary Current, Rated One-Second Current,
and Rated Ten-Second Current of Automatic Line Sectionalizers

		Current Ratings in Amperes*								
		Line 1 & 3 Single-phase Sectionalizers			Line 2 and 4 Single-phase Sectionalizers Line 5 Three-phase Sectionalizers			Line 6, 7, & 8 Three-phase Sectionalizers		
Continuous 60 Hz	Minimum Actuating Current rms Symmetrical	Momentary and Making rms Asymmetrical	1 s rms Symmetrical	10 s rms Symmetrical	Momentary and Making rms Asymmetrical	1 s rms Symmetrical	10 s rms Symmetrical	Momentary and Making rms Asymmetrical	1 s Symmetrical	10 s rms Symmetrical
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
10	16	1600	400	125	1600	400	125			
15	24	2400	600	190	2400	600	190			
25	40	4000	1000	325	4000	1000	325			
35	56	6000	1500	450	6000	1500	450			
50	80	6500	2000	650	7000	2000	650			
70	112	6500	3000	900	8000	3000	900			
100	160	6500	4000	1250	8000	4000	1250			
140	224	6500	4000	1800	8000	4000	1800			
200	320	6500	4000	2500	8000	5700	2600			
400	†				9000			15000	10000	3500
600	†							15000	10000	3500

*LINE 1, 2, 3, 4, & 7 sectionalizers are series coil devices. Current ratings are determined by the series coil or by the maximum rating of the contacts. Line 5, 6, 8, and 9 sectionalizers are nonseries coil units. Current ratings are determined by the rating of the contacts only.

†The minimum actuating current on nonseries coil sectionalizers is independent of the continuous current rating, being selected by means of [illegible] taps or similar means.

5.5.3 Momentary and Making Currents — This is the maximum assymmetrical current against which the sectionalizer is required to close and latch as well as carry until a fault interrupting device clears the fault. On series coil sectionalizers, this rating is dependent on the series coil, while nonseries coil sectionalizers momentary and making current rating is independent of the minimum actuating current setting.

5.5.4 One Second and Ten Second Short-Time Ratings — This rating is a measure of the sectionalizer's capability of withstanding the thermal and mechanical duty imposed on it by the repeated fault current timings of the source-side fault interrupting device. For hydraulic and dry-type sectionalizers, the short-time ratings are limited by the thermal capabilities of the series coil. Therefore, the cumulative effect of multiple reclosings must be considered. For nonseries coil sectionalizers the short-time ratings are dictated by the mechanical limitations of the sectionalizer mechanism. Therefore, only the most delayed fault timing need be considered.

5.6 Sectionalizer Application Factors

Since sectionalizers operate in conjunction with a source-side fault interrupting device, the choice of the proper sectionalizer rating for a given application is heavily dependent on the characteristics of the associated fault interrupting device. Some of these considerations will be discussed here, while others will be treated more thoroughly in the section on series device coordination.

In choosing the correct sectionalizer rating, the following factors must be considered:

- system voltage
- maximum load current
- maximum fault current
- sequence of operation and fault current timings of source- and load-side devices.

5.6.1 Rated Maximum Voltage — The rated maximum voltage of the sectionalizer should be selected to be higher than the maximum phase-to-phase voltage on the system where the sectionalizer is to be applied. For example, on a 14.4/24.9 kV system, a sectionalizer should be selected with a rated maximum voltage of 27 kV or higher.

5.6.2 Rated Impulse Withstand Voltage — The BIL of the sectionalizer should be chosen to be consistent with the insulation level of other equipment on the system where the sectionalizer is to be applied. In general, this criterion will be met if the rated maximum voltage is chosen to be higher than the system line-to-line voltage level.

5.6.3 Continuous Current Rating — The maximum continuous current rating of the sectionalizer should be greater than the maximum load current expected at the sectionalizer location. A 25-50 percent margin should be observed to allow for future load growth if specific information is not available. On hydraulic sectionalizers, the continuous current is generally not a limiting factor, since the coil size is chosen based on the minimum trip level of the source-side device. For example, if the maximum load current at the proposed sectionalizer location is expected to be 80 amps, a 200 amp hydraulic or dry-type sectionalizer frame size may be chosen (line 1, 2, 3, or 5). This specifies the rating of the contacts. A coil size of 100 amps or larger must also be chosen. An equivalent electronic sectionalizer would be chosen to have a continuous current (frame size) rating of 400 amps; the minimum actuating current level would be chosen to be larger than the maximum load current. In each case, the minimum trip level of the source-side device would dictate the maximum coil size or actuating current setting.

5.6.4 Momentary and Making Current — The maximum available asymmetrical fault current at the sectionalizer location should not exceed the sectionalizer's momentary and make and latch ratings. For example, if the available fault current at a proposed sectionalizer location is 3000 amps symmetrical, 4500 amps asymmetrical, the smallest coil size hydraulic or dry-type sectionalizer which may be used is a 35 amp coil. For electronic sectionalizers, the momentary and making current is independent of the actuating current. If an electronic sectionalizer were to be used, in the example above, the 15,000 amp rating would be adequate, regardless of the minimum actuating current selected.

5.6.5 Short-Time Ratings (one second and ten seconds) — For hydraulic and dry-type sectionalizers, the short time ratings are dictated by the thermal capabilities of the series coil. Therefore, the cumulative heating effect of multiple fault timings due to reclosing must be considered. The cumulative fault timings seen by the sectionalizer at the one second and ten second fault current level should be less than the one second and ten second ratings, respectively. For example, a source-side recloser has fault current timings of 0.05 seconds, and 0.2 seconds for a 3000 ampere fault, and employs a one fast, three delayed sequence. A downline, series coil, three-shot sectionalizer has been selected with a 70 amp coil. The sectionalizer has a one second short-time rating of 3000 amps. The cumulative timings seen by the sectionalizer for the proposed recloser sequence are 0.05 + 0.2 + 0.2 = 0.45 seconds. Since this cumulative fault timing is shorter than the one second short time rating at 3000 amps, the coil size is adequate, provided the ten second short-time rating also proves satisfactory. For electronic sectionalizers, only the most delayed timing need be compared to the sectionalizer's short time ratings.

5.6.6 Other Rating Considerations — In addition to the aforementioned application factors, one must also assure that the following requirements are met:

1. The sectionalizer must count all fault current interruptions of the backup fault interrupting device. This requirement is normally achieved by choosing the minimum actuating current to be less than 80 percent of the minimum trip of the backup device.

2. The sectionalizer must lockout in one less count than the total number of trips to lockout of the backup fault interrupting device. For example, a three-shot sectionalizer may be used with a four trip to lockout source-side device, but it cannot be used if the source-side device is set for three shots to lockout.

3. Three-phase sectionalizers can only be used with three-phase source-side interrupting devices. If the source-side devices are three, single-phase reclosers, then three, single-phase sectionalizers must be used. This prevents the nonsimultaneous tripping of the source-side device from interfering with the counting and tripping of the simultaneous operating three-phase sectionalizer, which might cause the sectionalizer to attempt to open under fault conditions.

4. The sectionalizer memory time must be sufficiently long such that the sectionalizer will retain its counts throughout the entire tripping and reclosing sequence of the backup fault interrupter. The memory times of hydraulic and dry-type sectionalizers vary with temperature, and this variable should be included in the calculation process. The consideration is not included here since the process is dependent on the type and manufacturer of the individual

sectionalizer. In general, if a series coil sectionalizer is used in conjunction with a source-side series coil recloser, the memory times will be adequate. If the backup device is electronically or relay controlled, the memory time should be more closely examined. For electronic sectionalizers, the memory time is selectable and does not vary with temperature. The memory time should be longer than the total accumulated tripping and reclosing times of the backup fault interrupter (TAT) prior to sectionalizer lockout. For example, consider a three-phase electronic sectionalizer down line of a three-phase electronic recloser. The operating sequence of the recloser at minimum trip is as shown in Figure 5.6. For a three-shot sectionalizer, the memory time should be greater than TAT = $R_1 + F_1 + R_2 + F_2$ or $2 + 10 + 5 + 10 = 27$ seconds. A 30 second memory time or longer should, therefore be selected.

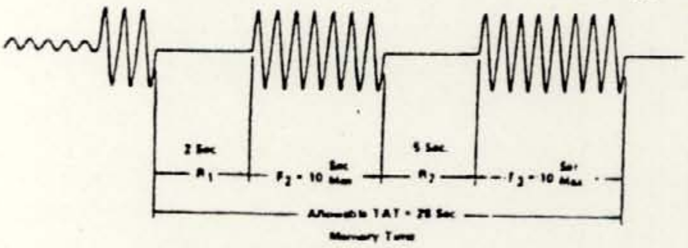

Fig. 5.6 Typical Recloser Sequence.

5. Effect of Downline Devices — Downline fuses, sectionalizers, and fault interrupting devices have an effect on the sectionalizer application. These considerations and others will be considered in more detail in series device coordination fundamentals.

However, a few basic instances of the effects of downline devices will be considered here:

a. Downline fuses. If fuses are located down line of a sectionalizer, Figure 5.7, one must assure that the fuse does not blow as the sectionalizer initiates its final count to lockout. For example, if a recloser has a two fast, two delayed sequence, a downline fuse would blow, if properly coordinated, on the first delayed operation of the recloser. An interposed sectionalizer would arm to count for the third time when the fuse melts, will initiate the count after fuse clearing, and open unfaulted sections of circuit. A one fast, three delayed sequence on the recloser with a three shot sectionalizer would prevent this needless lockout.

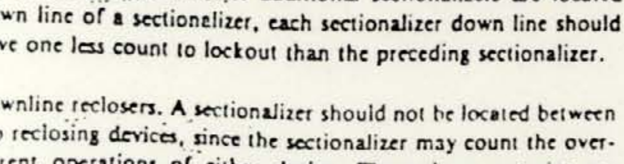

Fig. 5.7 Effects of Downline Devices, on Sectionalizer Application.

b. Downline sectionalizers. If additional sectionalizers are located down line of a sectionalizer, each sectionalizer down line should have one less count to lockout than the preceding sectionalizer.

c. Downline reclosers. A sectionalizer should not be located between two reclosing devices, since the sectionalizer may count the overcurrent operations of either device. The voltage restraint accessory, discussed later, will allow the use of sectionalizers in this manner.

5.7 Application Example (Series Coil Sectionalizer)

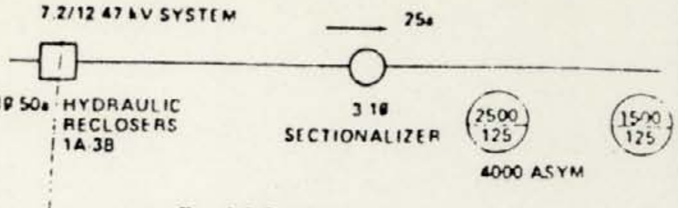

Fig. 5.8 Sample System 1.

In the example shown in Figure 5.8, the source-side device is a set of three, single-phase reclosers. The reclosers, set for four shots to lockout, one fast-three delayed sequence, are 50 amp coil, 100 amp minimum trip devices.

The choice of the proper sectionalizer rating would proceed as follows:

5.7.1 Rated Maximum Voltage — A 15.5 kV sectionalizer must be chosen in order to assure that the system voltage does not exceed the rated maximum voltage of the sectionalizer.

5.7.2 Single Phase Versus Three Phase — Single-phase devices must be used since the source-side fault interrupters employ single-phase tripping.

5.7.3 Minimum Actuating Current — A 50 ampere coil may be used in the sectionalizer. The series coil sectionalizers actuate at 160 percent of the coil rating. Therefore, the sectionalizer actuates at 80 amperes which is 80 percent of the minimum trip of the backup recloser. A frame size of 200 amps (line 1-3) is selected.

5.7.4 Momentary and Making Current — The maximum available asymmetrical fault current is 4000 amperes. The 50 ampere coil (line 1 or 3) has a 6500 ampere rating which is adequate for this application, as is a line 2 sectionalizer with a 7000 amp rating.

5.7.5 Short-Time Ratings — The short-time ratings for the 50 ampere sectionalizer are 2000 amps at one second, and 650 amps at ten seconds. At these current points, the recloser timings are as follows:

	F_1	F_2	F_3
	1st Trip	2nd Trip	3rd Trip
650 amp	0.1 sec	1.5 sec	1.5 sec
2000 amp	0.03 sec	0.3 sec	0.3 sec

At 650 amps, the accumulated fault timing seen by a three shot sectionalizer would be: $F_1 + F_2 + F_3 = 0.1 + 1.5 + 1.5 = 3.1$ seconds; at 2000 amps, the accumulated fault timings would be: $0.03 + 0.3 + 0.3 = 0.63$ seconds. These timings are less than the ten second and one second thermal rating, respectively, so the 50 ampere coil is adequate.

5.7.6 Counts to Trip — Since the backup recloser locks out after four trips, the sectionalizer must be set for three counts to trip, or less.

5.7.7 Memory/Reset Time — Series coil sectionalizers were expressly designed to operate with adequate memory and reset times when used with series coil reclosers. Therefore, this factor need not be considered. However, if the backup were a relay controlled breaker or electronic recloser, the manufacturer's recommendations concerning memory and reset time should be followed.

5.8 Application Example — Electronic Sectionalizer

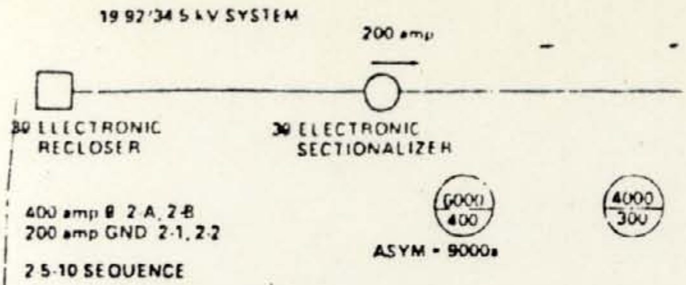

Fig. 5.9 Sample System 2.

In the example system shown the proper electronic sectionalizer rating would proceed as follows:

5.8.1 Rated Maximum Voltage — A 38 kV sectionalizer is necessary, since the system line-to-line voltage is 34.5 kV.

5.8.2 Single Phase vs Three Phase — Since the example is intended to illustrate electronic sectionalizer application, a three-phase device is used; standards do not list an electronic single-phase unit.

5.8.3 Minimum Actuating Current — Phase minimum actuating current = (0.8) (400) = 320 amps; ground minimum actuating current = (0.8) (200) = 160 amps

If the ground trip sensing were not employed, the phase actuating level should be set at 80 percent of the ground minimum trip level of the recloser. However, since the load current is above this level, ground sensing must be employed.

5.8.4 Continuous Current — The 400 amp frame size is selected.

5.8.5 Momentary and Making Current

The maximum available asymmetrical fault current is 9000 amps. The sectionalizer momentary and making current of 15,000 amp is satisfactory.

5.8.6 Short-Time Ratings

The short-time ratings of the sectionalizer are: 10,000 at one second, and 3500 amps at ten seconds.

At these points the recloser timings are:

	F_1	F_2	F_3
10,000 amps	0.04 sec	0.04 sec	0.06 sec
3,500 amps	0.04 sec	0.04 sec	0.13 sec

The most delayed fault timings of 0.06 seconds at 10,000 amps and 0.13 seconds at 3500 amps are shorter than the one second and ten second ratings respectively.

5.8.7 Counts to Trip

Since the backup recloser locks out after four trips, the sectionalizer must be set at three counts to trip or less.

5.8.8 Memory Time

The memory time must be longer than $R_1 + T_1 + R_2 + T_2$. The fault timings of the recloser at minimum trip are

$T_1 + T_2$ = .3 seconds
$T_3 + T_4$ = 15 seconds

Memory Time = 2 + 0.3 + 5 + 15 = 22.3 seconds. Therefore a 30 second or longer memory time should be selected.

5.8.9 Reset Time — On electronic sectionalizers, the memory time has an associated reset time. For the sectionalizer chosen, the reset time associated with a 30 second reclose time is 7.5 minutes. Shorter reset times are available through manufacturer's accessories.

5.9 Accessories

Several accessories are available for sectionalizers, although some are applicable only to electronic sectionalizers. Some of the more commonly applied accessories are briefly described below.

5.9.1 Voltage Restraint — The voltage restraint accessory permits the sectionalizer to count only the operations of a source-side device. This is accomplished by sensing source-side voltage at the sectionalizer location and preventing counting or tripping if source-side voltage is present following an overcurrent. Therefore, the sectionalizer is prevented from counting or tripping due to downline device operation or fuse blowing.

5.9.2 Inrush Current Restraint — The inrush current restraint allows the sectionalizer to be made less sensitive to inrush currents which might be mistaken for fault currents, thus preventing erroneous counting and tripping. This is accomplished by sensing source-side potential and employing a logic circuit. If source-side voltage were not present prior to the overcurrent, the accessory logically assumes the overcurrent is due to inrush. In this case, the actuating current is raised by a preset multiple for a preset time interval, to override the ensuing inrush.

5.9.3 Ground Fault Sensing — Sectionalizers may be equipped with circuitry which senses and responds to zero sequence or residual currents. The ground fault sensing circuitry can be coordinated with backup devices equipped with ground tripping to allow more sensitive fault protection.

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(3) Attewell, O.G., "System Application and Operation of the Electronically Controlled Sectionalizer and its Accessories", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-93, No. 3, pp. 854, 1973, Conference Paper C 73 053-6.

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(5) Electric Utility Reference Book, Volume 3, Distribution Systems, Westinghouse Electric Corporation, First Edition, 1965.

(6) Distribution-System Protection Manual, McGraw-Edison Power Systems Division, Bulletin 71022, 1971.

(7) Attewell, O.G., "Automatic Line Sectionalizers", The Line Magazine, Volume 73/1 pp. 23-24, 1973.

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(9) Slocum, P.B., "Reclosers and Sectionalizers Maintain Reliable Service", The Line Magazine, Volume 76/4, pp 10-12, 1976.

(10) "Distribution System Overcurrent Protection Workshop", Course Notes, McGraw-Edison Company Power Systems Division, 1979.

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ANEXO C

TYPE ERL
ELECTROSTATIC RESET FAULT INDICATOR

The Type ERL Fault Indicators are designed to locate permanent faults on overhead feeders. The ERL indicator operates on the principle of stored energy. The energy is stored in capacitors which are charged from the potential gradiant around the overhead cable. The source of power must be present in order to provide the stored energy necessary to trip and reset the indicator.

The type ERL fault indicator can be used on both bare conductor and covered wire. Installation and removal can be easily accomplished with a "grip-all" clampstick. Although the primary installation is on overhead conductor, the Type ERL indicator can also be applied on livefront switchgear if proper ground plane clearances are maintained.

Specifications—20kV & below

Voltage Range (Phase to Ground)	5kV minimum to 20kV maximum
Nominal Trip Currents	25A to 1000A
Accuracy	± 10%
Maximum Fault Current	20,000A for 10 cycles
Temperature Range	-40°C to +85°C
Trip Response Time	1ms at trip rating
Reset Time*	6 minutes at 5kV
Cable Diameter Range	.25" to 1.6"
Calibration	Factory preset based upon cable diameter specified when ordered.

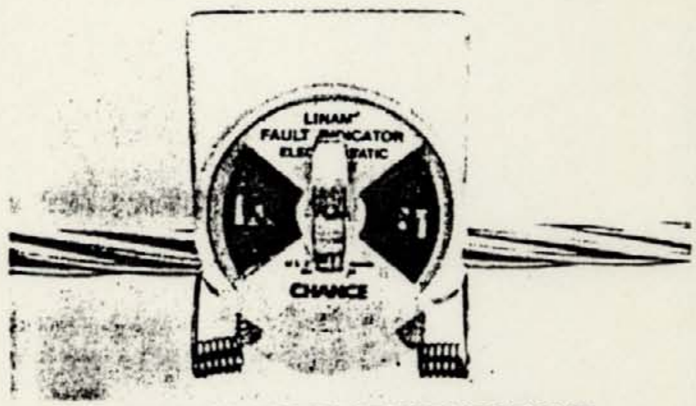
* Reset time decreases linearly as system voltage increases.

ORDERING INFORMATION—20 kV & below

Description	Trip Current (amps)	Catalog No.*
Type ERL Electrostatic Reset Fault Indicator with large face for applications 20kV and below	25 50 100 200 300 400 600 800 1000	ERL0025 ERL0050 ERL0100 ERL0200 ERL0300 ERL0400 ERL0600 ERL0800 ERL1000
Inrush Restraint** Feature	All	Add "IR" to the end of the catalog number
Type ERLTT Test Tool for Type ERL Indicator	----	ERLTT

* The Type 'ERL' fault indicator is factory calibrated based upon the specific cable diameter which must be supplied at the time of order.

** See Options Section for a complete description of inrush restraint.



FOR HIGH VOLTAGE APPLICATIONS

For applications above 20kV (Phase-to-Ground) the ERL indicator is equipped with a non-metallic clamp made of ultraviolet resistant Delrin. The Delrin clamp reduces the generation of radio noise. The unit can be applied on both bare and covered wire. The particular specifications are given below.

Specifications—above 20 kV

Voltage Range (Phase to Ground)**	7kV minimum to 42kV maximum
Nominal Trip Currents	25A to 1000A
Accuracy	± 10%
Maximum Fault Current	20,000A for 10 cycles
Temperature Range	-40°C to 85°C
Trip Response Time	1ms at trip rating
Reset Time*	10 minutes at 7kV
Cable Diameter Range	.25" to 1.6"
Calibration	Factory preset based upon cable diameter specified when ordered.

* Reset time decreases linearly as system voltage increases.
** For higher voltage applications contact the factory.

ORDERING INFORMATION—above 20kV

Description	Trip Current (amps)	Catalog No.*
Type ERL Electrostatic Reset Fault Indicator with large face for applications above 20kV	25 50 100 200 300 400 600 800 1000	ERL0025H ERL0050H ERL0100H ERL0200H ERL0300H ERL0400H ERL0600H ERL0800H ERL1000H
Inrush Restraint** Feature	All	Add "IR" to the end of the catalog number
Type ERLTT Test Tool for Type ERL Indicator	----	ERLTT

* The Type 'ERL' fault indicator is factory calibrated based upon the specific cable diameter which must be supplied at the time of order.

** See Options Section for a complete description of inrush restraint.

ANEXO D

SYSTEM CONSIDERATIONS - IMPEDANCE AND FAULT CURRENT CALCULATIONS

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ABSTRACT

The functions performed by the overcurrent protection equipments in power distribution systems are reviewed. To properly apply overcurrent protection equipments, values are required for the currents caused by faults throughout the system. Equations are presented for calculating the impedances of the elements in the system. With these impedances, the currents for different fault types can be found using simple equations. The effect of winding connections on the coordination of overcurrent devices located on the primary and secondary side of transformers is reviewed. Winding connections also may affect the level of protection that an overcurrent device provides a transformer on a through fault. The characteristics of an asymmetrical current wave are examined, and the conditions which result in a maximum for peak current, I^2t, and rms value are defined and tabulated.

1.1 INTRODUCTION

Overcurrent protection systems are required in the distribution system so that the level of service reliability experienced by all customers will be acceptable. This paper reviews the basic considerations in the overcurrent protection of radial distribution systems with emphasis on the functions performed by the overcurrent protection system. The application and coordination of reclosers, sectionalizers, and fuses to perform these functions are presented in companion papers.

Application and coordination of overcurrent protective devices requires that currents for faults at various locations throughout the system be known. Normal practice is to calculate values for fault currents using symmetrical component techniques. Presented are equations for calculating currents for each type of fault which can occur in the system, including faults on two-phase and single-phase lines. To use these equations, the sequence impedances of the elements (overhead lines, cable circuits, transformers) in the radial distribution system must be known. Also contained are equations for calculating the sequence impedances of the elements in the distribution system. It is not necessary to have a knowledge of symmetrical components when using the equations given herein, but a working knowledge of complex number arithmetic is required. Furthermore, only the final equations are given with references made to other papers and books containing the derivation or basis for the equations.

Included are curves showing the effect of system voltage level and circuit construction on the available fault currents for three-phase and single line-to-ground faults at locations along a radial feeder. These curves show that the use of higher distribution voltage levels, or underground circuits instead of overhead circuits, usually make it more difficult to obtain selective coordination of overcurrent protective devices.

Overcurrent protective devices frequently are located on opposite sides of three-phase transformers or transformer banks. The effect of winding connections on the coordination of overcurrent devices is discussed. Also, the effect of winding connections on the level of through fault protection provided the transformer by the primary side overcurrent device is presented.

The final section deals with asymmetry in the fault current wave. Asymmetry results in higher values for the instantaneous peak current, I^2t content in the first loop of current, and the rms value of the first loop of current than possible with a symmetric current wave. The fault initiation conditions which result in a maximum for each of these quantities are defined. Factors for converting the calculated rms value of the symmetrical current to a maximum value for either instantaneous peak current, I^2t content of the first loop, or rms value of the first loop are tabulated for different X to R ratios. Heretofore, these factors have not been contained in the same paper for convenient reference.

1.2 BASIC CONSIDERATIONS IN OVERCURRENT PROTECTION

If it were possible to design and construct radial distribution systems and the equipment used in them such that faults could not occur, and prevent excessive overload conditions, there would be virtually no need for overcurrent protection equipment. From the major causes of faults listed below, it is apparent that fault free systems can not be built economically.

1. Overvoltages due to lightning.
2. Overvoltages due to switching and ferroresonance.
3. Insulation degradation and breakdown due to aging and contamination.
4. Breakage of conductors, insulation, and support structures such as poles due to wind, snow, ice, trees, motor vehicles, aircraft, mobile cranes, earth digging equipment, and vandalism.
5. Shorting of insulators by rodents, birds, snakes, etc.
6. Fires
7. Equipment failure and wiring errors.

This list suggests that there are two basic classes of faults in distribution systems.

1.2.1 Classes of Faults

Faults on distribution systems are classified as temporary in nature or permanent in nature. A temporary fault is defined as one that may be cleared before serious damage occurs, either by self clearing or by a fault-clearing device operating sufficiently fast to prevent damage.

Examples of temporary faults are flashover of porcelain insulators initiated by lightning, conductors swinging together momentarily, and momentary tree contact with conductors. The majority of faults in overhead distribution systems are temporary in nature. A fault that initially is temporary in nature may become permanent in nature if it is not cleared rapidly, either through self-clearing or by the operation of an overcurrent protective device. A permanent fault is one that will persist regardless of the speed at which the circuit is de-energized, or the number of times that the circuit is de-energized. If two or more bare conductors in an overhead system become wrapped together due to conductor, cross arm, or pole breakage, the fault would be permanent in nature. Arcing between phases in a circuit with covered line wire initially may be a temporary fault, but if the fault is not rapidly de-energized, the conductors may break and develop into a permanent fault. Most faults in underground distribution systems are permanent in nature because de-energization, regardless of the speed of de-energization, will not restore the insulation strength of the faulted apparatus (cable, switchgear, transformers, etc.) to a level which withstands reapplication of normal 60 Hz voltage. Cable insulation failure due to overvoltages, and mechanical breakage of the cable are examples of permanent faults in underground systems.

If distribution feeder circuits were installed without overcurrent protection equipments, faults would cause an outage to every customer served from the feeders. This results in a level of reliability which would be unacceptable. To increase reliability to an acceptable level, there are two approaches for the distribution engineer to take. One is to design, construct, and operate a system so that the number of faults will be minimized. For instance, tree trimming programs may result in an appreciable reduction in the number of faults in overhead systems. The second approach is to install overcurrent protection equipments to minimize the effect on system reliability of the faults which do occur. The overall goal of the distribution engineer should be to employ both approaches in proper proportion so that each customer is served at an acceptable level of reliability at the lowest possible cost.

1.2.2 Functions of the Overcurrent Protection System

The overcurrent protection system is installed to perform numerous functions in the radial distribution system. These functions are briefly reviewed and illustrated using the simplified system in Figure 1.1. This system consists of a three-phase main feeder protected with a three-pole circuit breaker or recloser at the substation, a recloser in the three-phase main feeder, and single-phase lateral circuits connected to the three-phase main feeder through either sectionalizers or fuses. Manually or remotely operated switches for sectionalizing and for emergency ties to adjacent feeders are not shown. Also, sub-lateral circuits supplied from the laterals are omitted except for one.

Isolation of permanent faults

The first function of the overcurrent protection system is to isolate permanent faults from the unfaulted portion of the distribution system. In the system of Figure 1.1, a permanent fault on a lateral would be isolated by either the blowing of the lateral fuse or opening of the sectionalizer. However, if the recloser in the three-phase main and the fuses and sectionalizers were omitted, a fault on a lateral would be cleared by tripping of the station recloser or breaker. This would cause a permanent outage to every customer in the system for a permanent fault, and seriously degrade system reliability. Reference 1 shows that use of fuses or sectionalizers to isolate lateral circuits due to permanent faults can result in an appreciable improvement in reliability. This is also illustrated in the discussion of Reference 2 by Lawrence and Zimmerman.

If an automatic sectionalizing device were not used in the main three-phase feeder in Figure 1.1 and a permanent fault occurs on the main, it will be cleared by lockout of the station breaker or recloser. All customers will experience an outage. By installing an automatic sectionalizing device in the main feeder as in Figure 1.1, customers located between the substation recloser and feeder sectionalizing device will experience an improvement in reliability because a permanent fault beyond the device will not cause a permanent interruption for them. However, the feeder sectionalizing device will not prevent outages to customers beyond it for permanent faults at any point along the main feeder. The addition of a sectionalizing device or devices in the main feeder will improve the average reliability indices for permanent faults, but they will not improve the reliability of the worst case customer. This can be done by taking measures to minimize the number of permanent faults on the main feeder, or by providing automatic sectionalizing and ties to other feeders. However, a recloser located out on the feeder can be appreciably more effective than a station breaker or recloser in preventing temporary faults from becoming permanent faults.

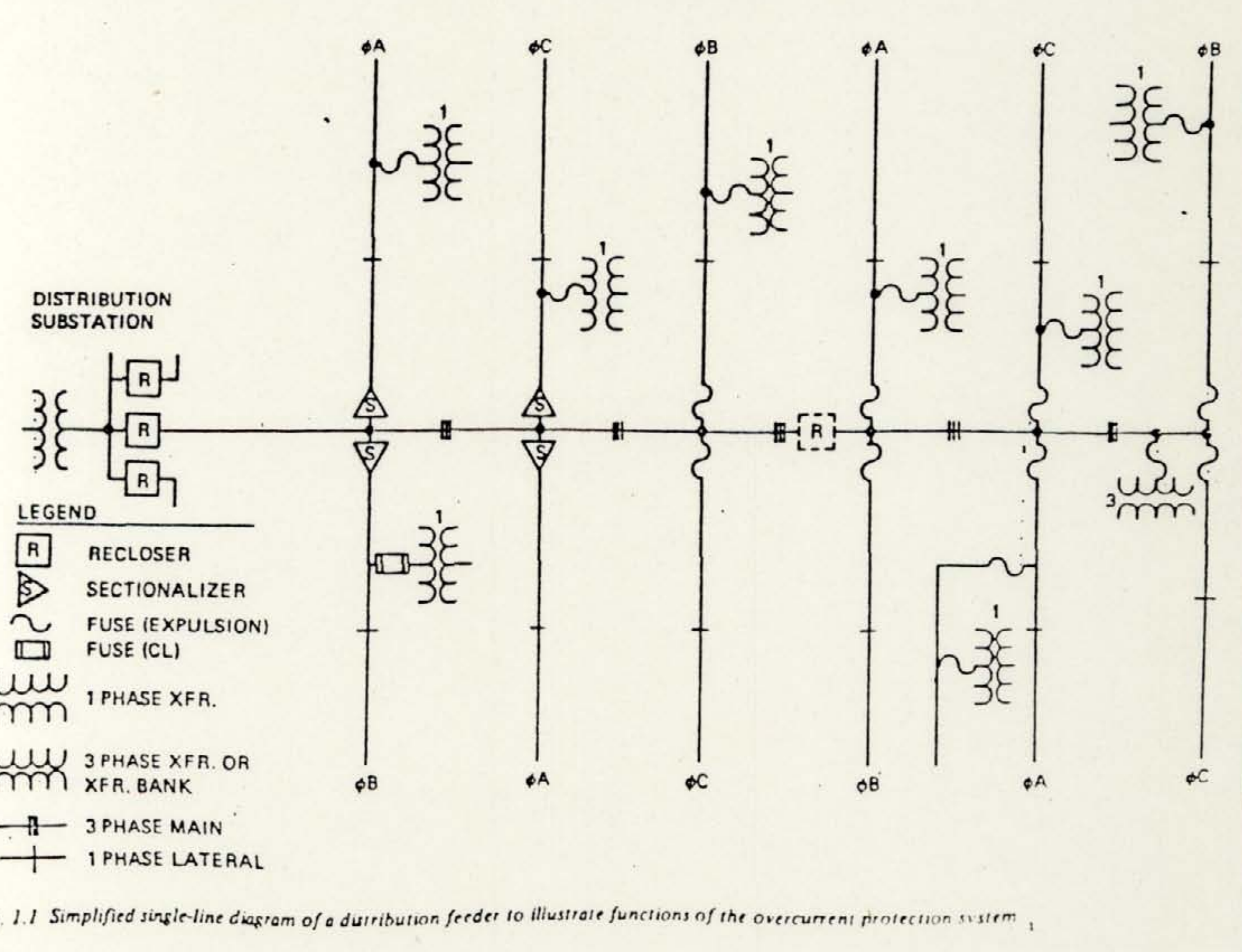


Fig. 1.1 Simplified single-line diagram of a distribution feeder to illustrate functions of the overcurrent protection system

In overhead distribution, a large percentage of the faults initially are temporary in nature. Reference 3 suggests that about 61 percent of the faults on overhead systems initially are temporary in nature, whereas other references[4,11] suggest that 80 percent or more of the faults are temporary. Reference 7 contains for 34.5 kV systems useful data on the ratio of temporary faults to total faults as seen by the substation transformer (51 percent), and data on fault type (single phase-to-ground, phase-to-phase, etc.).

Minimize number of permanent faults and outages

The second function of the overcurrent protection system is to rapidly de-energize temporary faults before any serious damage is done which could cause a permanent fault, and before any non-reclosing overcurrent device such as a fuse can operate. When this is achieved successfully, customers will experience only a temporary outage if the device which de-energizes the temporary fault, either a circuit breaker or recloser, is automatically reclosed to re-energize the circuit. However, it is not possible to prevent 100 percent of the temporary in nature faults from becoming permanent faults or from causing permanent outages because of the finite time required to de-energize the faulted circuit[3]. The speed at which the faulted circuit is de-energized is a critical factor which determines whether temporary faults will become permanent or cause permanent outages[16]. Regardless, application of quick tripping and automatic reclosing schemes will reduce the number of permanent faults and minimize the number of permanent outages.

Auer, in his discussion of Reference 5, shows that the effectiveness of quick (instantaneous) tripping and automatic reclosing in improving reliability increases as the ratio of temporary to total faults increases, and as the number of automatic reclosures is increased. This is substantiated by the data in Reference 7 for 34.5 kV systems where it is shown that time delayed rather than instantaneous reclosure results in a greater percentage of successful reclosures.

The simple system of Figure 1.1 shows that if all faults on the main circuit and lateral circuits were permanent in nature, automatic reclosing of the station recloser or feeder recloser would yield no benefits. However, if the station recloser can open fast enough for a temporary fault on a sectionalizer protected lateral such that the fault does not become permanent, customers served from the lateral will experience only a temporary outage. Similarly, if the station or feeder recloser can open fast enough for a temporary fault on a fuse protected lateral such that the fuse does not blow and the fault does not become permanent, customers served from the faulted lateral will not experience a permanent outage. However, "fuse saving" instantaneous trip and reclose operations of the station recloser cause a temporary outage to all customers on the feeder in order to prevent a permanent outage to the customers served from the faulted lateral. Because temporary outages affect some types of loads, and automatic circuit reclosers are used in the distribution feeder, some utilities are preventing the instantaneous trip of the breaker (recloser) in the substation.[4]

Minimize fault location time

The third function of the overcurrent protection system is to minimize the time required to locate permanent faults. To illustrate this function, assume the lateral circuits in Figure 1.1 are solidly connected to the main feeder, and a feeder recloser is not used. A permanent fault on any lateral or the main feeder will trip the station breaker and cause an outage to all customers. Customer "out of service" complaints would not have a pattern to aid in locating the fault. Extensive time may be required to patrol the lines and locate the fault. In contrast, with the installation of lateral and main feeder sectionalizing devices, the "out of service" complaints help in defining the area where the fault is located. Furthermore, sectionalizing devices usually give a visual indication of operation to assist troublemen in locating faults. To reduce the time required to locate faults, the overcurrent protective devices must be selectively coordinated, so that only the device closest to the permanent fault locks open.

Prevent equipment damage

The fourth function of the overcurrent protection system is to prevent damage in unfaulted equipment (bare conductor, cable, transformers, etc.) due to current in the equipment [illegible] point. For instance, in Figure 1.1 consider a permanent fault at the end of a fuse protected lateral circuit. The fuse must interrupt the fault before the limits of the conductor or cable for the lateral are exceeded. The fault-current limit of bare conductors is defined as the current (temperature) and time combination which produces the maximum acceptable loss in conductor mechanical strength.[6] Reference 6 presents the fault-current limits of ACSR conductors and all aluminum conductors in the form of time current curves plotted on a log-log scale to enable comparison with protective device time current curves. This reference also shows how these curves can be adapted to bare AAAC and ACAR conductors. For cables in underground circuits, IPCEA publication P-32-382[8] presents curves for determining the maximum time a cable may be subjected to a particular short circuit current without damaging the insulation. Curves are presented for cables with either aluminum or copper phase conductors with the insulation being either paper, rubber, varnished cloth, thermoplastic, crosslinked polyethylene, or ethylene propylene rubber. Information on the thermal limits of transformers during short circuits is contained in Section 1.6.

Minimize probability of conductor burndown

The fifth function of the overcurrent protection system is to minimize the possibility of conductor burndown due to arcing at the point of fault. As indicated in Reference 3, it is difficult to establish values of current vs time for limiting damage to bare conductors during arcing faults because of the many variable conditions which affect this performance. These include value of fault current, effect of motorizing action (arc moving away from source), velocity and direction of wind, size of conductors, and clearing times of protective devices; also, the presence or absence of items of line construction which might stop the travel of the arc. However, the results of limited testing using copper and ACSR bare conductors is contained in Reference 9 in the form of a "threshold of damage curve" and an "average burndown curve" for several small size conductors.

For arcing faults on covered conductors where the terminals of the arc do not move or move only a short distance in the time period of concern, conductor burndown can result. Reference 3 presents data on conductor burndown for circuits using covered copper conductors. Included are curves showing the time limits to prevent damage to a copper conductor and the burndown time of the covered copper wire versus current. Perhaps the most complete data on the burndown characteristics of bare and insulated conductors (ACSR, copper and aluminum) due to arcing is in a paper by Goode and Gaertner of the Baltimore Gas and Electric Company.[10] Their tests were designed purposely to minimize arc movement with both bare conductors and insulated (neoprene) conductors. The results showed that larger conductors burn down slower than smaller conductors, bare conductors of the same size and material burn down slower than neoprene-covered conductors, and bare ACSR burns down slower than plain aluminum and ACAR. The data and curves in their paper can be used to evaluate the effectiveness of overcurrent protective devices in minimizing the possibility of burndown for different types and sizes of conductors.

Minimize probability of disruptive failure

The sixth function of the overcurrent protection system is to minimize the probability of disruptive failure in system equipments such as liquid filled distribution transformers and capacitors. A disruptive failure is one which causes internal parts, hardware, fire, or excessive quantities of liquid to be expelled from the equipment enclosure. Tests and utility experience[12,13] have shown that the probability of disruptive failure due to high power-high energy arcs can be minimized with the proper application of current-limiting fuses or current-limiting devices.

Minimize safety hazards

The seventh function of the overcurrent protection system is to de-energize conductors in overhead systems which break and come into contact with earth, thereby minimizing the safety hazards to the general public. However, with present and forseeable technologies, there are no known methods for detecting 100 percent of all downed conductors in the multi-grounded neutral systems. This is because [illegible] simultaneously making low-impedance contact with other conductors. Under these conditions, the contact resistance to earth can be very high and the associated currents can be much less than normal load currents. Fuses, reclosers, and circuit breakers will not operate under these conditions, and the conductor will remain energized until manual switching is performed. However, anyone coming into contact with this downed conductor may receive fatal injuries.

1.2.3 Protection System Philosophies and Compromises

Overcurrent protection is considered both a science and an art. Well founded scientific and engineering principles are followed when calculating fault currents, determining required ratings of equipment, and when determining if the overcurrent equipments will coordinate properly. Techniques for conducting these portions of an overcurrent protection study are accepted and followed by engineers performing this work. But other aspects of overcurrent protection engineering are not as well defined. For instance, rules for specifying zones of protection, overcurrent protective equipment location, and type of equipment at each location are not well defined. In a given situation, different engineers may design overcurrent protection systems which are different from the standpoint of equipment type, location, and operation, yet both will perform satisfactorily the previously defined functions. Furthermore, local conditions along the route of the circuit and the location and nature of loads are important factors which must be considered in the design of the protection system. These can be factored into the design only by the engineer or technician with a knowledge of local conditions, and a knowledge of past history and performance.

Security, sensitivity, and selectivity

The overcurrent protection system in performing the functions defined in Section 1.2.2 should offer security, sensitivity, and selectivity. It should be secure from false operation, in that it does not cause de-energization of circuits due to load unbalances, inrush currents, cold load pickup, harmonics, and other transient or steady state conditions which will not be harmful to the system components, or create a hazard. The equipment in the overcurrent protection system should exhibit sufficient sensitivity such that it can perform the functions defined in Section 1.2.2. For instance, the station breaker or recloser in Figure 1.1 should detect temporary and permanent faults at the end of the main feeder and prevent blowing of lateral fuses at the most remote taps due to temporary faults on the lateral. However, in cases where the feeder circuits are long and loaded such that a high pickup setting is required for the station breaker, its sensitivity will not be good enough to detect faults at remote points. Then it is necessary to install a recloser or reclosers in the main feeder or main feeder branches to cover the ends of the feeder. That is, new zones of protection must be established. Reference 14 indicates that in the majority of cases the range of protection of a station breaker is insufficient to protect the ends of the circuit. Finally, the overcurrent protection equipments must be selectively coordinated so that the only device to lock out on a permanent fault is the one closest to the fault. Furthermore, if two or more reclosing devices are in series, only the device which is closest to the fault should operate on temporary faults.

Compromises in the protection system

Frequently, compromises must be made in the overcurrent protection system when trying to achieve the desired security, sensitivity, and selectivity levels. For instance, if the system is made secure from false operation due to unbalanced load current in a four-wire multigrounded neutral feeder by a high pick-up and time delay setting for a ground relay, the sensitivity needed for the detection of high impedance ground faults or downed conductors may be lost. To maintain selectivity when a large number of overcurrent devices are in series, it may be necessary to use higher pickup and time delay settings than normal for the devices closest to the distribution substation. This reduces the sensitivity of the overcurrent system. To have sensitivity sufficient to prevent conductor damage or burndown due to arcing faults on small covered conductors, selective coordination may not be fully obtainable. To prevent nuisance blowing of fuses protecting small distribution transformers due to lightning, it may be necessary to use a fuse larger than that required by other application considerations. Thus, sensitivity is sacrificed to obtain security from false operation.

1.2.4 Three-pole Vs. Single-pole Fault Interrupters

Distribution circuits typically supply both single phase and three-phase loads. A single-phase load usually is supplied from a single-phase distribution transformer whose primary winding is connected either phase-to-phase or phase-to-neutral. The single phase transformers may be connected to a three-phase section of the feeder, or else they may be supplied from either a single-phase or two-phase extension from the three-phase feeder. The fault current interrupters used in the distribution substation and on the three-phase feeders may be either single-pole (reclosers or fuses) or three-pole devices (reclosers or breakers). This section briefly reviews the merits of using three-pole and single-pole interrupters in three-phase circuits.

Many faults on three-phase lines involve only one or two phases, and it is necessary to de-energize only the faulted phases in order to isolate the fault. Using single-pole interrupters in three-phase lines enables maintaining service to single-phase loads connected to the unfaulted phases beyond the location of the single-pole interrupters. This is illustrated in Figure 1.2-a where all single-phase distribution transformers are connected from phase-to-neutral and all capacitor banks are connected grounded wye. With phase A protective device open as shown, the single-phase load connected to phase A is isolated, and the phase-to-neutral connected load on phases B and C will receive normal service. If all load beyond the single-pole devices is single-phase connected from phase-to-neutral as in Figure 1.2-a, the use of single-pole interrupters will result in an improvement in reliability without causing any adverse effects. In contrast, use of a three-pole interrupter in the circumstances of Figure 1.2-a would result in a degradation of system reliability. The following discusses some problems which may occur when using single-pole interrupters in three-phase circuits.

The system conditions in Figure 1.2-b are similar to those in Figure 1.2-a except that the neutral point of the wye connected capacitor bank is floating. With phase A protective device open due to a temporary fault, the line-to-neutral connected loads on phase A are energized from phases B and C through the capacitor bank. This can produce overvoltages on the phase-to-neutral connected load on the open phase and cause failure in customer equipment. It is not a good practice to install floating wye or delta connected capacitor banks beyond the location of single-pole interrupters in three-phase circuits.

When three-phase and single-phase loads are served beyond the location of single-pole interrupters, the single-phase loads may be subjected to low voltages, and the three-phase loads may be subjected to excessive *voltage unbalance* (negative-sequence voltage) which may damage three-phase motors. System conditions where this happens are illustrated in Figure 1.2-c where the single-phase load is connected from phase-to-neutral. The primary windings of the distribution transformers serving the three-phase load are connected in either delta, floating wye, or grounded wye as shown. With the grounded wye primary windings, the secondary windings should not be connected in delta as this causes the transformer bank to act as a ground source for the primary system.[17] With primary phase A open in Figure 1.2-c due to a temporary fault, the voltage from phase A to ground depends upon the nature and make-up of the three-phase loads and single-phase load connected to phase A. Regardless, the voltage on phase A could be low and cause *damage to* customer equipment, and the unbalanced voltage could cause damage to three-phase motors if they are not adequately protected. However, the single-phase line-to-neutral connected customers on phases B and C will receive satisfactory service. In situations as shown in Figure 1.2-c, the engineer familiar with the circuit, connected load, and local conditions should decide if the potential problems associated with the use of single-pole interrupters are offset by improvements in reliability. The ratio of single-phase to three-phase load must be considered when making this decision.

When single-pole interrupters are used in three-phase circuits, ferroresonance is possible during ungrounded faults as shown in Figure 1.2-d. In this circuit, the *ungrounded* phase-to-phase fault opens phases A and B protective devices. This establishes a circuit where ferroresonance is quite possible with the grounded wye capacitor bank and the floating wye-delta connected transformer bank. Whether ferroresonance will occur for the situation in Figure 1.2-d depends upon the amount of load connected to the floating wye-delta bank[18,19], and whether load is connected phase-to-neutral on primary phases A and B on the load side of the single-pole interrupters.

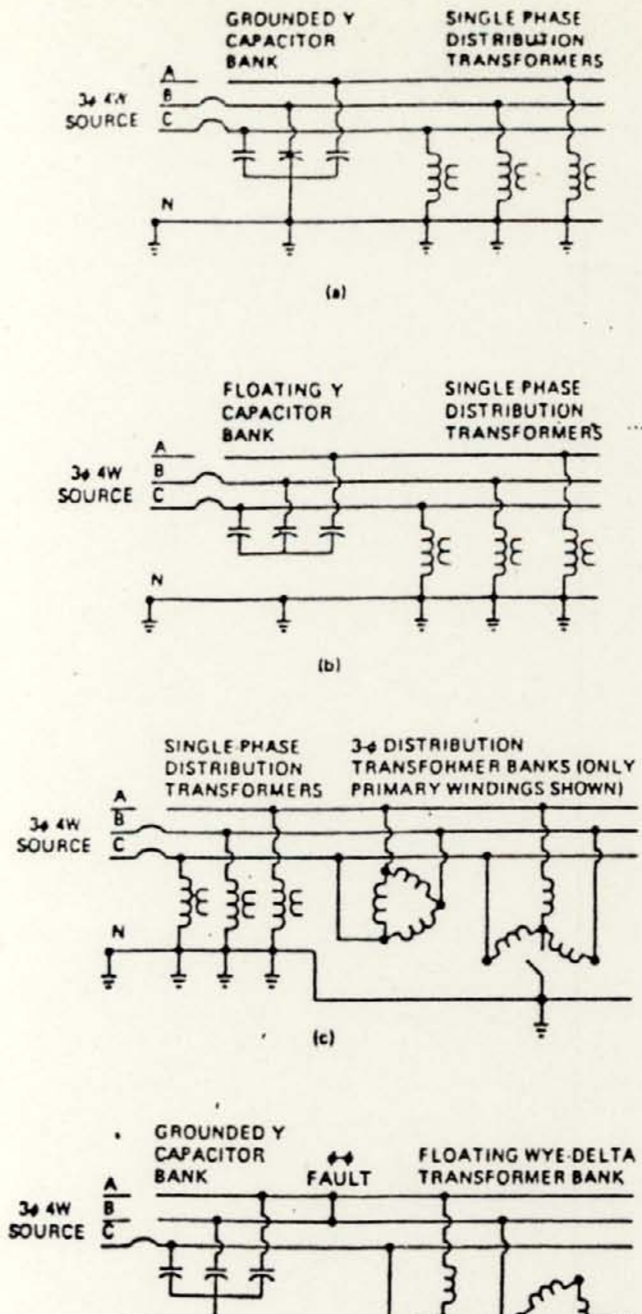


Fig. 1.2 Three line diagrams to illustrate potential problems from application of single-pole devices in three-phase feeders.

This load, if large enough, "shunts out" the capacitor bank and prevents the ferroresonant overvoltages. Even if the transformer in Figure 1.2-d were a three-phase unit with the grounded wye-wye connections, overvoltages can occur if the transformer is constructed on either a four-or five-legged core.[20]

Most utilities specify the grounded wye-grounded wye winding connections for three-phase pad mounted and submersible distribution transformers in systems with nominal voltages above 12000Y/6930 volts. These connections are specified to minimize the possibility of ferroresonance during single-phase conditions. Furthermore, most of these units are built on a four-or five-legged core to prevent tank heating during the most common open conductor-ground fault conditions which occur in multi-grounded neutral systems[21]. However, if an ungrounded phase-to-phase fault occurs in the overhead portion of the system supplying the grounded wye transformer as shown in Figure 1.2-e, and only one of the single-pole interrupters operates, the zero-sequence voltage impressed on the transformer is about 58 percent of winding rated voltage, and the transformer will experience tank heating[21,22]. Similarly, if the fault were a three-phase ungrounded fault and only two of the single-pole interrupters operated, the transformer would also experience tank heating. In contrast, use of a three-pole interrupter will prevent transformer tank heating for the conditions of Figure 1.2-e, but would not allow continuation of service to single-phase customers served phase-to-neutral. Note from Figures 1.2-b to 1.2-e that when single-pole interrupters are used in three-phase circuits, opening of one interrupter does not assure that the open phase is de-energized on the load side of the interrupter.

1.2.5 Other Considerations

The following sections present equations for calculating system impedances and fault currents. Also included is material on the effect of system voltage level and circuit construction on fault current profile, a discussion on the effects of transformer connections on coordination of overcurrent devices, and a review of asymmetry in the fault current wave.

In general, the following system information is needed to apply reclosers, sectionalizers, and fuses.

1. Maximum load currents at each sectionalizing point in the feeders during the time period of the study.

2. Location of large loads, or loads requiring special consideration.

3. Location of emergency ties to other circuits.

1.3 FAULT CURRENT CALCULATIONS

To apply overcurrent protective devices in distribution systems, currents for faults at locations throughout the system are needed. At each overcurrent protective device location, maximum values for fault currents are required to determine if equipment interrupting and momentary ratings are adequate, and if protective devices in series will coordinate properly. In a radial system, the maximum current through an overcurrent protective device occurs for a bolted fault at its load side terminals. Minimum values of fault current in radial systems are needed to determine the zone of protection of an overcurrent protective device. If the zone of protection does not reach to the end of the circuit or circuits, a new zone of protection must be established by installation of other protective devices. Minimum values of fault current are found by inserting an impedance of specified value into the fault path, or by assuming that they are a fixed percentage of the bolted value of fault current. For faults in the distribution system, currents can be determined from simple equations based on the methods of symmetrical components.

1.3.1 Fault Types, Three-Phase Lines

Faults in the distribution system can be categorized as either shunt or series. An open conductor in one or two phases, or the insertion of unequal series impedances in the phase wires of a three-phase line are examples of series faults. Series faults do not result in high currents, and usually there is no need to consider them in radial systems when applying overcurrent protective devices. In contrast, shunt faults can result in high currents which cause appreciable damage to the unfaulted portions of a system if they are not quickly isolated.

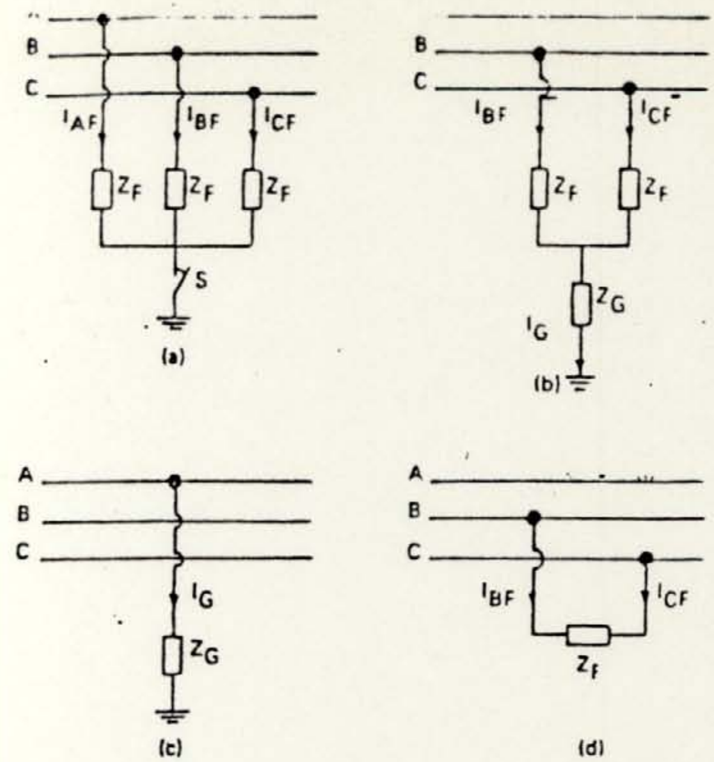


Fig. 1.3 Fault types considered for three-phase four-wire multi-grounded neutral distribution systems.

Figure 1.3 illustrates the four basic types of shunt faults which occur in a three-phase four-wire multi-grounded neutral system.

In Figure 1.3-a to 1.3-d, the fault types are referred to as three-phase, double phase-to-ground (DLG), single phase-to-ground (SLG), and phase-to-phase (LL) respectively. The impedances labeled Z_F and Z_G represent impedances which may be present in the fault path. When these impedances are set equal to zero, the "bolted fault" conditions result. The equations for calculating the fault currents for these shunt faults are quite simple and easily evaluated. Before presenting these equations, the assumptions upon which they are based will be reviewed.

1.3.2 Fault Current Equation Assumptions

The fault current equations assume that the system positive-sequence impedance (Z_1) and negative-sequence impedance (Z_2) at the point of fault are the same. This is true for most distribution systems because the total impedance which limits current for faults on the distribution substation secondary bus and on the distribution feeder is due to the impedance of transformers, open-wire lines, and cable circuits in the transmission, subtransmission, and distribution system. For these static (non-rotating) devices, the positive- and negative-sequence impedances are equal. For systems where Z_2 and Z_1 are not equal, the general methods of symmetrical components can be applied when calculating fault currents.[23,24] The fault current equations also assume the system is symmetrical such that intersequence mutual impedances are not present. Although this is never true theoretically, it is a valid assumption when calculating fault currents in the radial distribution system.

1.3.3 Fault Current Equations

Let Z_1 be the system positive-sequence impedance and Z_0 be the system zero-sequence impedance at the point of fault. These are the Thevenin impedances looking into each sequence network at the fault point. The currents in the fault path for different fault types can be calculated with the following equations. For the three-phase fault in Figure 1.3:

$$I_{AF} = \frac{E_F}{Z_1 + Z_F} \qquad (1.1)$$

where E_F is the phase to ground voltage on phase A at the fault point prior to the application of the fault. This is the reference phasor which usually is assumed to be at an angle of zero degrees. In some cases this is referred to as the prefault voltage. The current in phase B (I_{BF}) and phase C (I_{CF}) will have the same magnitude as I_{AF} but will be displaced by either plus or minus 120 degrees from I_{AF}. All symbols in equation (1.1) represent complex numbers. For the double phase-to-ground fault involving phases B and C, the phase currents and ground current in Figure 1.3-b are found with equations (1.2), (1.3), and (1.4)

$$I_{BF} = \frac{(Z_Z - aZ_P)\sqrt{3}\, E_F \angle{-90^\circ}}{Z_P^2 + 2Z_P Z_Z} \qquad (1.2)$$

$$I_{CF} = \frac{(Z_Z - a^2 Z_P)\sqrt{3}\, E_F \angle{90^\circ}}{Z_P^2 + 2Z_P Z_Z} \qquad (1.3)$$

$$I_G = \frac{-3E_F}{Z_P + 2Z_Z} \qquad (1.4)$$

where in equations (1.2), (1.3), and (1.4)

$$Z_P = Z_1 + Z_F$$

$$Z_Z = Z_0 + Z_F + 3Z_G$$

$$a = e^{j120^\circ} = 1\angle{120^\circ} = -\frac{1}{2} + j\frac{\sqrt{3}}{2}$$

and E_F is the phase-to-ground voltage on phase A at the point of fault prior to fault application. For the single phase-to-ground fault, the fault current can be determined from equation (1.5).

$$I_G = \frac{3E_F}{2Z_1 + Z_0 + 3Z_G} \qquad (1.5)$$

For the ungrounded phase-to-phase fault in Figure 1.3-d involving phases B and C, the fault currents are:

$$I_{BF} = \frac{\sqrt{3}\, E_F \angle{-90^\circ}}{2Z_1 + Z_F} \qquad (1.6)$$

$$I_{CF} = -I_{BF} \qquad (1.7)$$

where all terms appearing in equations (1.5), (1.6), and (1.7) have been defined. Once values for Z_1, Z_0, Z_F, Z_G, and E_F are known at any point in the three-phase system, calculation of the currents is a simple procedure requiring only a knowledge of complex number arithmetic. Values for the impedances and prefault voltage in equations (1.1) to (1.6) can be in either actual quantities (ohms and volts) or in per unit quantities on a specified base.

Recall that E_F is the phase-to-ground prefault voltage on phase A at the point of fault. It is not the system nominal voltage or rated voltage of a piece of equipment. To determine the maximum value for the fault current, the maximum expected value for E_F and minimum expected values for system sequence impedances should be used in equations (1.1) to (1.6). Also, note from Figure 1.3-b, -c, and -d that the double phase-to-ground, single phase-to-ground, and phase-to-phase fault are symmetrical with respect to phase A. However, the equations can be used to calculate fault currents regardless of which phases are involved. An examination of equations (1.1) to (1.6) enables the following observations.

1.3.4 Conditions Resulting in Maximum Currents

1. From equations (1.1) and (1.6), the phase currents for the three-phase fault and the phase currents for the phase-to-phase fault are maximum for the bolted fault conditions (i.e.: $Z_F = 0.0$). Furthermore, the maximum current for the LL fault is 86.6 percent of the maximum current for the three-phase fault.

2. From equations (1.4) and (1.5), the ground current I_G for the DLG fault and the ground current for the SLG fault will be maximum for the bolted fault conditions (when Z_F and Z_G are set to zero).

3. From equations (1.2) and (1.3) and the definitions of Z_P and Z_Z, it can be shown that theoretically the phase currents for the DLG fault with fault impedance could be greater than those for the bolted DLG fault. This is because the fault impedances Z_F and Z_G appear in both the numerator and denominator. Practically, the values for Z_F and Z_G which result in the maximum are not easily determined. Usually fault impedances are assumed to be zero in determining maximum currents for the DLG fault.

From equations 1.1, 1.2, 1.3, and 1.5, it is not apparent whether the three-phase, double phase-to-ground, or single phase-to-ground fault will result in the maximum phase current for bolted faults in three-phase systems. If it is assumed that fault impedances (Z_F and Z_G) are zero, and that the positive-sequence and zero-sequence impedances have the same angle, the following equations give the relationships between the magnitude of the phase currents and ground currents.

$$\frac{I_{DLG\phi}}{I_{3\phi}} = \left[\frac{3 + 3K + 3K^2}{1 + 4K + 4K^2}\right]^{\frac{1}{2}} \tag{1.8}$$

$$\frac{I_{SLG\phi}}{I_{3\phi}} = \frac{3}{2 + K} \tag{1.9}$$

$$\frac{I_{SLGG}}{I_{DLGG}} = \frac{1 + 2K}{2 + K} \tag{1.10}$$

were K is the ratio of the magnitude of Z_0 to Z_1, $I_{3\phi}$ is the phase current magnitude for a bolted three-phase fault, $I_{DLG\phi}$ is the phase current magnitude for the bolted DLG fault, $I_{SLG\phi}$ is the phase current magnitude for the bolted SLG fault, and I_{SLGG} and I_{DLGG} are the ground current magnitudes for the bolted SLG and DLG faults respectively.

Figure 1.4 is a plot of equations (1.8), (1.9), and (1.10) for values of K between 0.1 and 5.0. Shown with the dashed line in the figure is the ratio of the phase current for the LL fault to that for a three-phase fault, which is 0.866 independent of the ratio of Z_0 to Z_1. From the curves in Figure 1.4, approximate guidelines can be stated concerning the fault type which results in the maximum currents.

At locations where the ratio of Z_0 to Z_1 is less than 1.0, the phase currents will be maximum for the SLG fault, but the ground current will be maximum for the DLG fault. These conditions are encountered in and close to distribution substations whose transformers are connected delta on the primary side and grounded wye (solid) on the secondary side. At points in the three-phase system where the ratio of Z_0 to Z_1 is greater than 1.0, the phase currents will be maximum for the three-phase fault. The ground current will be maximum for the SLG fault when the ratio of Z_0 to Z_1 is greater than 1.0.

1.3.5 Two-Phase and Single-Phase Lines

In Section 1.3.3, equations were presented for calculating currents for faults on three-phase lines. Distribution systems may contain two-phase lines consisting of two phase conductors and the multi-grounded neutral conductor extended from the three-phase system. They also contain single-phase lines consisting of one phase conductor and the multi-grounded neutral conductor. The equations in Section 1.3.3 also can be used to calculate fault currents on two-phase and single-phase lines once the positive- and zero-sequence impedances for the two-phase and single-phase lines are known.

Section 1.4 presents equations for calculating the sequence impedances for two-phase and single-phase lines, either overhead or underground. To calculate these impedances, all three phases are assumed to be present in the line regardless of the number of actual phases. Then the line is treated as if it were a three-phase line. Thus the information in Figure 1.4 can be used to form approximate guidelines concerning the fault types which give the maximum phase and ground currents on two-phase lines, where obviously the three-phase

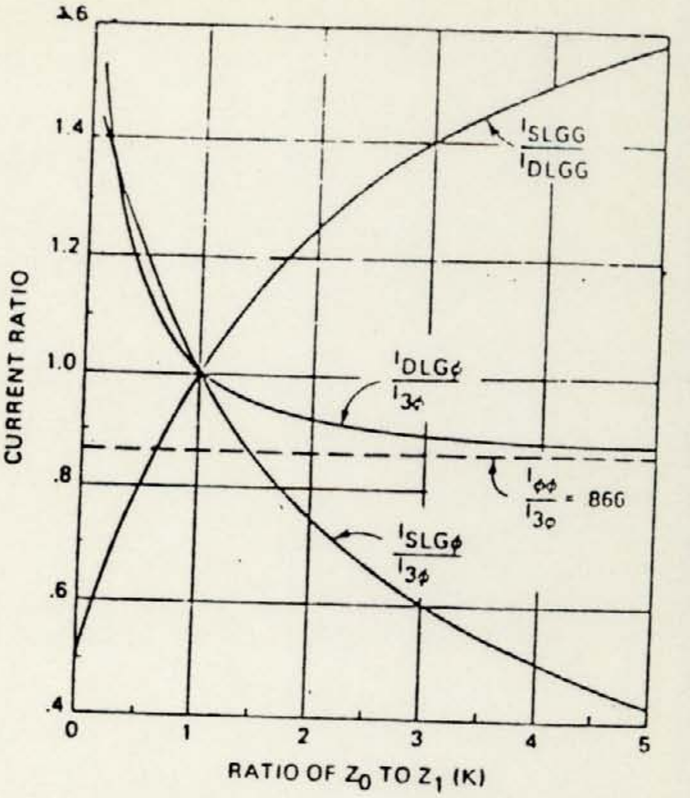


Fig. 1.4 Ratio of phase currents and ground currents for different values of the ratio of Z_0 to Z_1

fault is not considered. From Figure 1.4, the phase currents on a two phase-line generally will be maximum for the double phase-to-ground fault. However, the ground current usually will be maximum for the SLG fault since two phase lines usually are connected to the three-phase systems at points where the ratio of Z_0 to Z_1 is greater than 1.0.

For the single-phase line, only SLG faults are possible, and the maximum current occurs for the bolted fault condition.

1.3.6 Minimum Values for Fault Currents

Minimum values for fault current are used to determine if phase and ground overcurrent protective devices will detect "non-bolted" faults at the most remote point in the zone protected by the overcurrent protective device, or to determine the zone or reach of the overcurrent protective device. The minimum values for fault currents are found by assuming values for the fault impedance (resistance) in the fault current equations, or by calculating currents only for the bolted fault and assuming that the minimum value is a fixed percentage of the bolted value[14]. Usually, minimum values are determined only for single line-to-ground faults as this is the fault type which normally gives the lowest current.

Reference 25 suggests that if the actual fault involves arcing between phase wires, or phase wires and the multi-grounded neutral conductor in open wire systems, values in the range of perhaps 5 to 25 ohms may be typical for the apparent fault resistance. The apparent fault resistance is the value which makes the calculated value of fault current equal to the measured value in the actual circuit. Reference 27 suggests that several utilities use either 20 ohms or 40 ohms for the ground fault resistance. However, if a phase conductor breaks and falls on dry earth, concrete, or asphalt pavement without simultaneously contacting the multi-grounded neutral conductor, the current can be extremely small due to high contact resistance between the conductor and ground.[28]

Using values for fault resistance as suggested in Reference 25 or any other source may not give the absolute minimum value for ground fault current. Tests have shown that the currents for high resistance ground faults can be considerably less than the rating of low ampere fuses used to protect small branch circuits. Consequently, downed conductor f...

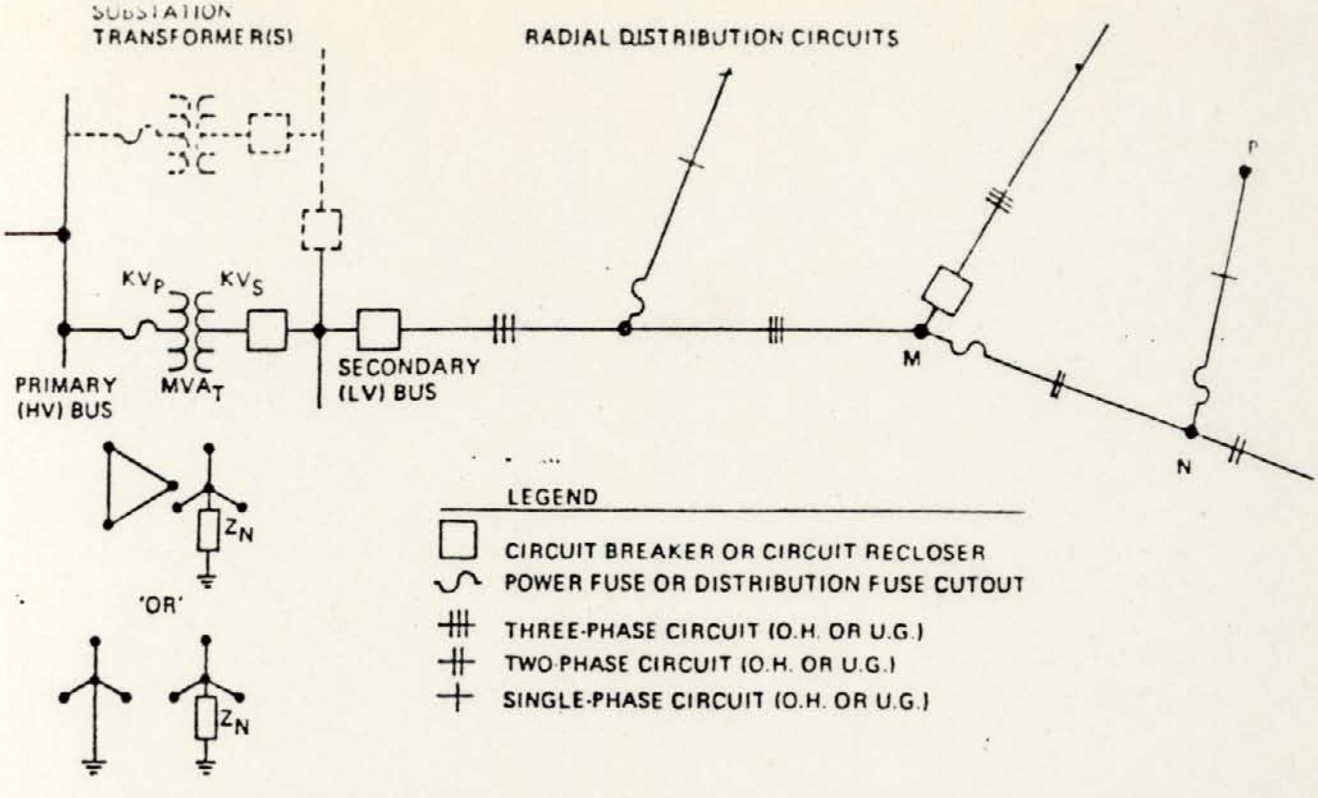


Fig. 1.5 Simplified single-line diagram showing elements in a radial distribution system for which impedances are calculated

phase and ground overcurrent protective devices in the multi-grounded neutral distribution systems.[26] Live conductors on or near the ground may be hazardous to life and property. The importance of this problem is recognized in the industry and the Electric Power Research Institute (EPRI) has three projects, Nos. RP1285-1, 2, and 3 entitled, "Detection of High Impedance Faults on Distribution Circuits" aimed at developing a device, scheme, or system that will reliably detect high-impedance faults on solidly grounded wye connected distribution circuits.

1.4 CALCULATION OF SEQUENCE IMPEDANCES

This section presents equations for calculating the sequence impedances for the components (elements) in the radial distribution system. Included are equations which apply to three-phase, two-phase, and single-phase open-wire lines and cable circuits, substation transformers with the more common winding connections, and the system supplying the primary side of the substation transformer(s). In each sequence network, the sequence impedances of the series connected elements between the source and fault point are combined to obtain the system sequence impedances at the point of fault. (designated as Z_1 and Z_0 in Section 1.3.3.) These impedance values are used in equations (1.1) to (1.6) to calculate the currents for the different fault types. In this paper, the sequence impedances of the system elements are determined in actual ohms referred to the voltage level of the distribution feeder. When these values are combined and inserted into the fault current equations with the prefault voltage E_F being in actual volts, the calculated currents are in actual amperes for use in applying and coordinating the overcurrent protective devices.

1.4.1 Distribution System Elements

Figure 1.5 is a simplified single line diagram showing the elements which make up a radial distribution system. The system sequence impedance in each sequence network at the fault point in a radial system is the sum of the sequence impedances of the distribution feeder circuits, substation transformer(s), and primary (HV) system supplying the substation transformer(s). If the substation has more than one transformer and the transformers are paralleled on both the primary and secondary sides, the transformers are represented by an equivalent impedance. In each sequence network, this equivalent impedance is obtained by paralleling the sequence impedance of each transformer in ohms referred to the secondary.

To demonstrate the combining of the sequence impedances, consider a fault at the end of the single-phase lateral (point P) in Figure 1.5. The system positive-sequence impedance (Z_1) at the point of fault is the sum of the positive-sequence impedances of the single-phase line, two-phase line, three-phase line, substation transformer(s), and primary supply system. This is illustrated in Figure 1.6 where the positive-sequence impedance diagram of the radial system is shown. The system zero-sequence impedance (Z_O) at the point of fault is the sum of the zero-sequence impedances of the series connected elements as illustrated in the zero-sequence impedance diagram in Figure 1.6. Figure 1.6 shows two zero-sequence networks, one applies when the substation transformer has the delta-grounded wye connections, and the other when it has the grounded wye-grounded wye connections. With the delta-grounded wye connections, the system zero-sequence impedance (Z_O) at the point of fault is independent of the zero-sequence impedance of the primary system (Z_{OP}). However, with the grounded wye-grounded wye connections, Figure 1.6 shows that the zero-sequence impedance of the primary system (Z_{OP}) is included in the system zero-sequence impedance (Z_O) at the point of fault.

Figure 1.6 lists, for easy reference, the equation number or numbers used for calculating the sequence impedances of the elements in the system, and lists the symbol used in the following sections to identify the quantity. The equations give sequence impedances for the open wire lines and cable circuits in ohms per mile and ohms per 1000 feet, respectively. The impedances calculated with these equations must be multiplied by the length of the circuit section to obtain the sequence impedance of the section. Figure 1.6 does not show the ideal phase shifting transformer which should be included in the positive-sequence network representing the substation transformer when the transformer has the delta-grounded wye winding connections. When the calculations are to determine currents on the secondary side of the substation transformer, the phase shifting transformer can be neglected.

Fault current equations (1.1) to (1.6) give values for the current(s) in the fault path. In the radial distribution system, the phase currents on the source side of the fault point are the same as the currents in the fault path if the effects of load, capacitors, etc., are neglected. These are the currents seen by the phase overcurrent devices located upstream from the fault. Strictly speaking, the load current at any point in the radial system should be added to the calculated value of fault current to obtain the total current. However, this usually is

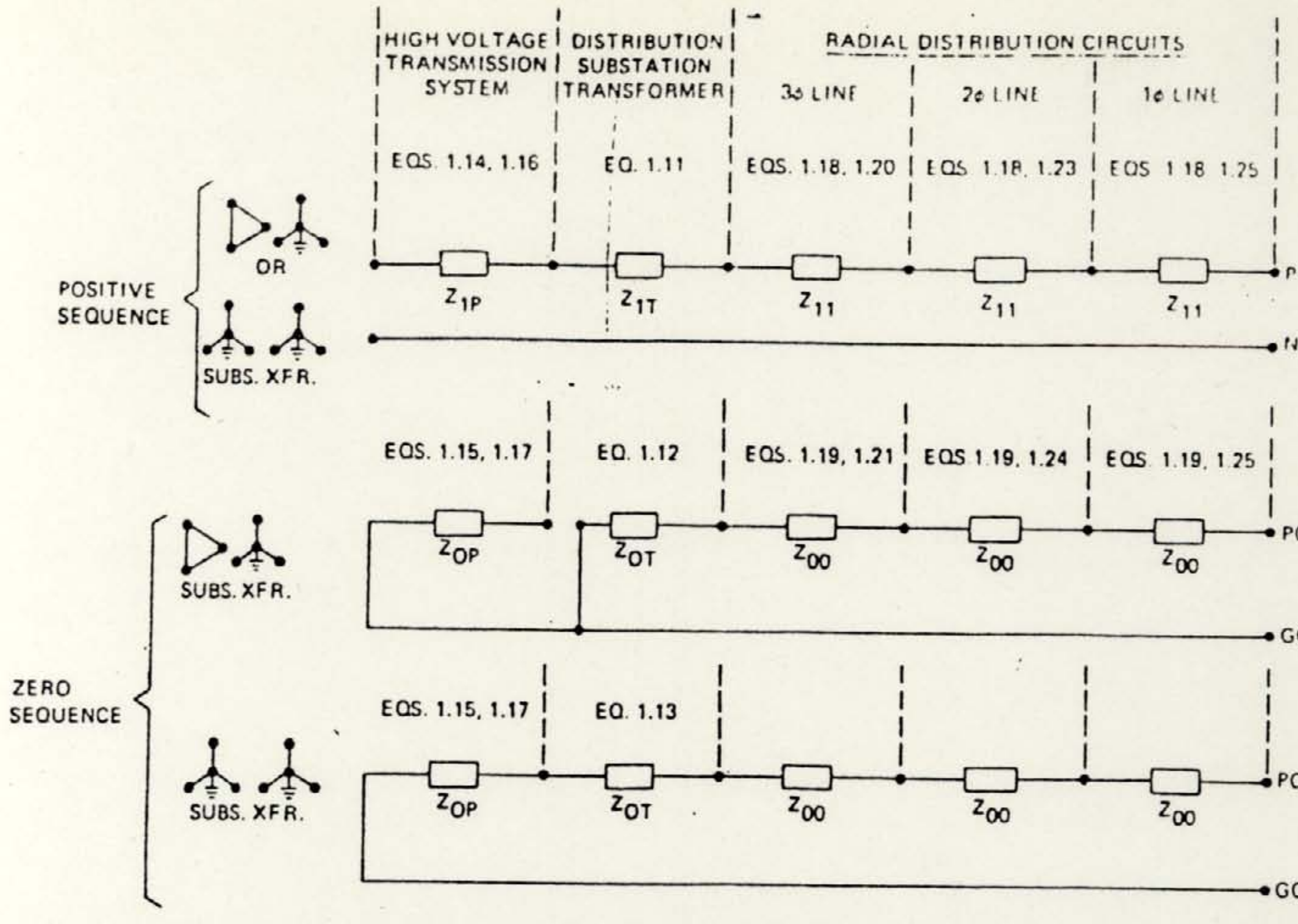


Fig. 1.6 Positive-and zero-sequence impedance diagram for a fault at point P in Figure 1.5. Sequence impedance of each element is found with indicated equations.

not done, but instead load current is accounted for by allowing a margin in the comparison of protective device time current curves.

The following sections present equations for calculating the sequence impedances of the elements in the distribution system.

1.4.2 Substation Transformers

This paper considers substation transformers with either the delta-wye or grounded wye-grounded wye winding connections. For two-winding trafusformers with other connections or three winding transformers, Reference 30 contains sequence network equivalent circuits for representing the transformers.

Regardless of whether the transformer in Figure 1.5 has the delta-wye or wye-wye connections, the positive-sequence impedance of the substation transformer (three-phase unit) in ohms referred to the secondary can be found with equation (1.11).

$$Z_{1T} = \frac{KV_S^2}{MVA_T}\left[\frac{KW_{TOT} - KW_{NL}}{1000\ MVA_T} + j\sqrt{\left(\frac{Z_{T\%}}{100}\right)^2 - \left(\frac{KW_{TOT} - KW_{NL}}{1000\ MVA_T}\right)^2}\right] \qquad (1.11)$$

where:

KV_S = transformer rated phase-to-phase voltage in kV on the secondary side of the three-phase transformer.

MVA_T = self cooled (OA) rating of the three phase transformer in MVA.

KW_{NL} = no load losses of the three-phase transformer in kW.

KW_{TOT} = total losses of the three-phase transformer in kW when delivering rated (OA) output.

$Z_{T\%}$ = transformer leakage impedance in percent.

If the substation transformer in Figure (1.5) is made from three identical single-phase units, equation (1.11) still can be used to calculate the positive-sequence impedance of the bank. However, for this case:

KV_S = transformer rated phase-to-neutral (winding) voltage in kV on the secondary side of the single-phase transformer.

MVA_T = self cooled (OA) rating of each single-phase transformer in MVA.

KW_{NL} = no load losses of each single-phase transformer in kW.

KW_{TOT} = total losses of each single-phase transformer in kW when delivering rated (OA) output.

$Z_{T\%}$ = leakage impedance in percent of each single-phase transformer.

The zero-sequence impedance of the substation transformer depends on the winding connections. For the delta grounded wye connections where the neutral point of the secondary windings is grounded through impedance Z_N as shown in Figure 1.5, the zero-sequence impedance in ohms referred to the secondary is:

$$Z_{0T} = K_1\ Z_{1T} + 3\ Z_N \qquad (1.12)$$

where

Z_N = neutral impedance in actual ohms

K_1 = 1.0 if the transformer bank is made from three single-phase units

K_1 = 0.9 for a three-phase transformer constructed on a three-legged core. This is an approximate value for K_1. Actual values may vary considerably depending upon the transformer design.

For the grounded wye-grounded wye connections where the neutral point of the primary windings is solidly grounded, and the neutral point of the secondary windings is grounded through impedance Z_N, the zero-sequence impedance in ohms referred to the secondary is:

$$Z_{OT} = Z_{1T} + 3\,Z_N \tag{1.13}$$

where Z_{1T} and Z_N have been previously defined. Equation (1.13) is valid for a wye-wye transformer bank made from three single-phase units, or for three-phase units with shell form construction or with four or five legged core construction. If the wye-wye connected three-phase transformer has a three legged core, the transformer is represented in the zero-sequence network with a "T" equivalent to take into account the effect of the fictitious tertiary. For the zero-sequence equivalent circuit of this case, Reference 30 should be consulted.

1.4.3 Subtransmission - Transmission (Primary) System

With reference to Figure 1.5, the system supplying the high-voltage or primary side of the substation transformer can be represented by a Thevenin impedance in ohms referred to the secondary side in both the positive- and zero-sequence network. The equations for calculating these impedances depend upon the form in which the data are given. Two cases are considered.

If the system supplying the primary side of the substation transformer is defined in terms of the available three-phase fault MVA, power factor, and the available current for a bolted ground fault, the sequence impedances of the primary system in ohms referred to the secondary side are:

$$Z_{1P} = \frac{KV_S^2}{MVA_{3P}}\left[PF_{3P} + j\sqrt{1 - PF_{3P}^2}\right]\left[\frac{KV_{3P}}{KV_P}\right]^2 \tag{1.14}$$

$$Z_{OP} = \frac{\sqrt{3}\,KV_S^2}{KI_{GP}\,KV_{3P}}\left[PF_{1P} + j\sqrt{1 - PF_{1P}^2}\right]\left[\frac{KV_{3P}}{KV_P}\right]^2 - 2Z_{1P} \tag{1.15}$$

where:

KV_S = transformer rated phase-to-phase voltage in kV on the secondary side of the transformer.

KV_P = transformer rated phase-to-phase voltage in kV on the primary side of the transformer.

MVA_{3P} = available three-phase fault capacity in MVA at the primary terminals of the substation transformer.

KI_{GP} = available ground fault current in kA at the primary terminals of the substation transformer.

KV_{3P} = phase-to-phase voltage of the primary system used as the base in calculating MVA_{3P} and KI_{GP}. Usually this is the same as KV_P making the ratio of KV_{3P} to KV_P equal to unity.

PF_{3P} = power factor in per unit of the available three-phase fault current at the primary terminals.

PF_{1P} = power factor in per unit of the available phase-to-ground fault current at the primary terminals.

If the system supplying the primary side of the substation transformer is defined in terms of per unit impedances for each sequence network on a specified base MVA, the sequence impedances in ohms referred to the secondary side for representing the primary system are

$$Z_{1P} = (r_1 + j\,x_1)\,\frac{KV_S^2}{MVA_B}\left[\frac{KV_{3P}}{KV_P}\right]^2 \tag{1.16}$$

$$Z_{OP} = (r_0 + j\,x_0)\,\frac{KV_S^2}{MVA_B}\left[\frac{KV_{3P}}{KV_P}\right]^2 \tag{1.17}$$

where MVA_B is the base MVA on which the per unit impedances representing the primary system are specified, and r_1, r_0, x_1, and x_0 are the real and imaginary components of the per unit sequence impedances.

1.4.4 Overhead Circuits

In this section, equations are presented for calculating the sequence self-impedances for the most common circuit types used in electric utility distribution systems.

Overhead (open-wire) distribution circuits may or may not have a neutral conductor. This neutral conductor may be grounded only at the source for the circuit (uni-grounded), or it may be grounded at various points along the circuit (multi-grounded). Since most utility distribution circuits operating in 15, 25, and 35 kV class systems have a multi-grounded neutral conductor, only multi-grounded neutral circuits are considered. For three-wire delta or uni-grounded neutral overhead circuits, Reference 29 shows how to calculate the sequence self-impedances.

The sequence self-impedances for circuits will be designated with a double subscript such as Z_{11} for the positive-sequence, Z_{22} for the negative-sequence, and Z_{00} for the zero-sequence. For open wire lines, Z_{11} and Z_{22} are identical, even if different size conductors are used for each phase. Normal practice is to make the following assumptions when deriving the equations for the sequence self-impedances of open-wire distribution lines.

1. The terms containing the height of a conductor above ground in Carson's[23] equations for the self-impedance of a conductor with earth return, and the mutual impedance between two conductors with common earth return are negligible.

2. The resistance to earth at each point where the neutral conductor is grounded is zero such that end effects may be neglected.

3. The leakage current from any phase conductor to earth or the neutral conductor to earth is negligible such that the current at the sending end and receiving end of each conductor is the same.

4. The same size conductor is used for each phase wire in a multi-phase circuit.

With the above assumptions, the positive-and zero-sequence self-impedances of three-phase, two-phase, and single-phase open wire circuits with a multi-grounded neutral conductor can be determined with equations (1.18) and (1.19). Equation (1.18) gives the positive-sequence self-impedance.

$$Z_{11} = R_\phi + j\,.2794\,\frac{f}{60}\log\frac{GMD_\phi}{GMR_\phi}\ \text{Ohms/mile} \tag{1.18}$$

where:

R_ϕ = resistance of the phase conductor in ohms per mile

f = system nominal frequency in hertz

GMD_ϕ = geometric mean distance between phase conductors in feet

GMR_ϕ = geometric mean radius of the phase conductor in feet. For different sizes and types of conductors, values for GMR_ϕ can be found in tables such as appear in Reference 6 or 30

The expression for the zero-sequence self-impedance, which is designated as Z_{00}, is:

$$Z_{00} = R_\phi + .2862 \frac{f}{60} + j.8382 \frac{f}{60} \log \frac{D_e}{\sqrt[3]{GMR_\phi \, GMD_\phi^{\,2}}} - \frac{3Z_{\phi N}^2}{Z_{NN}} \text{ Ohms/mile} \tag{1.19}$$

where:

$$Z_{\phi N} = .0954 \frac{f}{60} + j.2794 \frac{f}{60} \log \frac{D_e}{GMD_{\phi N}}$$

$$Z_{NN} = R_N + .0954 \frac{f}{60} + j.2794 \frac{f}{60} \log \frac{D_e}{GMR_N}$$

$$D_e = 2160\sqrt{\frac{\rho}{f}} \text{ feet}$$

ρ = average value of earth resistivity in ohm-meters along the route of the circuit. It is common practice to use a value of 100 for ρ unless a specific value is available.

$GMD_{\phi N}$ = geometric mean distance between the phase conductors and the neutral conductor in feet.

R_N = resistance of the neutral conductor in ohms per mile.

GMR_N = geometric mean radius of the neutral conductor in feet.

In equation (1.19) Z_{NN} is the self-impedance of the neutral conductor with earth return as determined from Carson's equation. The term $Z_{\phi N}$ can be thought of as a mutual impedance with common earth return between the three-phase conductors as a group and the multi-grounded neutral conductor. The term D_e is the distance between the actual conductor and the equivalent conductor which represents the earth return. The expressions for calculating GMD_ϕ and $GMD_{\phi N}$ can be found in Table 1.1 for three-phase, two-phase, and single-phase lines. In this table, d_{ij} is the distance in feet between the center of conductor i and the center of conductor j, where the phase conductors are designated with subscripts A, B, and C and the multi-grounded neutral conductor by subscript N.

TABLE 1.1
Geometric Mean Distances

Quantity	LINE TYPE (MULTI-GROUNDED NEUTRAL) Three-Phase	Two-Phase	Single-Phase
GMD_ϕ	$\sqrt[3]{d_{AB}\, d_{BC}\, d_{CA}}$	d_{BC}	d_{AN}
$GMD_{\phi N}$	$\sqrt[3]{d_{AN}\, d_{BN}\, d_{CN}}$	$\sqrt{d_{BN}\, d_{CN}}$	d_{AN}

Figure 1.7 shows where the distance given in Table 1.1 are measured for the three-phase, two-phase, and single-phase lines with multi-grounded neutral conductor. From either Table 1.1 or Figure 1.7, notice that the phase conductors in the two-phase line are labeled B and C, and for the single-phase line the conductor is labeled phase A. However, this is not to suggest that the equations apply only if a two-phase extension from a three-phase circuit is from phases B and C, or a single-phase extension is from phase A.

The concept of a positive-sequence or zero-sequence impedance existing for either a two-phase line (Figure 1.7-b), or a single-phase line (Figure 1.7-c) is difficult to rationalize since all three phase conductors are not present. By assuming a "fictitious" third phase conductor is present in the two-phase line, and two "fictitious" phase conductors are present in the single-phase line, sequence impedances can be determined assuming the actual line is a three phase line[29,32].

With these sequence impedances, the methods of symmetrical components can be applied for fault current calculations, where the two-phase or single-phase line is treated as if it were a three-phase line. Since the "fictitious" conductor or conductors will carry no current and will not be involved in faults, assuming their presence when calculating impedances and fault currents will give correct results. Theoretically, this is true only if the intersequence mutual impedances are included in the fault current calculations. However, the intersequence mutual impedances for open wire lines are very small compared to the sequence self-impedances when the fictitious conductor(s) is located reasonably close to the actual conductors. It is not necessary to include them in the fault current calculations.

By treating the two-phase and single-phase lines as "equivalent" three-phase lines, equation (1.18) can be used to calculate Z_{11} for the two-phase and single-phase lines, and equation (1.19) can be used to calculate Z_{00} for the two-phase and single-phase lines. However, the term GMD_ϕ in equations (1.18) and (1.19) is a function of the distance from the actual conductor(s) to the fictitious conductor(s). Also, the term $GMD_{\phi N}$ in equation (1.19) is a function of the distance from the neutral conductor to the actual conductor(s) and fictitious conductor(s). By proper location of the fictitious conductor(s), the expressions for calculating GMD_ϕ and $GMD_{\phi N}$ will not contain the distances to the fictitious conductor(s) as can be seen from Table 1.1. For instance for the two phase line of Figure 1.7-b, where the actual conductors are labeled B and C, the "fictitious" conductor in phase A is located a distance $\sqrt{d_{BN}\, d_{CN}}$ from the neutral conductor. Thus makes the $GMD_{\phi N}$ of the "equivalent" three-phase line equal to $\sqrt{d_{BN}\, d_{CN}}$. Furthermore proper selection of angle θ in Figure 1.7-b makes the GMD_ϕ of the "equivalent" three-phase line equal to d_{BC} or

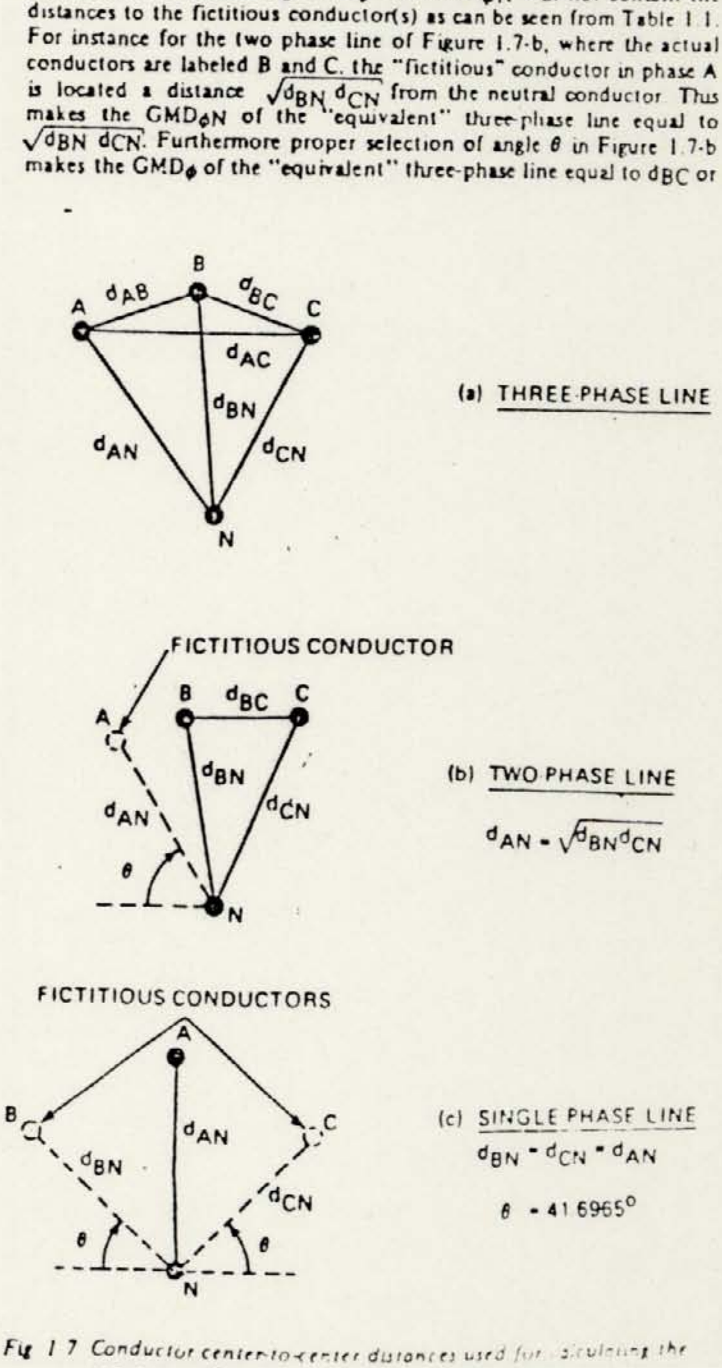


Fig 1.7 Conductor center-to-center distances used for calculating the sequence self impedances for open wire circuits

the phase-to-phase spacing of the two actual conductors. Similarly, for the single-phase line of Figure 1.7-c, where the actual conductor is labeled phase A, the two fictitious conductors are located a distance d_{AN} from the neutral conductor. This makes the $GMD_{\phi N}$ of the "equivalent" three-phase line equal to d_{AN}, or the actual spacing between the phase and neutral conductor. Setting the angle θ in Figure 1.7-c to 41.6965 degrees makes the GMD_{ϕ} of the "equivalent" three-phase line equal to d_{AN}.

For three-phase circuits, equations (1.18) and (1.19) show that the reactive components of Z_{11} and Z_{00}, which are designated as X_{11} and X_{00} respectively, are a function of the spacing between conductors (GMD_{ϕ}). Decreasing the spacing reduces X_{11} and increases X_{00}, such that the ratio of X_{00} to X_{11} increases as spacing decreases. As shown in reference 36, increasing this ratio results in higher phase-to-ground voltages on the unfaulted phases during ground faults. The expression for Z_{NN} shows that the resistive component of the self impedance of a conductor with earth return is independent of the earth resistivity. This is because the earth return current spreads over a wide area in high resistivity earth, and in low resistivity earth the earth current is concentrated in a smaller area[23].

1.4.5 Underground Circuits

Underground distribution circuits are made from different types of cables. Many primary circuits installed today in 15, 25, and 35 kV class distribution systems use single-conductor solid dielectric cables with a multi-wire concentric neutral on each cable. This section presents equations for calculating the sequence self-impedances for circuits made with this type of cable.

Three-phase circuits

Reference 31 presented methods for calculating the sequence self-impedances and intersequence mutual impedances for three-phase circuits made from single-conductor multi-wire concentric neutral cables. In that paper it was demonstrated that the multi-wire concentric neutral on each cable in a three-phase circuit could be treated as a uniform sheath when calculating sequence impedances. Dr. W. A. Lewis and R. C. Ender in their discussion of Reference 31 and Dr. Lewis in his own work in this area[32,33] showed that the sequence self-impedances can be accurately calculated with relatively simple equations, even when the three cables in the three-phase circuit are arranged unsymmetrically. This is made possible by assuming the three cables are located at the vertices of an equilateral triangle with a phase-to-phase spacing equal to the geometric mean of the actual spacings. This concept is illustrated in Figures 1.8-a and 1.8-b.

When the multi-wire concentric neutral cable in each phase is the same, the positive-sequence self-impedance (Z_{11}) and zero-sequence self-impedance (Z_{00}) of a three-phase circuit can be calculated with equations (1.20) and (1.21) respectively. The symbols appearing in these two equations are the same as in Dr. Lewis's work[32]. In addition, notice from the equations defining the terms found in equations (1.20) and (1.21) that all dimensions are in inches and the self impedances are in ohms per 1000 feet. These equations are easily evaluated using a hand held calculator or computer.

$$Z_{11} = Z_{aa} - Z_{ab} - \frac{(Z_{ax} - Z_{ab})^2}{Z_{xx} - Z_{ab}} \text{ Ohms/1000 ft.} \qquad (1.20)$$

$$Z_{00} = Z_{aa} + 2Z_{ab} - \frac{(Z_{ax} + 2Z_{ab})^2}{Z_{xx} + 2Z_{ab}} \text{ Ohms/1000 ft.} \qquad (1.21)$$

The terms appearing on the right hand side of equations (1.20) and (1.21) can be evaluated with the following expressions where the values of Z_{ij} are in ohms per 1000 feet.

$$Z_{aa} = R_{\phi} + .01807 \frac{f}{60} + j.0529 \frac{f}{60} \log \frac{D_e}{GMR_{\phi}} \qquad (1.21\text{-a})$$

$$Z_{ab} = .01807 \frac{f}{60} + j.0529 \frac{f}{60} \log \frac{D_e}{GMD_{\phi}} \qquad (1.21\text{-b})$$

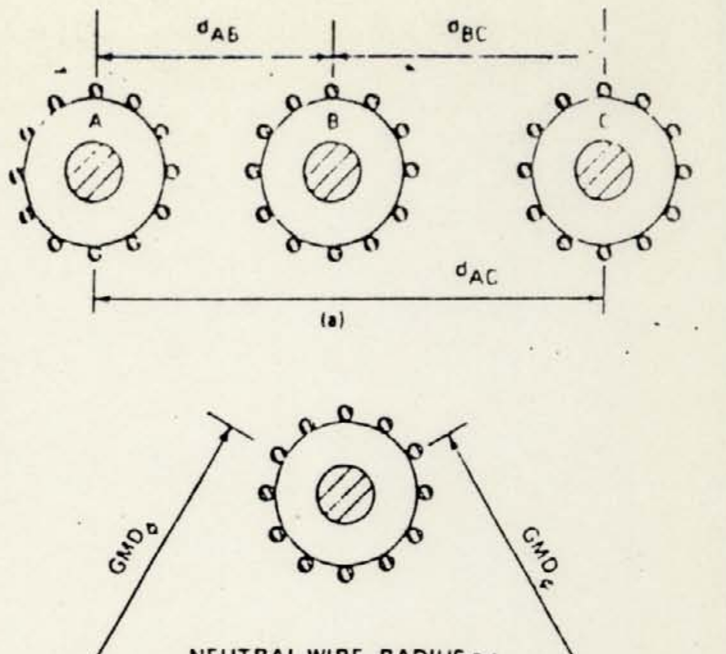


Fig. 1.8 *Three-phase circuit with single conductor multi-wire concentric neutral cables. (a) actual conductor arrangement. (b) assumed arrangement for calculating sequence self-impedances.*

$$Z_{ax} = .01807 \frac{f}{60} + j.0529 \frac{f}{60} \log \frac{D_e}{DN2} \qquad (1.21\text{-c})$$

$$Z_{xx} = R_N + .01807 \frac{f}{60} + j.0529 \frac{f}{60} \log \frac{D_e}{GMR_N} \qquad (1.21\text{-d})$$

$$D_e = 25920 \sqrt{\frac{\rho}{f}} \text{ inch} \qquad (1.21\text{-e})$$

$$GMD_{\phi} = \sqrt[3]{d_{AB}\, d_{BC}\, d_{CA}} \qquad (1.21\text{-f})$$

In equations (1.21-a) to (1.21-f) defining the terms appearing in equations (1.20) and (1.21), the symbols are:

R_N = resistance of the multi-wire concentric neutral on each cable in ohms per 1000 feet.

R_{ϕ} = resistance of the phase conductor in ohms per 1000 feet.

f = system nominal frequency in hertz.

D_e = depth of the equivalent earth return conductor in inches.

GMR_{ϕ} = geometric mean radius of the phase conductor in inches.

GMD_{ϕ} = geometric mean distance between the centers of the three cables in inches.

d_{ij} = actual distance in inches between the center of the cables for phases i and j.

DN2 = radius in inches of the circle formed by the centers of the wires in the multi-wire concentric neutral as shown in Fig 1.8-b.

GMR_N = geometric mean radius in inches of the multi-wire concentric neutral. This can be calculated from equation (1.22) which is taken from reference 32.

$$GMR_N = \sqrt[n]{n\ DN2^{(n-1)}\ r_n \times .7788} \qquad (1.22)$$

where:

n = number of strands in the multi-wire concentral neutral.

r_n = radius in inches of each strand in the neutral when each strand has a circular cross section.

From equation (1.22) it can be shown that for the size wire used in the concentric neutral of typical cable in underground distribution systems GMR_N and DN2 do not differ appreciably, especially as the number of strands (n) becomes large. In unpublished work of the author, it has been shown that letting GMR_N equal DN2 for cable sizes from 1/0 to 1000 MCM, with 1/3 neutral and insulation for either 15, 25, or 35 kV systems, does not result in more than a one half of one percent difference in the calculated values for Z_{11} and Z_{00}. Thus with equations (1.19) and (1.20), and cable and conductor tables giving physical dimensions and characteristics of cable, the sequence self-impedances for a three-phase circuit using single conductor multi-wire concentric neutral cables can be easily calculated.

Two-phase circuits

Next, consider a two-phase or V-phase circuit made with two single-conductor multi-wire concentric neutral cables as shown in Figure 1.9-a. Dr. Lewis[32] also shows that this case can be handled with an imaginary or fictitious conductor. However, the imaginary conductor can be introduced only after two-phase symmetrical components are used to create a three branch equivalent circuit as shown in Figure 1.9-b. When this is done, the following expressions result for the positive-sequence self-impedance and zero-sequence self-impedance of the two-phase circuit in Figure 1.9-a.

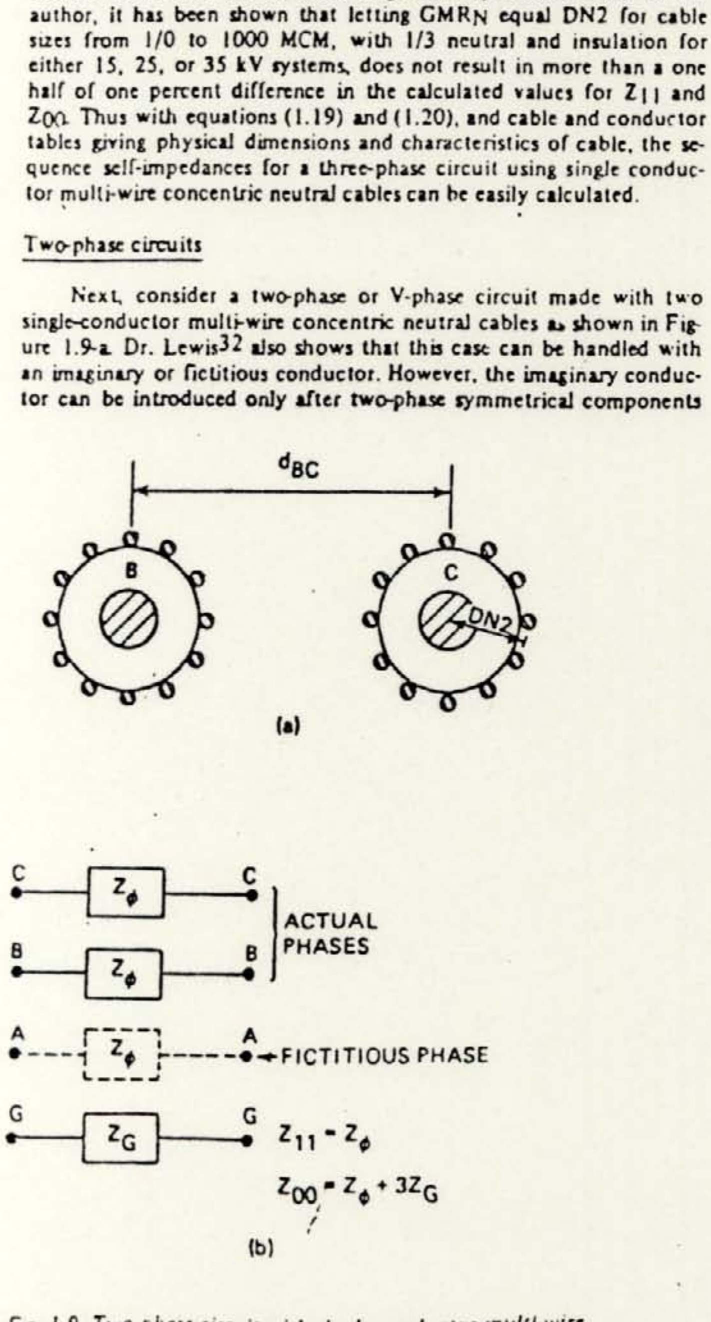


Fig 1.9 Two-phase circuit with single conductor multi-wire concentric neutral cables. (a) actual conductor arrangement. (b) lumped parameter equivalent with fictitious phase for calculating sequence self-impedances

$$Z_{11} = Z_{aa} - Z_{ab} - \frac{(Z_{ax} - Z_{ab})^2}{(Z_{xx} - Z_{ab})} \text{ Ohms/1000 ft} \qquad (1.23)$$

$$Z_{00} = Z_{aa} + 2Z_{ab} - \frac{3}{2}\frac{(Z_{ax} + Z_{ab})^2}{Z_{xx} + Z_{ab}} + \frac{1}{2}\frac{(Z_{ax} - Z_{ab})^2}{Z_{xx} - Z_{ab}} \text{ Ohms/1000 ft} \qquad (1.24)$$

All terms appearing in equations (1.23) and (1.24) have been previously defined (equations 1.21-a to 1.21-d) with the exception that GMD_ϕ for evaluating Z_{ab} is equal to the conductor center to conductor center distance of the two cables, d_{BC}. Equations (1.23) and (1.24) are easily evaluated with a hand held calculator or computer, although the determination of Z_{00} is quite tedious with the calculator. Fortunately, two-phase lines are uncommon in underground distribution systems.

Single-phase circuits

Finally, consider the single-phase underground circuit consisting of one multi-wire concentric neutral cable. The sequence self-impedances for the single-phase circuit can be calculated by introducing two fictitious conductors, but the two fictitious conductors can be introduced only after the circuit is represented by a lumped impedance in the actual phase. When this is done, the following equation results for calculating the sequence self-impedances.

$$Z_{11} = Z_{00} = Z_{aa} - \frac{Z_{ax}^{\,2}}{Z_{xx}} \qquad (1.25)$$

All terms appearing in the above equation have been previously defined.

1.4.6 Example Calculation - Cable Sequence Impedance

The following example calculation demonstrates the use of the equations for calculating the sequence self-impedances of a three-phase circuit with multi-wire concentric neutral. Consider a 15 kV class circuit made from cables with 1000 MCM aluminum phase conductor, 1/3 size neutral, and a flat spacing of cables with d_{AB}, d_{BC}, and d_{AC} equal to 8,8, and 16 inches respectively. From Reference 35, R_ϕ is 0.022 ohms per 1000 feet at 90°C, and R_N is 0.067 ohms per 1000 feet at 80°C., DN2 is 0.9159 inches, and the radius (r_n) of each of the 20 #10 copper neutral wires is 0.05095 inches. From Reference 6, the GMR_ϕ is 0.4452 inches for 61 strand 1000 MCM aluminum phase conductor. Assuming an earth resistivity of 100 ohm-meters and a frequency of 60 hertz, the calculations proceed as follows:

$$GMD_\phi = \sqrt[3]{8 \times 8 \times 16} = 10.08 \text{ inches}$$

$$D_e = 25920\sqrt{\frac{100}{60}} = 33463 \text{ inches}$$

$$GMR_N = \sqrt[20]{20 \times .9159^{19} \times .05095 \times .7788} = .9094 \text{ inches}$$

$$Z_{aa} = .04007 + j.2579 = .2610 \angle 81.17^\circ \ \Omega/1000 \text{ feet}$$

$$Z_{ab} = .01807 + j.1863 = .1872 \angle 84.46^\circ \ \Omega/1000 \text{ feet}$$

$$Z_{ax} = .01807 + j.2414 = .2421 \angle 85.72^\circ \ \Omega/1000 \text{ feet}$$

$$Z_{xx} = .08507 + j.2415 = .2560 \angle 70.59^\circ \ \Omega/1000 \text{ feet}$$

Placing the above values for Z_{aa}, Z_{ab}, Z_{ax}, and Z_{xx} into equations (1.20) and (1.21) yields the following values for Z_{11} and Z_{00}

$$Z_{11} = .04899 + j.04936 \ \Omega/1000 \text{ feet}$$

$$Z_{00} = .08759 + j.02363 \ \Omega/1000 \text{ feet}$$

From the value of Z_{11}, notice that the positive-sequence resistance is more than twice the resistance of the phase conductor. This is due to the high circulating currents in the concentric neutral[31,32,33] whose losses result in an increase in the effective positive-sequence resistance. Also, the positive-sequence reactance is appreciably less than that which would be calculated if the concentric neutrals were not present or open circuited. This is also due to the circulating currents in the concentric neutrals which have the effect of reducing the flux linkages between the phase conductors and consequently the positive-sequence reactance.

1.5 GENERALIZED RESULTS OF FAULT CURRENT STUDIES

In radial distribution feeders, the available current for a specific fault type is a maximum when the fault is located at the substation, and it decreases as the fault is moved away from the substation. Plots of available fault current versus distance from the substation to the fault location are called fault current profile curves. These curves provide information which is useful in performing protective device coordination studies. They show that the rate at which the available current decreases as the fault is moved out on the feeder is strongly influenced by system voltage level and the type of construction used for the feeder circuit (i.e.: open wire line or underground cable).

1.5.1 Available Fault Current Versus System Voltage Level

The effects of system voltage level on fault current profile curves for open wire lines are shown in Figure 1.10 for three-phase faults, and in Figure 1.11 for single line-to-ground faults. These curves show that increasing system voltage level decreases the rate at which the available fault current decreases. That is, when the available fault current at the substation bus is the same at the system voltage levels being considered, specifically 12.47, 24.94, and 34.5 kV in Figures 1.10 and 1.11, the fault current profile curve for the higher voltage system will be flatter and above that for the lower voltage system. The sequence impedances of the open wire line (336.4 MCM ACSR phase conductor) used in preparing the fault current profile curves are given in Figure 1.10 and 1.11. The power factor of the available three-phase and single line-to-ground fault current on the bus was 9.95 percent.

A comparison of the fault current profile curves for open wire lines in Figures 1.10 and 1.11 shows that as the fault is moved away from the substation, the available fault current decreases at a greater rate for the single phase-to-ground fault than for the three-phase fault. With open wire lines, this usually is the case because the zero-sequence impedance of the line is greater than the line's positive-sequence impedance. Also, from the curves of either Figure 1.10 or 1.11, it can be seen that the zone of protection of overcurrent devices of the same ampere rating can be longer in length in the higher voltage systems.

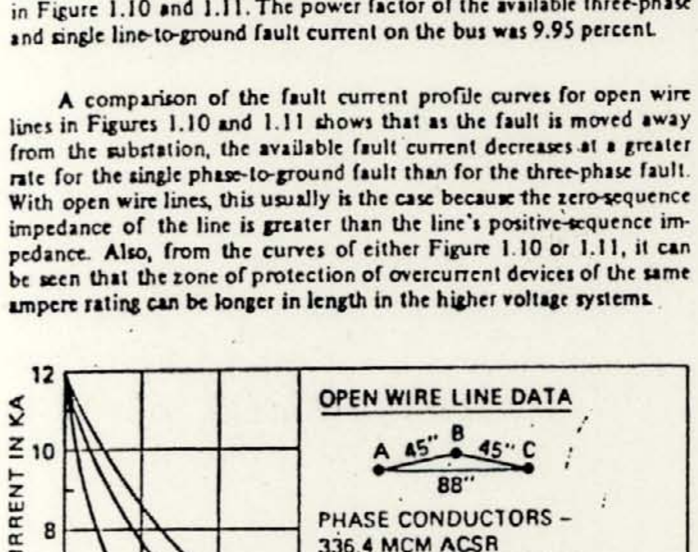


Fig. 1.10 Fault current profile curves for three-phase faults in a 12.47, 24.94, and 34.5 kV system

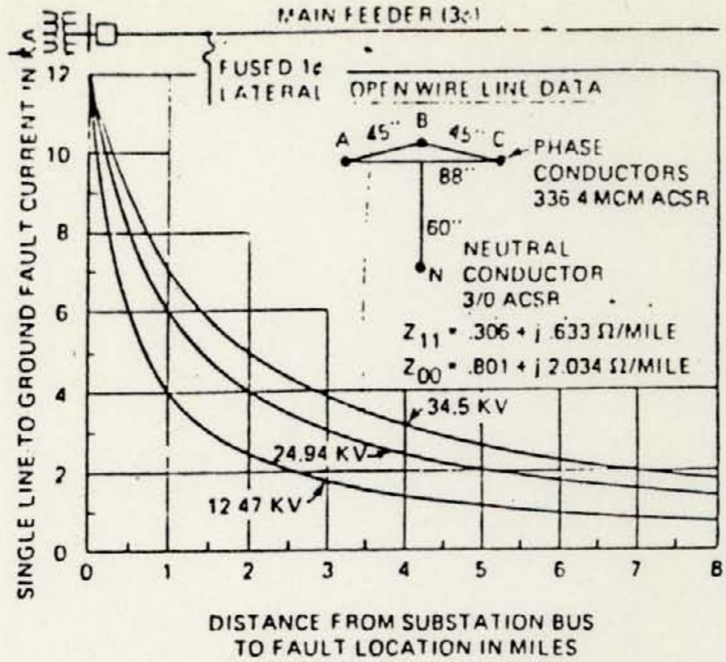


Fig. 1.11 Fault current profile curves for single line-to-ground faults in a 12.47, 24.94, and 34.5 kV system

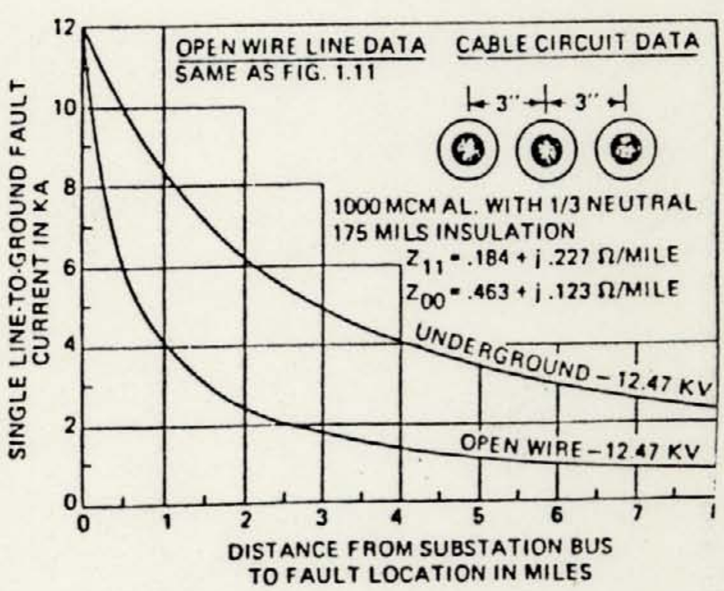


Fig. 1.12 Fault current profile curves for single line-to-ground faults in open wire and underground 12.47 kV circuits of approximately the same rating

1.5.2 Available Fault Current Versus Circuit Type

The effect of circuit type (overhead or underground) on fault current profile curves for single line-to-ground faults in a 12.47 kV system is illustrated in Figure 1.12. For the open wire line, the phase conductor is 336.4 MCM ACSR, and for the underground circuit the phase conductor is 1000 MCM aluminum. An open-wire line and cable circuit with these conductors have about the same kVA rating under both normal and emergency conditions[37]. The sequence impedances used for the cable circuit and the open wire line in plotting these fault current curves are given on Figures 1.11 and 1.12. It is the lower sequence impedances of the cable circuit which result in the available fault currents being higher in the underground feeder. A comparison of the curves in Figure 1.12 with those in Figure 1.11 shows that circuit type can have a greater effect than circuit voltage level on the rate at which the fault current decreases as the fault is moved away from the substation bus.

1.5.3 Effect of Fault Current Profile on Coordination

The information in Figures 1.10 to 1.12 shows that in 25 and 35 kV systems, or with total underground circuits at any voltage level, it may be more difficult to obtain the desired level of coordination than in the 15 kV class system with open wire lines[38]. For instance, two expulsion fuses will selectively coordinate if the available fault current at the "protecting" fuse (the one which is farthest from the source) is less than some value which is a function primarily of the size and type of the "protected" fuse (the one which is closest to the source). Since the available fault currents at a given distance from a substation usually are higher in 25 and 35 kV systems and in total underground systems than in a 15 kV class system with open wire lines, the probability of obtaining selective coordination between fuses is lower in the former systems. For another example, consider the case where it is desired that instantaneous tripping of a breaker in a substation prevents the blowing of a fuse for a temporary fault on a lateral circuit. With reference to Figure 1.11, assume that the fused lateral is located 1.5 miles from the substation in both the 12.47 kV and 34.5 kV systems, and that the same size and type fuse is used for the lateral in either system. Figure 1.11 shows that the maximum current in the fuse for a single line-to-ground fault beyond the fuse is 3000 amperes in the 12.47 kV system, but this current is 5800 amperes in the 34.5 kV system. Although it would depend upon the fuse size and type, it is possible that instantaneous tripping of the station breaker will prevent fuse blowing in the 12.47 kV system, but not in the 34.5 kV system.

Thus, any "rules of thumb" developed from successful practices used in obtaining coordination in 15 kV class systems with open wire lines may not be applicable in higher voltage distribution systems and in total underground systems.

1.6 FAULT CURRENTS ON OPPOSITE SIDES OF TRANSFORMERS

Overcurrent protective devices located on opposite sides of transformers in either the distribution substation or on the distribution circuits should be coordinated. For example, with small substation transformers, power fuses frequently are applied on the primary side, with reclosers or reclosing circuit breakers applied on the secondary side. To prevent unnecessary blowing of primary fuses on through faults, these devices must be selectively coordinated.

To coordinate overcurrent protective devices located on opposite sides of transformers, the maximum value for the ratio of the line current in amperes on the primary side of the transformer to the line current in amperes on the secondary side of the transformer must be known. For a symmetrical three-phase transformer bank or a three-phase unit (one with equal impedances in actual ohms or per unit on a common kVA base in each phase, and equal turns ratio in each phase), the ratio of primary line current in amperes to secondary side line current in amperes is a function of the ratio of the primary side rated phase-to-phase voltage (KV_P) to the secondary side rated phase-to-phase voltage (KV_S). The relationship between primary side and secondary side line current for many transformer connections also is a function of the type of fault on the secondary side of the transformer (i.e., three-phase, phase-to-phase, single phase-to-ground).

Transformer connections affect not only the ratio of primary line current in amperes to secondary line current in amperes, but also the relationship between the current in transformer windings and the current in the lines connected to the windings. For wye connected transformer windings, the winding current and the line current in the same phase are equal. However, for delta connected windings, the relationship between the winding currents and the current in the lines connected to the windings are a function of the type of through fault. These relationships must be considered when evaluating the degree that overcurrent devices protect the transformer against through faults. First, however, the effect of the more common winding connections on the ratio of primary side line current to secondary side line current will be considered.

1.6.1 Primary-Secondary Side Line Current Ratios

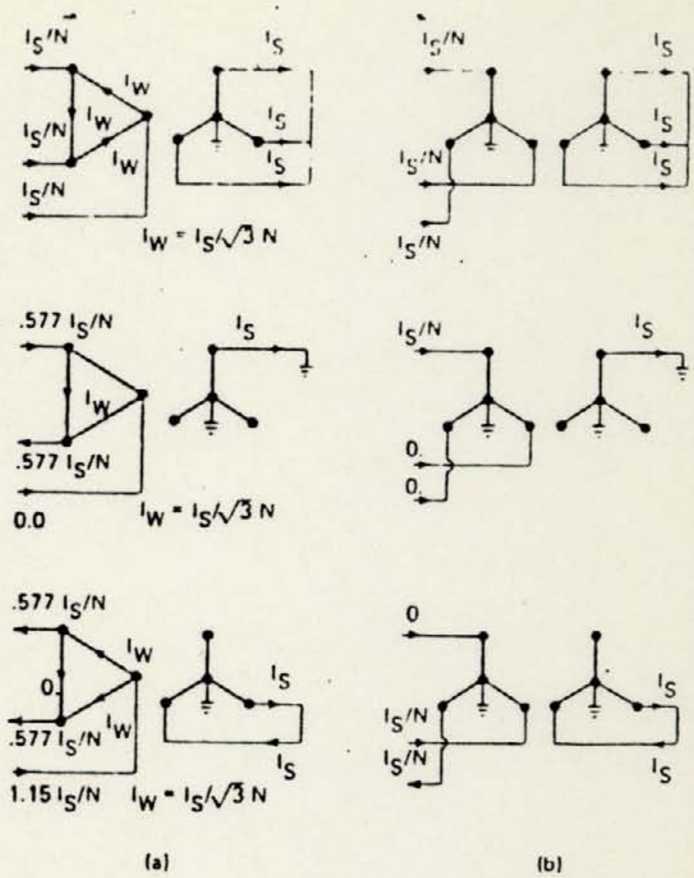


Fig. 1.13 Primary side and secondary side line currents in amperes for (a) delta-grounded wye and, (b) grounded wye-grounded wye transformer connections. N is the ratio of primary side to secondary side rated phase-to-phase voltage.

delta-grounded wye transformer connections during three-phase, single phase-to-ground, and phase-to-phase faults on the secondary side. Figure 1.13-b gives this information for the grounded wye-grounded wye connections. For the connections in Figure 1.13-b, the effects of any "fictitious" tertiary have been neglected. In these figures, I_S is the current in amperes in the secondary lines, and N is the ratio of the rated phase-to-phase voltage of the transformer primary (KV_P) to the rated phase-to-phase voltage of the transformer secondary (KV_S). For the three-phase fault shown in Figure 1.13-a, the current in each phase is equal in magnitude but 120 degrees displaced from that in the other two phases. However, for the single phase-to-ground and phase-to-phase faults, the phase currents are not balanced. For these faults, the arrows in the figure indicate the "direction" or phase of the currents following normal convention. The relationship between the current in the delta winding (I_W) and the current in the lines connected to the delta winding can be determined from the information in Figure 1.13-a.

Figures 1.14-a and 1.14-b give the same information as Figure 1.13 except that it applies to the delta-delta and the floating wye-delta connections. These connections are used in distribution transformer banks applied in overhead systems. The significance of the information in Figures 1.13 and 1.14 will be illustrated with the delta-grounded wye connections.

With reference to Figure 1.13-a, the ratio of primary side line current in amperes to secondary side line current in amperes is 1/N for the three-phase fault, but for the single phase-to-ground fault this ratio is 0.577/N or 57.7 percent of the ratio for a three-phase fault. Thus, if the phase overcurrent protective devices on the primary and secondary side of the transformer are selectively coordinated for the three-phase fault, they will be selectively coordinated for the single phase-to-ground fault. However, for the ungrounded phase-to-phase fault on the secondary side of the transformer, the ratio of primary line current in amperes to secondary line current in amperes is 1.15/N or 15 percent greater than the ratio for a three-phase fault. It is the un-

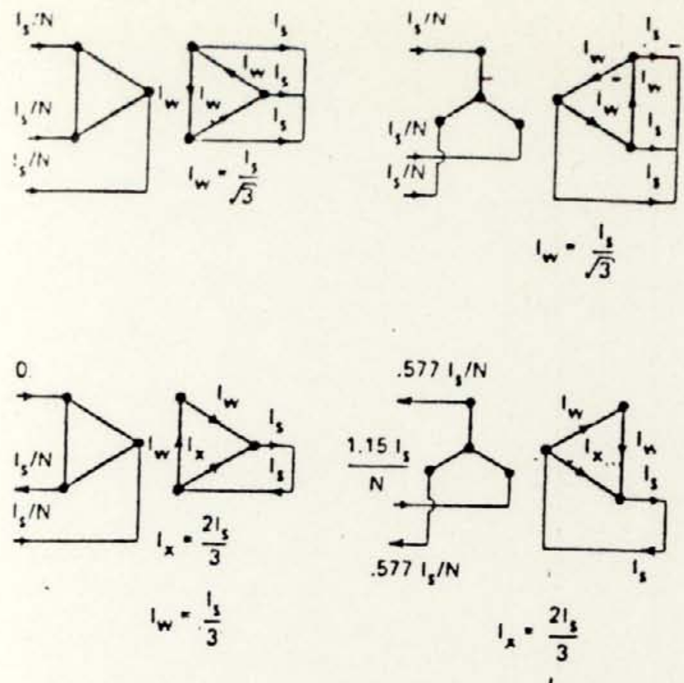


Fig. 1.14 Primary side and secondary side line currents in amperes for the three-phase and phase-to-phase fault on the (a) delta-delta and, (b) floating wye-delta connected transformer. N is the ratio of primary side to secondary side rated phase-to-phase voltage.

The phenomenon illustrated in Figure 1.13-a is accounted for in the plotting of the time current curves of the protective devices located on the primary and secondary sides of the transformer[39]. Figure 1.15 shows this where it is assumed, for simplicity sake, that the overcurrent devices on both sides of the transformer are fuses. The time-current curves are plotted with the scale on the abscissa being current in amperes at secondary voltage KV_S. The curve labeled FS gives the time current characteristics of the fuses on the secondary side. Since the secondary side fuses see the value of current indicated on the abscissa, the curve labeled FS gives the minimum melting and total clearing time for any value of secondary current regardless of the fault type. However, for a value of secondary line current indicated on the abscissa (I_S), the current in a primary line can be one of three values depending upon the type of secondary fault. This is reflected in Figure 1.15 where three curves are required to represent the minimum melting time of the primary fuse (FP) as a function of secondary current. Each curve applies only to the indicated fault type. In Figure 1.15, the curve representing the primary fuse for the single phase-to-ground fault is the fuse curve for the three-phase fault shifted to the right by a factor of $\sqrt{3}$. The curve representing the primary fuse for the phase-to-phase fault is the fuse curve for the three-phase fault shifted to the left by a factor of $\sqrt{3}/2$ or 0.866. These curves illustrate that it is the phase-to-phase fault which must be considered when coordinating phase overcurrent devices located on opposite sides of the delta-grounded wye transformer. To better understand this, recall that the phase-to-phase fault on the secondary side gives the same current in the primary side fuse as the three-phase secondary fault, yet the current in the secondary side fuse for the phase-to-phase fault is only 86.6 percent of the secondary current for the three-phase fault. Thus the time to melt the first primary fuse is the same regardless of whether the secondary fault is phase-to-phase or three-phase, but the total clearing time of the secondary side fuse will be greater for the phase-to-phase fault.

From Figure 1.13-b and 1.14-a, notice that when the transformer has the grounded wye-grounded wye or the delta-delta connections, the ratio of primary line current in amperes to secondary line current in amperes is the same (1/N) regardless of the type of fault. Thus, when the time current characteristics of the fuses on the primary side are plotted in terms of secondary amperes (when the scale on the abscissa is in secondary amperes as in Figure 1.15), only one minimum melting and one total clearing curve is needed to represent the fuse on the primary side.

For the floating wye-delta bank in Figure 1.14-b, it is also the ungrounded phase-to-phase fault which must be considered when coordinating protective devices. This fault type gives a maximum value for the ratio of primary line current in amperes to secondary line current in amperes. In this respect, the floating wye-delta connections respond similarly to the delta-grounded wye connections.

In general, if the symmetrical transformer (bank) either (1) creates a ground source on either the primary or secondary side, (2) introduces a phase shift between the primary and secondary sides, or (3) is unsymmetrically grounded as with the center tap or corner ground on a delta winding, all fault types should be considered when coordinating phase overcurrent devices located on opposite sides of the transformer. In addition, if a transformer bank is made from single-phase units of different size or impedance, all fault types should be considered in the coordination of overcurrent devices.

1.6.2 Effect of Connections on Protective Level

The windings of single-phase and three-phase transformers which satisfy short circuit requirements of ANSI standards[40,41] are capable of withstanding a specified multiple of rated winding current for a specified time period. When the phase overcurrent device such as a fuse or recloser is connected in series with the transformer winding, as occurs with the wye connected windings, the current in the winding and the current in the overcurrent device are the same. For these cases, the time-current characteristics of the overcurrent device can be compared directly with the point[40] or curve[42] defining the thermal capability of the transformer winding. From this comparison, the degree of thermal protection provided by the phase overcurrent device can be determined.

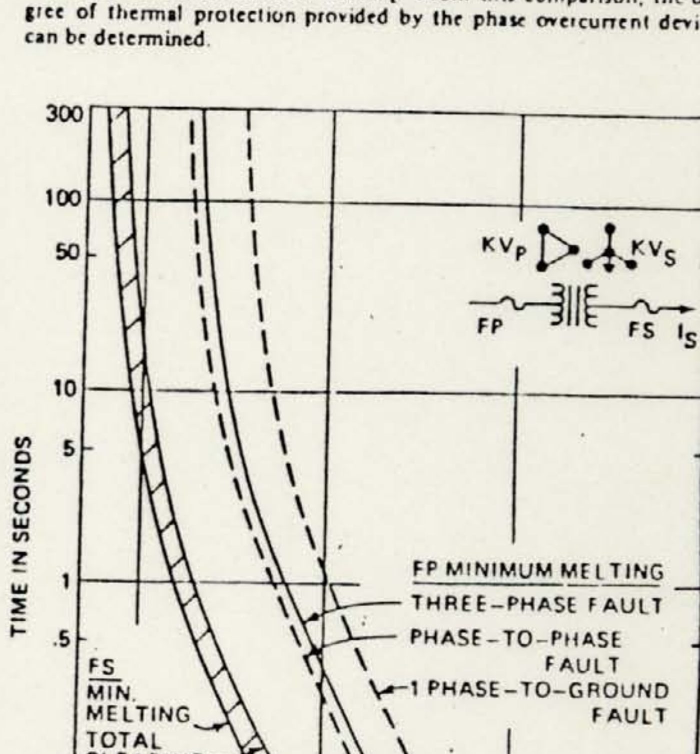


Fig. 1.15 Time current curves for primary and secondary side fuses when plotted in terms of secondary line current in amperes

With delta connected transformer windings, in general, the current in the lines connected to the windings are not the same as the current in the windings. Furthermore, the ratio of the current in the line to the current in the winding is a function of the type of through fault. For example, Figure 1.13 shows that the ratio of primary line current to primary winding current is $\sqrt{3}$, 1, and 2 respectively for the three-phase, single phase-to-ground, and phase-to-phase fault on the secondary side of the delta-grounded wye transformer. With the same value of current in a delta connected winding, the line current for the single line-to-ground fault is 57.7 percent of that for the three-phase fault as shown in Figure 1.13-a. A fuse on the delta side of the transformer would require a longer time to clear a secondary single line-to-ground fault than a secondary three-phase fault even though the winding currents are the same for both faults. It is possible that the phase overcurrent devices in the lines supplying the delta connected winding could thermally protect the transformer for a three-phase fault, but not for a single line-to-ground through fault. If the phase overcurrent device thermally protects the transformer for both fault types, the margin between the time current curve of the phase overcurrent device and the thermal curve of the transformer will be less for the single line-to-ground fault.

When the thermal protection of a transformer for through faults is provided by phase overcurrent devices in the lines connected to a delta winding, the time current characteristic of the overcurrent device is compared with the point[40] or curve[42] defining the thermal limits of the transformer recognizing that the ratio of line current to winding current is a function of the fault type. This is illustrated in Figure 1.16 where the through fault protection for an OA/FA transformer is provided by the 150E ampere fuses in the lines on the delta side (34.5 kV) of the transformer. Since the abscissa in Figure 1.16 gives the current in amperes in the lines connected to the delta winding, the fuse is represented by one set of time current curves. However, the transformer thermal capability is represented by three curves when plotted in terms of line current at 34.5 kV, where the thermal capability of the winding is assumed to be that defined in Figure 1 of

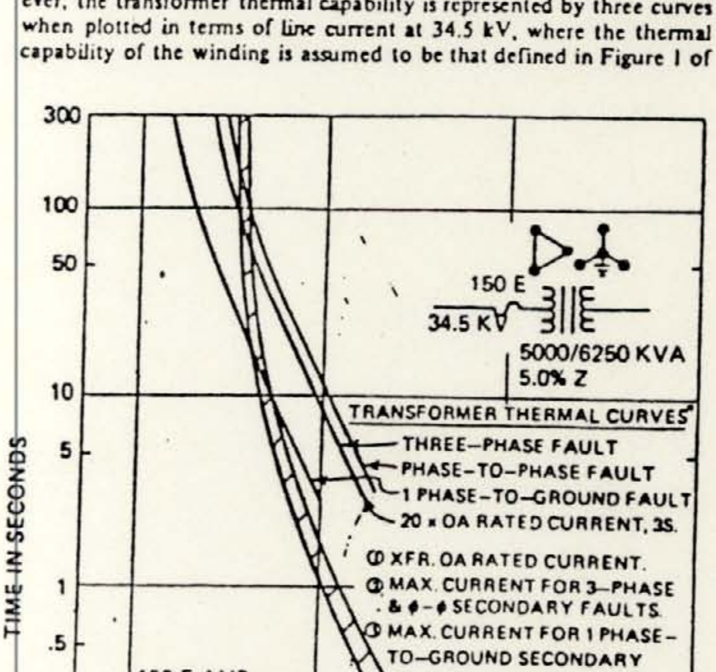


Fig. 1.16 Comparison of primary side fuse characteristics and transformer thermal curves for different types of secondary faults.

Reference 42. The thermal curve for a single phase-to-ground fault on the secondary is the same as that for a three-phase fault except it is shifted to the left by a factor of $1/\sqrt{3}$. The 150 E fuse total clearing curve lies below the transformer thermal curve for a three-phase fault if the fault current is greater than 390 amperes or 4.67 times rated line current. For the single phase-to-ground fault, the fuse curve is below the transformer thermal curve for currents which are greater than about 500 amperes, or 5.98 times rated OA current. Figure 1.16 shows that the margin between the fuse total clearing curve and transformer thermal curve is greater for the three-phase secondary fault than for the single phase-to-ground secondary fault. It also shows that, in general, external fuses on the primary side of a transformer may not provide overload protection for the transformer.

Referring to the single line diagram in Figure 1.16, the 150E ampere fuses on the primary side provide the through fault protection for faults between the secondary terminals of the transformer and the first downstream protective device on the secondary side. For faults beyond the first protective device on the secondary, usually a main or feeder breaker, the through fault protection is provided by the secondary side device. The time current curve(s) of the secondary side device should be compared with the curve or point representing the transformer thermal capability to evaluate the through fault protection.

1.7 FAULT CURRENT ASYMMETRY

The fault current calculations presented in previous sections determine the rms value of the steady state (alternating) component of the total fault current. Whenever a fault occurs, the total current in the fault path consists of the a.c. or steady state component, plus a direct current component (d.c.) which decays exponentially in time. If the currents due to load are neglected, which is a valid assumption in many cases, most distribution circuits during a fault can be reduced to the simple form shown in Figure 1.17. In this figure, closing of switch S simulates the occurrence of a fault. The instantaneous value of current at any time following switch closure is given by equation (1.26).

$$i(t) = \sqrt{2}\, I_{rms} \sin(wt + \theta - \theta_Z) - \sqrt{2}\, I_{rms} \sin(\theta - \theta_Z) \exp\left(-\frac{wt}{X/R}\right) \qquad (1.26)$$

where:

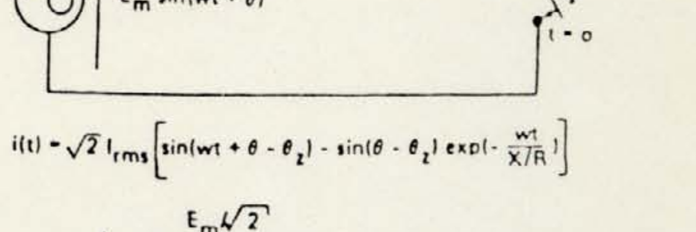
$i(t)$ = the instantaneous value of current at time t

I_{rms} = the root mean square (rms) value of the a.c. component of current

θ = the closing angle which defines the point on the source sinusoidal voltage wave at which switch S is closed.

$\theta_Z = \tan^{-1}\frac{X}{R}$ = system impedance angle

w = system frequency in radians per second, which is 120π radians per second for a 60 Hz system.



$$i(t) = \sqrt{2}\, I_{rms}\left[\sin(wt + \theta - \theta_z) - \sin(\theta - \theta_z)\exp\left(-\frac{wt}{X/R}\right)\right]$$

$$I_{rms} = \frac{E_m/\sqrt{2}}{\sqrt{R^2 + X^2}}$$

Fig. 1.17 Simple R-L circuit for determining effects of asymmetry on peak current, I^2t and rms value of current.

The first term on the right hand side of equation (1.26) represents the a.c. or steady state component of current. The peak value of the a.c. component is simply $\sqrt{2}$ times the rms value of the a.c. component (I_{rms}). On the right hand side, the second term represents the exponentially decaying d.c. component of current. Although the time constant at which the d.c. component decays is a function of the L to R ratio of the circuit, the initial magnitude of the d.c. component is a function of the closing angle θ. If the closing angle θ is selected such that $\theta - \theta_Z$ equals $n\pi$ radians where n is an integer or zero, the initial value of the d.c. component will be zero. That is, the closing angle θ can be selected such that a d.c. component of current will not exist in the circuit of Figure 1.17. If the closing angle is selected such that $\theta + \theta_Z$ equals $n\pi/2$ radians, where n is an odd integer (i.e., 1, 3, 5 . . .), the d.c. component will have a maximum value at time zero. This maximum equals $\sqrt{2}$ times I_{rms}.

Figure 1.18 is a plot of equation (1.26) to illustrate the two components which make up the total (asymmetric) current wave. For this plot, the circuit X/R ratio is 10, and the closing angle θ is zero degrees. If the closing angle were adjusted such that a d.c. component were not present, the waveform of the total current would be that of the a.c. component of current. A comparison of the waveform of the a.c. component with that of the total (asymmetric) current in Figure 1.18 shows that the maximum peak value of the asymmetric current wave is much greater than the peak of the symmetric current wave. Furthermore, intuition suggests that the energy content of the first loop of the asymmetric wave will be greater than that in the first loop of a symmetric wave. These observations are examined further in the following sections.

1.7.1 Peak Current Factors

In designing system apparatus, it frequently is necessary to determine the maximum peak current which can occur for a known value of the symmetrical or a.c. component of current. This is because the forces developed in the apparatus are a function of the square of the peak current. Knowledge of the maximum peak current which can occur during fault conditions also is useful in evaluating the ability of current-limiting fuses to limit peak current.

The ratio of the maximum peak current (I_p) which can occur in a circuit to the rms value of the a.c. component of current (I_{rms}) is called the peak current factor in this paper. The maximum peak current in the R-L circuit, regardless of the magnitude of I_{rms}, is the product of the peak current factor and the rms value of the a.c. component of current. The maximum peak current will occur in the simple R-L circuit of Figure 1.17 when the closing angle θ is zero degrees, regardless of the X to R ratio of the circuit[43]. In contrast, with a current-limiting fuse in the circuit, the maximum peak let-thru current usually occurs when the closing angle is near 90 degrees[45].

With equation (1.26), peak current factors can be determined. To do this, the closing angle θ is set to zero, and equation (1.26) solved iteratively for any specified X to R ratio to determine the maximum peak current as a multiple of I_{rms}. Peak current factors, for a range of X to R ratios are listed in Table 1.2 under the header, I_p/I_{rms}. Listed under the header t_p are the times in milliseconds after switch closure at which the maximum peak current occurs.

Approximate values for the peak current factors for given X to R ratios can be calculated to an accuracy of 0.7 percent or less using equation (1.27)[40, 44].

$$\frac{I_p}{I_{rms}} = \sqrt{2}\left[1 + \exp\left(-\left(\theta_Z + \frac{\pi}{2}\right)\frac{R}{X}\right) \cdot \sin\theta_Z\right] \qquad (1.27)$$

For example, consider a circuit with an X to R ratio of 2.0. Table 1.2 shows that the exact value (to 3 places) for the peak current factor is 1.756. By comparison, the value calculated from the equation is 1.746, which is the same for practical purposes. In evaluating equation (1.27), θ_Z should be in radians.

1.7.2 I^2t Factor

Two of many parameters characterizing the performance of current-limiting fuses in the current-limiting region are the fuses minimum melting I^2t and maximum total clearing I^2t values. The term,

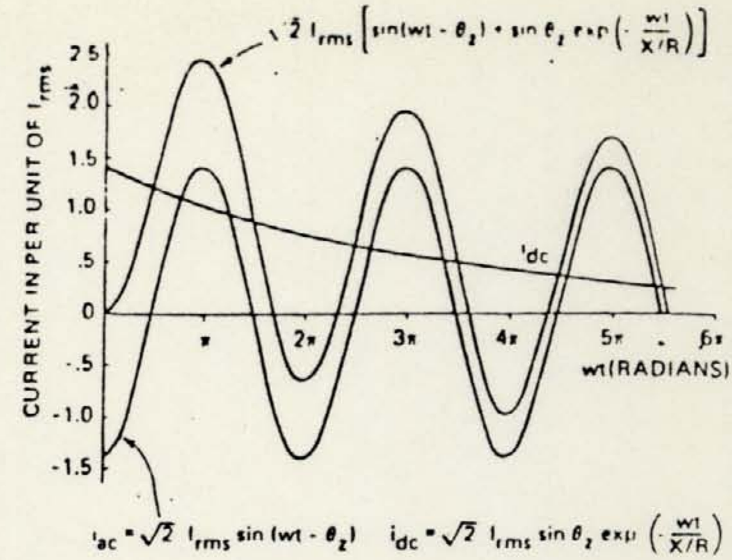


Fig. 1.18 Plot of total (asymmetric) current for a zero degree closing angle. Total current consists of a d.c. component (i_{dc}) and an a.c. component (i_{ac}).

I^2t, is an abbreviation for the time integral of the square of the instantaneous value of current of a current waveform, such as shown in Figure 1.18, over a specified time period. For a constant resistance element, the product of the I^2t value of the current waveform and the resistance is the energy in joules (watt-seconds) supplied to the resistive element. Thus the I^2t value of a current waveform gives a relative indication of the energy content of a wave. By comparing the maximum total clearing I^2t value of a current-limiting fuse with the I^2t value of the first loop of the waveform of the available current, the ability of the current-limiting fuse to limit energy dissipation can be evaluated. Note that the I^2t value of the waveform of the available current is a good indicator of the I^2t value in the current waveform of zero-current interrupters such as expulsion type fuses.

The relationship between the I^2t content in a current waveform and the rms value of the a.c. component of current can be determined from equation (1.26). Of particular interest is the maximum value for the I^2t in the first loop of the available current. If the current waveform is sinusoidal as shown by the a.c. component wave in Figure 1.18, the I^2t in the first loop is the product of the square of the rms value of the a.c. component of current and the time to the first zero in the current waveform, which is 0.008333 seconds for a 60 Hz system. Comparison of the waveforms for the total current and the a.c. component of current suggests that the I^2t content of the first loop of an asymmetric wave will be greater than that of the first loop of the symmetrical wave. Furthermore, it can be shown that the first loop of an asymmetric wave will have maximum I^2t value if the closing angle θ is zero degrees. Setting θ in equation (1.26) to zero, squaring and integrating both sides from t equal zero to t equal t_0, where t_0 is the time to the first current zero, and dividing both sides by I_{rms}^2 will give the ratio of the maximum value of I^2t in the first current loop to I_{rms}^2. This ratio is defined as first loop I^2t factor, and its value is a function of only the circuit X to R ratio.

Values for the first loop I^2t factor are given in Table 1.2 under the header, $\int i^2\,dt/I_{rms}^2$, for a range of X to R values typical of distribution circuits. Given under the header t_0 is the time to the first current zero in milliseconds for the zero degree closing angle. If the rms value of the available a.c. current is known, the maximum possible value for the I^2t in the first loop is simply the square of the rms value of the a.c. component (symmetrical component of current) times the first loop I^2t factor in Table 1.2. Notice from the values of the first loop I^2t factors that the ratio of the I^2t content of a fully asymmetric wave ($X/R = \infty$) to that of a symmetric wave (closing angle θ adjusted such that d.c. component is zero) is 6.0. This suggests that the energy which can be delivered in the first loop of current to a piece of apparatus protected with a zero current interrupter is strongly affected by the closing angle or fault initiation angle.

TABLE 1.2
Fault Current Asymmetry Data

PEAK CURRENT FACTORS			FIRST LOOP I^2t FACTORS		FIRST LOOP RMS VALUES		
X/R	I_p/I_{rms}	t_p (ms)	$\int i^2\,dt/I_{rms}^2$	t_o (ms)	I'_{rms}/I_{rms}	θ (DEG)	t_o' (ms)
0	1.414	4.167	.008333	8.333	1.103	51.3	5.96
.2	1.414	4.690	.008367	8.857	1.042	41.7	6.93
.4	1.418	5.157	.008574	9.343	1.008	34.5	7.75
.6	1.436	5.530	.009021	9.770	1.000	29.2	8.41
.8	1.469	5.824	.009679	10.137	1.010	25.9	8.93
1.0	1.512	6.059	.010490	10.453	1.030	23.4	9.36
2.0	1.756	6.772	.015302	11.540	1.172	17.1	10.73
3.0	1.950	7.137	.019743	12.194	1.291	14.5	11.50
4.0	2.089	7.362	.023366	12.644	1.377	13.3	12.01
5.0	2.192	7.514	.026283	12.978	1.439	12.6	12.37
6.0	2.271	7.652	.028652	13.239	1.487	12.0	12.66
7.0	2.332	7.709	.030605	13.451	1.524	11.6	12.88
8.0	2.382	7.775	.032237	13.627	1.553	11.3	13.08
9.0	2.422	7.829	.033620	13.777	1.577	11.1	13.23
10.0	2.456	7.873	.034805	13.906	1.597	11.0	13.36
11.0	2.485	7.910	.035832	14.020	1.613	10.8	13.48
12.0	2.509	7.941	.036729	14.120	1.627	10.7	13.59
13.0	2.531	7.969	.037520	14.210	1.639	10.6	13.68
14.0	2.549	7.992	.038223	14.290	1.650	10.6	13.76
15.0	2.566	8.012	.038850	14.363	1.659	10.6	13.83
16.0	2.580	8.031	.039415	14.430	1.667	10.5	13.90
17.0	2.594	8.047	.039925	14.491	1.674	10.4	13.97
18.0	2.605	8.062	.040388	14.548	1.680	10.3	14.02
19.0	2.616	8.075	.040810	14.600	1.686	10.4	14.03
20.0	2.626	8.088	.041197	14.648	1.691	10.4	14.12
∞	2.818	8.333	.05000	16.667	1.768	14.9*	15.29

*Closing angle accurate to limits possible with single precision arithmetic.

7.3 RMS Value of Current Waveforms

The root mean square value, or rms value of a current waveform such as shown in Figure 1.18 is defined by equation (1.28), where I' is the rms value of the current i(t) between time t_1 and time $t_1 + T$.

$$I' = \sqrt{\frac{1}{T}\int_{t_1}^{t_1+T} i^2(t)\,dt} \qquad (1.28)$$

Both sides of equation (1.28) are squared:

$$I'^2 = \frac{1}{T}\left[\int_{t_1}^{t_1+T} i^2(t)\,dt\right] \qquad (1.29)$$

where the term in brackets is the I^2t value of the current waveform in time interval T. From Section 1.7.2 recall that the I^2t value of a current waveform is proportional to the energy transferred to a resistive element with constant resistance in time period T, where the resistance is the proportionality constant between I^2t in ampere squared seconds and energy in joules. Thus the square of the rms value of a current waveform, from equation (1.29), is proportional to the average time rate at which energy is transferred to a resistive element with constant resistance. The average time rate at which energy is transferred to an element in an electric circuit is, by definition, the average power. Reference to equation (1.29) also shows that the square of the rms value of a current waveform, times the time interval T over which the rms value was determined, is proportional to the energy delivered to a resistive element with constant resistance.

The rms value of any current waveform can be determined from equation (1.28). Several cases will be considered. If the current waveform is sinusoidal and the integration time interval T is an integer multiple of one half the period of the sine wave, the rms value is simply the peak value of the wave divided by the square root of 2. This is always true regardless of the value of t_1. Another interesting case appearing in the literature[46, 47] is concerned with determining the rms value of the first loop of an asymmetric current wave as defined by equation (1.26). If the expression for i(t) given by the right hand side of equation (1.26) is squared, placed into the right hand side of equation (1.28), and the indicated operations performed, the result is the rms value for the first loop of current. In performing these operations with equation (1.28), t_1 is set to zero and T is the time to the first current zero.

With reference to equation (1.26), it is not known what value of closing angle θ, for a given X to R ratio, will result in the first loop of current having a maximum rms value. Although the I^2t value of the first loop of current will be maximum if the closing angle θ is zero, Gross and Thapar[47] have shown that the closing angle is a non-zero value if the object is to maximize the rms value of the first loop of current. Furthermore, they show that for a given X to R value, the ratio of the rms value of the first loop of current (I_{rms}') to the rms value of the symmetrical component of current (I_{rms}) is a function of only the closing angle θ. The value of θ which yields the maximum can be found with iterative techniques after the value for i(t) from equation (1.26) is placed into equation (1.28) and the indicated operations performed.

Table 1.2 lists, under the header first loop rms values, values for the ratio of the maximum rms value of the first loop of current to the rms value of the symmetrical component of current (I_{rms}'/I_{rms}). Also given in the table for each X to R is the value of the closing angle θ which results in the maximum, and the time in milliseconds (t_o') to the first current zero. Notice from the data that when the closing angle θ is adjusted such that the rms value of the first loop of current is a maximum, the corresponding I^2t value is not at a maximum. For instance, consider the case where the X to R ratio is 5. With the closing angle set at 12.6 degrees, the I^2t value in the first loop is $(1.439)^2 \times .01237$ or .02561 ampere squared seconds when the available symmetrical current is 1.0 ampere rms. In contrast, when the closing angle θ is zero degrees, the I^2t value is 0.02628 ampere squared seconds per Table 1.2. Selecting the closing angle to maximize the average time-rate at which energy is transferred in the first loop of current to a resistive element of constant resistance does not result in the energy transfer by the first loop of current being maximized.

The rms value of a current wave is significant since it is the measure or basis for establishing the momentary and interrupting ratings for equipment. ANSI apparatus standards define the methods whereby the rms value of an asymmetrical current wave obtained from a test oscillogram is determined, and values determined with these methods establish the momentary or interrupting rating of the equipment. Furthermore, these apparatus standards also establish methods whereby a calculated rms value for the symmetrical component (a.c.) of current can be used to determine the momentary and interrupting rating required for a piece of equipment to be applied. Although these methods are not exact, they should be followed in determining if equipment interrupting rating is adequate for an intended application.

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ANEXO E

CIUDAD : PROP94

ALIMENTADOR NO. 5 SAN BLAS S/E PLANTA DEL ESTE
VOLTAJE LINEA A LINEA 13.80 KV
FACTOR DE POTENCIA 84. %
TENSION EN BARRA 102. %

DEMANDA 7817. KVA 6602. KW 4186. KVAR

SECC/ NODO	KVA CONEC S PRESENT	CARGAS KW	CARGAS KVAR	LONGIT KM	CONDUCTOR TIPO	CONDUCTOR % CARGA	IMPEDANCIA RESIS	IMPEDANCIA REACT	CARGA/SECCION KW	CARGA/SECCION KVAR	PCT DE CAIDA SECC.	PCT DE CAIDA ACUM.	% KVLL	PERD./SECC. KW	PERD./SECC. KVAR	CORRIENTE AMPS
200.........	3 FASE			.680	4/0 CU	66.81	.128	.290	6602.	4186.	1.07	1.07	100.93	39.5	89.3	320.7
200	150	59.	51.													
201.........	3 FASE			.920	350 CU	47.39	.106	.367	6503.	4046.	1.14	2.21	99.79	31.9	111.0	317.5
201	45	18.	15.													
235.........	3 FASE			.540	266 ARV	71.95	.120	.220	6453.	3919.	.87	3.08	98.92	36.0	66.1	316.6
235	2200	866.	747.													
202.........	3 FASE			.200	266 ARV	61.15	.044	.081	5551.	3107.	.27	3.35	98.65	9.6	17.7	269.0
202	0	0.	0.													
203.........	3 FASE			.710	4/0 ARV	.44	.200	.298	30.	25.	.01	3.35	98.65	.0	.0	1.7
203	75	30.	25.													
COMENZANDO EN EL NODO 202																
204.........	3 FASE			1.420	266 ARV	60.80	.315	.578	5512.	3063.	1.90	5.25	96.75	67.7	124.2	267.5
204	2300	906.	780.													
205.........	3 FASE			.100	2/0 CU	60.37	.030	.044	4538.	2159.	.13	5.38	96.62	4.2	6.3	217.3
205	0	0.	0.													
206.........	3 FASE			1.030	2/0 CU	.63	.308	.457	39.	34.	.02	5.39	96.61	.0	.0	2.3
206	100	39.	34.													
COMENZANDO EN EL NODO 205																
207.........	3 FASE			.160	2/0 CU	59.76	.048	.071	4495.	2119.	.20	5.58	96.42	6.6	9.9	215.2
207	0	0.	0.													
208.........	3 FASE			.200	2/0 CU	1.18	.060	.089	74.	64.	.01	5.58	96.42	.0	.0	4.2
208	188	74.	64.													
COMENZANDO EN EL NODO 207																
209.........	3 FASE			.110	2/0 CU	58.63	.033	.049	4414.	2045.	.13	5.71	96.29	4.4	6.5	211.1
209	870	343.	295.													
210.........	3 FASE			.580	2/0 CU	53.40	.173	.257	4067.	1743.	.63	6.34	95.66	19.2	28.6	192.3
210	75	30.	25.													
211.........	3 FASE			.040	266 ARV	43.33	.009	.016	4018.	1689.	.03	6.38	95.62	1.0	1.8	190.6
211	45	18.	15.													
236.........	3 FASE			.095	266 ARV	43.10	.021	.039	3999.	1672.	.08	6.46	95.54	2.3	4.2	189.7
236	0	0.	-900.													
212.........	3 FASE			.095	266 ARV	47.28	.021	.039	3997.	2568.	.10	6.56	95.44	2.7	5.0	208.0
212	187	74.	64.													
213.........	3 FASE			.290	2/0 ARV	1.65	.130	.127	80.	69.	.01	6.57	95.43	.0	.0	4.6
213	203	80.	69.													
COMENZANDO EN EL NODO 212																
14.........	3 FASE			.110	266 ARV	45.28	.024	.045	3841.	2430.	.11	6.67	95.33	2.9	5.3	199.2
14	87	34.	30.													
15.........	3 FASE			.130	266 ARV	1.56	.029	.053	118.	102.	.00	6.68	95.32	.0	.0	6.8

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FACTOR DE POTENCIA 84. %
TENSION EN BARRA 102. %

DEMANDA 7817. KVA 6602. KW 4186. KVAR

SECC/	KVA CONEC	C A R G A S		LONGIT	C O N D U C T O' R		IMPEDANCIA		CARGA/SECCION		PCT DE CAIDA		.% KVLL	PERD./SECC.		CORRIENTE
NODO	S PRESENT	KW	KVAR	KM	TIPO	% CARGA	RESIS	REACT	KW	KVAR	SECC.	ACUM.		KW	KVAR	AMPS
215	300	118.	102.													
COMENZANDO EN EL NODO 214																
216.........3 FASE				.460	4/0 ARV	50.13	.130	.193	3685.	2293.	.51	7.18	94.82	14.1	21.0	190.5
216	405	160.	137.													
217.........3 FASE				.220	2/0 CU	48.88	.066	.098	3418.	2054.	.24	7.42	94.58	6.1	9.1	176.0
217	113	45.	38.													
218.........3 FASE				.190	4/0 ARV	3.72	.054	.080	242.	209.	.02	7.44	94.56	.0	.0	14.1
218	615	242.	209.													
COMENZANDO EN EL NODO 217																
221.........3 FASE				.170	2/0 CU	44.30	.051	.075	3125.	1798.	.16	7.58	94.42	3.9	5.8	159.5
221	730	287.	248.													
222.........3 FASE				.180	2/0 CU	19.24	.054	.080	1184.	1021.	.08	7.66	94.34	.8	1.1	69.3
222	45	18.	15.													
23.........3 FASE				.100	1/0 CU	22.01	.038	.045	1165.	1004.	.05	7.71	94.29	.5	.6	68.2
23	900	354.	305.													
24.........3 FASE				.320	1/0 CU	15.31	.121	.145	810.	698.	.11	7.82	94.18	.8	1.0	47.5
24	1035	408.	351.													
25.........3 FASE				.150	1/0 CU	7.60	.057	.068	402.	346.	.03	7.85	94.15	.1	.1	23.6
25	1020	402.	346.													
COMENZANDO EN EL NODO 221																
37.........3 FASE				.150	266 ARV	16.71	.033	.061	1591.	473.	.05	7.63	94.37	.5	1.0	73.5
37	0	0.	-900.													
26.........3 FASE				.150	266 ARV	21.16	.033	.061	1590.	1372.	.08	7.70	94.30	.9	1.6	93.1
26	245	96.	83.													
27.........3 FASE				.110	266 ARV	5.76	.024	.045	432.	373.	.02	7.72	94.28	.0	.1	25.3
27	1098	432.	373.													
COMENZANDO EN EL NODO 226																
28.........3 FASE				.200	266 ARV	14.12	.044	.081	1061.	915.	.07	7.77	94.23	.5	.9	62.1
28	75	30.	25.													
29.........3 FASE				.110	266 ARV	3.35	.024	.045	251.	217.	.01	7.78	94.22	.0	.0	14.7
29	225	89.	76.													
0.........3 FASE				.310	266 ARV	1.57	.069	.126	118.	102.	.01	7.79	94.21	.0	.0	6.9
0	150	59.	51.													
1.........3 FASE				.230	2 ARV	1.92	.207	.107	59.	51.	.01	7.80	94.20	.0	.0	3.5
1	150	59.	51.													
COMENZANDO EN EL NODO 229																
2.........3 FASE				.160	266 ARV	.59	.036	.065	45.	38.	.00	7.78	94.22	.0	.0	2.6
2	113	45.	38.													

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DEMANDA 7817. KVA 6602. KW 4186. KVAR

ECC/ ODO	KVA S	CONEC PRESENT	C A R G A S KW	KVAR	LONGIT KM	C O N D U C T O' R TIPO	% CARGA	IMPEDANCIA RESIS	REACT	CARGA/SECCION KW	KVAR	PCT DE CAIDA SECC.	ACUM.	% KVLL	PERD./SECC. KW	KVAR	CORRIENTE AMPS
COMENZANDO EN EL NODO 228																	
233.........		3 FASE			.070	266 ARV	10.38	.016	.029	779.	672.	.02	7.79	94.21	.1	.2	45.7
233	488		192.	166.													
234.........		3 FASE			.150	266 ARV	7.82	.033	.061	587.	506.	.03	7.82	94.18	.1	.2	34.4
234	1490		587.	506.													
COMENZANDO EN EL NODO 221																	
238.........		3 FASE			.250	2 ARV	1.92	.225	.116	59.	51.	.01	7.59	94.41	.0	.0	3.5
238	150		59.	51.													
239.........		3 FASE			.150	2 ARV	.00	.135	.070	0.	0.	.00	7.59	94.41	.0	.0	.0
239	0		0.	0.													
COMENZANDO EN EL NODO 216																	
19.........		3 FASE			.180	1/0 CU	1.76	.068	.081	94.	81.	.01	7.19	94.81	.0	.0	5.4
19	202		80.	69.													
20.........		3 FASE			.330	1/0 CU	.26	.124	.149	14.	12.	.00	7.19	94.81	.0	.0	.8
20	35		14.	12.													

PERDIDAS TOTALES EN EL ALIMENTADOR 256.8 518.8

CIUDAD : PROP94

S U M A R I O   P O R   A L I M E N T A D O R

	A L I M E N T A D O R	MAXIMA CAIDA DE TENSION		MAXIMA CARGA EN CONDUCTOR		PERDIDA TOTAL	DEMANDA
		SECCION	PORCENTAJE	SECCION	PORCENTAJE	(KVA)	(KVA)
5	SAN BLAS S/E PLANTA DEL ESTE	225	7.85	235	71.95	578.90	7816.80

DEMANDA TOTAL CALCULADA 7816.80

CIUDAD : PROF94

PROGRAMA DE CORTOCIRCUITO

ALIMENTADOR NO. 5 SAN BLAS S/E PLANTA DEL ESTE
VOLTAJE LINEA A LINEA 13.80 KV
TENSION EN LA BARRA 102 %
NEUTRO NO

MVA DE CORTOCIRCUITO EN LA S/E : 930.00

IMPEDANCIA DE FALLA :CERO

SECC/ NODO	FASES	LONGITUD	C O N D U C T O R	IMPED.(+/-) R	X	IMPED.(0) R	X	C O R R I E N T E S D E F A L L A S E N (K A) 3 FASES	FASE-FASE	2F.-TIERRA	1F.-TIERRA
200......	..3	.680	4/0 CU	.128	.290	.249	1.279				
200								15.5853	13.4972	13.9303	9.5582
201......	..3	.920	350 CU	.106	.367	.269	1.706				
201								9.0127	7.8052	7.9786	4.8397
235......	..3	.540	266 ARV	.120	.220	.216	1.006				
235								7.0672	6.1204	6.2488	3.7154
202......	..3	.200	266 ARV	.044	.081	.080	.372				
202								6.5426	5.6660	5.7831	3.4207
203......	..3	.710	4/0 ARV	.200	.298	.327	1.331				
203								5.0910	4.4089	4.4988	2.6486

COMENZANDO EN EL NODO 202

SECC/ NODO	FASES	LONGITUD	CONDUCTOR	R	X	R	X	3 FASES	FASE-FASE	2F.-TIERRA	1F.-TIERRA
204......	..3	1.420	266 ARV	.315	.578	.568	2.644				
204								4.2804	3.7069	3.7790	2.1877
205......	..3	.100	2/0 CU	.030	.044	.048	.190				
205								4.1644	3.6065	3.6768	2.1301
206......	..3	1.030	2/0 CU	.308	.457	.491	1.956				
206								3.2536	2.8177	2.8736	1.6753

COMENZANDO EN EL NODO 205

SECC/ NODO	FASES	LONGITUD	CONDUCTOR	R	X	R	X	3 FASES	FASE-FASE	2F.-TIERRA	1F.-TIERRA
207......	..3	.160	2/0 CU	.048	.071	.076	.304				
207								3.9912	3.4565	3.5241	2.0440
208......	..3	.200	2/0 CU	.060	.089	.095	.380				
208								3.7938	3.2855	3.3500	1.9456

COMENZANDO EN EL NODO 207

SECC/ NODO	FASES	LONGITUD	CONDUCTOR	R	X	R	X	3 FASES	FASE-FASE	2F.-TIERRA	1F.-TIERRA
209......	..3	.110	2/0 CU	.033	.049	.052	.209				
209								3.8802	3.3604	3.4262	1.9887
210......	..3	.580	2/0 CU	.173	.257	.277	1.101				
210								3.3831	2.9299	2.9879	1.7403
211......	..3	.040	266 ARV	.009	.016	.016	.074				
211								3.3572	2.9074	2.9649	1.7263
236......	..3	.095	266 ARV	.021	.039	.038	.177				
236								3.2972	2.8555	2.9118	1.6940
212......	..3	.095	266 ARV	.021	.039	.038	.177				
212								3.2393	2.8053	2.8605	1.6630
213......	..3	.290	2/0 ARV	.130	.127	.182	.549				
213								3.0305	2.6245	2.6769	1.5647

COMENZANDO EN EL NODO 212

CIUDAD : PROP94

C O N T I N U A C I O N

SECC/ NODO	FASES	LONGITUD	C O N D U C T O R	IMPED.(+/-) R	X	IMPED.(0) R	X	CORRIENTES DE FALLAS EN (KA) 3 FASES	FASE-FASE	2F.-TIERRA	1F.-TIERRA
214......	3	.110	266 ARV	.024	.045	.044	.205				
214								3.1748	2.7494	2.8034	1.6283
215......	3	.130	266 ARV	.029	.053	.052	.242				
215								3.1017	2.6862	2.7388	1.5893

COMENZANDO EN EL NODO 214

SECC/ NODO	FASES	LONGITUD	C O N D U C T O R	IMPED.(+/-) R	X	IMPED.(0) R	X	3 FASES	FASE-FASE	2F.-TIERRA	1F.-TIERRA
216......	3	.460	4/0 ARV	.130	.193	.212	.863				
216								2.9116	2.5215	2.5711	1.4936
217......	3	.220	2/0 CU	.066	.098	.105	.418				
217								2.7944	2.4200	2.4677	1.4352
218......	3	.190	4/0 ARV	.054	.080	.087	.356				
218								2.7054	2.3429	2.3891	1.3895

COMENZANDO EN EL NODO 217

SECC/ NODO	FASES	LONGITUD	C O N D U C T O R	IMPED.(+/-) R	X	IMPED.(0) R	X	3 FASES	FASE-FASE	2F.-TIERRA	1F.-TIERRA
221......	3	.170	2/0 CU	.051	.075	.081	.323				
221								2.7101	2.3470	2.3933	1.3931
222......	3	.180	2/0 CU	.054	.080	.086	.342				
222								2.6261	2.2743	2.3193	1.3511
223......	3	.100	1/0 CU	.038	.045	.056	.191				
223								2.5780	2.2326	2.2770	1.3280
24......	3	.320	1/0 CU	.121	.145	.178	.610				
24								2.4350	2.1088	2.1511	1.2591
25......	3	.150	1/0 CU	.057	.068	.083	.286				
25								2.3732	2.0552	2.0967	1.2292

COMENZANDO EN EL NODO 221

SECC/ NODO	FASES	LONGITUD	C O N D U C T O R	IMPED.(+/-) R	X	IMPED.(0) R	X	3 FASES	FASE-FASE	2F.-TIERRA	1F.-TIERRA
37......	3	.150	266 ARV	.033	.061	.060	.279				
37								2.6486	2.2938	2.3389	1.3601
26......	3	.150	266 ARV	.033	.061	.060	.279				
26								2.5899	2.2429	2.2870	1.3286
27......	3	.110	266 ARV	.024	.045	.044	.205				
27								2.5484	2.2070	2.2503	1.3064

COMENZANDO EN EL NODO 226

SECC/ NODO	FASES	LONGITUD	C O N D U C T O R	IMPED.(+/-) R	X	IMPED.(0) R	X	3 FASES	FASE-FASE	2F.-TIERRA	1F.-TIERRA
28......	3	.200	266 ARV	.044	.081	.080	.372				
28								2.5155	2.1785	2.2211	1.2888
29......	3	.110	266 ARV	.024	.045	.044	.205				
29								2.4764	2.1446	2.1865	1.2679
0......	3	.310	266 ARV	.069	.126	.124	.577				
0								2.3724	2.0546	2.0946	1.2125
1......	3	.230	2 ARV	.207	.107	.247	.441				
1								2.2451	1.9443	1.9834	1.1621

COMENZANDO EN EL NODO 229

SECC/ NODO	FASES	LONGITUD	C O N D U C T O R	IMPED.(+/-) R	X	IMPED.(0) R	X	3 FASES	FASE-FASE	2F.-TIERRA	1F.-TIERRA
2......	3	.160	266 ARV	.036	.065	.064	.298				
2								2.4216	2.0972	2.1381	1.2387

COMENZANDO EN EL NODO 228

CIUDAD : PROP94

C O N T I N U A C I O N

SECC/ NODO	FASES	LONGITUD	C O N D U C T O R	IMPED.(+/-) R	X	IMPED.(0) R	X	C O R R I E N T E S D E F A L L A S E N (K A) 3 FASES	FASE-FASE	2F.-TIERRA	1F.-TIERRA
233.......3		.070	266 ARV	.016	.029	.028	.130				
233								2.4905	2.1568	2.1990	1.2754
234.......3		.150	266 ARV	.033	.061	.060	.279				
234								2.4385	2.1118	2.1530	1.2477
COMENZANDO EN EL NODO 0											
238.......3		.250	2 ARV	.225	.116	.269	.480				
238								2.5314	2.1922	2.2373	1.3213
239.......3		.150	2 ARV	.135	.070	.161	.288				
239								2.4329	2.1069	2.1513	1.2813
COMENZANDO EN EL NODO 216											
219.......3		.180	1/0 CU	.068	.081	.100	.343				
219								2.8072	2.4311	2.4792	1.4437
220.......3		.330	1/0 CU	.124	.149	.183	.629				
220								2.6337	2.2809	2.3265	1.3603

F I N D E L A L I M E N T A D O R

CIUDAD : PROP94

PROGRAMA DE CORTOCIRCUITO

ALIMENTADOR NO. 5 SAN BLAS S/E PLANTA DEL ESTE
VOLTAJE LINEA A LINEA 13.80 KV
TENSION EN LA BARRA 102 %
NEUTRO NO

MVA DE CORTOCIRCUITO EN LA S/E : 930.00

IMPEDANCIA DE FALLA : 30.00 OHM

ECC/ ODO	FASES	LONGITUD	CONDUCTOR	IMPED.(+/-) R	IMPED.(+/-) X	IMPED.(0) R	IMPED.(0) X	CORRIENTES DE FALLAS EN (KA) 3 FASES	FASE-FASE	2F.-TIERRA	1F.-TIERRA
200......	..3	.680	4/0 CU	.128	.290	.249	1.279				
200								.2663	.2306	.4305	.3898
201......	..3	.920	350 CU	.106	.367	.269	1.706				
201								.2630	.2278	.3978	.3749
235......	..3	.540	266 ARV	.120	.220	.216	1.006				
235								.2609	.2259	.3814	.3663
202......	..3	.200	266 ARV	.044	.081	.080	.372				
202								.2601	.2253	.3758	.3632
203......	..3	.710	4/0 ARV	.200	.298	.327	1.331				
203								.2572	.2227	.3574	.3523
COMENZANDO EN EL NODO 202											
204......	..3	1.420	266 ARV	.315	.578	.568	2.644				
204								.2548	.2206	.3422	.3427
05......	..3	.100	2/0 CU	.030	.044	.048	.190				
05								.2543	.2203	.3401	.3412
06......	..3	1.030	2/0 CU	.308	.457	.491	1.956				
06								.2501	.2166	.3204	.3270
COMENZANDO EN EL NODO 205											
07......	..3	.160	2/0 CU	.048	.071	.076	.304				
07								.2537	.2197	.3368	.3389
08......	..3	.200	2/0 CU	.060	.089	.095	.380				
08								.2528	.2190	.3328	.3361
COMENZANDO EN EL NODO 207											
09......	.3	.110	2/0 CU	.033	.049	.052	.209				
09								.2532	.2193	.3346	.3374
10......	.3	.580	2/0 CU	.173	.257	.277	1.101				
10								.2508	.2172	.3236	.3294
11......	.3	.040	266 ARV	.009	.016	.016	.074				
11								.2507	.2171	.3229	.3289
36......	.3	.095	266 ARV	.021	.039	.038	.177				
36								.2503	.2168	.3214	.3277
2......	.3	.095	266 ARV	.021	.039	.038	.177				
2								.2500	.2165	.3198	.3265
3......	.3	.290	2/0 ARV	.130	.127	.182	.549				
3								.2487	.2153	.3147	.3226

COMENZANDO EN EL NODO 212

CIUDAD : PROP94

CONTINUACION

SECC/ NODO	FASES	LONGITUD	CONDUCTOR	IMPED.(+/-) R	X	IMPED.(0) R	X	CORRIENTES DE FALLAS EN (KA) 3 FASES	FASE-FASE	2F.-TIERRA	1F.-TIERRA
233.......	3	.070	266 ARV	.016	.029	.028	.130				
233								.2443	.2116	.2971	.3082
234.......	3	.150	266 ARV	.033	.061	.060	.279				
234								.2438	.2111	.2952	.3065
COMENZANDO EN EL NODO 0											
238.......	3	.250	2 ARV	.225	.116	.269	.480				
238								.2447	.2119	.3004	.3108
239.......	3	.150	2 ARV	.135	.070	.161	.288				
239								.2438	.2111	.2978	.3085
COMENZANDO EN EL NODO 216											
219.......	3	.180	1/0 CU	.068	.081	.100	.343				
219								.2471	.2140	.3078	.3171
220.......	3	.330	1/0 CU	.124	.149	.183	.629				
220								.2456	.2127	.3027	.3129

FIN DEL ALIMENTADOR

ANEXO F

HIGH VOLTAGE FUSES – THEORY OF OPERATION

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RTE Corporation
Waukesha, Wisconsin

2.1 INTRODUCTION

Fuses are the most basic type of overcurrent interrupting device available and are presently being used by the millions. All of us use a variety of devices each day which incorporate fuses; they will be found in automobiles, houses, television sets, and a host of other devices.

The fuse has also been utilized for many years as a simple overcurrent protective device for high voltage distribution and power systems. It is probably the most reliable device that can provide the basic functions required and still be expected to remain reliable for 15-20 years with no maintenance.

2.2 FUSING BASICS

There are several primary functions that a fuse must provide. First, it will sense an overcurrent condition on the system it is protecting. The overcurrent will force the fuse element to rise sufficiently in temperature to finally cause melting (fusing) at one part (low overcurrent) or multiple sections (high overcurrent) of the element. At that instant the second primary function will come into play – interruption of this overcurrent and withstand of the transient recovery voltage during or following interruption.

After the interruption has been completed, the blown fuse must withstand system voltage and thus protect the system from the overcurrent problem, permitting continued service to as many customers as possible. Generally, when the fuse is called upon to operate, it will be functioning such as to limit and minimize the damage that can be caused by the overcurrent flow. This becomes especially significant when the fault can be of a very high magnitude and the protective device utilized is a current-limiting fuse.

A secondary function, and yet of great importance, is that the fuse must be capable of coordinating with other protective devices on the system so as to minimize the number of customers affected by the fusing action. This coordination oftentimes has to be with both downstream and upstream devices. Manufacturers make available time-current curves on their fuses as one of the prime tools used in coordination studies.

2.3 TYPES OF FUSES

There exist two basic types of fuses presently available for application on electrical distribution systems. The first type is what we can call the current zero awaiting type because the principle operation does not fully utilize the interrupting means until the circuit normal current zero occurs; at that time the full effect of the interrupting medium built into the fuse becomes significant and allows complete interruption and withstand of voltage. A typical example of this type of fuse is the well-known outdoor expulsion fuse utilizing the gas generation and exhaust to produce the interruption. Modifications of this basic fuse include the type with boric acid as the gas generating liner, producing primarily water vapor; this type of fuse can then utilize condensors so that the bulk of the water vapor does not have to be exhausted out of the complete fuse assembly (although it is exhausted from the main interrupting chamber).

Another version of this current zero awaiting type is the oil fuse cutout. In this case, the expulsion gases consist of those produced by a breakdown of the oil as well as associated fuse tubing materials.

The most recent addition to the current zero awaiting fuse is the vacuum fuse. This is truly a non-expulsion fuse because all of the interruption does take place in a completely sealed body; however, the fuse must still wait for the normal current zero to occur before interruption can take place.

The other basic type of fuse is the current zero shifting type, which is commonly called a current-limiting or energy-limiting fuse. This type of fuse not only reduces the magnitude of fault current that is flowing by its ability to introduce a high resistance into the circuit, but by this very same fact it changes a low power factor circuit to a relatively high power factor circuit and thereby shifts the normal current zero to a point close to the normal voltage zero. There are three classes of current-limiting fuse that fall into this category. There is the Backup current-limiting fuse which is very effective at high fault currents but always has a lower limit of current that it can successfully interrupt; this fuse must always be utilized with some other device (fuse or switch) to handle low overcurrent conditions. A second class is a General Purpose fuse which by ANSI standard definition is a current-limiting fuse which can interrupt a current that causes the fuse to operate in one hour or less. The third class (common usage) is a Full Range fuse which is designed to interrupt any current that causes element melting under normal fusing operations at any ambient temperature up through the maximum application allowed by the manufacturer.

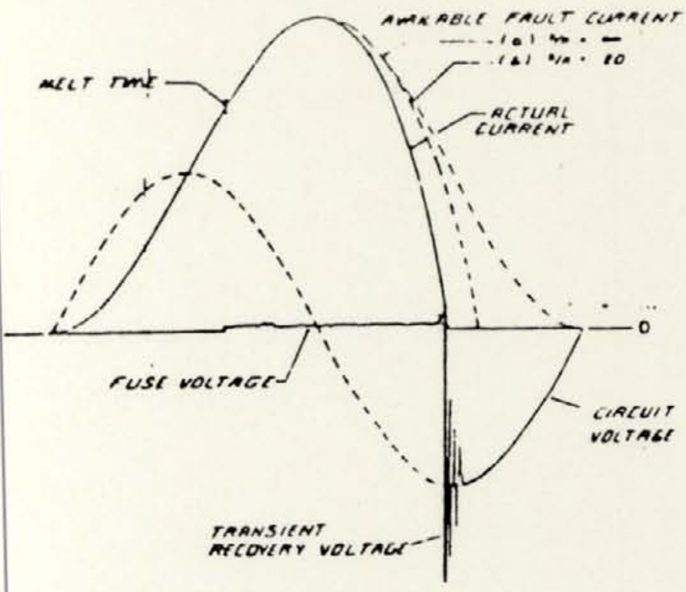
Fuses, regardless of type, can be classified as distribution or power class fuses. The distinguishing characteristics by standards are:

(1) Dielectric withstand (BIL) level.
(2) Application (station or substation versus distribution lines and equipment).
(3) Mechanical construction adapted to application requirements.
(4) Ampere rating range (significantly higher for power fuses).

2.4 THEORY OF FUSE OPERATION

2.4.1 Expulsion Fuses

The typical expulsion fuse will utilize a relatively short fusible element section to sense the overcurrent and start the arcing required for interruption. Attached to this short fusible element will be a larger type of conductor, commonly called a fuse leader, which then connects to the rest of the fuse hardware as required. This construction always causes the arcing to start in a known area and thus produce the desired effects. The arc that is produced will rapidly create gases from special materials located in close proximity to the fuse element; the arc temperatures are typically 4000-5000 K. Some of the gas generating materials have been fiber, melamine, boric acid, and liquids, such as oil or carbon tetrachloride. The primary function of the gases that are generated is to create a high pressure turbulent medium surrounding the arc area so that when the current does reach zero and the arc channel reduces to a minimum, the ablated gases can rapidly mix with the remaining ionized gases, and deionize and remove them from the area to allow a rapid buildup of dielectric strength that can withstand the transient recovery voltage and steady state power system voltage. Of course, consideration must be given to the fact that these gases will be produced and will be exhausting from the fuse assembly. Some types, such as the boric acid fuses, can utilize condensors to prevent much exhaust beyond the fuse assembly.



EXPULSION FUSE
Fig. 2.1

Figure 2.1 shows the typical current-voltage-time relationships that occur on a normal expulsion fuse interruption. The significant thing to learn from this illustration is that practically no current limiting or shifting of the normal current zero occurs, so that at the final time of the interruption, the voltage must quickly recover to the peak system voltage; thus, typically a rather high transient recovery voltage will occur. Expulsion fuses are designed to handle this type of interrupting duty.

One of the main advantages with typical expulsion fuses is that they can be reloaded with a relatively economical fuse link. Furthermore, there are a wide variety of fuse link types and sizes that could be used in the same fuse holder. This allows common usage of the same holder for a number of applications and also permits a wide latitude of coordination possibilities.

A second main advantage of expulsion fuses is that the release of the fuse leader, and the following expulsion gas action, can also be utilized to provide a drop open action of the fuse assembly. This, in turn, provides dual benefits – a high dielectric insulation is produced by the fuse mounting which can withstand system voltage for a very long period; also a very excellent visual indication of operation occurs so that the utility lineman can easily determine where the blown fuse is.

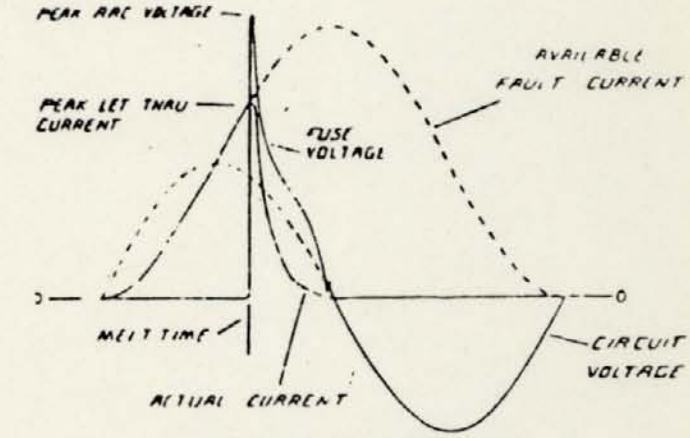
2.4.2 Vacuum Fuse

The vacuum fuse would be very similar in design and operation to the expulsion fuse in that it utilizes a short fusible element and has a similar current-voltage-time relationship as shown in Figure 2.1. The main difference is that it is a completely sealed unit and has no expulsion action; the interruption occurs because of the extremely rapid dielectric buildup that can occur in a vacuum after current zero is reached. The design utilizes the typical vacuum interrupter electrodes to cause arc splitting and rotation needed for satisfactory high fault current interruption, similar to that in the vacuum breakers.

The main advantage of the vacuum fuse is that a high rated ampere overcurrent protective device with non-expulsion action can be fitted into a very compact package. Also the operation of the fuse produces low arc energy, easily absorbed by the fuse end fittings.

2.4.3 Current-Limiting Fuse

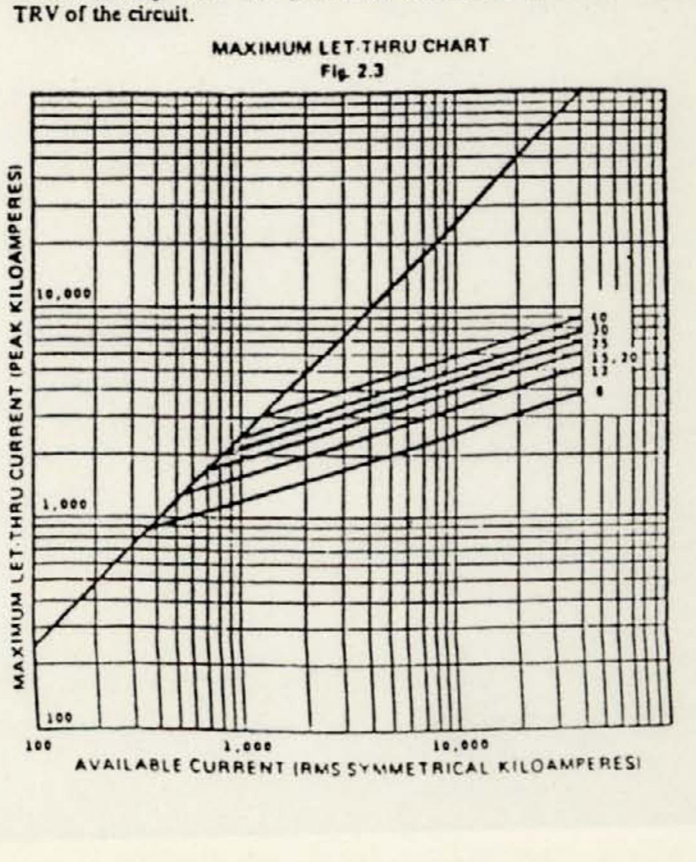
The common characteristic of all current-limiting fuses is that instead of the short fusible element of the previously described fuses, the fusible elements of this type of fuse must be very long. For instance, an 8.3 kV fuse would utilize an element of about 22 inches in length. The element is completely surrounded with a carefully packed filler material, typically silica sand, to contain the arc and maintain a very high pressure in the long restricted arc area caused by the practically simultaneous melting of the full length of the element. This then allows the fuse to produce a very high resistance in the circuit in a very short period of time (typically hundreds of microseconds).



CURRENT LIMITING FUSE
Fig. 2.2

Figure 2.2 shows the current-voltage-time relationships for the current-limiting fuse operating under the same high fault interruption duty as that of the expulsion fuse. You will note that even though the melt time is identical, the following characteristics change quite rapidly. The rapid insertion of the resistance by the fusing action causes a high arc voltage to develop across the fuse. This is being produced by the attempt to stop the current flow in the circuit inductance. The resistance also limits the current rise and actually starts forcing it to a much lower value. The very high power factor of the circuit under this condition then causes the current to reach a zero very close to the normal voltage zero. At that point full recovery occurs and the transient recovery voltage is very small; thus current-limiting fuses are practically insensitive to the inherent TRV of the circuit.

MAXIMUM LET-THRU CHART
Fig. 2.3



and potential energy limiting capability. Several different types of data are required to fully describe its capability. Historically the manufacturer has used sets of peak let thru currents that can occur with his fuse design as related to the available fault current. Figure 2.3 shows these relationships for one family of energy-limiting fuses as compared to the maximum available peak let thru. However, because of the shifting of the normal current zero, there is a much greater reduction of effective fault current that occurs and can only be satisfactorily identified by use of an I^2T factor; this is the current-time integral and has the units amp^2 seconds. This factor really represents the heating that could be occuring per increment of resistance anywhere in the same current path. Thus it truly relates to the potential allowable energy anywhere in the system that is being affected by the fault current.

There are two parts to the I^2T factor. The first part is the melting I^2T which can be determined best by calculation; the short time melt current-time integral (assuming no heat loss) is fully dependent on the fuse element material and minimum cross-sectional area. Appendix I gives the basic formula and material constant K for the commonly used fuse elements - silver, copper, tin. The approximate melt I^2T can also be determined from a melting time current curve for the fuse by squaring the .01 second RMS current value and multiplying it by .01 seconds; the slight inaccuracy will be due to the fact that within .01 seconds some heat transfer does occur from the minimum cross-sectional area. For coordination considerations, the average melt I^2T is reduced by a suitable factor to the minimum melt I^2T to allow for manufacturing tolerances.

The total I^2T is the sum of the melting, or pre-arcing I^2T, plus that which occurs after arcing starts and until complete interruption occurs. This has to be determined by testing because it is dependent on not only the fuse element but the total fuse design and its ability to handle the fault currents. Both minimum melt and total I^2T factors are necessary for coordination studies. Figure 2.4 shows how significant the I^2T factor can be as compared to the commonly used current-time relationship by itself. A fuse manufacturer will normally provide the minimum melting I^2T and the maximum total I^2T of his current-limiting fuses. The published maximum total will generally be the maximum produced at any fault current through maximum rated interrupting capacity at maximum design voltage.

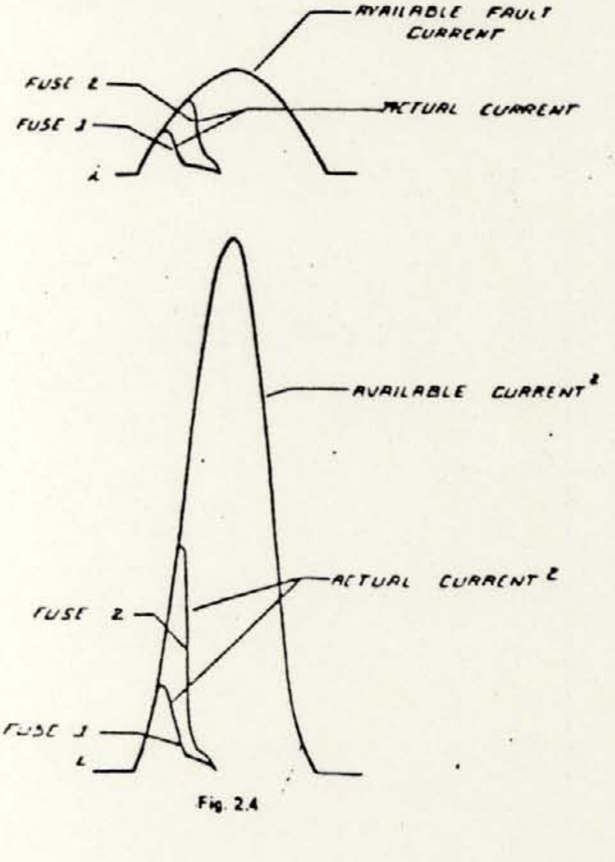


Fig. 2.4

A significant feature of current-limiting fuses is the fact that they must and can absorb all of the energy of fault current interruption without any detrimental physical display, all of this energy produces heat within the fuse. The excellent current-limiting ability of this fuse allows it to have practically unlimited interrupting rating. The fact that no gases are exhausted from the fuse allows the fuse to be installed in rather tight confinements, just so that sufficient dielectric clearances are provided for steady state operation conditions.

Because the current-limiting fuse can produce a very high resistance rapidly, this factor must be carefully considered in the design so that it does not occur so rapidly that excessively high arc voltages are produced. Such overvoltages could cause breakdowns in the system insulation or cause unnecessary lightning arrester operation and possible difficult duty if the arrester had to discharge the stored energy of the faulted circuit. This has been taken into consideration with modern current-limiting fuse designs; the resistance is introduced at a controlled rate and the arc voltage peak is within about 2.1 times the peak system voltage, where no operating problems will occur.

One additional interesting feature of current-limiting fuses is the fact that the maximum thermal stress for this type of fuse does not generally occur at its maximum interrupting rating. It occurs at a current called the critical current where the combination of ampere rating, available fault, and current-limiting ability produce the maximum stored circuit energy at the time of fusing; this must be absorbed by the fuse and causes maximum thermal duty for the fuse. Above this range the thermal duty generally will remain at or below this level. However, at the higher available fault currents, the fusing operation occurs more rapidly and can generate higher pressure shock waves which must also be withstood by the fuse design.

2.5 STANDARDS STATUS

2.5.1 Existing Standards Completed

There presently exists a set of nine fuse standards, C37.40-C37.48 of the ANSI standards that adequately prescribe the required design tests, definitions, and specifications for both expulsion fuses and current-limiting fuses. In addition, there are IEC standards (282-1 and 282-2) which also cover both types of fuses and are used in most countries outside of the United States. There presently exists fairly close agreement between the ANSI and IEC standards, due to the cooperative engineering efforts in the past 10 years.

It has been very difficult to standardize on time-current characteristics of fusible elements. However, standards do exist on two basic types of expulsion fuse links – the K type and the T type; families of curves for both types of fuses are available from a number of manufacturers. The complete curves are fairly well defined by standards. Current-limiting fuses do not have the same degree of TCC definition. There exist basically a power class E type and a distribution C type current-limiting fuse. In each case, the characteristic is really defined for one short part of the time-current curve, permitting some degree of standardization between these fuses.

2.5.2 Standards Work in Process

Even though the basic standards have been quite well established, there are some additions that are presently in process that will aid in more fully defining the testing and application of fuses. One of these is a standard to cover application of fuses in enclosures, which initially is designed to cover the application of current-limiting fuses in restricted areas where they might encounter very high ambient temperatures. This will include placing fuses in cannisters, in transformer bushings, and complete immersion in transformer oil. Work is also in process to specify suitable transient recovery voltages for all of the interrupting tests, especially as related to testing of fuses most sensitive to high TRV.

2.5.3 Standards Under Consideration

Some of our future efforts will be to more fully standardize fuse physical sizes to promote interchangeability and encourage multiple sources for the fuses.

Another possible standard as related to fuses, reclosers, and sectionalizers, would be a numeric format for time-current characteristic curves so that the information could be placed in a computer and a relatively simple means of providing coordination studies made available. Consideration for additional standards is an ever continuing process in addition to a constant review of the existing standards for updating.

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APPENDIX I

Calculation of element melt i^2t
Based on action integral $\int i^2\,dt$ through melting (no heat loss)

$(i^2t)\ AMP^2\ SEC = K\ A^2$ Where A is (inch²)

ELEMENT MATERIAL	K
Silver	3.[illegible] × 10^{10}
Copper	4.03 × 10^{10}
Tin	18 × 10^{10}

ANEXO G

HIGH VOLTAGE FUSE PROTECTION
THEORY & CONSIDERATIONS

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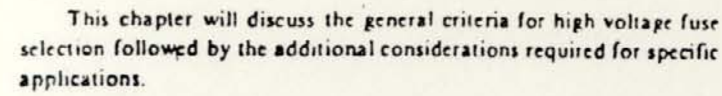
ABSTRACT

Fuses have been the basic overcurrent protective device used on distribution systems since their inception many years ago and are still the major element on modern systems. In terms of quantity they far outnumber any other overcurrent protective device. The main reason is economy. The initial and refusing costs are lower than those of other devices. The many ratings and time-current characteristics that are available provide flexibility in achieving optimum protection.

This chapter will discuss the general criteria for high voltage fuse selection followed by the additional considerations required for specific applications.

3.1 GENERAL CONSIDERATIONS

The basic function of a fuse is to limit the extent of an outage caused by a fault condition thus improving service continuity to customers. To accomplish this fuses are used in distribution lines (lateral tap or sectionalizing fusing) and on equipment, such as transformers and capacitors which are connected to the distribution lines.



Location of Fuses on a Distribution Circuit

Fig.3.1

Figure 3.1 shows the use of fuses on a distribution system. Each transformer and capacitor bank is fused, primarily for disconnecting this equipment from the system if a fault occurs within the equipment. Transformer fuses may also provide some overload protection. The sectionalizing fuses divide the system into small sections which are then isolated from the rest of the system by fuse operation when a fault occurs on the line protected by the fuse. For the fault shown on Fig. 3.1, fuse A operates, disconnecting the faulted line from the rest of the system. Only the customers connected to this line are affected. If there were no fuse at A, fuse B would operate causing a service outage for many more customers.

Reclosers are also widely used for sectionalizing when the additional benefits they provide can justify their higher cost. Their use will be covered in a later chapter. Generally fuses are used toward the ends of distribution lines, on lightly loaded lines and on lines serving non-critical loads.

The selection of fuse ratings and time current characteristics for sectionalizing fuses involves the principles of coordination covered in a later chapter.

3.1.1 Selection of Fuses Types and Rating

High voltage fuses are divided into two types, Power and Distribution. Power fuses are used mainly in substations and metal-clad switchgear. They have the highest voltage, current and interrupting ratings.

Distribution fuses have ratings and constructions adapted for general use on distribution circuits. The expulsion type is used where expulsion gases pose no problem such as on overhead circuits and equipment. Current limiting fuses are used for indoor applications, pad mounted transformers, metal enclosed equipment, etc. Where energy limitation is required, they also have a wide application on overhead circuits.

The principal system parameters that determine fuse ratings are voltage, load current, and available fault current at the fuse location. The fuse rating should equal or exceed the respective parameter.

The voltage rating of the fuse determines not only its dielectric characteristics but also its interrupting performance. The interrupting rating is based on single phase tests at the maximum rated voltage of the fuse. When applied phase to ground on three phase systems, the voltage rating of the fuse should equal or exceed the phase to ground system voltage. When applied in the line on the same system, the conservative approach is to base the fuse voltage on system phase to phase voltage. Because faults which produce conditions where one cutout must interrupt against phase to phase voltage are not too common, lower voltage rated cutouts are sometimes used because of economy. Expulsion cutouts developed for such application have dual voltage ratings, such as 7.8/15 kV.

Current limiting fuses used on three phase transformers in underground systems generally may be selected on the basis of line to ground voltage since faults usually involve ground. However certain transformer winding configurations and types of loading may dictate a higher voltage rating (1, 2, 3). The fuse manufacturers' recommendations should be followed.

When applying current limiting fuses, consideration must be given to the peak arc voltage generated by the fuse when interrupting fault current, as this voltage has an effect on other devices connected to the system. Lightning arresters are particularly effected by such overvoltages (4). If the fuse voltage does not exceed the system voltage, the arc voltage generally does not present any problem. When the fuse voltage exceeds the system voltage, the fuse manufacturers' recommendations should be followed.

The interrupting rating of the fuse should equal or exceed the maximum available fault current at the fuse location. Fuses may operate in the asymmetric portion of the fault current and are given both symmetric and asymmetric interrupting ratings based on specified X/R ratios. For location where the X/R of the circuit exceeds the specified values, derating may be needed, generally this is not required since the specified values are high enough to cover the majority of applications. Derating of current limiting fuses is not required.

The continuous current rating should be greater than the maximum load current it is required to carry. Rated load current, overload current, allowance for load growth and transient currents such as inrush and cold load pick-up should be considered. These vary for the equipment being protected and will be discussed in the following portions of this paper.

3.2 DISTRIBUTION TRANSFORMER PROTECTION

There are many factors to consider when fusing a transformer. Ideally, the fuse should:

1. Remove a faulty transformer from the distribution system.
2. Prevent disruptive failure of the transformer.
3. Protect the transformer from severe overloads.
4. Withstand harmless short time overloads.
5. Withstand inrush and cold load pick-up currents.
6. Resist damage from lightning induced surges.
7. Coordinate with the next up-stream protective device.

It is not always possible to achieve this ideal performance since large fuses best meet some of the requirements and small fuses the others. Trade offs may be required to obtain the best overall protection. All factors should be considered and weighed in making the choice.

3.2.1 Tank Damage Considerations

When arcing faults occur inside a transformer, high internal pressures are produced by the oil decomposition which if not kept within limits may cause tank rupture or cover blowing with accompanying oil fires (5, 6, 7, 8, 9). Pressure is related to the magnitude and duration of the fault current, let thru by the fuse. The I^2t of this let thru current is a comparative measure of the energy generated by the arc, but there is no agreement as to what its maximum limiting value must be to prevent catastrophic failure of the transformer. In fact, there is disagreement as to whether I^2t or It is the best measure of the energy generated. Current limiting fuses provide the best protection and it is common practice to limit the use of expulsion fuses to locations where fault current is 3000 amperes or less.

3.2.2 Inrush Current

When a transformer is energized, there is an inrush of exciting current, whose magnitude and duration are determined by the residual flux in the transformer core and the point on the voltage wave when the circuit is closed. Tests and experience have established that the I^2t of the maximum inrush current is equivalent to 25 times transformer full load current flowing for 0.01 seconds and 12 times transformer full load current flowing for 0.1 seconds (10). These points establish the lower limits of the fuse time-current curve in order that the fuse will not be damaged or blown by the inrush current.

3.2.3 Cold Load Pick-Up Current

The transformer fuse must also be large enough to withstand the cold load pick-up current which results when a transformer is reenergized after an outage. This overcurrent is caused by loss of diversity and motor starting currents. Its magnitude and duration depend on the system and type of loads and can be shown in the form of a time current curve - Fig 3.2. This curve is for a 7.2 kV, 50 KVA transformer and also includes the two inrush current points discussed previously.

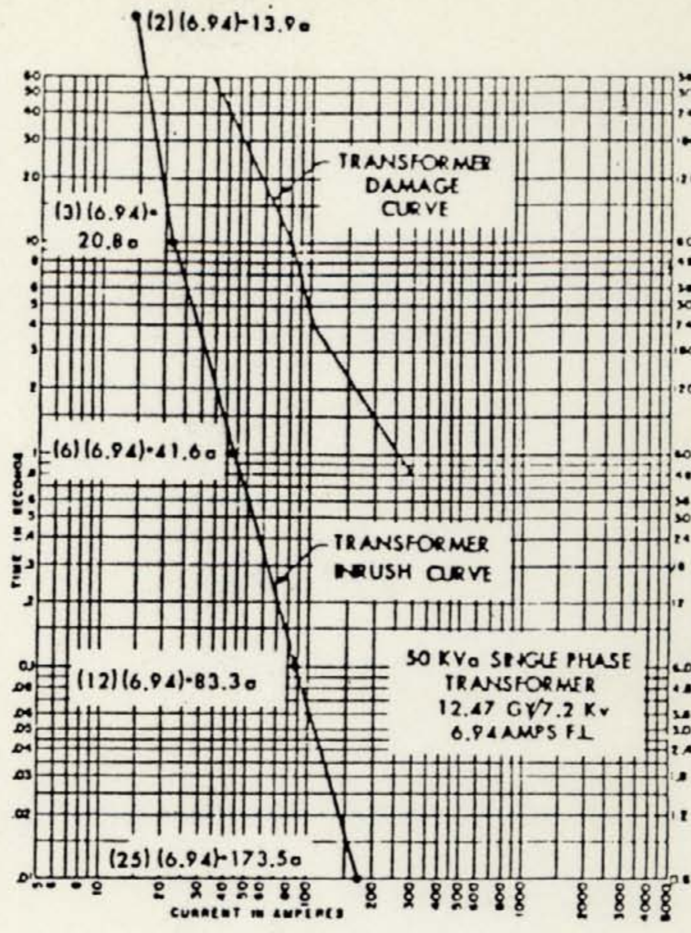


Fig. 3.2

Because of differences in systems it is not possible to establish one curve that will cover all systems. The curve shown is based on studies made on a number of distribution systems and is widely used. On systems with considerable electric heating load, the 2 times rated load point may be raised to 300 seconds instead of 100 seconds as shown.

This curve establishes the lower limits of the fuse curve. No comprise should be made — the fuse curve should always lie on the right side of the inrush curve and should not cross it, especially in the region below 0.1 seconds.

3.2.4 Transformer Thermal Damage

While the basic function of a transformer fuse is to protect the system from the effects of a fault in the transformer, it is possible to choose a fuse that provides some degree of overload protection to the transformer. ANSI C57.92 provides a basis for this consideration. Figure 3.2 shows the transformer damage curve for a 7.2 kV 50 KVA transformer. This damage curve is not a transformer failure curve — it is only an indication of loss of life, so occassional operation of the transformer in the region to the right of the curve is not too critical.

This curve was established for 55°C rise transformers so it is conservative for todays 65°C rise transformers which can operate at higher temperatures without suffering loss of life.

The objective of fuse selection is to squeeze its time current characteristics between the inrush and transformer damage curve. The minimum melt curve should be slower than the inrush curve and the maximum clear curve should be faster than the transformer damage characteristics. If a compromise is necessary, it should be with the damage [illegible]

The curves provide considerable leeway in fuse selection and utilities generally establish a practice or philosophy on which fuse selection is based. With a high fusing ratio philosophy, fuses are chosen to protect the system from a damaged transformer with little effort made toward overload protection. With a low fusing ratio philosophy fuses are chosen as small as possible to provide maximum overload protection. Fusing ratio is defined as the ratio of the fuse minimum melting current to the transformer full load current and gives the minimum per unit transformer full load current that will cause the fuse to operate. Typical ratios are 2 to 4 but ratios as low as 1 and as high as 15 are sometimes used.

There are advantages and disadvantages of both high and low ratios which have to be considered in establishing a fusing philosophy. Figure 3.3 shows in graphical form the effect fusing ratio has on service continuity, refusing costs, transformer failures due to overload, and coordination with other system fuses. The relative importance of these factors on the operation of a particular distribution system determines the choice of a particular fusing philosophy.

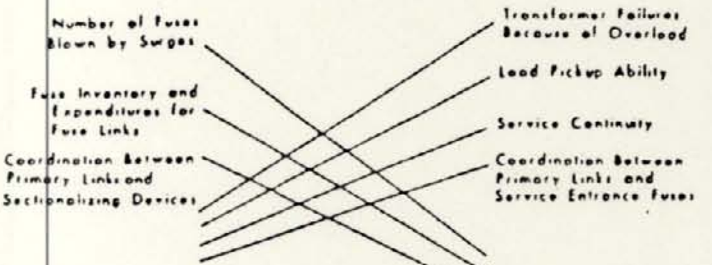


Fig. 3.3

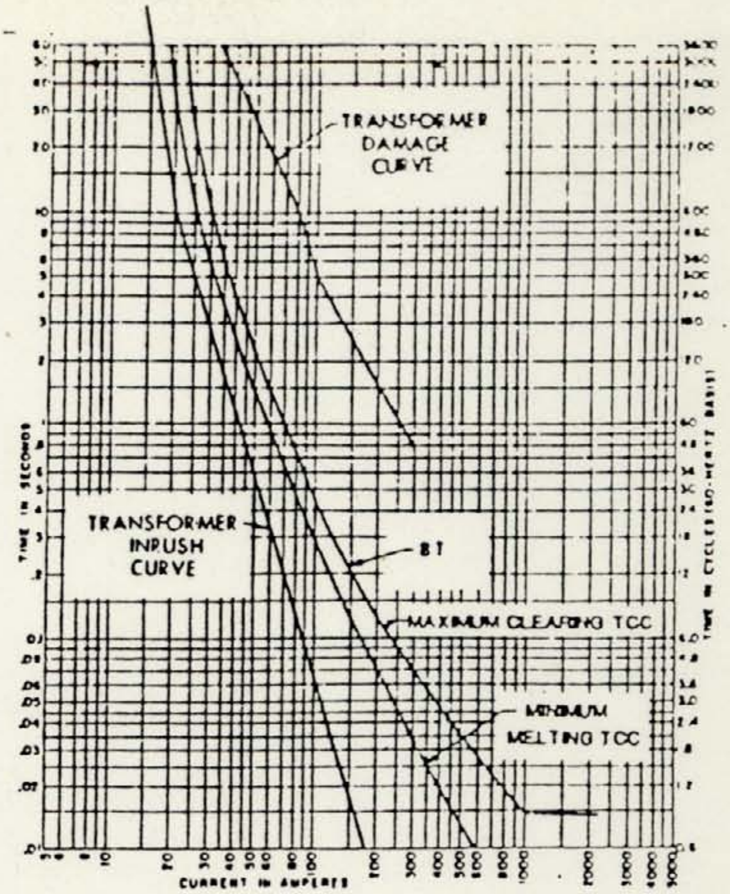


Fig. 3.4

3.2.6 Lightning Effects

During lightning storms, utilities often experience numerous outages caused by blown fuses on transformers; subsequent examination reveals no transformer damage. Studies made on this problem (11), show that fuse blowing is mainly due to transient inrush currents produced by transformer core saturation by the lightning induced surge voltages. There is no easy method of calculating this current to aid in choosing the proper fuse as it requires a knowledge of transformer characteristics not readily available. Experience has shown that the use of slow fuse links (Type T) with a minimum fusing ratio of 3 greatly reduces the number of fuse operations in areas where severe lightning storms frequently occur.

3.2.7 Fusing Examples

Some fusing examples will illustrate the protection offered by various types of fuses. Figure 3.4 shows the minimum melt and maximum clearing time current curve of an 8T fuse superimposed on the transformer inrush and damage curves ducussed previously. It fits well between the two curves — in fact, first glance indicates a larger fuse would be better. We must consider the upper ends of the curves where the fuse and damage curves are converging. While not shown, the damage curve of the transformer continues upward until it becomes asymptotic to the twice rated current value at 1800 sec. The fuse curve does intersect the damage curve. Actually the fusing ratio is 2.8. In order for the fuse curve to lie completely under the damage curve the fusing ratio must be 2 or less.

This example illustrates the problems encountered in fusing to obtain complete overload protection. Due to the differences in heat capacity of fuses and transformers, the fuse and transformers curves do not match in the long time region. A transformer can operate for hours at small overloads before reaching temperatures that reduce its life. An expulsion fuse chosen to protect against this overload would operate in 5 to 10 minutes. Much of the overload capability of the transformer would be sacrificed. Even the use of current limiting fuse, where the operating time is 3 to 4 hours does not provide much improvement in utilizing the full transformer capability.

These are the reasons that most utilities have adopted 2 or 3 as the minimum fusing ratio. Experience has shown that while this practice may result in an occassional transformer failure from overload, this is more than offset by reduced unnecessary outages and expensive service calls to replace blown fuses caused by harmless short time overloads.

Figure 3.5 shows a 10 K fuse. While it is larger than the 8 T the fusing ratio being 3.4, its curve comes uncomfortably close to the inrush curve. The reason is that the K fuses are faster than the T fuses.

Figure 3.6 shows a 12 C current limiting fuse. Being extremely fast, larger sizes are required to meet the inrush requirements. The fusing ratio for this example is 2.9. For current limiting fuses the 4 hour current point on the fuse maximum clear time current curve is used to determine the fusing ratio.

Figure 3.7 shows an expulsion and current limiting fuse in series, a combination that has attained wide usage. Only the expulsion fuse operates on overloads and low current faults. Above 500 amperes the current limiting fuse operates. The advantages are that fuse blowing on an overload or low fault current requires the replacement of only the inexpensive expulsion fuse link, while with high current faults the current limiting fuse provides the energy limitation to prevent disruptive failure of the transformer.

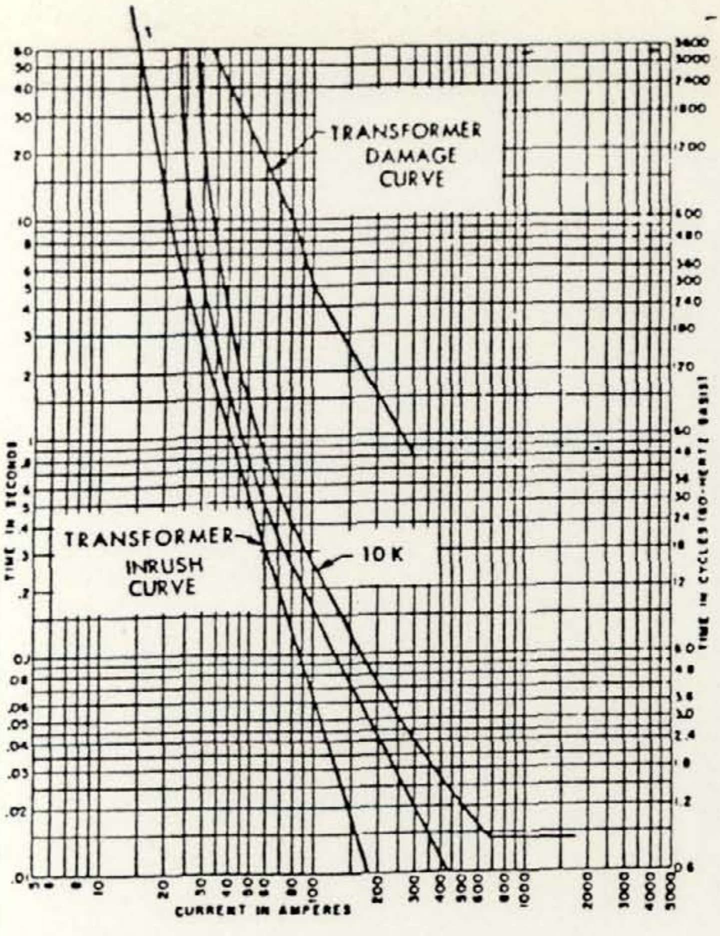


Fig. 3.5

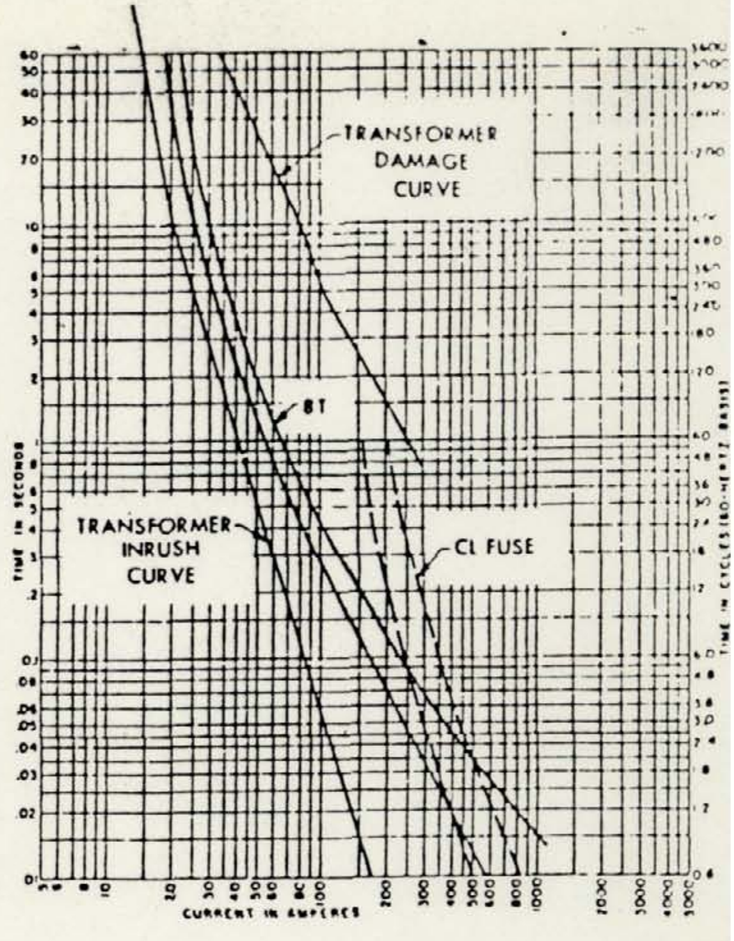


Fig. 3.7

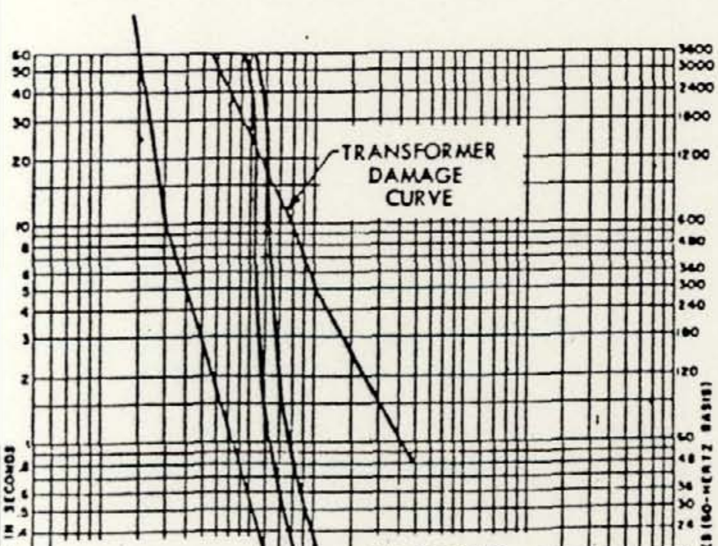


Fig. 3.6

3.2.8 Overhead Transformer Fusing Arrangements

There are many mechanical arrangements for fusing transformers. The fuse can be part of the transformer or a separate unit. The most widely used arrangement for overhead transformers is the expulsion fuse mounted on a crossarm, next to the transformer. Initial cost is low and refusing is fast and economical.

Another arrangement widely used in the past is the self-protected transformer where the expulsion fuse is mounted inside the transformer. Since the fuse is not field replaceable it is large (fusing ratio 8 or more) so as not to blow on overloads. An internal secondary breaker is often used to provide overload protection. With the expulsion fuse inside the transformer, a fuse operation on a high fault current produces high internal pressure in the transformer tank. This limits the application to locations where fault current does not exceed 3000 amperes.

A very popular arrangement is the expulsion fuse-current limiting fuse combination, obtained by adding a current limiting fuse on an existing expulsion fuse mounting. The advantages of such a combination were discussed previously. This is an economical method of obtaining current limiting fuse protection when system growth raises the fault current beyond the levels where expulsion fuses alone are not satisfactory.

3.2.9 Pad Mounted Transformer Fusing Arrangements

With the advent of pad mount transformers, current limiting fuses became the primary protective device since gases produced by expulsion fuse operation limit or prohibit their use in the enclosure. Initially, the current limiting fuses were mounted in insulated compartments inside the pad mounted cabinet. Various fusing and switching arrangements were used to permit the isolation of faulted transformers or faulty sections of underground cable. Since there are exposed live parts inside the enclosure, they are called "live front" construction.

With the development of submersible connectors, the shielded ("dead front") construction evolved. Here the transformer is energized by the submersible connector connected directly to the transformer high voltage terminal. Fuses are mounted inside the transformer in different manners. There are no exposed live parts inside the pad mount cabinet. Operation is safer than with the live front construction and line to ground faults caused by dirt and condensed moisture inside the enclosures are practically eliminated. Shielded is now the most popular construction for pad mount transformers.

The bayonet fuse concept utilizes an expulsion fuse mounted on a structure which is located on to the side wall of the transformer placing the fuse in the transformer oil. The bayonet is removable, permitting easy fuse replacement. The interrupting rating of such a fuse is limited but by adding an oil-proof current limiting fuse, mounted inside the transformer, the interrupting capacity is greatly increased. This scheme is becoming very popular since it provides all the advantages of the expulsion fuse - current limiting fuse combination discussed previously.

For applications where conventional current limiting fuses are desired or required, a canister (sometimes called a dry well) has been developed to contain the fuse. The canister is mounted in the side wall of the transformer but is completely sealed from the oil. The fuse can be removed or inserted into the canister with conventional hot line tools.

3.3 SUBSTATION TRANSFORMER FUSING

Protective devices used to provide protection on the primary side of substation transformers are circuit breakers, circuit switchers and fuses. For small substations serving industrial plants, and small power transformers serving shopping centers, large buildings, hospitals, etc., power fuses are often used because they are the least expensive means for providing transformer protection. The following circuit parameters must prevail if a fuse is used:

a. System line to line voltage is 169 kV or less.
b. Fault currents are within the fuse interrupting ratings.
c. Load requirements are within the fuse current ratings.
d. Single phase interruptions are tolerable.

The basic function of the fuse is to interrupt any faults between the fuse and the protective device on the secondary side of the transformer. The fuse also provides back-up protection for the secondary side protective device.

The most important consideration in selecting the fuse is its ability to withstand inrush and cold load pick-up currents. As with distribution transformers the fuse curves should coordinate with the inrush and transformer damage curves as discussed previously. The fuse must also be large enough to carry emergency peak loads and coordinate with the protective device on the secondary side of the transformers. This may require a fuse so large that overload protection is not provided. In such cases, other means of detecting harmful transformer temperatures can be incorporated in the transformer.

3.4 CAPACITOR FUSING

As with transformers, the main function of the capacitor fuse is to protect the distribution system from failed capacitors and faults that occur within banks of capacitors. Unlike transformers, the capacitor fuse cannot prevent the capacitor from failing. When the capacitor does fail, the fuse should remove it from the system before tank rupture occurs. The fuse should also operate before upstream protective devices.

3.4.1 Capacitor Characteristics

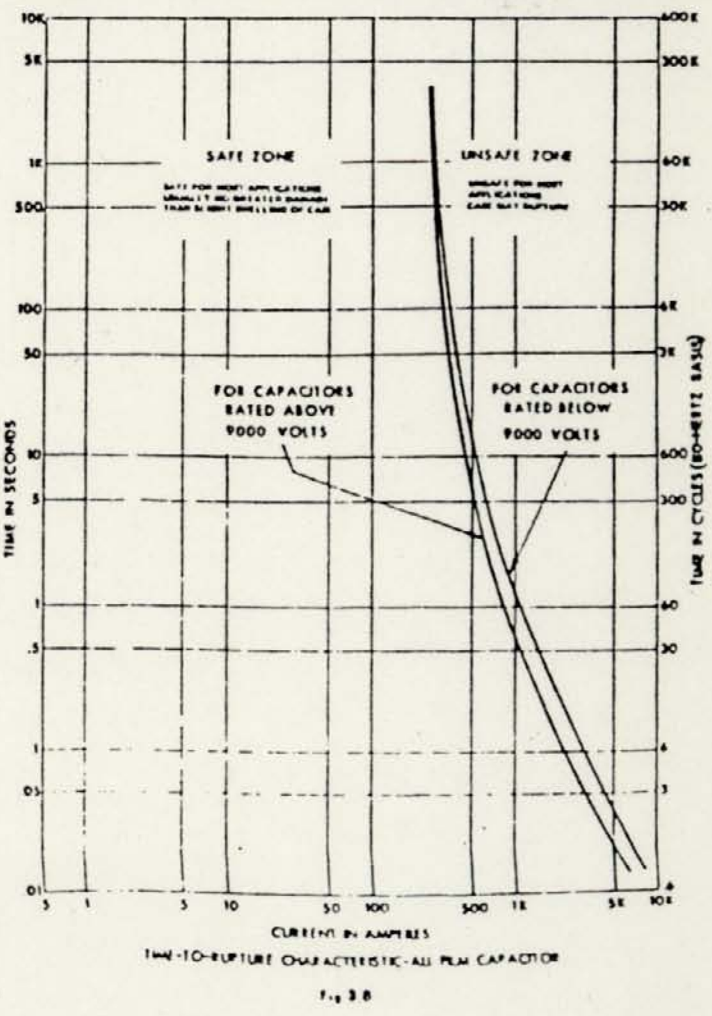
While capacitors are considered constant current devices, they are subject to overcurrents in actual operation on a system. These are caused by over capacitance, operation at higher than rated voltage, and system harmonic currents. Standards allow operation at 10 percent overvoltage and a 15 percent over capacitance. These two factors increase rated current by 25 percent. Harmonic currents depend on system conditions and are difficult to predict. Generally, an allowance of 5 to 10 percent of rated current is used.

When a capacitor is energized, there is an initial inrush current. This is a short duration, high frequency damped sinusoidal current whose characteristics depend on the capacitor size and supply circuit impedance. The I^2t of the fuse must be larger than that of the inrush current. The I^2t of the inrush current can be calculated with good accuracy using the following relationship (12)

$$I^2t = 2.65\,(I)\,(I_{sc})\quad \sqrt{1+K^2}\ \text{amp}^2\text{sec}$$

where I_{sc} = three phase fault current at capacitor bank location - KA
I = capacitor bank line current - amperes
K = X/R ratio of the fault current

A capacitor unit consists of a number of series groups of parallel connected packs. Capacitor failure usually starts with the breakdown of one pack which then shorts out this group. The capacitor current increases as does the voltage on the remaining series groups. This increased voltage will eventually lead to the dielectric failure of another pack causing another increase in current and voltage across the remaining good groups. This process will continue until all the groups have failed and the capacitor acts as a bolted fault. The process may take hours or longer during which time current escalates in discrete steps. It is desirable that



TIME-TO-RUPTURE CHARACTERISTIC - ALL FILM CAPACITOR

Fig 3.8

the capacitor fuse operate before all the series groups have failed, since the then remaining good groups will limit the fault current and the possibility of tank rupture will be minimized. When this is not possible, the ffect of high fault current flowing through a failed capacitor must be .onsidered.

Tank rupture curves have been established by the manufacturers of capacitors. Such a curve is shown in Figure 3.8. Obviously, the fuse curve should lie to the left of the rupture curve. For applications where the fault exceeds 5000 amperes, expulsion fuses in many cases are unsuitable and current limiting fuses are required [13, 14, 15, 16, 17, 18.]

3.4.2 Fundamental Rules of Fusing

The previous factors discussed enable us to establish the following fundamental rules for fusing capacitors.

1. The fuse must carry continuously X% of rated capacitor current. In practice X varies from 120 to 165 but 135 is most commonly used.
2. The fuse must interrupt available power frequency fault currents, both inductive and capacitive.
3. The fuse must withstand transient inrush current without damage. The fuse should operate before tank rupture occurs.

3.4.3 Types of Fusing

Two general types of fusing are used, group and individual. With individual fusing, each capacitor has its own fuse while with group fusing a number of paralleled capacitors are protected by one fuse. Individual fusing is used on large banks installed in substations. Special fuses, both expulsion and current limiting, designed to facilitate mounting in the ank are utilized.

Group fusing is used on the smaller pole mounted capacitor bank used extensively on distribution systems. Standard fuses mounted on the capacitor rack are normally used.

The effectiveness of the protection provided by the group fuse decreases as the number of capacitors per phase increases since the larger fuse required will not operate until all the series groups in a faulty capacitor have failed and full system fault current will flow through the failed pacitor.

Group fuses chosen to carry 135 percent rated current of the capacitor bank generally will withstand inrush currents. The exception is when another bank is located within 100 feet. Then when one bank is switched on when the adjacent bank is energized, inrush current from the adjacent bank will greatly increase the total inrush current.

Capacitor banks are connected to the distribution system in either a delta or wye configuration. With the wye configuration, the neutral can be either grounded or floating. When grounded, the fault current through a failed capacitor is the available system line to ground fault current. For the delta connection, line to line system fault current will flow through the failed capacitor. In high fault current locations, current limiting fuses may be required to prevent tank damage.

If the neutral of a wye connected bank is not grounded, the fault current is limited to three times normal line current so the duty on the failed capacitor and group fuse is reduced. The fuse must be small enough to ect this fault current. While the faulted capacitor is in the circuit, the eutral shift causes the voltage across the capacitors in the unfaulted phases to increase to 1.73 times their rated voltage. Operation under these conditions will result in capacitor failure in a short time. The general rule for selecting fuses is to require the fuse to operate within five minutes at 95 percent of the fault current.

References 19-21 provide additional information on capacitor fuse performance and application.

3.5 LATERAL TAP FUSING

Fuses used on lateral taps serve two purposes. They protect the conductors from thermal damage in the zone from the fuse to the next downstream protective device (if used) or to the end of the line. They also provide sectionalization which in most applications dictates the fuse selection.

The factors that determine fuse rating and time current characteristics are:

a. Circuit Parameters
   - Maximum load current
   - System voltage
   - Available fault current
   - Line conductor size and type
b. Thermal damage time current characteristics of the conductor
c. Upstream and downstream protective devices

If conductor protection is the objective, its damage time current characteristics must be considered. This information is available from conductor suppliers and "The Insulated Power Cable Engineers Association" (IPCEA). The curves give the times required for various fault currents to heat the conductors to a temperature that will cause damaging annealing. The fuse curve should be faster than the conductor damage curve for fault current up to the maximum available.

The lateral tap fuse, whether chosen for conductor protection or sectionalizing must coordinate with upstream and downstream protective devices, using procedures covered in a later chapter.

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ANEXO H

CORRIENTE MAGNETIZANTE DE INRUSH EN TRANSFORMADORES DE POTENCIA

Cuando se energiza un transformador de potencia con el secundario en abierto, se origina un fenómeno transitorio de magnetización, ya que al aplicar un voltaje senoidal circula una corriente, llamada corriente magnetizante de inrush, la cual da origen a un flujo quién a su vez produce el voltaje inducido en el secundario del transformador. El tiempo que transcurre desde el instante de aplicar tensión en el primario hasta que aparece una tensión inducida en el secundario, es de aproximadamente seis (6) ciclos.

La forma de onda de la corriente de inrush no es senoidal y va a depender de las características magnéticas del transformador (ciclo de histéresis), de su tamaño, capacidad y del contenido de hierro en el núcleo. Por su parte, el valor máximo de dicha corriente va a estar en función del punto de energización de la onda de voltaje y del contenido de flujo residual en el transformador.

Si la energización se produce en el instante cero del primer ciclo de la onda de voltaje, el flujo puede incrementarse hasta llegar al valor correspondiente al extremo de saturación de las características magnéticas. Bajo esta condición, la inductancia disminuye y la corriente aumenta repentinamente su valor, el cual estará por encima de la corriente nominal de carga del transformador. Cuando el flujo alcanza nuevamente su máximo valor, que ocurre en el próximo paso por cero de la onda de voltaje, el semiciclo negativo de ésta reduce el flujo de arranque y la corriente cae simétricamente a cero, siendo completamente desplazada. Los dispositivos de protección podrían interpretar esto como una falla, cuando en realidad no lo es, por lo que deben ser dimensionados para asegurar su correcto funcionamiento durante este fenómeno transitorio.

ANEXO I

COORDINATION OF SERIES OVERCURRENT DEVICES

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Abstract

The basic philosophy of the application and coordination of series connected overcurrent protective devices is presented. Specific emphasis is given to protection of Electric Utility distribution systems through the use of various types of fuses and reclosers. The fuse types and their characteristics are described as well as the coordination of these fuses with reclosers.

6.1 Introduction

The principal objective behind the effort to secure coordination of series overcurrent devices is to improve the service to the user of electric power, the customer. The application of this objective to the Electric Utility distribution system requires a complete knowledge of the system and certain calculations. The normal starting point is the circuit diagram which shows all of the necessary information such as the locations of transformers, breakers, reclosers, sectionalizers and fuses, plus the ratings of each of these devices. Also usually shown are conductor locations, sizes and lengths along with special terrain conditions. Connected KVA and any special loads are indicated along with calculated maximum available fault current at the location of each piece of equipment or protective device. After ratings and settings of each of the overcurrent protective devices is determined, these are normally also added to the one line circuit diagram. This diagram can be the working guide and tool which is expanded in steps as each required piece of information is secured. A simplified example of the initial one-line circuit diagram is shown in Fig. 6.1.

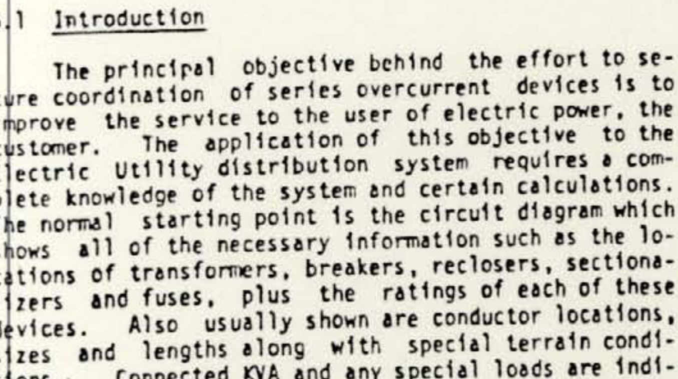

Fig. 6.1 One-Line Diagram of a Distribution Circuit

6.2 Basic Philosophy For Distribution Systems

Since the purpose for overcurrent device coordination is to improve system reliability, one of the primary objectives is to isolate a faulted line or piece of equipment rapidly with a minimum disturbance to the rest of the system. This is accomplished by taking steps to prevent a system outage as a result of temporary faults. Since many system outage studies have shown that up to 90% of distribution system faults are transient in nature, the clearing of these fault conditions is a major benefit. The primary causes of transient faults are tree branches across lines, conductor swing due to wind, and voltage surges on the system, principally caused by lightning, which result in flashover of insulation. The identification of the causes for transient fault conditions permits the implementation of specific procedures designed to minimize the effects of these faults.

In the event that the system fault condition is permanent, the primary approach used is to isolate the effects to the least number of customers possible. This is accomplished by coordination of the series connected overcurrent protective devices. In addition the system overcurrent protection is designed to facilitate rapid service restoration by making sectionalizing points easily accessible and providing means for localized fault isolation and loop feeding. Coordination of the overcurrent protective devices will be covered in detail later in this paper.

The first step required for a distribution system coordination study is to set down the criteria which will apply for the application of each of the overcurrent protective devices which may be applied to the distribution feeder. The next task is the creation of a detailed circuit diagram which indicates both maximum and minimum available fault currents at specific locations, load currents and the location of critical loads. Exposure of the lines to conditions which might affect continuity of service are also shown. Some of the criteria usually considered when reclosers or fuses are specified are:

a) Ratings and operating time-current characteristics of the devices.

b) Special circuit conditions with regard to terrain, load density, critical nature of the load etc.

c) The zone of protection of fuses and reclosers to avoid both too much overlap or unprotected zones.

Fig. 6.2 shows the simple addition of reclosers and fuses to the one-line circuit diagram of Fig. 6.1. The solid lines illustrate the three-phase main feeder and the three-phase branches, and the dotted lines are single phase taps. The reclosers A, B and C are expected to clear temporary faults within their zone of protection. These zones of protection are shown by the dashed lines. Looking first at recloser A, the calculated maximum available fault current at its location must not exceed its rating. Recloser A's zone of protection will extend out to the point where the minimum available fault current will equal the pickup current of the recloser coil. This value is equal to two times the coil rating plus its tolerance. At this point another recloser with a smaller coil rating must be installed to cover the more remote portions of the system. This is illustrated in Fig. 6.2 by reclosers B and C.

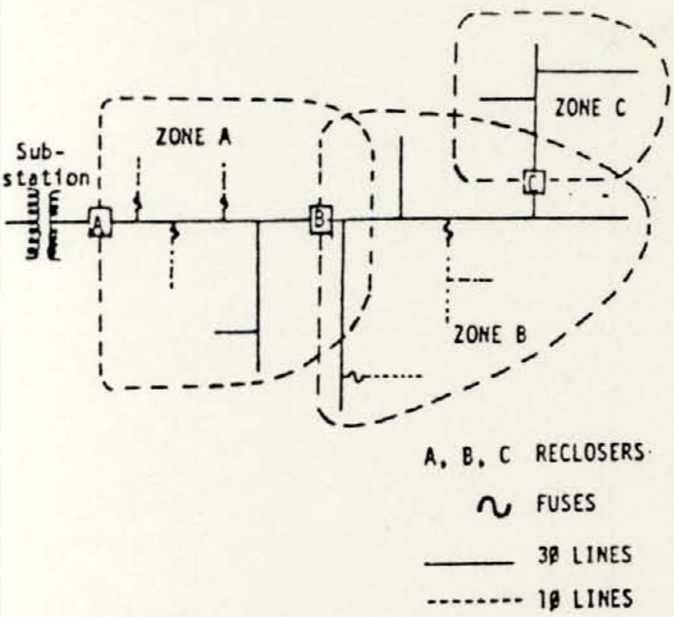

Fig. 6.2 Distribution Circuit with Protective Devices

6.3 Fuse-to-Fuse Coordination

The majority of fuse-to-fuse coordination is accomplished through the use of published fuse minimum melting and total clearing time current characteristic curves. The requirement for proper fuse-to-fuse coordination is that the protecting fuse must melt and clear the circuit before the protected fuse is damaged, Fig. 6.3.

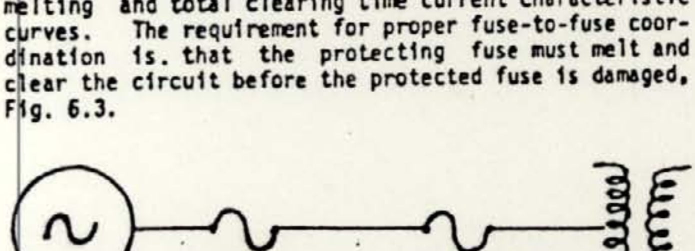

Fig. 6.3

6.4 Fuse Characteristics

Most fuse time current curves are plotted in the time range of 0.01 seconds to 1000 seconds. This indicates that the use of these curves permits coordination only to approximately the one-half cycle time region. Since expulsion fuses normally must wait for the first current zero following element melting in order to interrupt the fault current, there is a maximum current level for each fuse size for which coordination is possible. For this reason curves for expulsion fuses are stopped at 0.8 cycle to indicate the minimum time for which coordination can be achieved. However, when current-limiting fuses are involved in the coordination study, or when it is necessary to accurately determine if an expulsion fuse link will withstand a single loop or cycle of fault current without melting, there is a need to express the fuse's melting and/or total clearing characteristic in the one cycle or sub-sycle time region. The aggregate effect of a short circuit current pulse can be evaluated in terms of a single composite electrical quantity, the time integral of current squared ($\int i^2 dt$) which is commonly referred to as I^2t.[1] For the expulsion fuse case, the I^2t of a single loop of fault current can be compared with the protected fuse's minimum melting I^2t to assure that the fuse will withstand this current.

When considering current-limiting fuse to current-limiting fuse coordination the requirement that the protecting fuse must melt and clear the circuit before the protected fuse is damaged can be determined by comparing the fuse's respective total clearing I^2t, and minimum melting I^2t, see Fig. 6.4.[2][3]

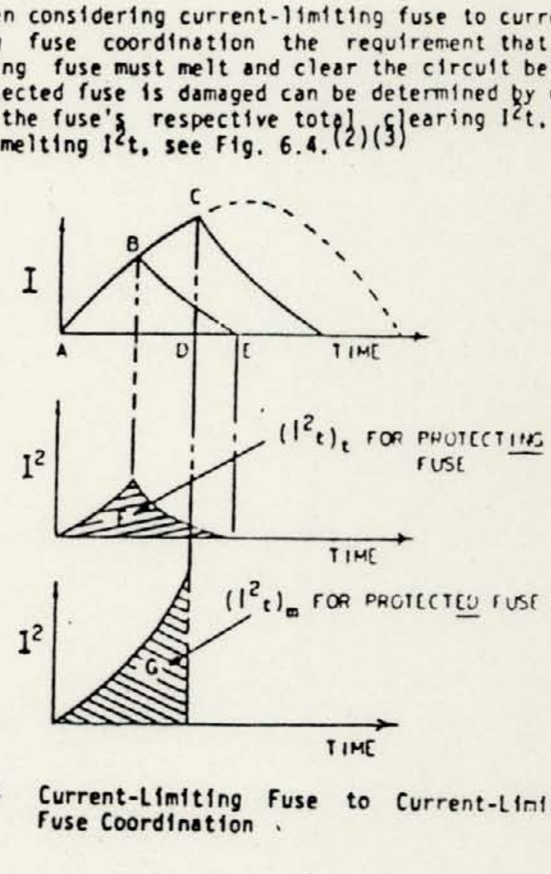

Fig. 6.4 Current-Limiting Fuse to Current-Limiting Fuse Coordination

In the example shown, the fault current starts at A and the protecting fuse cuts off at B with the current falling to E. If this protecting fuse had not been in the circuit the current would have continued to flow in the protected fuse until cutoff occurred at C. The time AD for the protected fuse to melt can be less than the total interrupting time AE of the protecting fuse. But coordination will still exist in this case if the melting I^2t of the protected fuse (Area G) is greater than the total clearing I^2t of the protecting fuse (Area F).

6.5 Expulsion Fuses

The majority of expulsion fuses used on utility distribution systems are either mounted in cutouts or are transformer fuses used with self-protected distribution transformers. Careful attention must be given to matching the electrical ratings of these fuses or cutouts with the system or transformer ratings. If cutout interrupting ratings are given in asymmetrical amperes system X/R ratios at the points of installation must be considered.

The shape of the time-current characteristics for each of the series connected fuses must be similar in order to achieve good coordination. The curve shape is specified by its speed ratio which is the ratio between the melting current at 0.1 sec. and the melting current at 300 or 600 seconds, whichever is specified. The most commonly used expulsion links are the ANSI Type " and Type T links. Fig. 6.5 shows typical total-clearing time-current curves for these fuse links. For a given current rating it can be seen that the Type T fuse link has a larger speed ratio and therefore will have a greater capability to withstand temporary current surges such as might be caused by transformer in-rush current, surge arrester discharge current, lightning current or load pickup current.

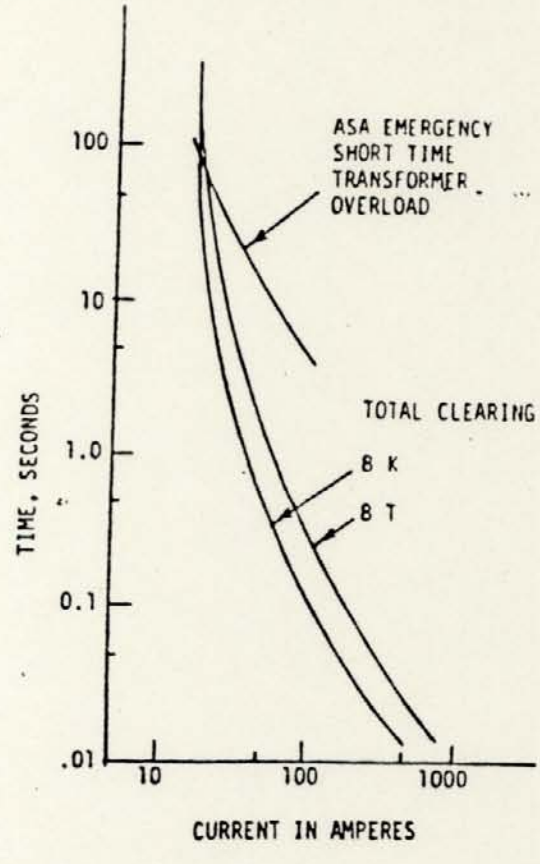

Fig. 6.5 Comparison of Type K and Type T Fuses for Protection of a Conventional 10 KVA Distribution Transformer

6.5.1 Expulsion Fuse Protecting an Expulsion Fuse

When the coordination between two series connected expulsion fuse links is to be determined, the total-clearing time-current curve of the protecting fuse link, plotted to maximum values so all manufacturing variables will be minus, is compared with the minimum values so all manufacturing variables will be plus. In addition, it is common practice to shift the minimum melting curve to 75 per cent of the time. This shift provides a margin for such operating variables as pre-heating due to load and to avoid melting of the fusible wire but not the parallel connected high resistance strain wire used in many fuse links.

Fig. 6.6 shows an example of this expulsion fuse link coordination. This illustrates the case where protecting fuse A is series connected with either fuse B or fuse C. The maximum current to which fuse link A will protect fuse B is current I_1, since the curves cross at this current level. The maximum current to which fuse A will protect fuse C is current I_2 since fuse C will melt at this or higher current before fuse A can protect it.

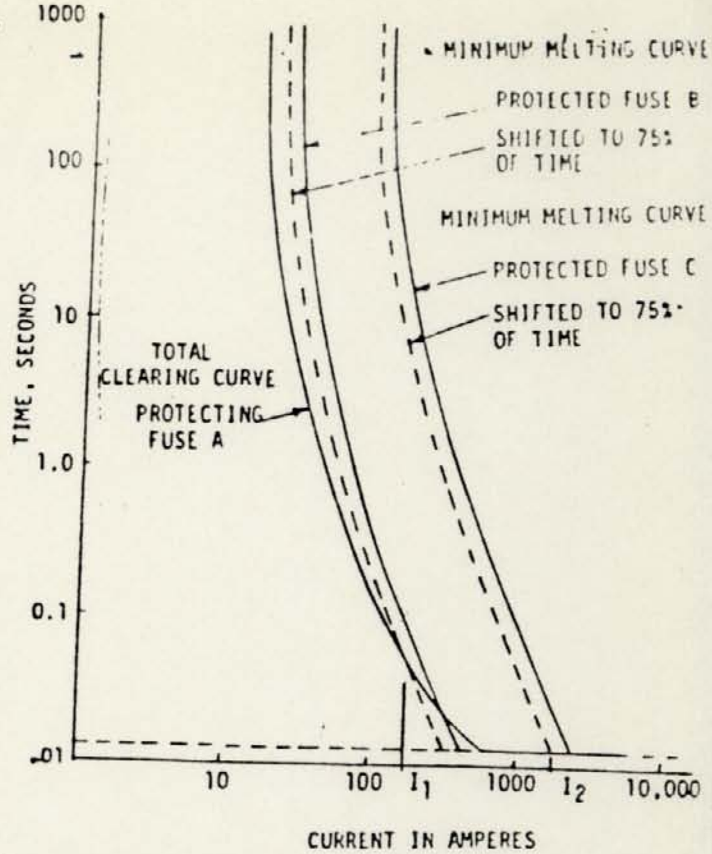

Fig. 6.6 Expulsion Fuse A, Protecting Either Fuse B or Fuse C

6.6 Current-Limiting Fuses

The coordination concepts used are similar to those described above if one or both of the fuses is a current-limiting fuse. The principal difference is that the current-limiting characteristic of the fuse is described by its total let-through I^2t as has been previously illustrated in Fig. 6.4.

When using I^2t comparisons for current-limiting fuse coordination it is not common to provide for a "no damage" boundary area since several factors are present which provide the necessary safety factor. The total clearing I^2t of a fuse must be determined by tests. These tests are made at the maximum rated fuse voltage and conditions of current and fault initiation time which yield the maximum I^2t. In service there is a high probability that the circuit voltage will be lower, and the fault timing other than worst case resulting in a total clearing I^2t lower than the maximum. The melting I^2t values secured from time current curves or from published values also have a built-in safety factor since the minimum melting time is reduced to 90% of the average melting time to allow for tolerances in fuse manufacturing. The calculated minimum melting I^2t is therefore 81% of the average melting I^2t since the reduction of melting current (90%) is squared.

In the following examples of fuse-to-fuse coordination using plotted time-current characteristic curves, the time range is carried down to 0.1 ms for illustrative purposes only. Published curves are normally plotted down to 10 ms only, and I^2t comparisons are used for high current coordination as previously illustrated.

Detailed information on the performance criteria and operating characteristics of current-limiting fuses can be found in (4, 5, 6, 7, 8, 9, 10).

6.6.1 Current-Limiting Fuse Protecting a Current-Limiting Fuse

Coordination studies in the current-limiting current range are performed by comparing the melting I^2t of the protected fuse with the total clearing I^2t of the protecting fuse, as has been previously shown. The time current characteristic as shown in Fig. 6.7 gives the information necessary to assure proper coordination for the complete time range plotted.

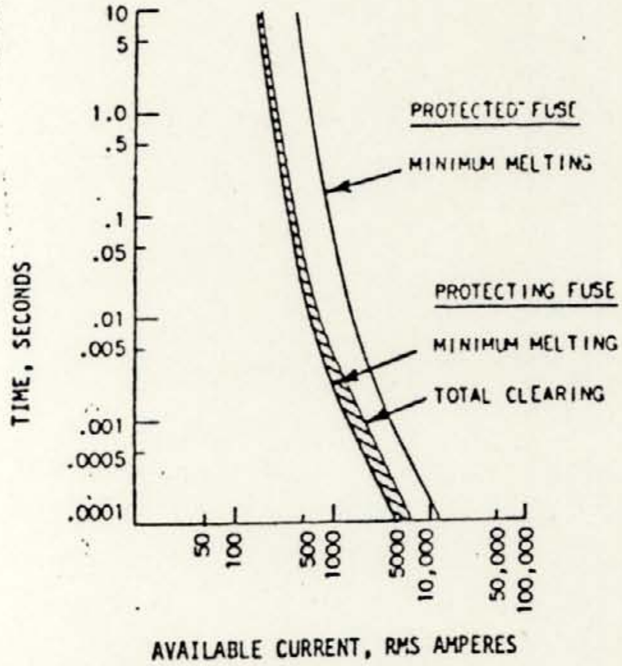

Fig. 6.7 Current-Limiting Fuse to Current-Limiting Fuse. Good Coordination Is Possible Through The Whole Current Range

The total clearing time-current characteristic of the protecting fuse must be to the left of the minimum melting time-current characteristic of the protected fuse. In general, good coordination will exist with this fuse combination.

6.6.2 Current-Limiting Fuse Protecting an Expulsion Fuse

Here again a comparison of the melting I^2t of the protected expulsion fuse can be made with the total clearing I^2t of the current-limiting fuse to see if proper coordination exists in the current-limiting current range. A comparison of time-current characteristic curves as shown in Fig. 6.8 gives the information necessary to assure proper coordination for the complete time range plotted. Good coordination will usually exist when a current-limiting fuse is the protecting fuse.

6.6.3 Expulsion Fuse Protecting a Current-Limiting Fuse

This application will only provide coordination up to a finite current level. The total clearing time-current characteristic of the expulsion fuse is compared with the minimum melting time-current characteristic of the current-limiting fuse. Since the protecting expulsion fuse cannot clear the circuit until the approximate time of the first current zero, its total clearing curve is drawn parallel to the cur-

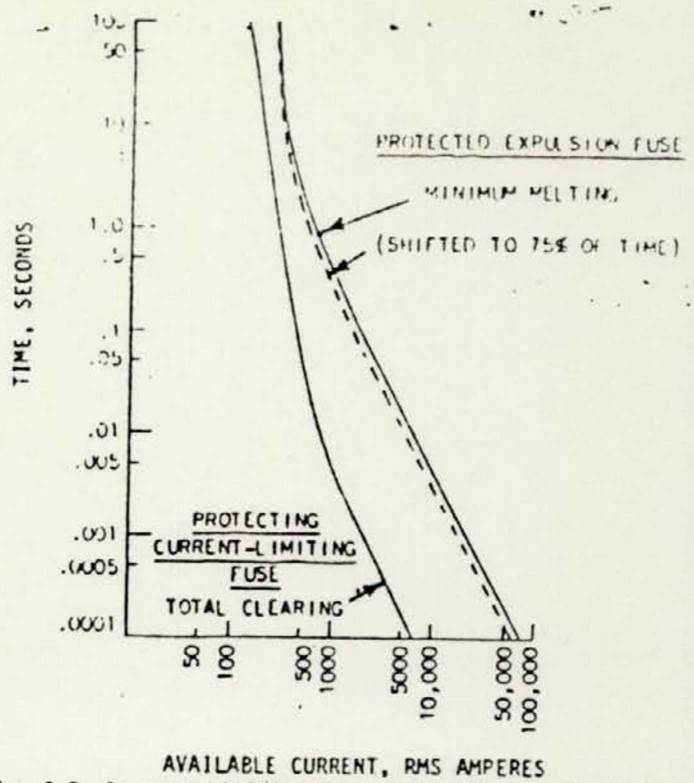

Fig. 6.8 Current-Limiting Fuse Protecting An Expulsion Fuse. Good Coordination Is Possible Through the Whole Current Range.

rent axis at 0.8 cycle or .0133 seconds. Fig. 6.9 shows this break in the characteristic and indicates that coordination is only possible up to the current values indicated in the figure.

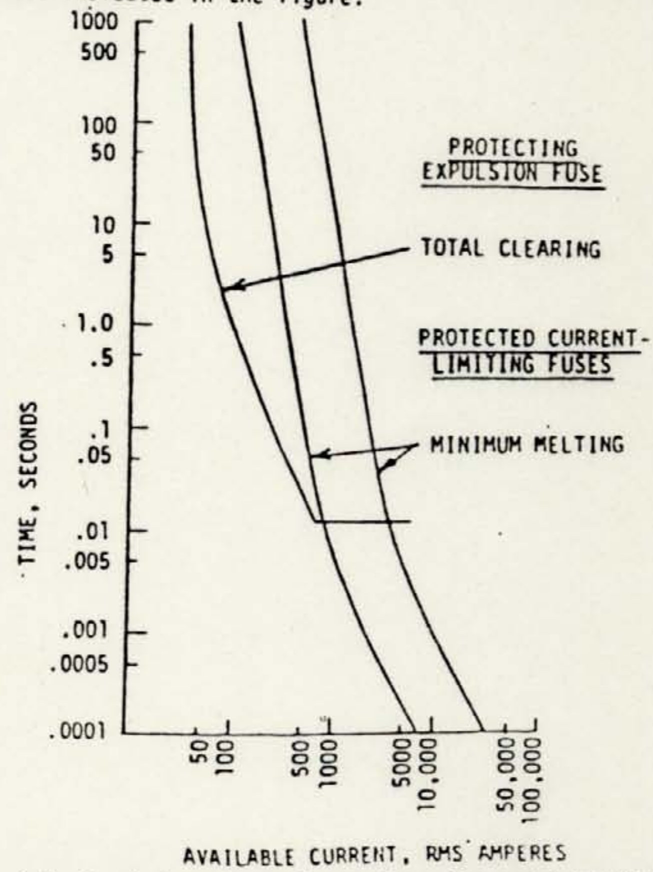

Fig. 6.9 Expulsion Fuse Protecting Current-Limiting Fuses Showing That Coordination Is Only Possible Up To Currents Of Approximately 850 Amperes And 4000 Amperes For The Two Current-Limiting Fuse Minimum Melting Curves Shown.

The typically different shape of the time-current characteristic curves for expulsion and current-limiting fuses indicates the importance of checking for proper coordination throughout the entire time range of interest (usually out to 1000 seconds).

6.7 General Purpose Current-Limiting Fuse

A general purpose current-limiting fuse is defined as a fuse capable of interrupting all currents from the rated maximum interrupting current down to the current that causes melting of the fusible element in one hour.[11] The use of this fuse type on the primary of distribution transformers to isolate the system from a fault has been a natural extension of expulsion fusing practice in locations where available fault current is too high for expulsion fuses. However, the principal reason for the rapid growth in the use of current-limiting fuses is their fault current limiting capability which translates directly into a reduction in fault energy. The general purpose fuse application and coordination is illustrated by the current-limiting fuse time-current curves shown in the preceding examples.

6.8 Backup Current-Limiting Fuse

A backup current-limiting fuse is defined as a fuse capable of interrupting all currents from the rated maximum interrupting current down to the rated minimum interrupting current.[11] The use of this type of fuse has been growing rapidly in recent years for utility application although it has always been predominate in Europe and in many industrial applications. In the principal utility application the backup fuse is series connected with an expulsion fuse to cover the complete range of fault and overload current interrupting duty. The two fuses are coordinated to take advantage of the best current interrupting range of each type. The first step in this application is to choose the required expulsion fuse characteristic in the conventional manner. This is normally based on in-rush considerations and overload protection practice if there are no supplementary secondary protective devices. With primary fusing only, protection against overloading or low fault currents in the region of 2 to 4 times full load current is most commonly used. When secondary fuses or breakers are involved the primary expulsion fuse must be coordinated with these devices.

There have been two approaches used in selecting the backup current-limiting fuse. These approaches involve the selection of the two fuse's time-current characteristics, and there are certain advantages and disadvantages of each. Fig. 6.10 illustrates these two approaches showing the time-current characteristic of one expulsion fuse as it would be matched with either current-limiting fuse A or current-limiting fuse B. Matching the expulsion fuse with fuse A involves a crossover of the characteristics in the time region between 0.1 and 10 seconds. Matching with fuse B requires that current-limiting fuse B have a melting I^2t approximately equal to or larger than the melting I^2t of the expulsion fuse. This latter approach results in the melting of the expulsion fuse element at all levels of fault current.

6.8.1 Approach 1: Expulsion Fuse Melts on Low Current Faults Only (Current-Limiting Fuse A)

a) The backup current-limiting fuse must have a minimum interrupting capability which includes the diamond-shaped crossover region, to cover its minimum melting current. In addition it is advisable to include some safety factor below this. In the case of fuse A on Fig. 6.10 this would require a minimum fault current interrupting capability of approximately 700 amperes.

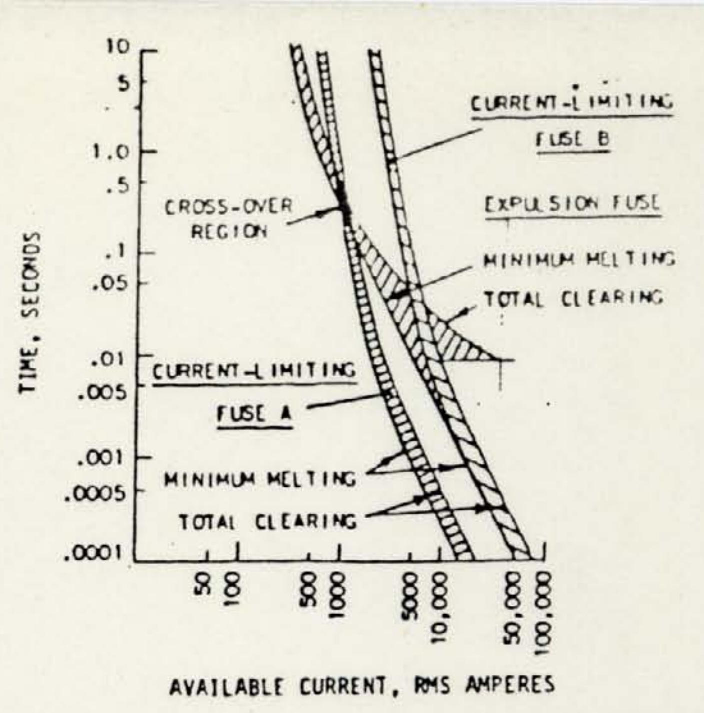

Fig. 6.10 Time-Current Curves Showing The Effects Of Two Different Crossover Regions Currently In Use

b) This requirement, to provide interrupting capability down to currents which are slightly below the diamond-shaped crossover region, requires a physically larger fuse for the same melting I^2t than a fuse which will not be subjected to this duty.

c) As can be seen from Fig. 6.10 fuse A has a smaller melting I^2t than fuse B, and this usually means it will also have a smaller total clearing I^2t than fuse B, even though they both match the same expulsion fuse. The use of fuse A for the protection of a given transformer kVA rather than fuse B will mean less energy in a transformer fault because of the lower let-through I^2t.

6.8.2 Approach 2: Expulsion Fuse Melts at all Levels of Fault Current (Current-Limiting Fuse B)

a) Since the expulsion fuse will melt and arc for all levels of fault current, it will share the interrupting duty with the current-limiting fuse and remove voltage from it. This permits the design of the current-limiting fuse to be smaller and simpler. The relative amount of interrupting duty which will be imposed upon the expulsion fuse will depend on how early it melts on the current wave. A comparison of the melting I^2t for the expulsion fuse versus the backup current-limiting fuse will indicate relative melting times. This matching of fuses must be done carefully since too large an expulsion fuse will not properly protect the current-limiting fuse from fault currents below its interrupting capability, and too small an expulsion fuse may impose too much of the interrupting duty on the expulsion fuse. This latter factor is of less importance for expulsion fuses mounted in cutouts, but certain types of internal transformer expulsion fuses have a limited energy withstand capability. The combination of the expulsion fuse and the series connected backup current-limiting fuse should be tested to assure proper interrupting performance.

b) Since the melting I^2t of the backup current-limiting fuse used in this matched melting I^2t approach (fuse B) is larger than that of fuse A, it is very likely that the high current total clearing I^2t will also be larger. This factor could be a disadvantage for fuse B, but for many transformer voltage and kVA ratings this slightly higher let-through I^2t will not be a problem.

c) If the expulsion fuse of Approach 2 is an internal transformer fuse, its arcing will add some energy to that generated by the transformer internal arcing fault. Due to the presence of the current-limiting fuse this energy increase will be significantly less than it would otherwise be. The resultant duty on the transformer is therefore increased somewhat as compared with Approach 1 (fuse A).

Additional information on transformer protection using current-limiting fuses can be found in (12,13,14,15).

6.9 Recloser-Load Side Fuse Coordination

Where automatic circuit reclosers are used with fuses, the basic coordination theory of limiting the effects of any system fault to the smallest number of customers and minimizing the potential damage to equipment, still applies. The most commonly used basic system is as was previously shown in Fig. 6.2 where the main line sectionalizing is done with pole type reclosers. The tripping characteristics for conventional reclosers are as shown in Fig. 6.11. There are two basic types of operating characteristics, A curves (instantaneous) and B curves (time delay). The recloser can be adjusted to operate one, two, or three times instantaneously if a fault occurs on its load side. This type of operation is an attempt to deal with temporary faults which are self-clearing. However, since the fault may be permanent, it is desirable to provide some other interrupting means which will be located closer to the fault. For this reason, the recloser can be adjusted for one, two or three time delay curve operations which are designed to permit the fault current to flow for a time sufficient to blow a fuse located on the load side of the recloser. After the fourth opening, if the fault is still on the line, the recloser will lock open. For this type of recloser-fuse coordination, the time-current characteristic of the fuse must be selected such that the instantaneous operations do not melt the fuse, but the fuse will melt and clear on the time delay operation before the recloser locks open.

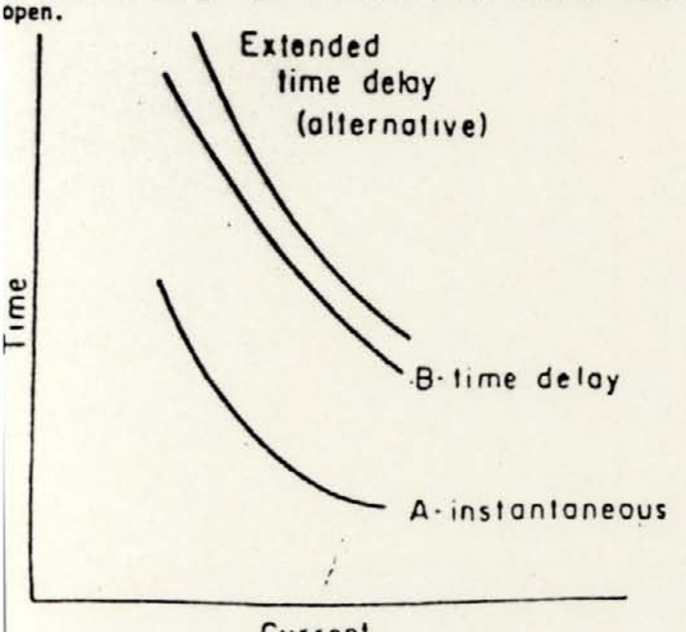

Fig. 6.11 Tripping Characteristic for Conventional Automatic Circuit Recloser

– If properly coordinated fuses are located at each branch or sub-branch on a distribution feeder as shown in Fig. 6.12 then a permanent fault on a branch line (such as at point X) will not result in a lockout of the main line.

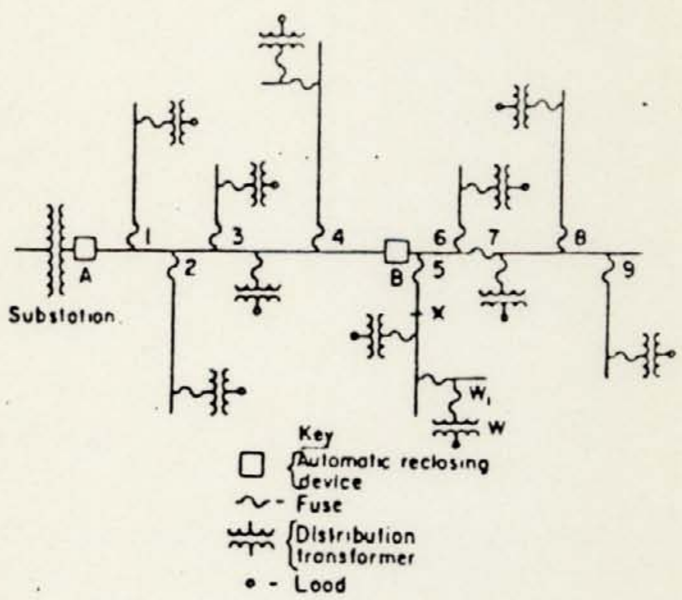

Fig. 6.12 Method for Dealing with Permanent Faults

6.9.1 Coordination Using Expulsion Fuse Links

Fig. 6.13 shows recloser time current characteristics similar to those shown in Fig. 6.11. Superimposed on these curves are the time-current characteristics of a typical expulsion fuse, curve C. Both the minimum melting and the total clearing curves are shown for the fuse link. The total clearing curve is used to establish the lower current limit of coordination with the time delay recloser curve. The minimum melting curve is used to establish the upper current limit of coordination with the instantaneous recloser curve.

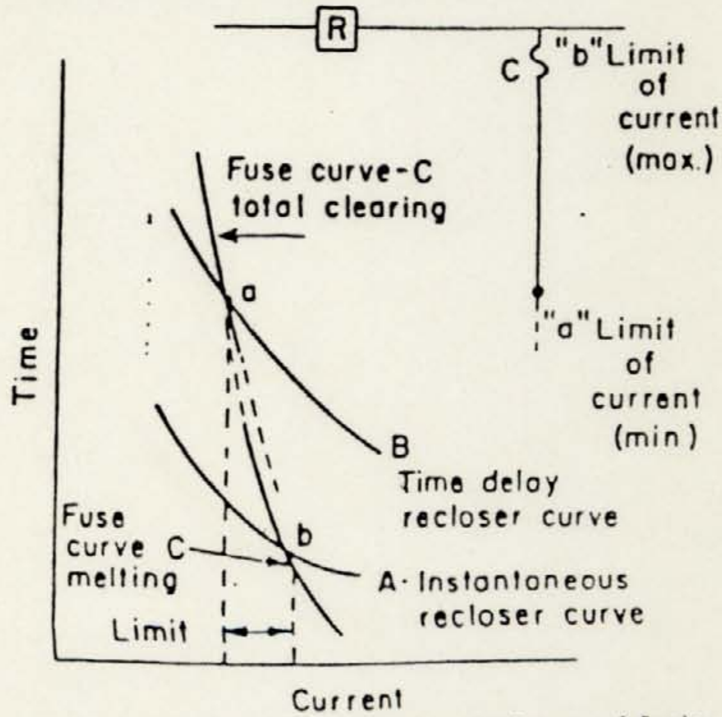

Fig. 6.13 Time-Current Characteristic Curves of Recloser of Fig.6.11 Superimposed on Fuse Curve C

In order to accurately establish the intersection points a and b, it is necessary that the characteristic curves of the recloser be modified to reflect the settings being used and the fuse curves be shifted or modified to take into account alternate heating and cooling of the fusible element as the recloser goes through its sequence of operations.

For a typical two-two recloser operation Fig. 6.14 indicates the type of heating and cooling that occurs in a fuse link due to the current flowing through it. For this sequence the first two operations are instantaneous each requiring two cycles. The two time delay operations require twenty cycles each.

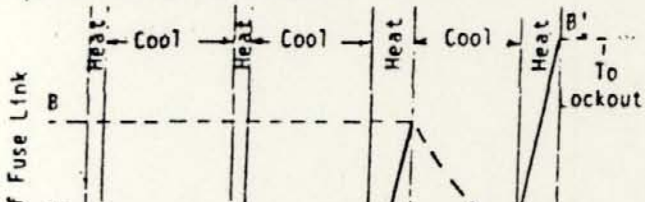

Fig. 6.14 Fuse Link Heating and Cooling

The heat input from the fault current during the the two instantaneous operations must not damage the fuse link thermally. Curve A' in Fig. 6.15 is the sum of the two instantaneous openings (A) and it is compared with the fuse damage curve plotted to 75% of the minimum melting curve of the fuse link. This procedure establishes the high current limit of satisfactory coordination as indicated by the intersection point b' in Fig. 6.15.

To establish the low current limit of successful coordination, the total heat input to the fuse represented by curve B' (which is equal to the sum of two instantaneous (A) plus two time-delay (B) openings) is compared with the total clearing-time curve of the fuse. The point of intersection is indicated by a'.

The limits for coordination are therefore between the current levels represented by a' and b'. If the maximum calculated short circuit current at the fuse location does not exceed the current b', the fuse will be protected during transient faults since the one or two instantaneous recloser operations will not damage the fusible element. However, if the fault is permanent the fuse should clear the circuit before the recloser locks out. When the minimum calculated line to ground short circuit current at the end of the protected branch circuit is greater than the current indicated by point a' in Fig. 6.15, the fuse will interrupt the fault before the recloser locks out.

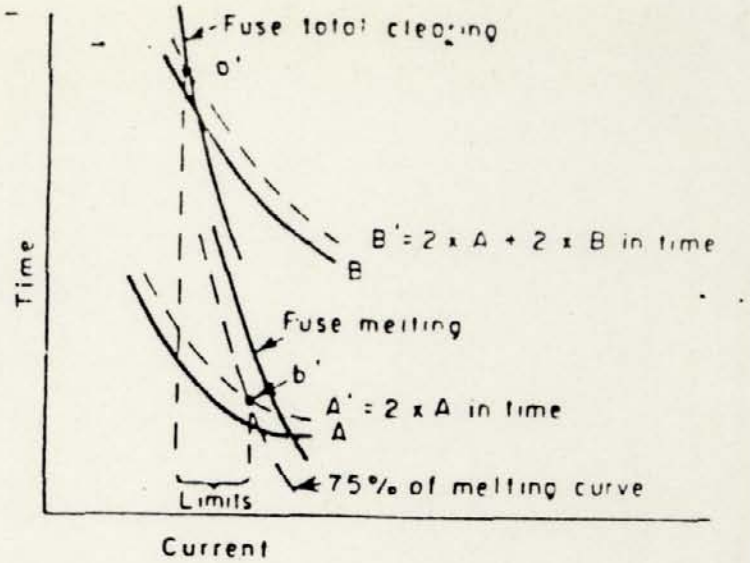

Fig. 6.15 Recloser-Fuse Coordination (Fuse Corrected for Heating and Cooling)

If this coordination between the recloser and the load side fuse is based on the use of published fuse time-current curves, the limits established will tend to be conservative. On the other hand when the effects of fuse element cooling are included, the coordination range (the current range between the limits) will tend to increase. The cooling period will shift both the melting and the total clearing fuse curves to the right but the effect on the crossover current level is more pronounced in the high current region. The reasons for this are a result of the characteristic curve shape for expulsion fuse links. The crossover in the low current region takes place where the fuse clearing curve is quite steep. This means that an increase in the fuse total clearing time results in only a small change in the crossover current level. The high current crossover takes place where the fuse melting curve is approaching the 2:1 slope of the adiabatic condition (all heat stored). This means that an increase in the fuse melting time results in a large increase in the crossover current level. It can therefore be seen that increasing the expulsion fuse link melting time to compensate for off-time cooling will tend to increase the current range for coordination. Calculations can be made which will correct for the heat lost from the fusible element due to the open time of the recloser, and if more accuracy is desired this additional step can be taken.[16,17]

The selection of the proper fuse link rating and speed ratio to accomplish this recloser-fuse coordination is commonly referred to as "slot fusing". An important requirement is that the entire circuit, including all the branches and taps be fault current protected by relayed breakers and reclosers. The permanent faults will then be effectively isolated to the smallest number of customers possible. At high fault current locations there may be some unnecessary fuse operations if a very low impedance fault develops, but for most fault conditions this "slot fusing" will be successful.

There are two predominate fuse link types which are currently used in this coordination with reclosers. These are the previously mentioned ANSI Type K and T fuse links. The speed ratio of the K type links is specified to be between 6 and 8.1, while the speed ratio of the T type link is between 10 and 13.[18] This means that the T characteristic will be slower which has the advantage of providing coordination over a larger current range when they are used on the load side of reclosers. A specific example of this variation in coordination range is shown in Fig. 6.16. For this combination of 25 K or 25 T fuse links with a 35 ampere recloser, the coordination range for the K link is approximately 370 amperes compared with a range of approximately 525 amperes for the T link.

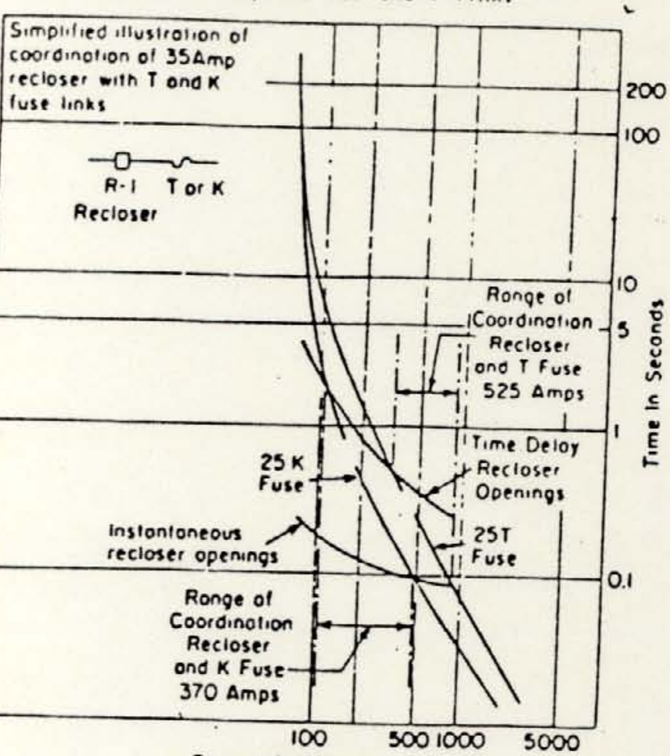

Fig. 6.16 Coordination of Type 35 Amp. Recloser with Type T and Type K Fuse Links

The series connected fuses which are applied within the zone of protection of a recloser must be coordinated (as has been previously described) so isolation will be accomplished by the fuse closest to the fault. The use of current-limiting fuses for the protection of individual distribution transformers against the potential explosive effects of a low impedance internal fault fits very neatly into this coordination scheme. The commonly used transformer expulsion fuse protects against low current or secondary transformer faults and its time-current characteristic coordinates well with branch or tap fuses. The time-current characteristic of the series connected backup current-limiting fuse is chosen to provide protection against permanent internal transformer faults. For this purpose its fast clearing characteristic is very desirable and it will isolate the faulty transformer before a branch fuse blows.

6.10 Recloser-Source Side Fuse Coordination

Fuses located on the source side of automatic circuit reclosers would normally be line sectionalizing fuses between the substation breaker and the recloser. This type of fusing is not often used as a part of the latest distribution system protection. The principal reason is that fuses in this location are difficult to coordinate with station breakers and reclosers to maintain the recloser's capability for quick service restoration after temporary faults. If there is a permanent fault on the main feeder the fuse will isolate this fault and give good visual indication to expedite the location of the fault. However, if the available fault current at the fuse location is high it may be difficult or impossible to choose a fuse rating which will not operate during the instantaneous breaker operations. If the fusing planned is an ANSI type K or T fuse link in a cutout, the maximum available fault current for which coordination is possible is approximately 10,000 amps. This current level is additionally reduced if fusing below 200 amperes is required. Current-limiting fuses would normally be too fast acting at high fault currents to be of much value in this type of application. They are very valuable for equipment protection in substations where the available fault current is normally quite high and where personnel are likely to be in close proximity.

The best fuse types for recloser-source side coordination are the expulsion power fuses. Certain types of these fuses are produced in current ratings up to at least 400 E amperes and in voltage ratings covering the sub-transmission range. The time-current characteristics of these fuses are best suited for the required coordination with substation breakers and with load side automatic circuit reclosers.

One additional problem associated with the use of line sectionalizing fuses on the source side of reclosers is that the feeder from the source is normally a 3-phase circuit and these fuses are single phase devices. The unbalanced currents and voltages which result from opening one phase, which would occur if a fuse cleared a phase to ground fault, could cause damage to customer's equipment, operating difficulties and extended interruptions. For this reason fusing is normally confined to circuit branches or taps where only one phase, or two phase and neutral circuits are involved.

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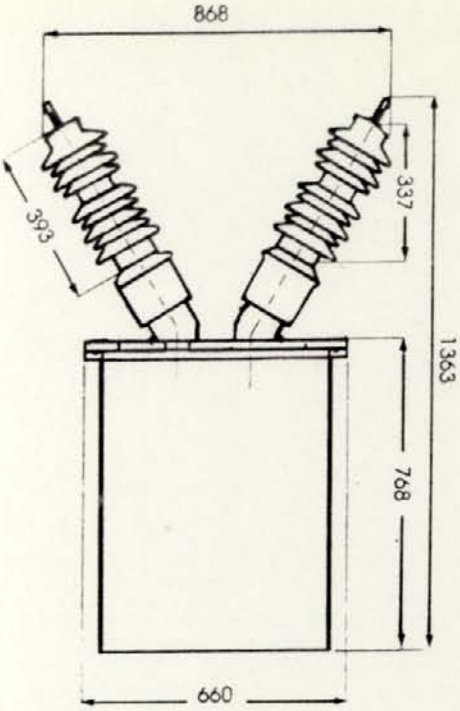
ANEXO J

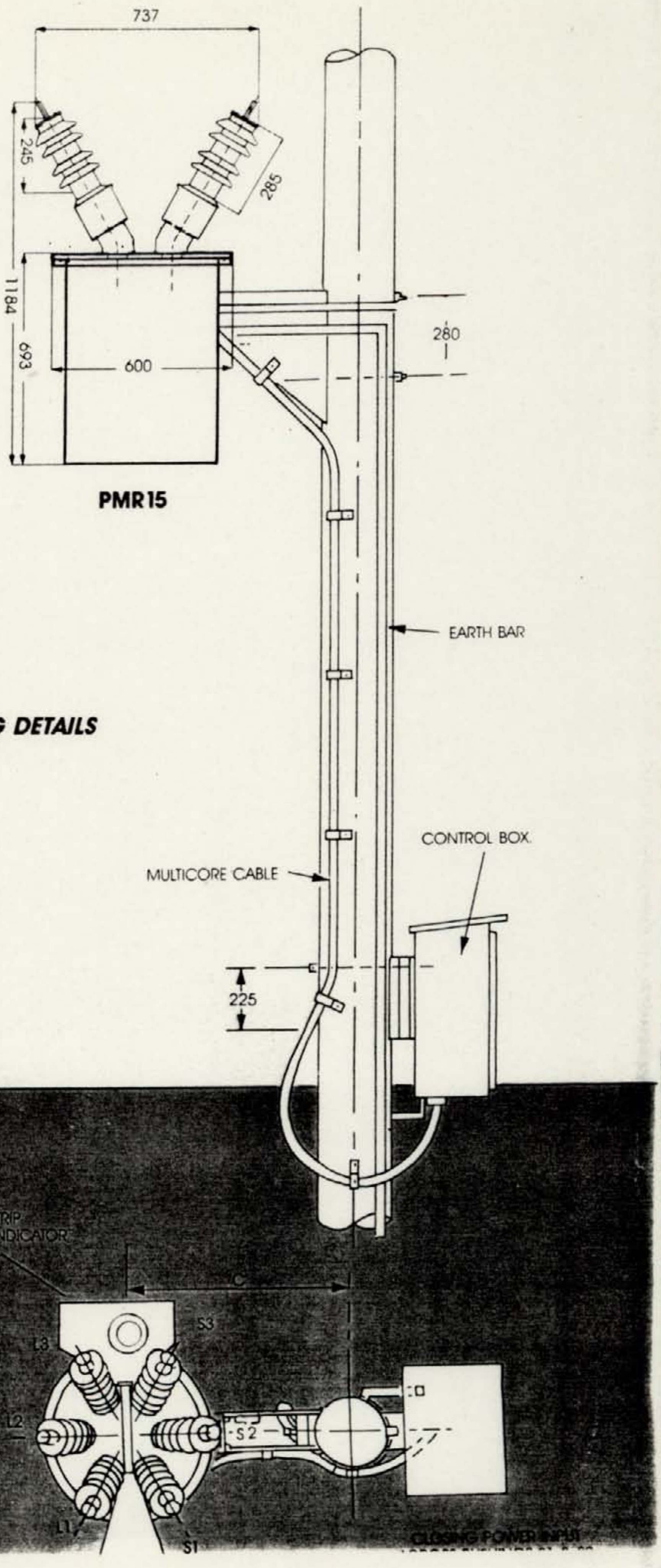
HAWKER SIDDELEY

Hawker Siddeley
Switchgear

BRUSH PMR 3
SF6 Pole Mounted Auto Recloser



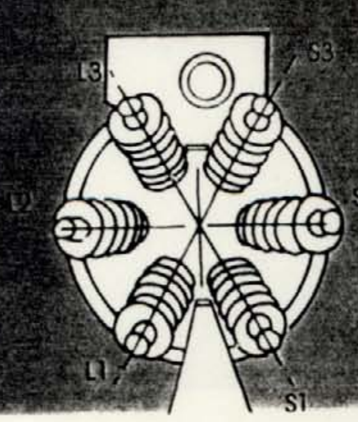
PMR 27/38



PMR15

POLE MOUNTING DETAILS

SUPPORT DIA	'C'
203 (8")	705
254 (10")	740
305 (12")	770



Brush Type PMR 3 Three Phase SF6 Pole Mounted Auto Recloser

Introduction

Most faults occurring on overhead lines are transient in nature and leave no permanent damage when they are cleared. For this reason the auto recloser, also known as an automatic circuit recloser, was introduced. This is essentially a circuit breaker with the necessary intelligence to sense overcurrents, to time and interrupt fault currents and, if selected to do so, to reclose automatically, thus restoring supply to an overhead line. If the fault persists, then the auto recloser locks out after a preset number of operations, thus isolating the faulty line from the system. In the PMR auto recloser, the intelligence is derived from an electronic control module.

The Brush type PMR auto recloser uses SF6 as the insulating and current interrupting medium, thus avoiding the adverse effects of humidity and eliminating fire risk. The heart of the unit is an SF6 rotating arc circuit breaker which is controlled by an external microprocessor based electronic control unit. The contact system of the circuit breaker has erosion characteristics better than that required of vacuum reclosers in ANSI C37.60-81, and can, in most instances, be regarded as maintenance free and sealed for life, although access to the interior of the unit is possible.

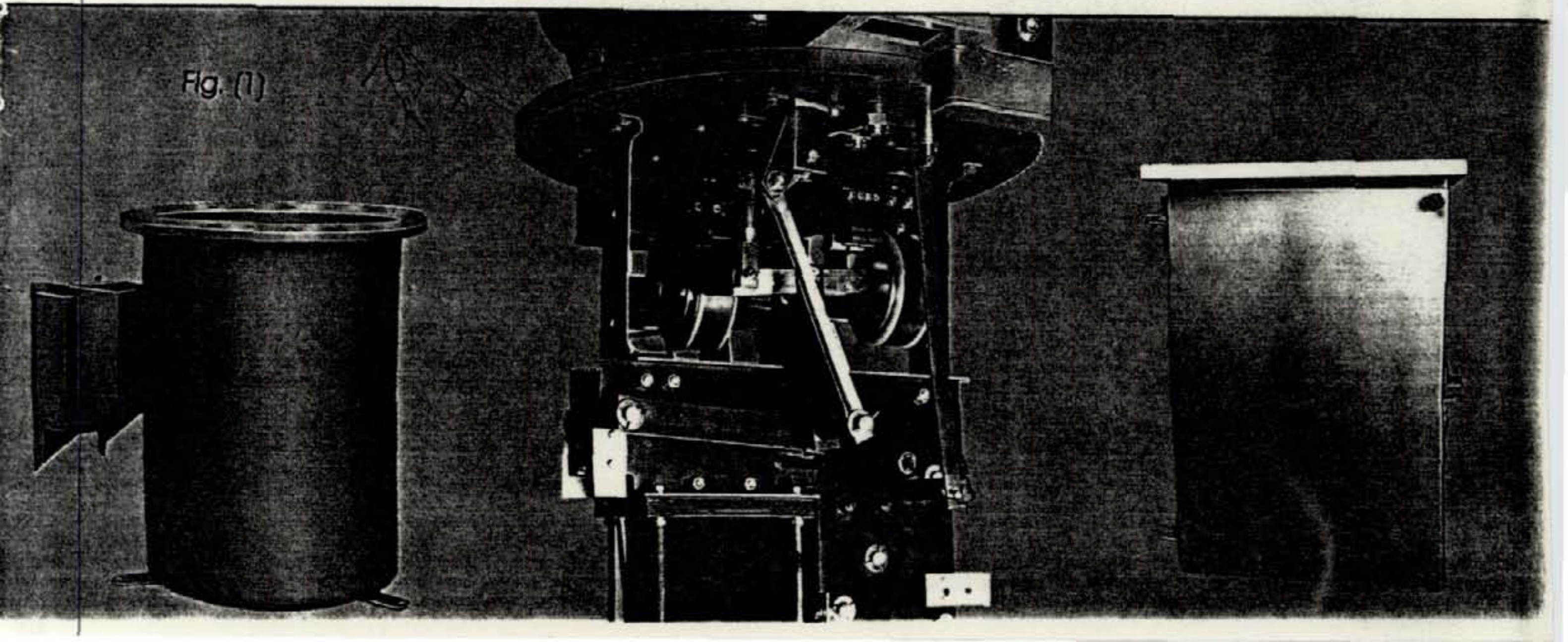
The PMR auto recloser has been subjected to continuous development since the original 15kV version was first announced. Reclosers are available for voltages up to 38kV in the two frame sizes.

Construction

The PMR auto recloser consists of three main assemblies, see Fig. (1)

1. A top plate which supports the through type bushings, externally mounted current transformers and auxiliary switches, and internally the rotating arc circuit breaker and solenoid mechanism.
2. *A single tank which encloses this circuit* breaker and mechanism in SF6 gas.
3. A weatherproof control box which contains a microprocessor based electronic control unit and DC power supplies. This box can be mounted direct onto the pole mounted recloser or connected by a multi-core cable to allow the control box to be positioned at any height to meet user requirements.

Fig. (1)



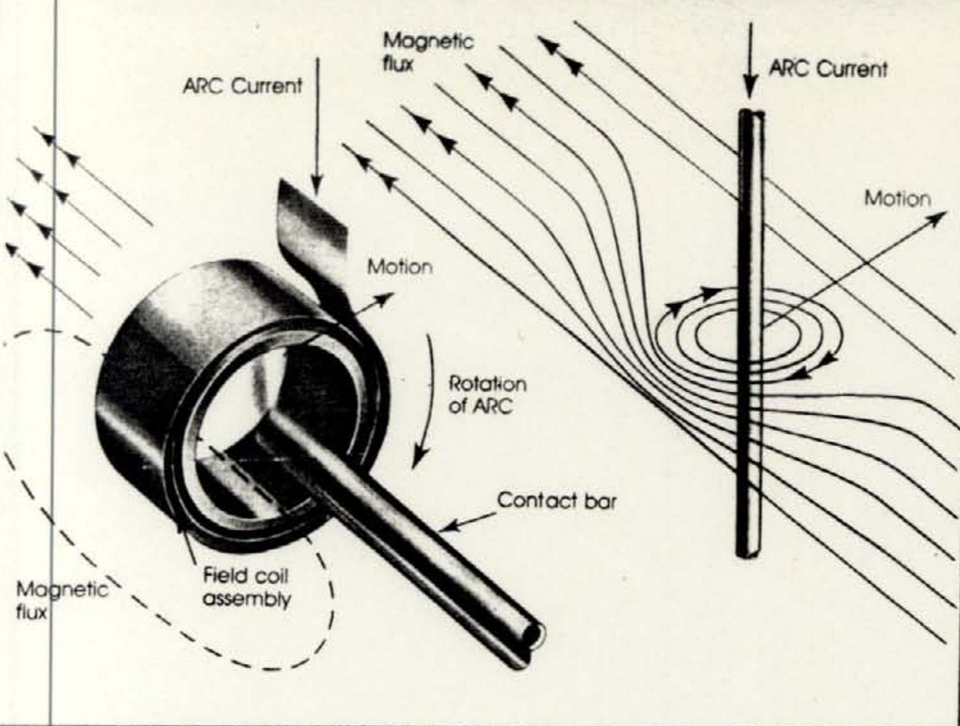


Fig. (2)

In practice this principle of arc interruption is achieved in the auto recloser using the contact and coil system shown in Fig. (3).

Apart from being very efficient, the rotating arc interrupter offers another distinct advantage in that the interrupting process, unlike SF6 puffer interrupters, does not produce back-forces on the operating mechanism and so allows the designer to use relatively lightly loaded drive systems and low stored operating energy.

Circuit Breaker

The interrupters in the auto recloser operate on the principle used in electric motor design, Fig. (2) in that a conductor suspended in an electro-magnetic field will experience a driving force in the direction of the weakest flux density; defined as Flemming's rule of Current, Flux and Motion. In the auto recloser, the arc is initiated by the separation of plain break contacts; the arc root at the fixed contact end, rapidly transfers, under electro-magnetic force, to a metal former within the interrupter coil, bringing the coil into the electrical circuit. The electro-magnetic field produced by the current in the coil, once it is in circuit, is at right-angles to the arc column causing the arc to rotate at high speed, under Flemming's rule within the coil former. This high speed rotation brings the arc into intimate contact with cool SF6 gas which extracts energy from the arc column and leads to extinction at the first available current zero.

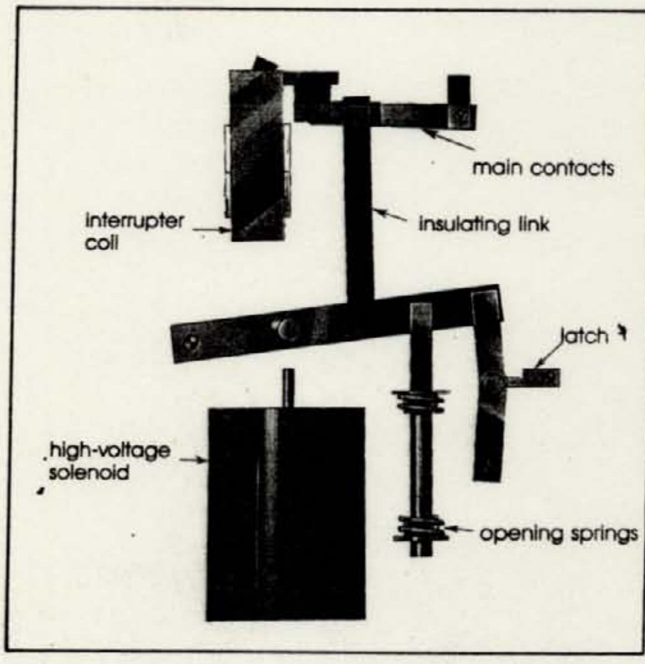


Fig. (4)

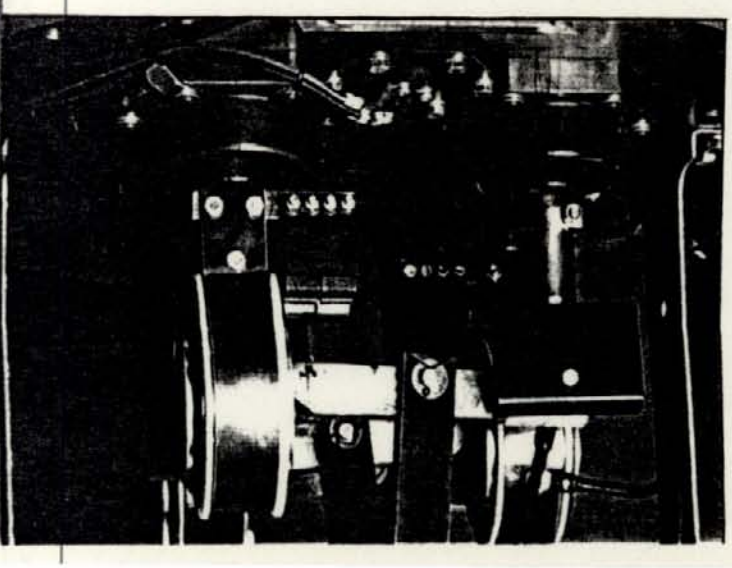
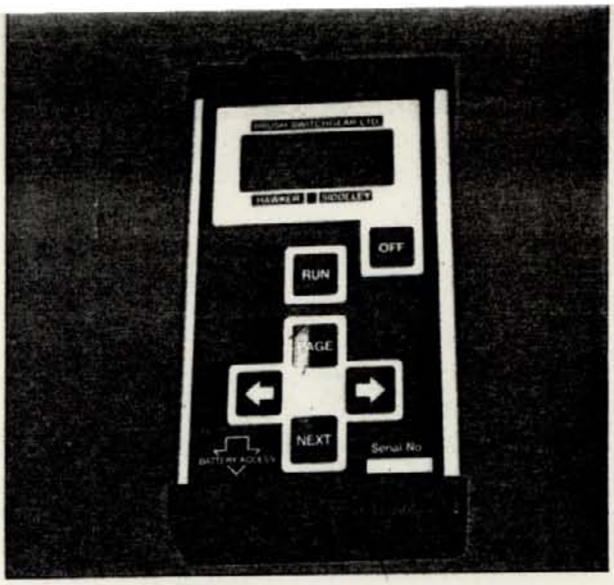


Fig. (3)

Operating Mechanism

The operating mechanism is of the single shot to close high voltage solenoid type. Closing is achieved by the solenoid being connected across two phases of the incoming supply, and during the closing stroke energy is stored in a spring for a subsequent opening operation. The energy stored in the opening springs is held by a latch which is released by a small solenoid when the unit is commanded to trip by the controlling microprocessor. See Fig. (4).



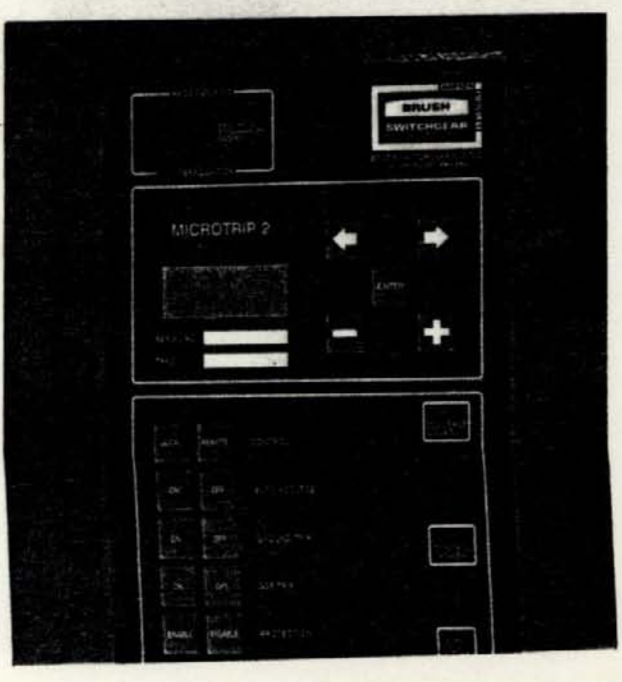
Hand Held Controller

Control Module

HHC

This is a microprocessor based electronic relay which controls the protection characteristics of the auto recloser. It is in two versions, one for use with a portable hand held controller (HHC), and one with an integral keypad/display (See Fig 5). On both units the lower part of the front panel is a membrane type keypad which provides local control and indication features detailed later. On the version using the hand held controller plugging into the RS232 serial communication socket enables adjustment of the relay characteristics. New setting data is transmitted over the RS232 link and is stored inside the relay in a non-volatile memory. In addition to programming new settings the HHC can retrieve information on the relay settings and its fault history.

The second version complete with integral keypad/display enables direct programming and interrogation. The RS232 communication socket is also standard on this version, and can be used to download information to a central point, and for setting changes.



When in service both versions of the relay continuously monitor the current in each phase and any residual current via current transformers mounted in the bushings of the recloser. Should a fault current be detected, the recloser will undertake a pre-selected sequence of trip and close operations.

Hand Held Controller

The HHC has three functions:

- To set the microprocessor relay characteristics
- To record historical data on previous faults
- To test the accuracy of the relay and its battery condition.

The HHC is supplied as an optional extra on the basis that requirements will fall into three categories:

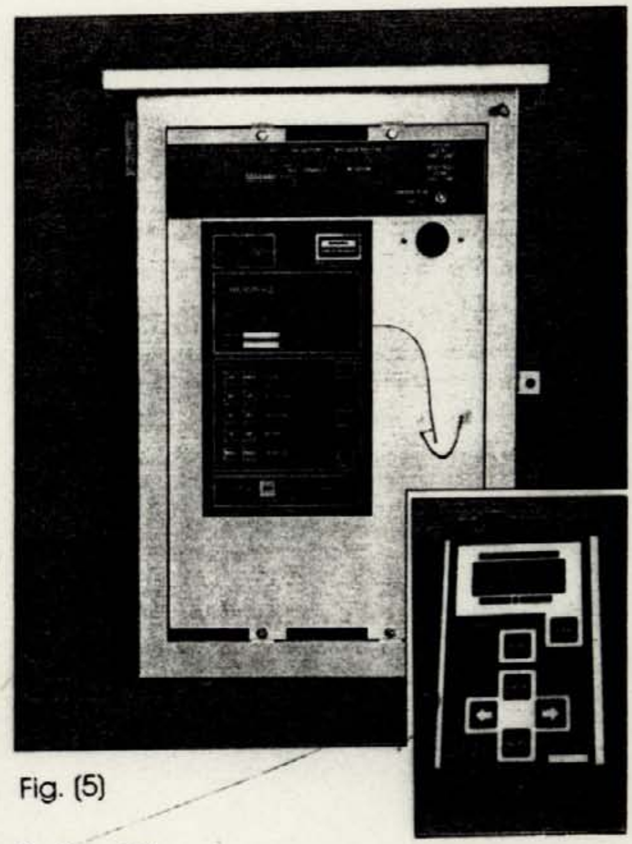


Fig. (5)

Option (1)

Reclosers are supplied with Microtrip relays factory preset to customers requirements. In this option HHCs would not be required.

Option (2)

Reclosers are supplied with Microtrip factory preset to standard or customers settings. A small number of HHC's are provided. (For example, one HHC per 10 reclosers).

Option (3)

Reclosers are supplied with Microtrip relay incorporating an integral keypad/display for programming and interrogation.

Selectable Characteristics

Both the Hand Held Controller and the Integral Keypad/Display options present relay characteristics settings to the user by means of a LCD Display.

Information is presented in clear, easy to understand messages, and programming requires the use of only four keys.

Using these methods the following parameters are selectable:

Operating Sequence

Up to 3 reclose operations can be selected which may be any combination of instantaneous or delayed trips including 4 instantaneous or 4 delayed trips.

Dead Times

Dead times within a sequence are individually selectable from:	0.25, 0.5, 0.75, 1, 2, 3, 4, 5, 10, 15, 25, 30, 40, 50, 60, 70, 80, 90, 100, 120, 140, 160 and 180 secs.

Reclaim Time

Selectable from:	5, 10, 15, 25, 30, 40, 50, 60, 70, 80, 90, 100, 120, 140, 160 and 180 secs.

Current Transformer Ratio

Standard: Dual Ratio	300/100/1A(200/1A Option)

Minimum Trip Levels

Phase, Earth Fault and Sensitive Earth Fault (SEF) minimum trip levels are selectable as a percentage of current transformer ratio in the following ranges:

PHASE	from 20% to 320% in 20% steps (for all phases)
EARTH FAULT	from 10% to 160% in 10% steps
SEF	from 1% to 8% in 1% steps

Phase Overcurrent Characteristics

Number of trips to lockout — Up to 4

The following parameters are selectable for each trip in a sequence:

Protection Curve	IDMT/VIDMT/EIDMIT/McGraw Eddison and Definite time in the range 0.5 to 2.0 in steps of 0.1 and 3 to 20 in steps of 1.
Time Multiplier	0.1 to 0.5 in steps of 0.05 and then 0.6 to 2 in steps of 0.1.
Instantaneous override level	OUT, 1.0 to 3.0 in steps of 0.1 and then 4 to 20 in steps of 1.

Earth Fault Tripping Characteristics

As for Phase Protection.

SEF Tripping Characteristics

Number of trips to lockout — Up to 4

The following parameter is selectable for each trip in the sequence:

Protection Curve	Instantaneous or Definite Time in the range 0.5 to 2 in steps of 0.1 and then 2 to 20 in steps of 1

Sequence Co-ordination

A selection to enhance co-ordination between two reclosers in series. Selectable IN or OUT.

Protection Sequence Modifiers

The following features are available as standard and can be used to modify the selected phase and earth fault protection sequences.

Minimum Response Time	0 to 2 secs in steps of 0.1 secs.
Additional Tripping Delay	0 to 2 secs in steps of 0.1 secs.
Cold Load Pick Up	Selectable IN or OUT.
Auto/Non Auto Protection	Selectable as either AUTO or NON AUTO.

Time Current Characteristics

Figs. (7, 8 and 9) give examples of typical instantaneous, standard IDMT and very inverse IDMT time characteristic curves. Definite time and McGraw Eddison characteristics are a standard feature.

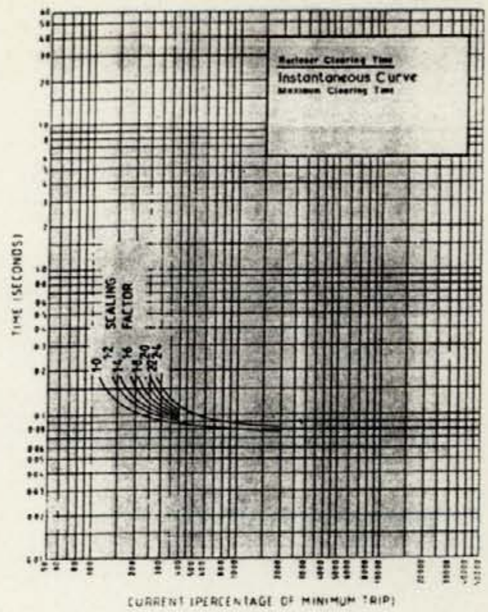


Fig. (7) Instantaneous curves

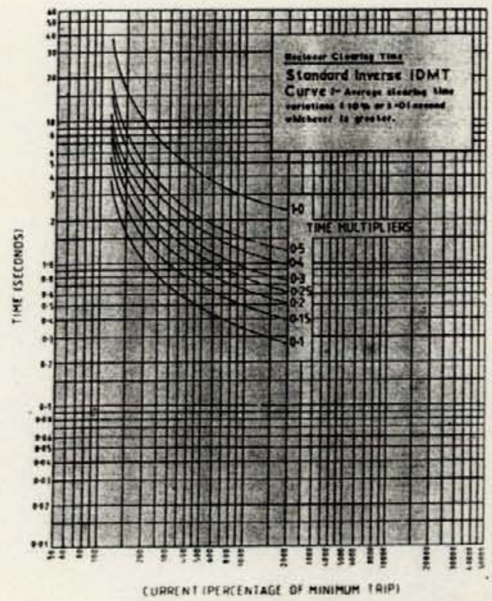
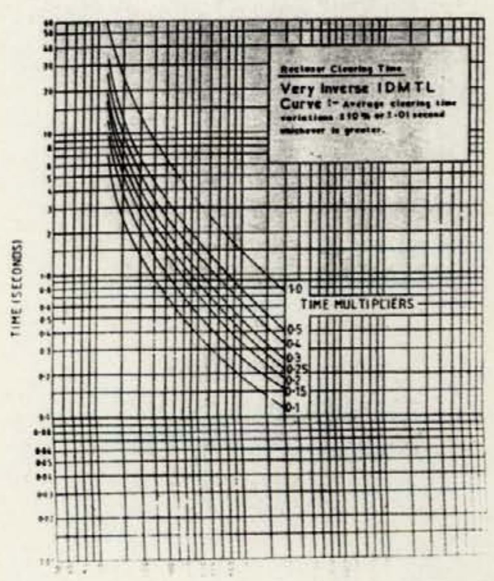


Fig. (8) Standard IDMT curves



Controls

Manual Control

The auto recloser can be mechanically tripped and locked out by means of an external handle which can be operated from ground level by a hook stick.

Local Control

The front panel of the relay provides the following local controls.

Local/Remote Control Selection
Close, including Cold Load Pickup
Trip
Auto Reclose in/out (one shot to lockout)
Protection enable/disable
Earth Fault in/out
SEF in/out
Relay Status

Local control by external handles on the recloser which are designed for manual operation from ground level by hook sticks is available as a contract option.

Local Indication

Status pushbutton on the relay gives on demand indication of the following:

Local/Remote Control Selected
Auto Reclose in/out
Protection enabled/disabled
Earth Fault in/out
SEF in/out
End of Sequence Lockout
Relay Active
Fault Target Indicator screen (Integral Keypad/Display only)

Remote Control and Indication

Both versions of microtrip can be supplied with remote control and indication facilities as follows:

Remote Control (Standard)

Trip
Close

Remote Control (Optional)

Auto reclose in/out (one shot to lockout)
Protection enable/disable
Earth Fault in/out
SEF in/out
Relay Test

Remote Indication (Standard)

Recloser open/closed by volt free auxiliary switches.

Remote Indication (Optional)

Volt free contacts give indication of:

Local/Remote Control Selected
Auto Reclose in/out
Protection enabled/disabled
Earth Fault in/out
SEF in/out
End of sequence lockout

Relay Test Feature

A relay test facility is available locally with the integral keypad/display version. Also remote test facility is available on both units when remote control and indication is provided. The test facility simulates an overload condition on the earth fault element causing the recloser to perform the selected earth fault sequence. The tripping times and dead times will be stored in the relay memory and can be checked later using the hand held controller or by the keypad in the integral display unit.

Interrogation of the Relay

On the basic unit with no hand held controller, the status pushbutton can be used to establish the basic relay setting. (See local indication). With the hand held controller connected, the serial link can be used to interrogate the relay further. Information can then be retrieved concerning the full range of relay settings, the magnitude and cause of up to 16 most recent automatic trips, the total trips per element and the percentage contact life remaining. In addition the condition of the relay power supply (a non-rechargeable lithium source) can be checked.

The above interrogation can also be carried out with the optional keypad/display when available.

Also the integral keypad/display version incorporates a clock/calendar as standard. On interrogation this provides date and time information on the first event within a sequence. This version also includes security coding, two levels being available:

1. The first level allows programming and/or changes to protection characteristics.
2. The second level allows change of first level security code.

No security code is required for interrogation of the unit.

Software is also available to allow programming and interrogation to be carried out using a personal or laptop computer.

Power Supplies

The relay is of a low current drain design and has its own lithium battery supply mounted within the control cabinet. Another lithium battery, also mounted within the control cabinet supplies trip and close functions to the recloser. Both batteries are rated for 10 years. The recloser can therefore be used in all locations including those with very small normal currents

Accessories

The PMR recloser, together with its controller, can be ordered to meet a variety of application requirements by including optional factory installed accessories.

1. Recloser Accessories

1. Extra Creepage Bushings.
2. Alternative Polymeric Bushings
3. Duplex Arcing Horns on Bushings
4. Surge arresters (for separate mounting)
5. Metering Current Transformers for Class 3 Ammeters.
6. Plug and Socket Termination of Control Cable
7. Alternative Pole Mounting Bracket or Ground Mounting Frames
8. Low Pressure Switch/Lockout Device
9. Pressure Gauge
10. LV Main Closing Coils

2. Controller Accessories

1. Load Current Indicators (Ammeters)
2. Thermostatically controlled Heater in Cabinet (Separate External Supply Required).
3. Solar Shield for Control Cabinet.
4. Large externally visual Operations Counter.
5. Portable Microtrip Test Set

Technical Data

Specifications

ANSI C37.60 1981

Ratings

Designation		PMR15	PMR27	PMR38
Nominal System Voltage	kVrms	14.4	24.9	34.5
Rated Maximum Voltage	KVrms	15.5	27	38
Frequency	Hz	50/60	50/60	50/60
Rated Continuous Current	Amps	560	560	560
Rated Short Circuit Breaking Current	kA	6 12	12	8
Rated Making Current	kApeak	15.4 30.8	26.2	20.5
Short Time Current	kA for 3 s	6 12	12	8
Rated Impulse Withstand Voltage	KVpeak	110	125	170
Power Frequency Withstand Dry	KVrms for 60 s	50	60	70
Power Frequency Withstand Wet	KVrms for 10 s	45	50	60

Dimensions

See drawing on page 2

Weight

Circuit Breaker: 276kG
Control Unit: 37.5kG

The design and manufacture of Hawker Siddeley Switchgear are subject to constant review therefore slight variations may occur between the details given and the equipment supplied.

HAWKER SIDDELEY

Hawker Siddeley Switchgear

INSTRUCCIONES DE MANTENIMIENTO Y MANEJO

RELE DE RECONEXION

MICROTRIP 2

Con un mantenimiento de rutina normal y correcto este equipo proporcionará al comprador un servicio satisfactorio.

En las comunicaciones con fábrica deberá indicarse el contrato y los números de serie de las unidades para facilitar la rápida respuesta a todas, las consultas.

Los diseños se están mejorando constantemente y en consecuencia puede haber pequeñas diferencias en los detalles entre el equipo suministrado y el descrito en este manual.

Las instrucciones de este manual están destinadas para la información y guía de personal de instalacion cualifacado y, donde proceda, tendrán que tenerse en cuenta juntamente con los requisitos pertinentes de las normas de higiene y seguridad nacionales e internacionales y sus posteriores enmiendas.

En caso de que el usuario tenga cualquier duda relativa a la interpretación de la información contenida en este manual, nuestro Departmento de Ingeneria atenderá gustosamente cualquier consulta.

HAWKER SIDDELEY

Hawker Siddeley
Switchgear

1. INTRODUCCION

El relé Microtrip basado en un microprocesador se ha diseñado y desarrollado especialmente para las tareas de reconexión automática y debido al bajo consumo de energía de las pilas internas es muy adecuado para aplicaciones en las que no existen fuentes de alimentación auxiliares.

Las características seleccionables incluyen ajustes para sobrecargas independientes en las fases, faltas sensibles a tierra y faltas a tierra, tiempos muertos independientes para un máximo de 3 maniobras de reconexión y numerosas curvas de corriente en función del tiempo que pueden estar de acuerdo con la norma BS142/IEC255; las desarrolladas en Estados Unidos y denominadas comumente del tipo McGraw Edison.

Se pueden seleccionar funciones adicionales que incluyen coordinación de secuencias, tiempos mínimos de respuesta, conexion de carga fria y protección automática/no automática conocida normalmente con el nombre de un disparo para el bloqueo.

El Microtrip 2 esta disponible en dos versiones, con y sin teclado integrado. En la version con teclado todos los ajustes y selecciones anteriores se pueden programar en le relé utilizando la pantalla LCD y el teclado integrado. Los datos de las últimas operaciones por faltas se conservan en el relé y se pueden visualizar en la pantalla.

Alternativamente hay disponible un controlador manual separado que permite al técnico de sistemas introducir las datos de ajuste del relé desde la comodidad de su oficina. El controlador se puede entonces conectar al relé para su programación mediante simples pulsaciones de teclas. El controlador también puede interrogar y puede almacenar los datos de las faltas para su visualización posterior.

El control local mediante pulsadores se encuentra en el panel frontal del relé para cierre y disparo, protección de falta a tierra activada/desactivada, protección de falta sensible a tierra activada/desactivada, automático/no automático, activación/desactivación de la protección y control local/remoto.

Un pulsador CONTROL STATUS (estado del control) proporciona a petición una indicación mediante LEDs del estado del relé.

El relé también tiene una posibilidad de control remoto de las funciones anteriores lo que exige contactos sin tensión para suministrar las señales entrantes. Las señales de estados salientes (para lámparas, etc) se pueden incluir mediante contactos sin tensión desde el interior del relé (es decir se necesita una fuente de alimentación auxiliar). Para detalles consultar los esquenas del contrato.

TIPOS DE SECUENCIAS DE PROTECCION

La secuencia de protección ejecutada para el Microtrip puede ser de cuatro tipos dependiendo de los parámetros programados y de los ajustes de control de relé. Existe un nivel de prioridad asociado con cada secuencia y los tipos por orden del más bajo al más alto se describen de la manera siguiente:

a) Secuencia automática

Cuando se selecciona AUTO como activado, y no se activa ninguna secuencia con prioridad más alta, el Microtrip responderá a los parámetros de protección AUTO permitiendo hasta cuatro operaciones de disparo. La falta de fase., la falta de tierra y la SEF tienen una secuencia exclusiva automática y el número de disparos de cada una puede ser distinto. Las características de cada disparo se pueden seleccionar separadamente para obtener la máxima flexibilidad. Cuando está funcionando una secuencia AUTOMATICA, los circuitos de fase, tierra y SEF vigilan sus respectivas entradas hasta que uno o más exigen una operación de disparo. Después de cada maniobra de disparo, el Microtrip comprueba la secuencias que han exigido el disparo para ver si se ha alcanzado la posición de bloqueo. Si es así, termina con el reconectador abierto.

Si el bloqueo no se ha alcanzado estas secuencias se hacen avanzar a sus disparos siguientes. Además, las secuencias que no han exigido este último disparo también se hacen avanzar a menos que ya estén ajutadas para su último disparo.

De esta manera todas las secuencias se hacen avanzar con cada disparo (incluso aquellas secuencias que no han registrado una corriente de falta). Sin embargo una secuencia solamente puede avanzar más allá de su último disparo hasta la posición de bloqueo si se ha solicitado el último disparo correspondiente a esa secuencia.

b) Secuencia de protección no automática

Cuando la protección AUTOMATICA está seleccionda como DESACTIVADA, y no hay activada una secuencia de prioridad más alta, el Microtrip responderá a sus parámetros de protección NO AUTOMATICA.

La secuencia NO AUTOMATICA es siempre de un disparo para el bloqueo. Las características de protección para las secuencias de falta a tierra y de falta de fase se seleccionan separadamente. La secuencia SEF no tiene ninguna característica seleccionada separadamente sino que toma por defecto la característica del primer disparo de la secuencia automática.

c) Secuencia de conexión de carga fría

Cuando se ha seleccionado la conexión de carga fría (CLPU) como activada, y no hay una secuencia de prioridad más alta activada, el Microtrip responderá a sus parámetros de protección CLPU cuando se aplique una señal de CERRAR.

La secuencia CLPU es siempre de un disparo para el bloqueo. Las características de protección para la secuencias de falta de tierra y de falta de fase se pueden seleccionar separadamente y se tienen que introducir siempre que se selecciona la secuencia CLPU como activada.

La característica SEF toma por defecto el valor del primer disparo en la secuencia automática.

La función CLPU está destinada para su uso cuando se cierra manualmente (local o remotamente) el reconectador automático en un sistema en buenas condiciones en el que la corriente transitoria inicial puede hacer que los ajustes de protección normales disparen el reconectador. Manteniendo la señal de CERRAR, los ajustes y la protección se modifican de acuerdo con los parámetros CLPU, que se seleccionan de manera que cualquier estado transitorio esperado no origine que la protección se dispare.

d) Secuencia del esquema en bucle

Esta protección solamente está disponible cuando está montado el accesorio de control del esquema en bucle y puede ser de tres tipos – Enlace, seccionador o punto intermedio y el Microtrip se tiene que configurar de acuerdo con el tipo adecuado.

La protección del sistema en bucle se debe seleccionar como desactivada utilizando la pantalla integral si el accesorio no está montado o si la proteccion no es necesaria.

Cuando se precisa la protección del esquema en bucle el tipo se tiene que especificar como de enlace, de seccionador o de punto intermedio. Durante una secuencia de protección el esquema en bucle vigilará la entrada remota y si está ajustado, la protección actuará. Esta será siempre del tipo de un disparo para el bloqueo.

En la práctica solamente los accesorios de enlace o de punto intermedio son capaces de controlar entradas remotas y solicitar la protección del tipo de un disparo para el bloqueo y por tanto si el tipo seleccionado es el tipo de Enlace o de Punto Intermedio se tendrán que introducir los parámetros de la protección del esquema en bucle. El accesorio Seccionador no puede solicitar la secuencia del esquema en bucle y no se necesitan parámetros de protección.

COORDINACION DE SECUENCIA

Se pueden presentar problemas especiales cuando hay reconectadores conectados en serie.

Consideremos por ejemplo el caso de dos reconectadores instalados en serie ambos con una secuencia de 3 disparos rápidos o instantáneos y un disparo retardado. Los ajustes de la protección de las unidades normalmente se coordinarán de manera que el reconectador aguas abajo responda más rápidamente para una condición de falta dada.

Cuando se presente una falta el reconectador aguas abajo responderá con tres disparos rápidos (superando en velocidad los disparos rápidos del reconectador aguas arriba) y avanzará a su disparo retardado. El reconectador aguas arriba responderá ahora con tres disparos rápidos (anticipándose al disparo retardado del reconectador aguas abajo) y avanzará a su disparo retardado.

Finalmente, el disparo retardado del reconectador aguas abajo se realizará antes que el del reconectador aguas arriba, eliminará la falta y se bloqueará. Entonces se reinicializará el reconectador aguas arriba.

En el ejemplo anterior tienen lugar siete disparos antes de que se elimine la falta en su caso (tres por el reconectador aguas abajo, tres por el reconectador aguas arriba y finalmente uno por el reconectador aguas abajo).

La coordinación de secuencia evita este problema haciendo avanzar las secuencias del reconectador aguas arriba despues de cada uno de los tres disparos del reconectador aguas abajo.

Cuando la coordinación de secuencia está activada y el Microtrip detecta una corriente de falta que se elimina antes de iniciar un disparo, el Microtrip supone que la falta ha sido eliminada por un reconectador de aguas abajo y hace avanzar su secuencia (cualquier secuencia ya ajustada a su último disparo no avanzará).

Para utilizar la función de coordinación de secuencia se tienen que respetar las reglas siguientes:

1. Todos los reconectadores deben ajustarse a la misma secuencia de disparos instantáneos retardados.
2. Todos los reconectadores tendrán que tener el mismo tiempo muerto.
3. La protección retardada del reconectador tiene que ajustarse para conseguir la coordinación de la característica de protección con tiempo de discriminación mínimo de 170 mS.
4. El tiempo de alerta de los reconectadores aguas arriba tiene que ajustarse a un valor superior al tiempo muerto más largo de los reconectadores aguas abajo. Esto asegurará que los reconectadores agua arriba no se reinicializen antes de la conexión de los reconectadores aguas abajo.

PANEL FRONTAL DEL MICROTRIP 2
(VERSION CON TECLADO)

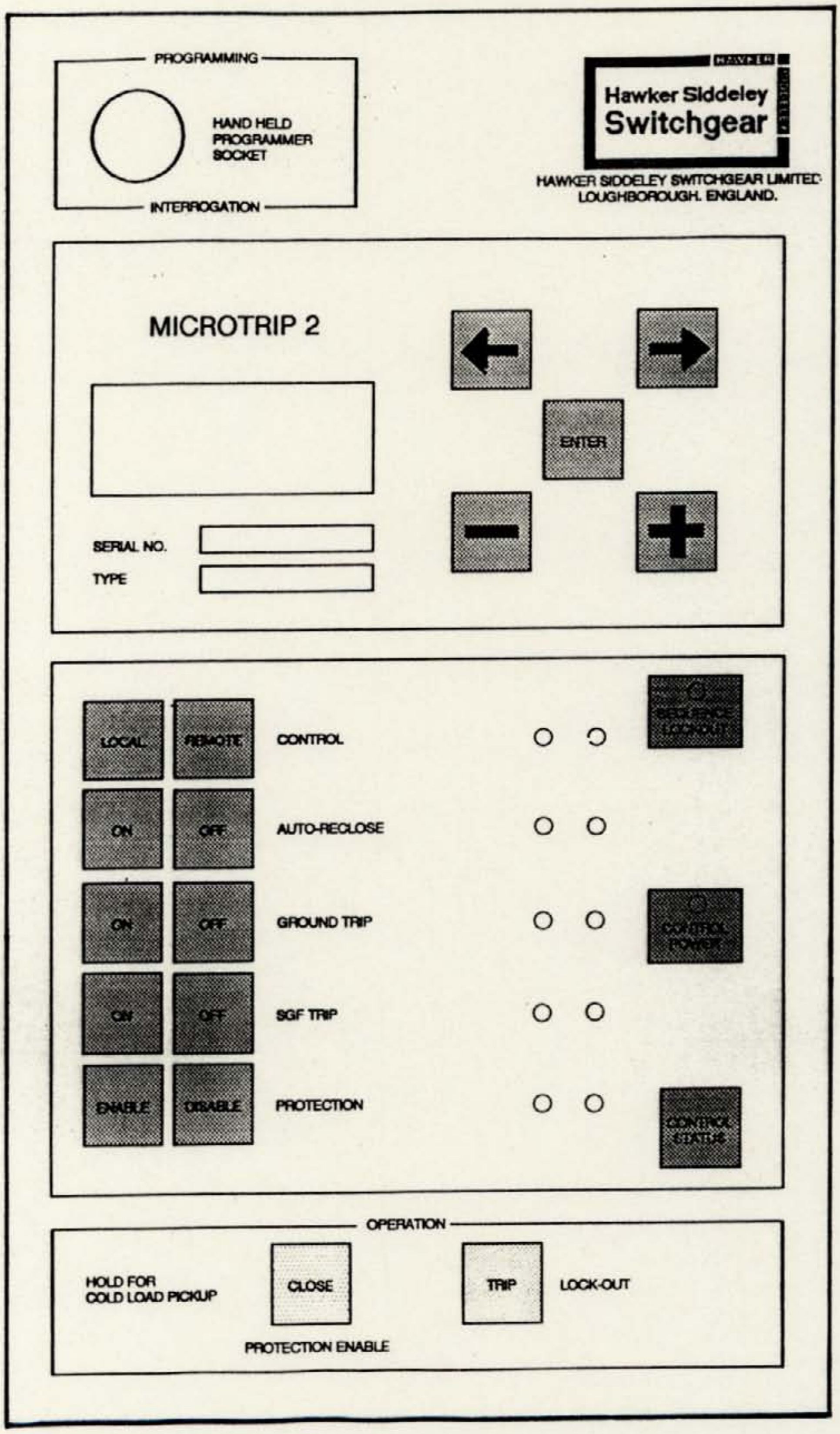


FIG.1.

PANEL FRONTAL DEL MICROTRIP 2
VERSION SIN TECLADO

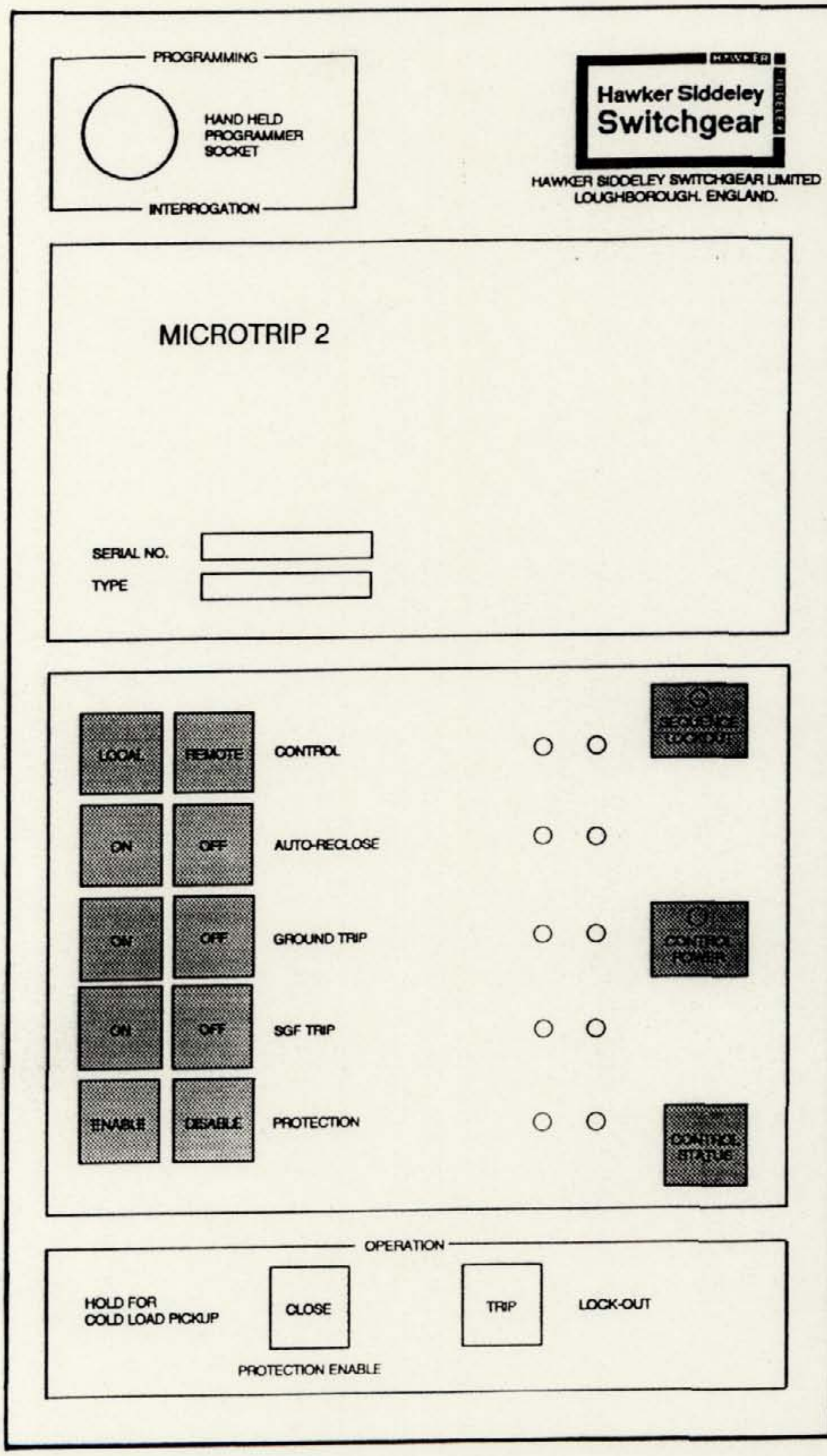


FIG.1A.

5. USO DE LA PANTALLA INTEGRADA

Esta sección describe como utilizar la pantalla del Microtrip para la programación, interrogación y pruebas.

5.1 FUNCIONES DEL TECLADO

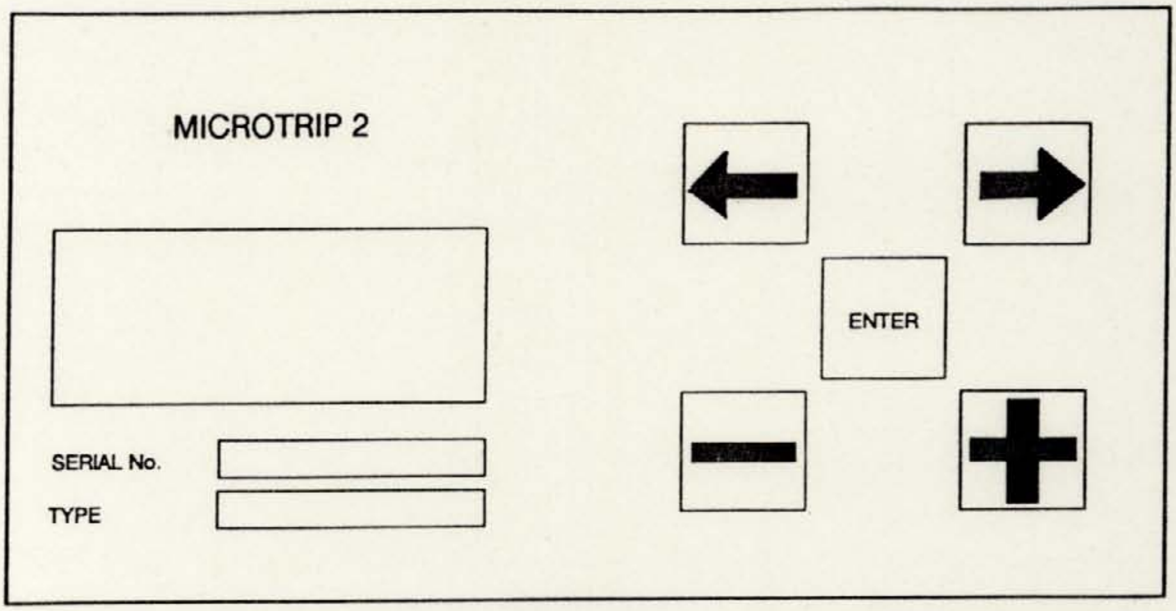


Fig. 2.

1) La tecla ENTER hará lo siguiente:
   a) Activar la pantalla preparándola para su uso.
   NOTA: la protección tiene que estar activada antes antes de poder utilizar la pantalla.
   b) Desplazar el cursor de una línea a otra dentro de la pantalla.
   c) Simular una condición de falta utilizando la función TEST.
2) La tecla AVANCE (→) hace pasar a la pantalla siguiente o alternativamente, si la pantalla actual proporciona opciones, aparecerá la pantalla de la opción seleccionada.
3) La tecla RETROCESO (←) hace retroceder a la pantalla interior.
4) La tecla ARRIBA (+). Algunas pantallas presentan un valor que se puede modificar. Por ejemplo números opcionales y valores de parámetros. Esta tecla se puede utilizar para aumentar estos valores.
5) La tecla ABAJO (–). Esta tecla se puede utilizar para disminuir los números de las opciones y los valores de los parámetros. Funciona al revés que la tecla ARRIBA.

5.2 CODIGOS SEGURIDAD

El Microtrip exige dos códigos de seguridad que se tienen que introducir antes de poder ejectutar determinadas operaciones. Si los códigos se introducen incorrectamente el acceso se niega.

Estos códigos de seguridad son los siguientes:

Código de seguridad 1	=	0000
Código de seguridad 2	=	9999

Los códigos pueden ser modificados por el usuario. Consultar la sección 5.3 y en particular la opción 3 para detalles.

5.3 PANTALLAS DE ACTIVACION Figura 3a.

Cuando la protección está activada y se pulsa la tecla ENTER la pantalla 1 de la figura 3a aparecerá durante dos segundos aproximadamente.

La pantalla 2 puede aparecer mostrando los elementos que estaban activados durante la última secuencia de falta. Si no se pulsa la tecla AVANCE el Microtrip se desconectará al cabo de 5 segundos y se conservarán los datos.

La pulsación de la tecla AVANCE reinicializará la pantalla 2 y los datos previamente visualizados se perderán. Al seguir utilizando la pantalla, la pantalla 2 no volverá a aparecer a menos que se haya producido posteriormente otra secuencia de falta. Aparecerá entonces la pantalla 3.

Esta pantalla visualiza el número de serie, la alimentación de tensión bajo carga del Microtrip, la hora y la fecha.

El Microtrip se puede desconectar en este punto pulsando la tecla RETROCESO (Pantalla 4. Si se pulsa por error la tecla AVANCE volverá la visualización a la pantalla 3).

La pulsación de la tecla AVANCE mientras se está en la pantalla 3, hará que se presente la pantalla 5 que ofrece 3 opciones.

1) HISTORIAL – esta opción visualiza pantallas para los datos de las cuatro secuencias más recientes, el contador de disparos totales y la vida restante de los contactos.

2) AJUSTES – esta opción permite ver y editar los ajustes de protección de Microtrip.

3) VARIOS – esta opción activa los códigos de seguridad, la fecha y la hora a cambiar y proporciona acceso a la función TEST.

Para seleccionar una opción particular no hace falta utilizar la teclas arriba/abajo hasta que se visualiza el número de la opción y a continuación hay que pulsar la tecla AVANCE.

Las opciones anteriores se describen a continuación con más detalle.

5.4 HISTORIAL Fig. 3b.

La selección del HISTORIAL presenta la pantalla 1 que ofrece las siguientes opciones:

(Cuando se están visualizando las pantallas 2, 3 ó 4, pulsar la tecla RETOCESO para volver a la pantalla 1).

1) ESTADO (pantalla 2) visualiza el número total de disparos y el número total de secuencias desde el momento de la instalación y el porcentaje de vida restante de los contactos.

2) DISPAROS (pantalla 3) visualiza el número total de disparos registrados en cada uno de los elementos.

3) SECUENCIAS (pantalla 4) visualiza las horas de comienzo de las cuatro secuencias más recientes. Para visualizar con más detalle una secuencia particular, pulsar la tecla ENTER hasta que parpadee el número de esa secuencia. A continuación pulsar la tecla AVANCE para pasar a la pantalla 5.

   Esta pantalla muestra el número de disparos en la secuencia, las horas de disparo y si la secuencia ha terminado con bloqueo o reinicialización.

   Para visualizar un disparo particular con más detalle, utilizar la tecla ENTER para seleccionar el número del disparo y pulsar la tecla AVANCE para pasar a la pantalla 6.

   Esta pantalla visualiza la corriente en cada elemento en el momento del disparo y resalta aquellos elementos que han exigido el disparo. Utilizar las tecla RETROCESO para volver a la pantallas anteriores a fin de ver otro disparo o secuencia.

5.5 AJUSTES – (Fig. 3c)

La selección de AJUSTES presenta la pantalla 1, que ofrece opciones para visualizar y editar los ajustes.

Nota: La sección 6 de este manual describe los ajustes de protección y las pantallas con más detalle y debe leerse antes de intentar la EDICION.

Las opciones son:

a) VER (opción 2) – esto permite visualizar los ajustes existentes pero no permite modificarlos. Utilizar las teclas AVANCE y RETROCESO para desplazarse por las diversas pantallas. Consultar la sección 6 para una descripción detallada de estas pantallas y su contenido.

b) EDITAR (opción 1, pantalla 2) – Introducir el código de seguridad según lo solicitado. Si no se introduce el código correctamente, se negará el acceso y será necesario pulsar la tecla RETROCESO para volver a la pantalla 1.

Aparecerá la pantalla 3 cuando se introduzca el código correcto y a partir de aquí se tiene que utilizar el teclado para editar los ajustes. Son de aplicación las reglas siguentes:

- utilizar las teclas AVANCE y RETROCESO para pasar de una pantalla a otra en la dirección necesaria.
- utilizar las teclas ARRIBA y ABAJO para cambiar el valor del parámetro resaltado.
- utilizar la tecla ENTER para pasar al parámetro siguiente.

Una vez terminada la edición, los nuevos ajustes se pueden grabar utilizando la opción 2 de la pantalla 5 (fig. 3c).

5.6 VARIOS Figs. 3d, 3e, y 3f.

La selección de VARIOS presenta la pantalla 1 de la figura 3d que ofrece las opciones siguientes.

1) CODIGO DE SEGURIDAD (pantalla 2, Fig. 3d) – solicita que se introduzca el código de seguridad 2 antes de poder cambiar cualquiera de los códigos. La pantalla 3 aparecerá cuando se introduzca el código correcto. Pulsar la tecla AVANCE para acceder a la pantalla 5 a fin de seleccionar el nivel de código 1 (pantalla 6) o el nivel de código 2 (pantalla 8). El código de seguridad adecuado se podrá entonces modificar y grabar.

2. AJUSTAR HORA/FECHA (pantalla 2, fig 3e) – seleccionar nueva hora o nueva fecha a fin de obtener las pantallas 3 ó 5 para los editores de la fecha o la hora. Pulsar las teclas ARRIBA o ABAJO para especificar los valores para cada parámetro y pulsar la tecla ENTER para pasar al parámetro siguiente. Utilizar la tecla AVANCE para grabar los nuevos valores.

3) PRUEBA (pantalla 2, Fig. 3f) – **Cómo medida de seguridad esta función exige que se introduzca el código de seguridad 1.**

Esta opción permite simular una falta a tierra haciendo que el Microtrip responda con la secuencia de falta a tierra programada.

Mantener pulsada la tecla ENTER para simular la falta a fin de que se produzca la secuencia completa hasta el bloqueo o liberar la tecla durante la secuencia para comprobar el tiempo de alerta.

El Microtrip se desconectará cuando la secuencia se termine o al final del tiempo de reinicialización.

Después de la prueba, se puede utilizar la opción HISTORIAL (sección 5.4) para comprobar que el Microtrip ha respondido correctamente.

6. CARACTERISTICAS DE LAS PROTECCIONES. (VERSION CON PANTALLA)

Las características de las protecciones están dispuestas en 8 categorías básicas, cuyas pantallas se muestran en las figs. 4a y 4b. En la práctica, algunas pantallas pueden no aparecer si decisiones hechas anteriormente las hacen redundantes.

(1) Varios

(2) Fase

(3) Tierra

(4) Falta sensible a tierra SEF

(5) Bloqueo por alta intensidad

(6) No automático

(7) Conexión de carga fría

(8) Esquema en bucle

6.1 VARIOS (Fig. 4a)

Pantallas

(1) Disparos para el bloqueo
El número de disparos para el bloqueo se puede seleccionar separadamente para fase, tierra y SEF. Las opciones permitidas son 1, 2, 3 ó 4.

(2) Tiempos muertos
Este es el tiempo entre una operación de disparo y las operaciones sucesivas de cierre. Se pueden seleccionar hasta 3 tiempos dependiendo del número de disparos seleccionados en la secuencia. Ver la sección 10.3 para la lista de las opciones de los tiempos muertos.

(3) Tiempo de alerta
El concepto de tiempo de alerta se explica en la sección 3.1. Ver la sección 10.4 para la lista de las opciones del tiempo de alerta.

(4) Coordinación de secuencia y conexión de carga fría
La coordinación de secuencia es una técnica utilizada cuando están instalados en serie dos o más reconectadores y se describe en la sección 3.3. Se puede seleccionar como ACTIVADA o DESACTIVADA.
La función de conexión de carga fría se puede utilizar para discriminar las corrientes de entrada cuando se cierra manualmente y se describe en detalle en la sección 3.2 (c). Se puede seleccionar como ACTIVADA o DESACTIVADA.

(5) Relación trafos de intensidad
La relación T.I. de protección se tiene que facilitar de acuerdo con el valor especificado en la placa de características del disyuntor. Ver la sección 10.6 para la lista de opciones.

(6) Ajustes mínimos del disparo
El ajuste mínimo del disparo determina el valor de la corriente expresado como un porcentaje de la relación T.I. a la cual el Microtrip comenzará una secuencia de falta, es decir el ajuste mínimo del disparo del 50% con una relación T.I. de 400:1 dará una corriente de falta de fase de 200A. Ver las secciones 10.7 a 10.9 para las listas de opciones para la protección de fase, tierra y SEF.

6.2 CARACTERISTICAS DE LA PROTECCION DE FASES

Se puede seleccionar una característica definida separadamente para cada disparo en la secuencia de fases.

Pantallas

(7) Curva de fondo
Esta curva está activada para la protección de fase siempre que la corriente de fase excede el ajuste mínimo del disparo. Cada disparo de la secuencia puede tener una curva de fondo distinta.

Ver la seccion 10.10 para la lista de las opciones de curvas y la sección 9 para las curvas características. La fig. 5a muestra una cruva de de fondo crítica y el efecto de los distintos modificadores de la curva que se describen a continuación.

(8) Multiplicador del tiempo de la curva
Este valor multiplica la curva de fondo a lo largo del eje de tiempos. Se pueden seleccionar distintos multiplicadores de tiempo para cada disparo en la secuencia . Ver la sección 10.11 para la lista de opciones de los multiplicadores de tiempo. La figura 5a muestra el efecto.

(9) Curva de retardo adicional
Este tiempo se añade a la curva de fondo que se ha modificado mediante el multiplicador de tiempo. Se pueden especificar distintos retardos adicionales para cada disparo de la secuencia. Ver la sección 10.12 para la lista de opciones. La fig. 5a muestra el efecto.

(10) Curva del tiempo de respuesta mínimo
Este tiempo especifica el tiempo de despeje más rápido posible para la protección de fondo. Se pueden especificar distintos tiempos de respuesta mínimos para cada disparo de la secuencia. Ver la sección 10.13 para la lista de opciones. La figura 5a muestra el efecto.

(11) Curva de característica instantánea
Esta especifica el valor de la corriente a la cual el Microtrip cancelará la protección de fondo y ejecutará un disparo instantáneo. Esta función se puede desactivar si no se precisa su actuacion. Ver la sección 10.14 para la lista de opciones. Ver la fig. 5c para las caracteristicas de disparo instantáneo. La fig. 5b muestra el efecto.

(12) Curva de retardo adicional instantáneo
Este tiempo se añade a la característica de disparo instantáneo. Esta función se puede seleccionar como desactivada si no se precisa un retardo adicional. Ver la sección 10.12 para la lista de opciones. La fig. 5 muestra el efecto.

6.3 CARACTERISTICAS DE LA PROTECCION DE FALTAS A TIERRA (Pantallas 13 a 18)

Las características ofrecidas son exactamente las mismas que las ofrecidas para la protección de fase y se deben especificar de la misma manera.

Nota: La protección contra faltas a tierra se puede activar/desactivar manualmente utilizando los interruptores de protección contra falta a tierra ACTIVADA/DESACTIVADA.

6.4 PROTECCION CONTRA FALTAS SENSIBLES A TIERRA SEF

La protección SEF está limitada para funcionamiento a tiempo definido. El disparo instantáneo se considera como un disparo a tiempo definido.

Pantalla

(19) Retardo definido
Cada estado de la secuencia puede tener una característica de disparo a tiempo definido seleccionada separadamente. Ver la sección 10.15 para una lista completa de las opciones.

Nota: La protección SEF se puede activar/desactivar manualmente utilizando los interruptores SEF ACTIVADA/DESACTIVADA.

6.5 BLOQUEO POR ALTA INTENSIDAD

Las funciones del bloqueo por alta intensidad se definen de la manera siguiente:

Pantallas

(20) Número de disparos activados
Estos valores seleccionan los números de disparos en la secuencias por falta a tierra y por falta de fase a las cuales la característica de bloqueo por alta intensidad se activa. Si se selecciona como no activada la función de bloqueo por alta intensidad, no funcionará en esta secuencia.

(21) Nivel de bloqueo por alta intensidad
Estos valores especifican el nivel de bloqueo por alta intensidad para la secuencias de falta de tierra y falta de fase. Para cualquiera de las secuencias, si se supera este nivel y el número de disparos activados se alcanza, la secuencia termina y el Microtrip se bloquea. Ver la sección 10.16 para la lista completa de opciones.

(22) Retardo adicional del bloqueo por alta intensidad
Estos valores especifican el período de retardo entre el momento en que se alcanza el nivel de bloqueo y el momento en que el reconectador elimina el estado de falta y se bloquea. Ver la sección 10.12 para la lista completa de opciones.

6.6 PROTECCION NO AUTOMATICA

La protección no automática se define de la manera siguiente:

Pantallas

(23) Curva de fondo
Estas selecciones determinan las curvas de protección de fondo para la protección de fase y tierra cuando está en funcionamiento la protección no automática. Ver la sección 10.10 para la lista de opciones.

(24) Multiplicadores de tiempo
Este valor multiplica la curva de fondo a lo largo del eje de tiempos. Ver la sección 10.11 para la lista de opciones.

(25) Nivel de la característica instantánea
Estas selecciones determinan los niveles para la secuencia de falta de tierra y falta de fase a los cuales la curva de protección de fondo se cancelará y el Microtrip ejecutará un disparo instantáneo. Ver la sección 10.14 para la lista de opciones.

(26) Retardo adicional instantáneo
Estos tiempos se añaden a las características de disparo instantáneo para la protección de falta a tierra y falta de fase. Ver la sección 10.12 para la lista de opciones.

6.7 CONEXION DE CARGA FRIA

Las protección de la conexión de carga fría se define de la siguiente manera:

Pantallas

(27) Curva de fondo
Estas selecciones determinan las curvas de fondo la para protección de tierra y de fase cuando está en funcionamiento la protección de conexión de carga fria. Ver la sección 10.10 para la lista de opciones.

(28) Multiplicadores de tiempo
Este valor multiplica la curva de fondo a lo largo del eje de tiempos. Ver la sección 10.11 para la lista de opciones.

(29) Nivel de la característica instantánea
Estas selecciones determinan los niveles para la secuencia de falta de tierra y falta de fase a las cuales la curva de protección de fondo será cancelada y el Microtrip ejecutará un disparo instantáneo. Ver la sección 10.14 para la lista de opciones.

(30) Retardo adicional instantáneo
Estos tiempos se añaden a las características de disparo instantáneo para la protección de falta a tierra y falta de fase. Ver la sección 10.12 para la lista de opciones.

6.8 PROTECCION DE ESQUEMA EN BUCLE

La protección del esquema en bucle se define de la manera siguiente:

Pantallas

(31) Tipo de esquema en bucle
La protección del esquema en bucle puede exigir que el reconectador automático actúe de diversas formas dependiendo de la configuración del sistema. Ver la Sección 3.2 para una descripción de los distintos tipos. Si el reconectador automático no forma parte del esquema en bucle, el tipo deberá seleccionarse como DESACTIVADO. Ver la Sección 8.17 para la lista completa de opciones.

(32) Ajustes mínimos del disparo alternativo

El ajuste mínimo del disparo alternativo determina el valor de la corriente expresado como porcentaje de la relación de los transformadores de intensidad, al que funcionará el Microtrip, es decir un ajuste mínimo del disparo del 50% con una relación T.I. de 400:1 dará una corriente de falta de fase de 200A. Ver las secciones 10.7 a 10.9 para las listas de opciones para la protección de fase, tierra y SEF.

(33) Curva de fondo

Estas selecciones determinan las curvas de protección de fondo para la protección de tierra residual y de fase cuando la protección del esquema en bucle está en funcionamiento. Ver la sección 10.10 para la lista de opciones.

(34) Multiplicadores de tiempo

Este valor multiplica la curva de fondo a lo largo del eje de tiempos. Ver la sección 10.11 para la lista de opciones.

(35) Nivel de la característica instantánea

Estas selecciones determinan los niveles para la secuencia falta a tierra y falta de fase a las cuales la curva de protección de fondo será cancelada y el Microtrip ejecutará un disparo instantáneo. Ver la sección 10.14 para la lista de opciones.

(36) Retardo adicional instantáneo

Estos tiempos se añaden a las características de disparo instantáneo para la protección contra falta a tierra y contra falta de fase. Ver la sección 10.12 para la lista de opciones.

CARACTERISTICAS DE LAS PROTECCIONES

VARIOS

(1)

TRIPS TO LOCKOUT
PHASE 4
GROUND 3
SGF 4

(2)

RECLOSE INTERVAL
1ST 002.00
2ND 002.00
3RD 002.00

(3)

RESET TIME
20 (S)

(4)

SEQ COORDINATION
OUT
COLD LOAD PICKUP
IN

(5)

CT RATIOS
560:1

(6)

MINIMUM TRIP %
PHASE 100%
GROUND 50%
SGF 5%

PROTECCION DE FASES

(7)

PHASE: 1 SI
CURVE 2 SI
3 SI
4 SI

(8)

PHASE: 1 0.10
CURVE 2 0.15
TIME MULT 3 0.20
4 0.25

(9)

PHASE: 1 0.00
CURVE 2 0.00
ADD DELAY 3 0.00
4 0.00

(10)

PHASE: 1 0.00
CURVE 2 0.00
MRT 3 0.00
4 0.00

(11)

PHASE: 1 1.0
INST TRIP 2 1.0
3 OUT
4 OUT

(12)

PHASE: 1 0.00
INST TRIP 2 0.00
ADD DELAY 3 OUT
4 OUT

PROTECCION DE TIERRA

(13)

GROUND: 1 SI
CURVE 2 SI
3 SI
4 SI

(14)

GROUND: 1 0.10
CURVE 2 0.15
TIME MULT 3 0.20
4 0.25

(15)

GROUND: 1 0.00
CURVE 2 0.00
ADD DELAY 3 0.00
4 0.00

(16)

GROUND: 1 0.00
CURVE 2 0.00
MRT 3 0.00
4 0.00

(17)

GROUND: 1 1.0
INST TRIP 2 1.0
3 OUT
4 OUT

(18)

GROUND: 1 0.00
INST TRIP 2 0.00
ADD DELAY 3 OUT
4 OUT

FALTA SENSIBLE A TIERRA

(19)

SEF: 1 INST
DEF TIME 2 0.5
3 0.6
4 0.7

Fig. 4a

CARACTERISTICAS DE LAS PROTECCIONES

BLOQUEO POR ALTA INTENSIDAD

(20)

HIGH "I" LOCKOUT
ACTIVE TRIP No
PHASE OUT
GROUND 1

(21)

HIGH "I" LOCKOUT
MULT MIN. TRIP
PHASE OUT
GROUND 6

(22)

HIGH "I" LOCKOUT
ADDITIONAL DELAY
PHASE OUT
GROUND 0.10

PROTECCION NO AUTOMATICA

(23)

NON AUTO
CURVE
PHASE SI
GROUND VI

(24)

NON AUTO
TIME MULTIPLIERS
PHASE 0.10
GROUND 0.15

(25)

NON AUTO
INST TRIP
PHASE 5
GROUND 6

(26)

NON AUTO
INST ADD DELAY
PHASE 0.00
GROUND 0.10

CONEXION DE CARGA FRIA

(27)

COLD LOAD PICKUP
CURVE
PHASE SI
GROUND VI

(28)

COLD LOAD PICKUP
TIME MULTIPLIERS
PHASE 0.10
GROUND 0.15

(29)

COLD LOAD PICKUP
INST TRIP
PHASE 5
GROUND 6

(30)

COLD LOAD PICKUP
INST ADD DELAY
PHASE 0.00
GROUND 0.10

PROTECCION DE ESQUEMA EN BUCLE

(31)

LOOP SCHEME
MIDPOINT

(32)

ALT MIN TRIP %
PHASE 20%
GROUND 10%
SGF 1%

(33)

LOOP S NON AUTO
CURVE
PHASE SI
GROUND VI

(34)

LOOPS NON AUTO
TIME MULTIPLIERS
PHASE 0.10
GROUND 0.15

(35)

LOOPS NON AUTO
INST TRIP
PHASE 5
GROUND 6

36

LOOPS NON AUTO
INST ADD DELAY
PHASE 0.00
GROUND 0.10

Fig.4b

10. OPCIONES DE PROTECCION

10.1 Disparos

1
2
3
4

10.2 Disparos + fuera de servicio

1
2
3
4
DESACTIVADO

10.3 Tiempos muertos (segundos)

000.25	010.00	070.00
000.50	015.00	080.00
000.75	020.00	090.00
001.00	025.00	100.00
002.00	030.00	120.00
003.00	040.00	140.00
004.00	050.00	160.00
005.00	060.00	180.00

10.4 Tiempos de alerta (segundos)

05	40	100
10	50	120
15	60	140
20	70	160
25	80	180
30	90	

10.5 Activado/desactivado

activado
desactivado

10.6 Relaciones de los transformadores de intensidad

560:1	400:1	300:1
250:1	200:1	100:1
	50:1	

10.7 Ajustes mínimos de disparo de fase (%)

20	140	260
40	160	280
60	180	300
80	200	320
100	220	
120	240	

10.8 Ajustes mínimos de disparo de tierra (%)

10	70	130
20	80	140
30	90	150
40	100	160
50	110	
60	120	

10.9 Ajustes mínimos de disparo SEF (%)

1	4	7
2	5	8
3	6	

10.10 Curvas

Estándar inversa	**SI**
Muy inversa	**VI**
Extremadamente inversa	**EI**
Disparo por tiempo definido de un segundo	**Df**
Disparo por tiempo definido de 10 segundos	**Ds**

Curvas de tierra McGraw	1	7	14
	2	8*	15
	3	8	16
	4	9	18
	5	11	
	6	13	
Curvas de fase McGraw	A	L	V
	B	M	W
	C	N	Y
	D	P	Z
	E	R	
	KP	T	

10.11 Multiplicadores de tiempo

0.10	0.50	1.30
0.15	0.60	1.40
0.20	0.70	1.50
0.25	0.80	1.60
0.30	0.90	1.70
0.35	1.00	1.80
0.40	1.10	1.90
0.45	1.20	2.00

10.12 Retardos adicionales (segundos)

0.00	0.70	1.40
0.10	0.80	1.50
0.20	0.90	1.60
0.30	1.00	1.70
0.40	1.10	1.80
0.50	1.20	1.90
0.60	1.30	2.00

10.13 Tiempos de respuesta mínimos (segundos)

0.00	0.70	1.40
0.10	0.80	1.50
0.20	0.90	1.60
0.30	1.00	1.70
0.40	1.10	1.80
0.50	1.20	1.90
0.60	1.30	2.00

10.14 Caracteristica instantánea (Múltiplo del ajuste mínimo de disparo)

OUT	2.2	8.0
1.0	2.3	9.0
1.1	2.4	10.0
1.2	2.5	11.0
1.3	2.6	12.0
1.4	2.7	13.C
1.5	2.8	14.0
1.6	2.9	15.0
1.7	3.0	16.0
1.8	4.0	17.0
1.9	5.0	18.0
2.0	6.0	19.0
2.1	7.0	20.0

10.15 Retardos SEF (segundos)

INST	1.9	16.0
0.5	2.0	17.0
0.6	3.0	18.0
0.7	4.0	19.0
0.8	5.0	20.0
0.9	6.0	30.0
1.0	7.0	40.0
1.1	8.0	50.0
1.2	9.0	60.0
1.3	10.0	80.0
1.4	11.0	100.0
1.5	12.0	120.0
1.6	13.0	140.0
1.7	14.0	160.0
1.8	15.0	180.0

10.16 Característica instantánea por alta corriente

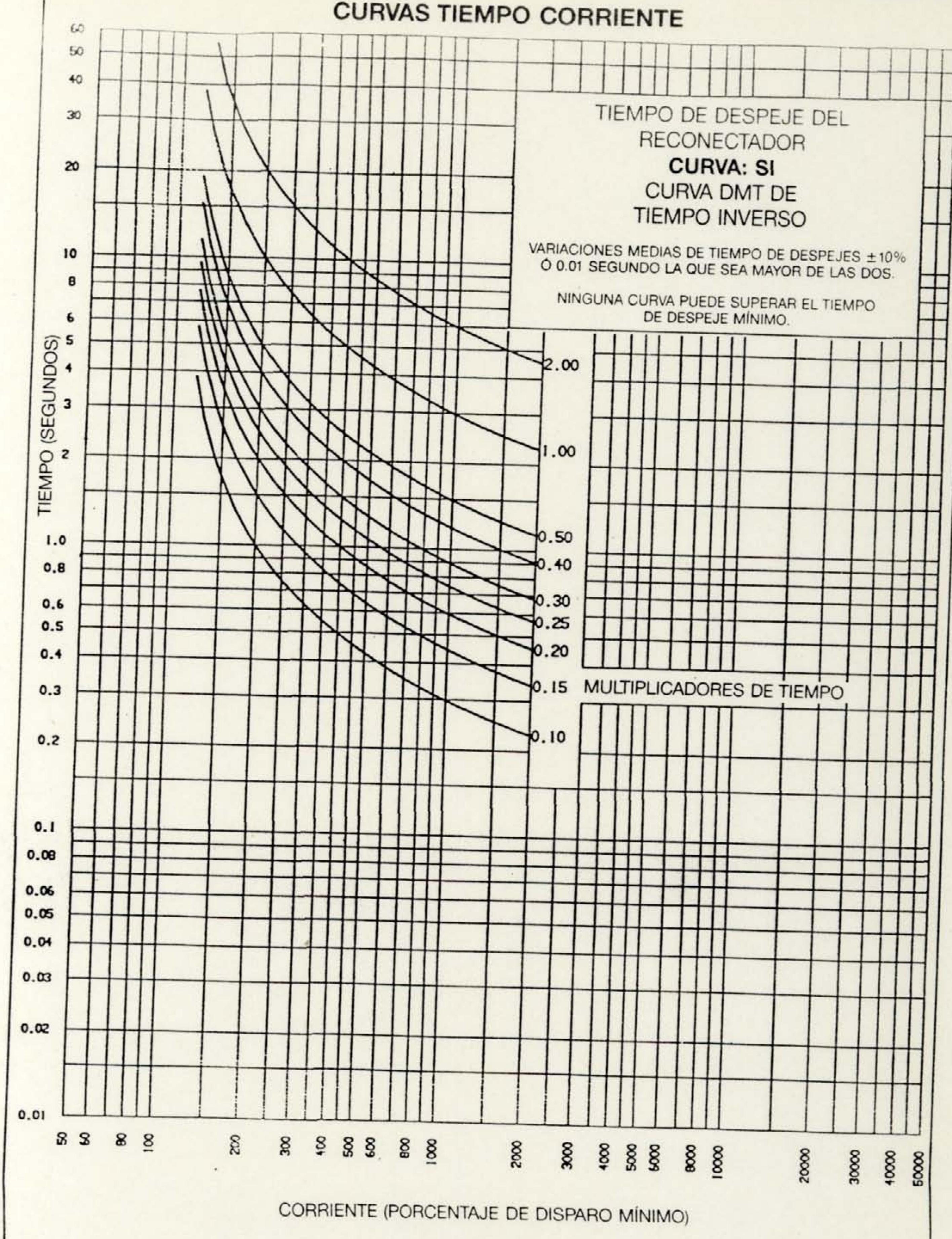
5.0	11.0	17.0
6.0	12.0	18.0
7.0	13.0	19.0
8.0	14.0	20.0
9.0	15.0	
10.0	16.0	

10.17 Tipos de esquema en bucle

Out	Fuera de servicio
Tie	Enlace
Sectionaliser	Seccionador
Midpoint	Punto Intermedio

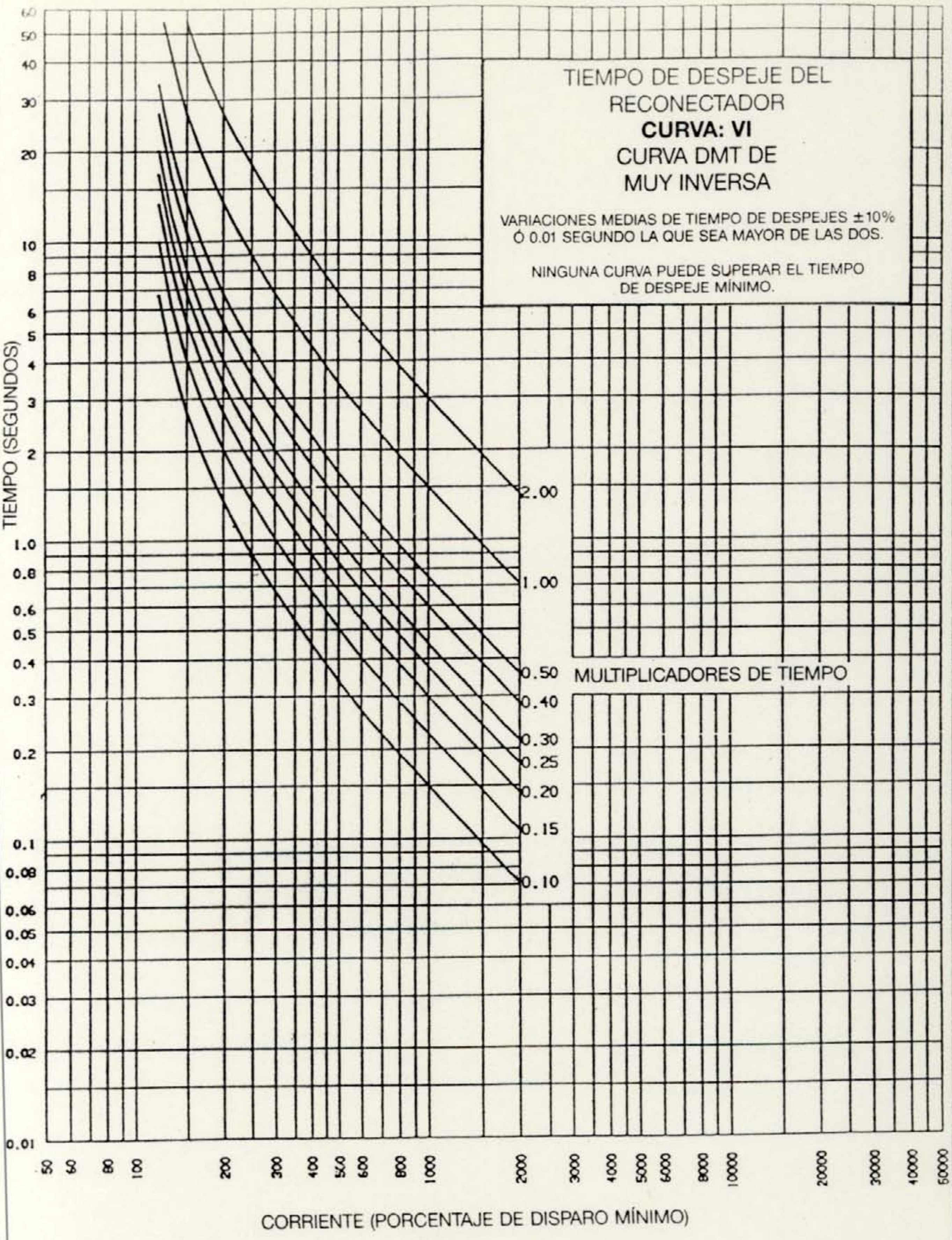
SECCION II

CURVAS TIEMPO – CORRIENTE


CURVAS TIEMPO CORRIENTE
TIEMPO DE DESPEJE DEL RECONECTADOR
CURVA: SI
CURVA DMT DE TIEMPO INVERSO
VARIACIONES MEDIAS DE TIEMPO DE DESPEJES ±10% Ó 0.01 SEGUNDO LA QUE SEA MAYOR DE LAS DOS.
NINGUNA CURVA PUEDE SUPERAR EL TIEMPO DE DESPEJE MÍNIMO.
2.00
1.00
0.50
0.40
0.30
0.25
0.20
0.15
0.10
MULTIPLICADORES DE TIEMPO
TIEMPO (SEGUNDOS)
60 50 40 30 20 10 8 6 5 4 3 2 1.0 0.8 0.6 0.5 0.4 0.3 0.2 0.1 0.08 0.06 0.05 0.04 0.03 0.02 0.01
50 60 80 100 200 300 400 500 600 800 1000 2000 3000 4000 5000 6000 8000 10000 20000 30000 40000 50000
CORRIENTE (PORCENTAJE DE DISPARO MÍNIMO)

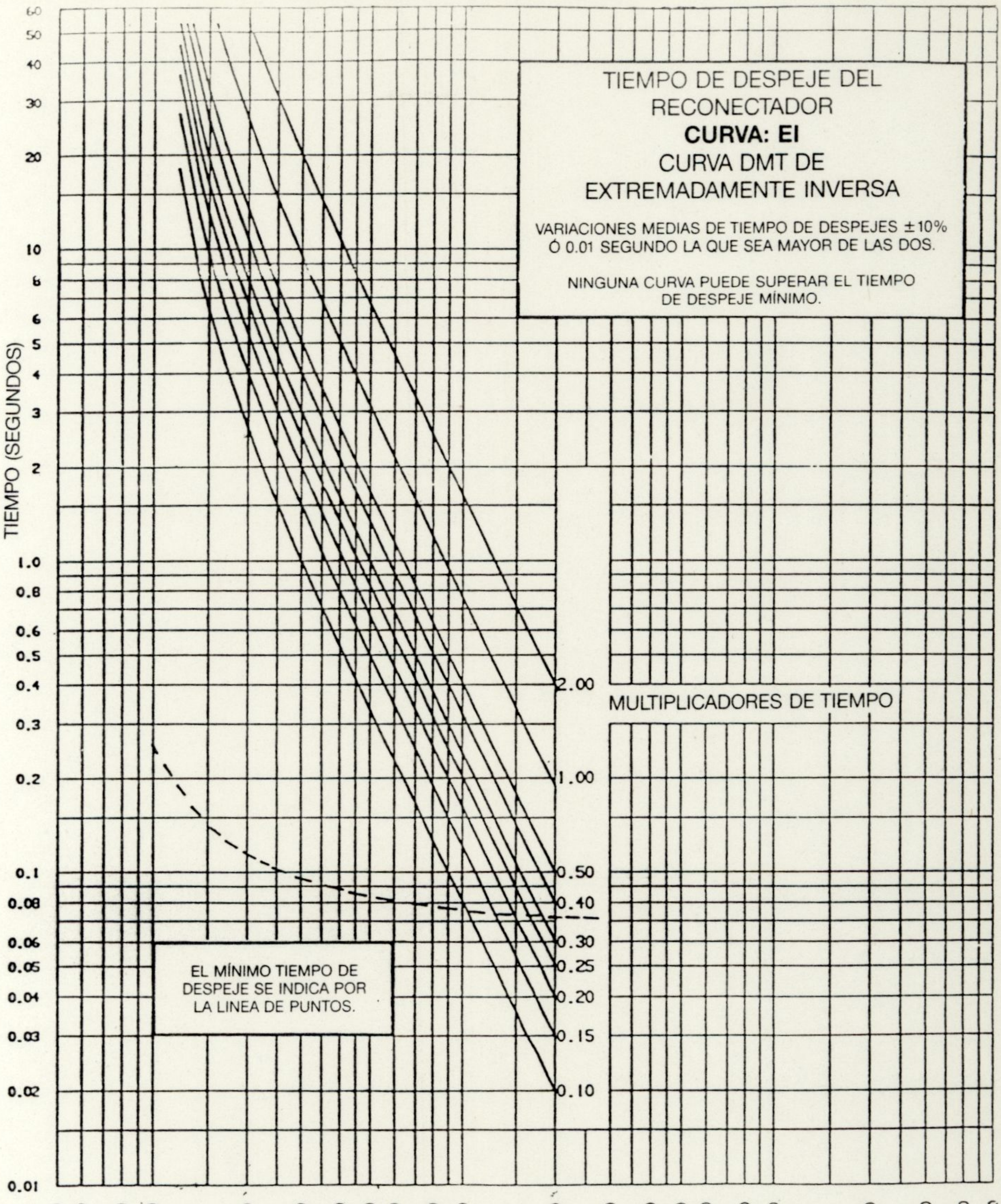
CURVA. SI.

CURVAS TIEMPO CORRIENTE

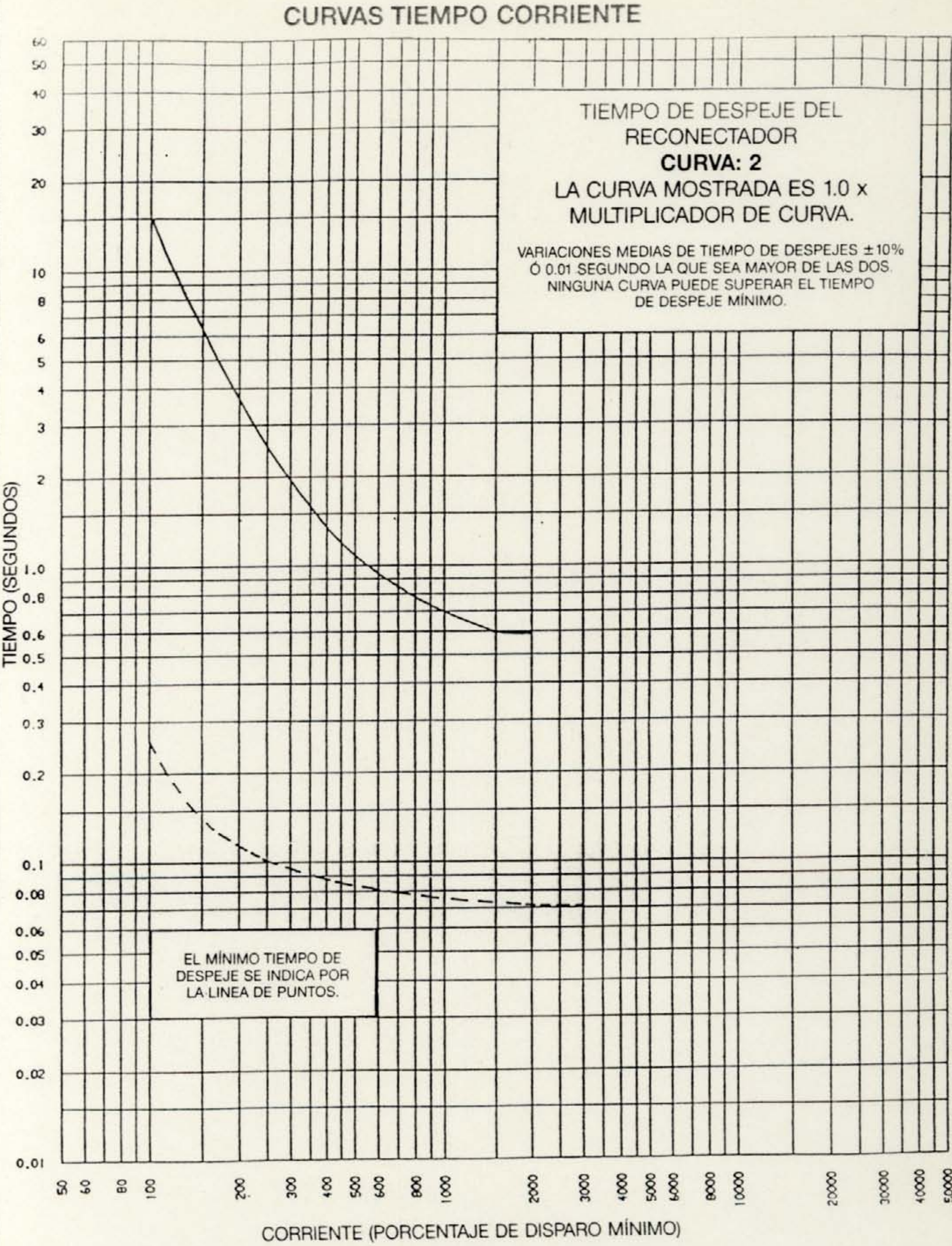


CURVA. VI.

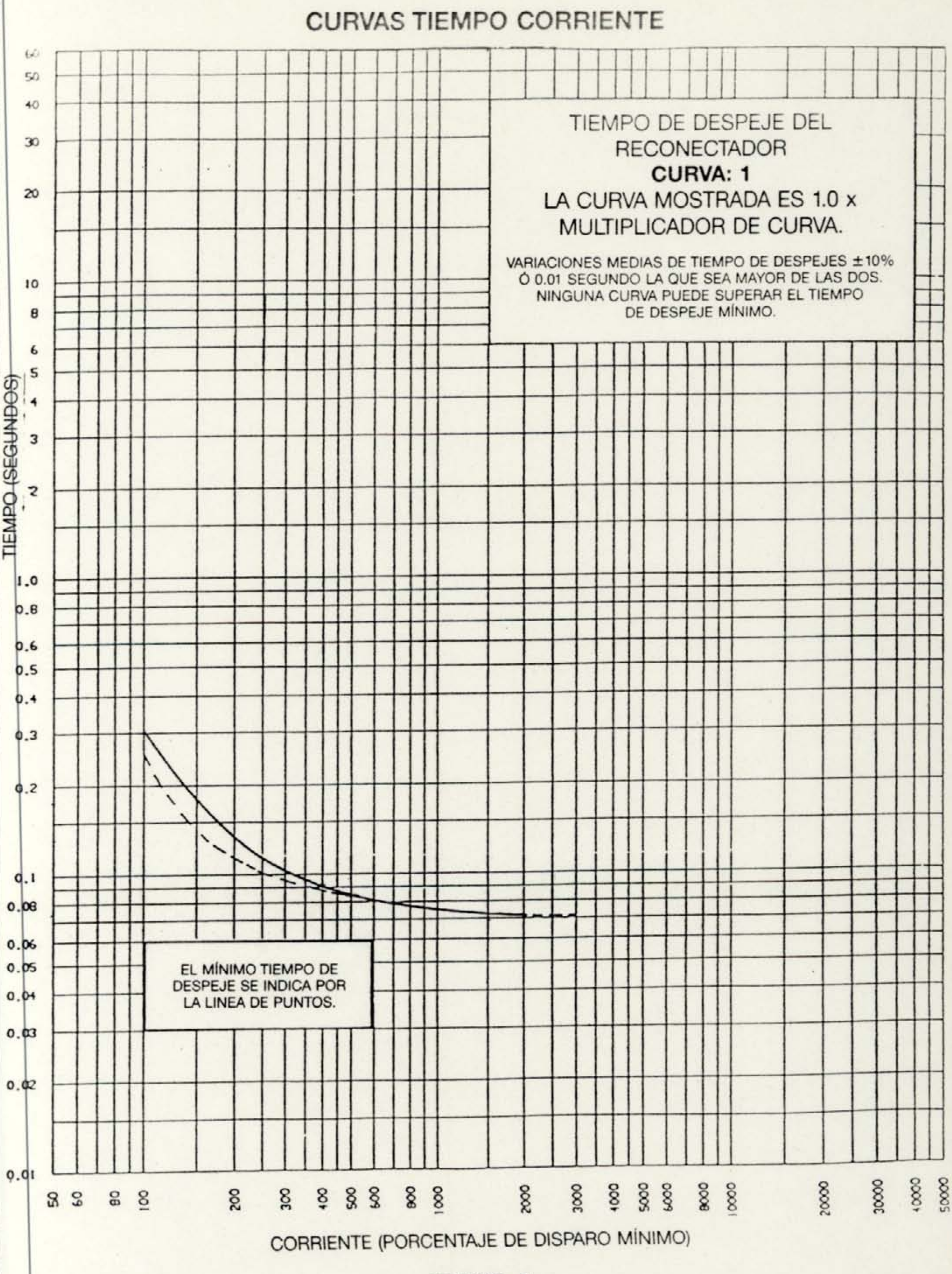
CURVAS TIEMPO CORRIENTE



CURVA. EI.


CURVAS TIEMPO CORRIENTE
TIEMPO DE DESPEJE DEL
RECONECTADOR
CURVA: 2
LA CURVA MOSTRADA ES 1.0 x
MULTIPLICADOR DE CURVA.
VARIACIONES MEDIAS DE TIEMPO DE DESPEJES ±10%
Ó 0.01 SEGUNDO LA QUE SEA MAYOR DE LAS DOS.
NINGUNA CURVA PUEDE SUPERAR EL TIEMPO
DE DESPEJE MÍNIMO.
EL MÍNIMO TIEMPO DE
DESPEJE SE INDICA POR
LA LINEA DE PUNTOS.
TIEMPO (SEGUNDOS)
60
50
40
30
20
10
8
6
5
4
3
2
1.0
0.8
0.6
0.5
0.4
0.3
0.2
0.1
0.08
0.06
0.05
0.04
0.03
0.02
0.01
50
60
80
100
200
300
400
500
600
800
1000
2000
3000
4000
5000
6000
8000
10000
20000
30000
40000
50000
CORRIENTE (PORCENTAJE DE DISPARO MÍNIMO)

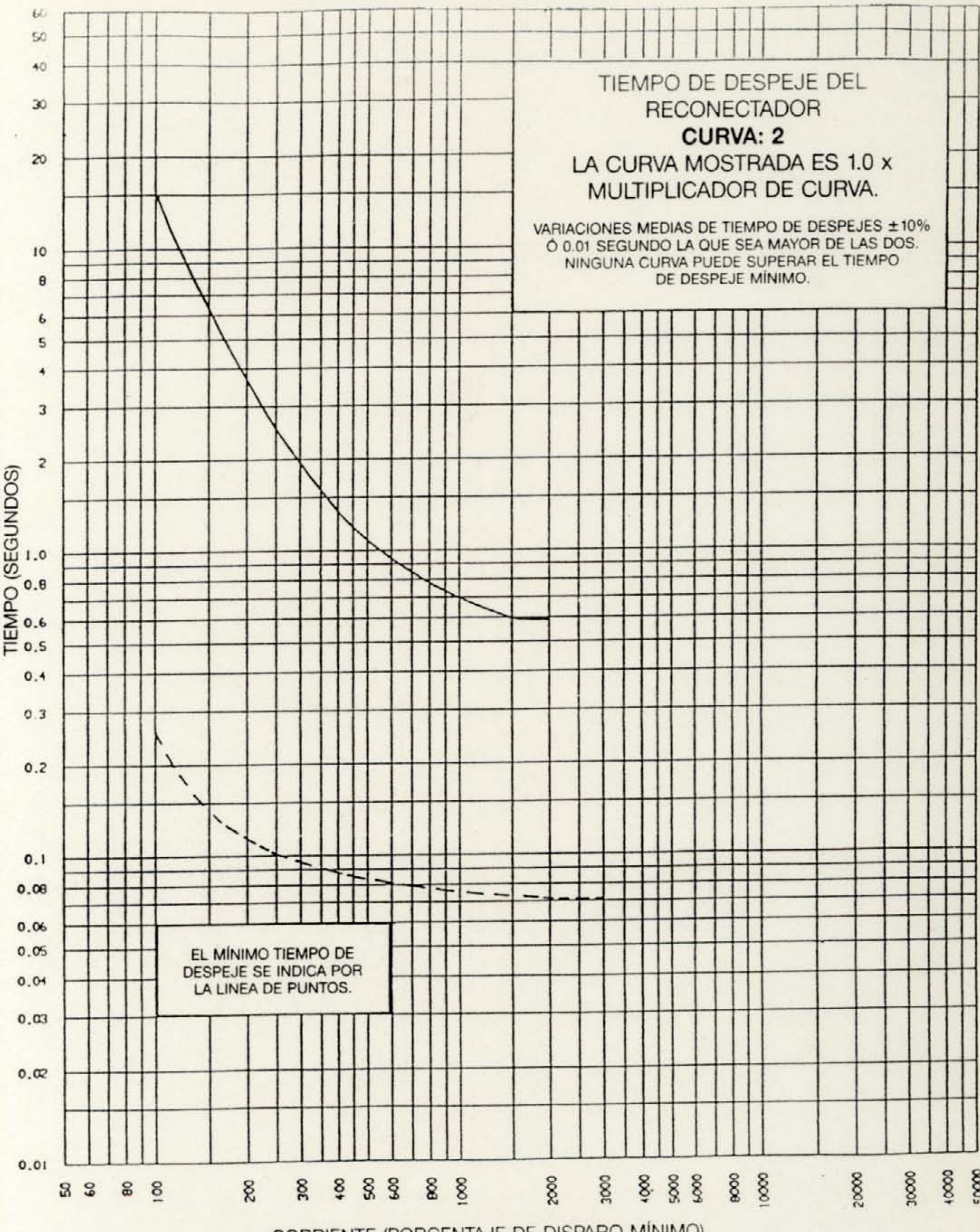
CURVA. 2.



CURVAS TIEMPO CORRIENTE
TIEMPO DE DESPEJE DEL
RECONECTADOR
CURVA: 1
LA CURVA MOSTRADA ES 1.0 x
MULTIPLICADOR DE CURVA.
VARIACIONES MEDIAS DE TIEMPO DE DESPEJES ±10%
Ó 0.01 SEGUNDO LA QUE SEA MAYOR DE LAS DOS.
NINGUNA CURVA PUEDE SUPERAR EL TIEMPO
DE DESPEJE MÍNIMO.
EL MÍNIMO TIEMPO DE
DESPEJE SE INDICA POR
LA LINEA DE PUNTOS.
TIEMPO (SEGUNDOS)
CORRIENTE (PORCENTAJE DE DISPARO MÍNIMO)

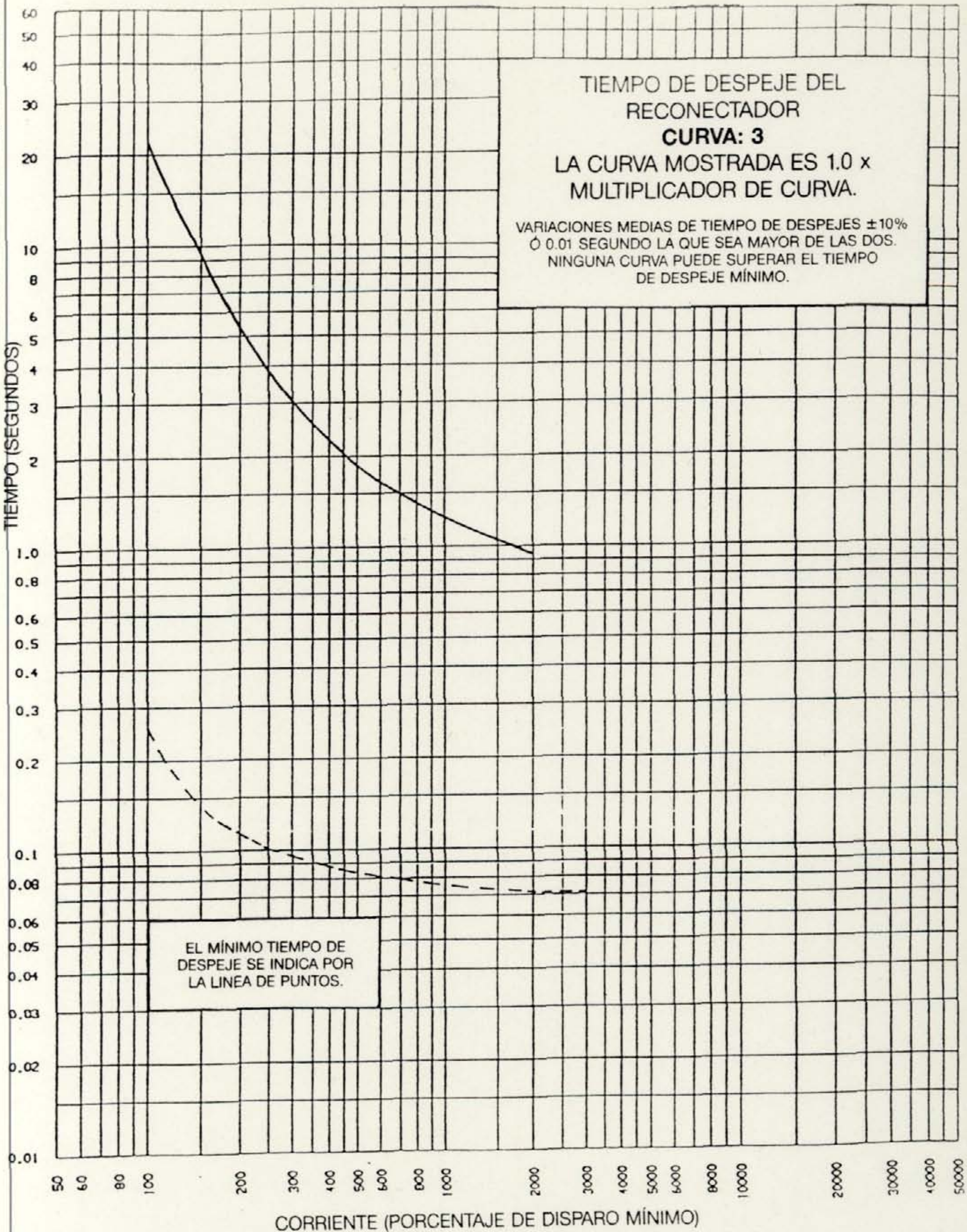
CURVA. 1.

CURVAS TIEMPO CORRIENTE



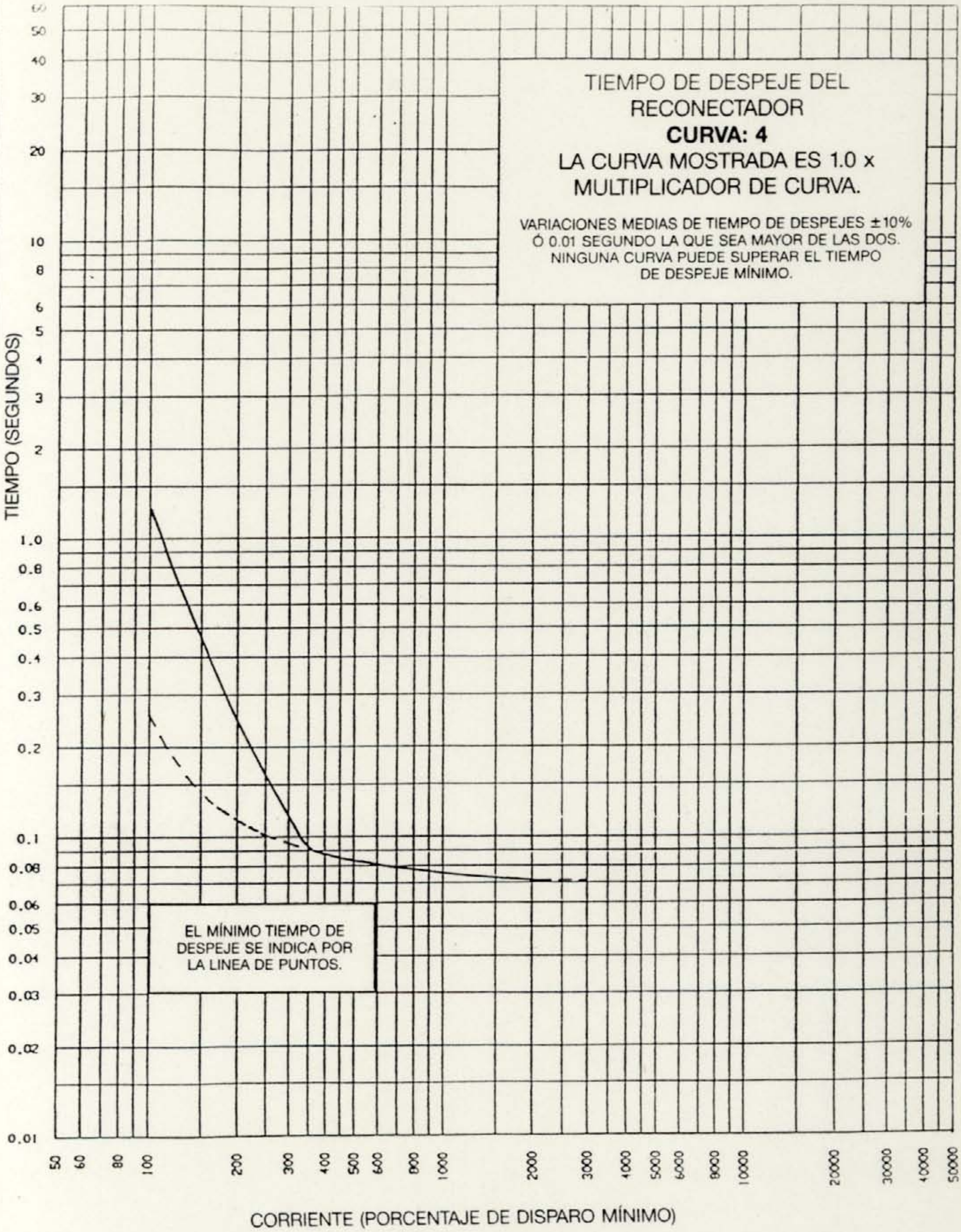
CURVA. 2.

CURVAS TIEMPO CORRIENTE



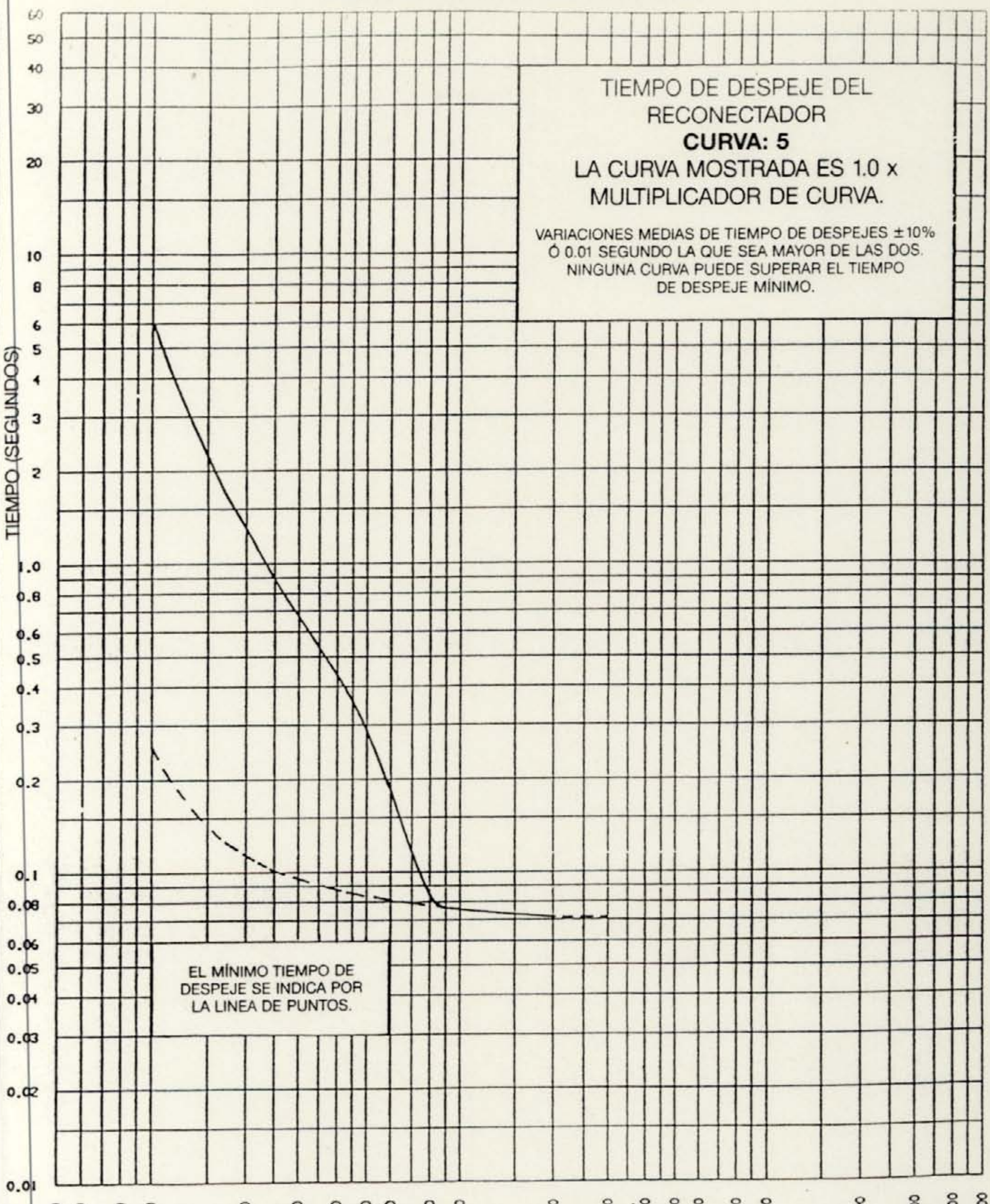
CURVA. 3.

CURVAS TIEMPO CORRIENTE



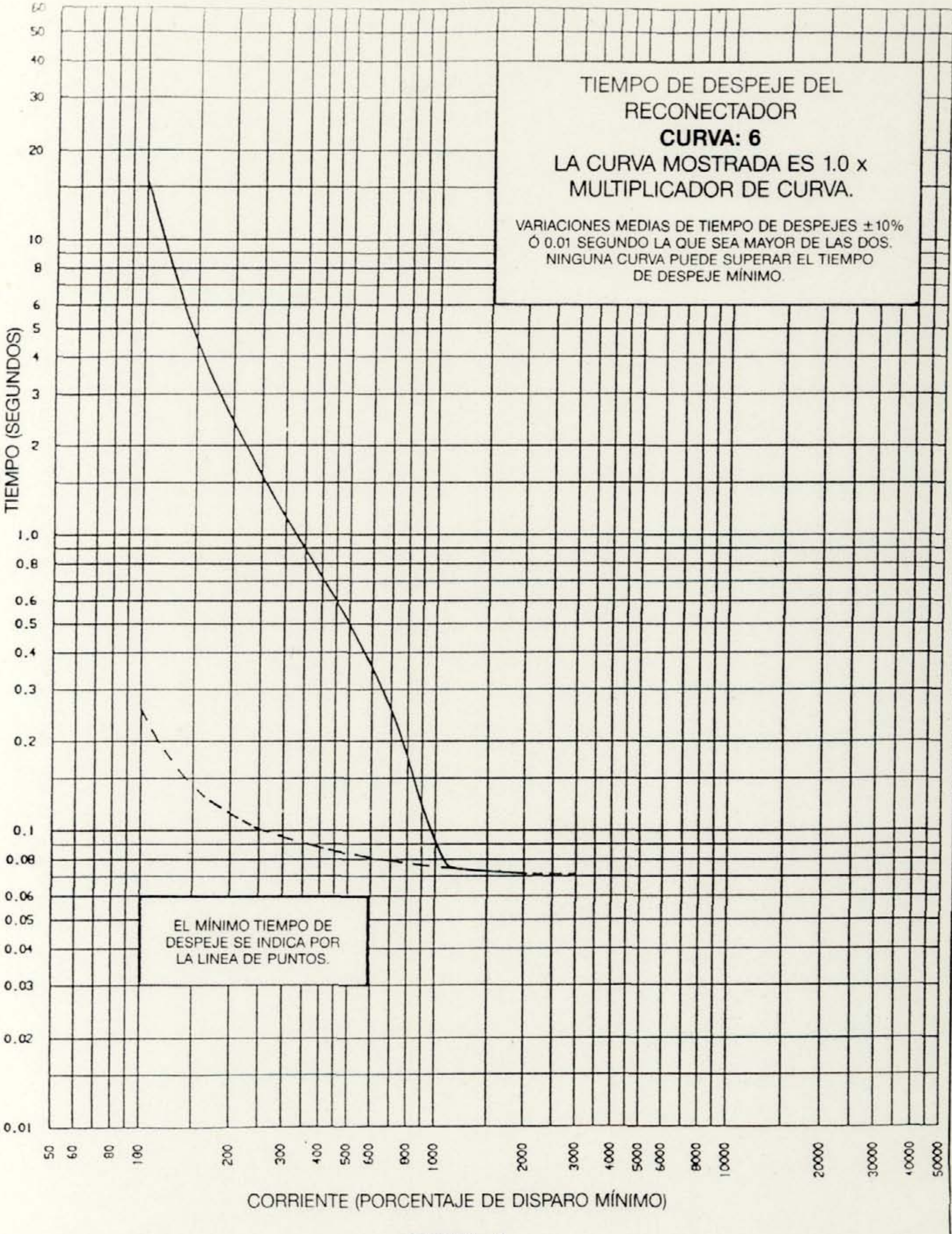
CURVA. 4.

CURVAS TIEMPO CORRIENTE



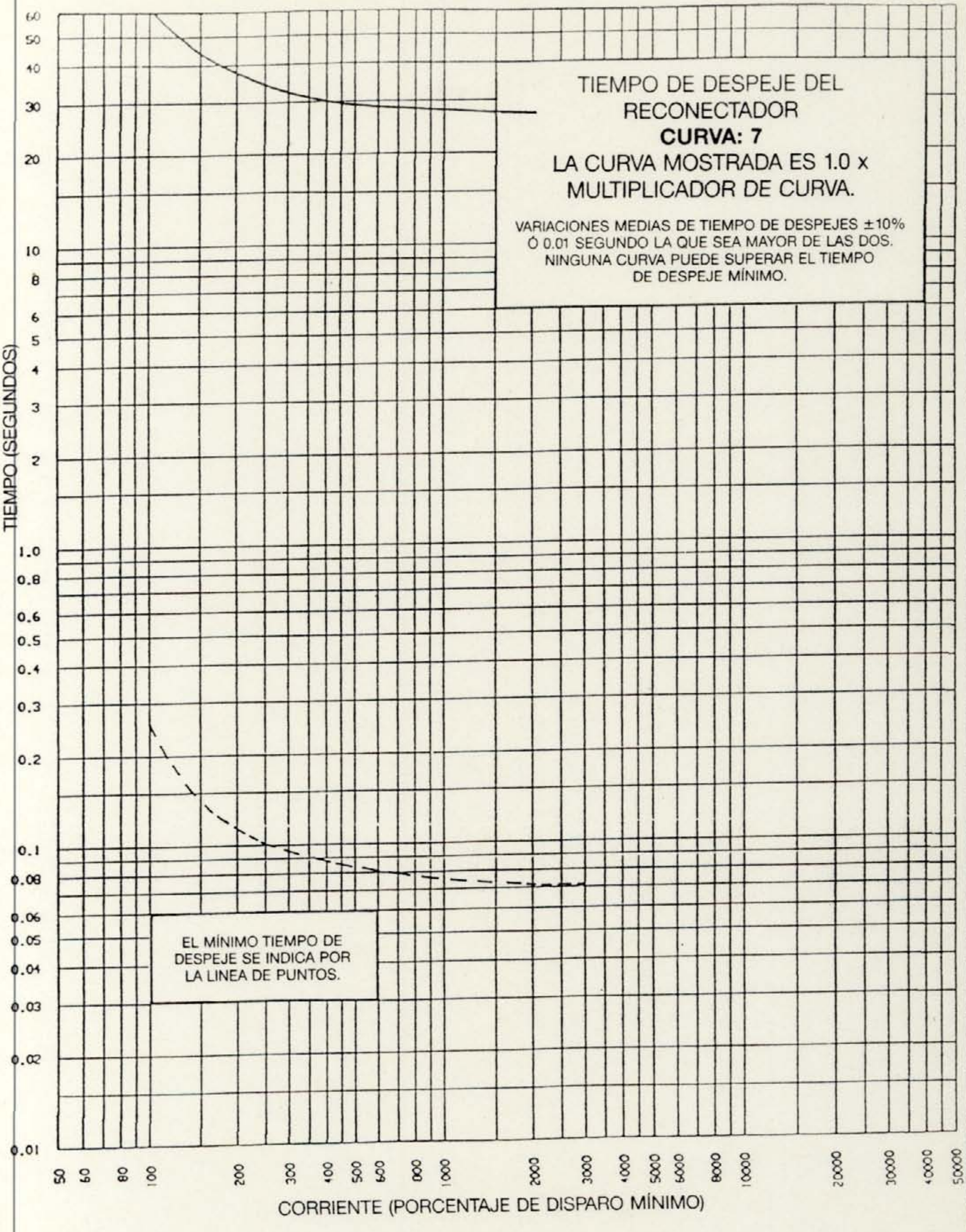
CURVA. 5.

CURVAS TIEMPO CORRIENTE



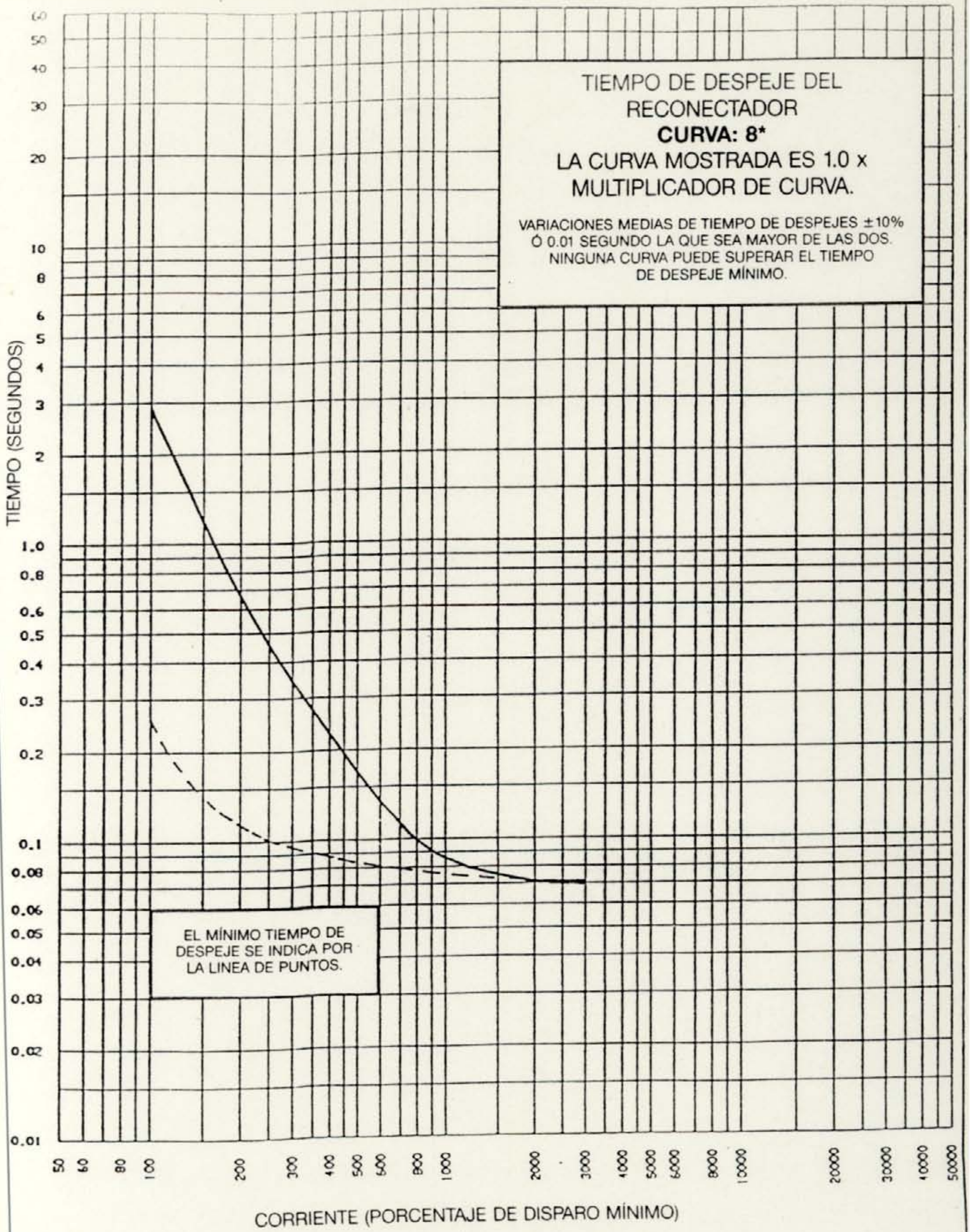
CURVA. 6.

CURVAS TIEMPO CORRIENTE

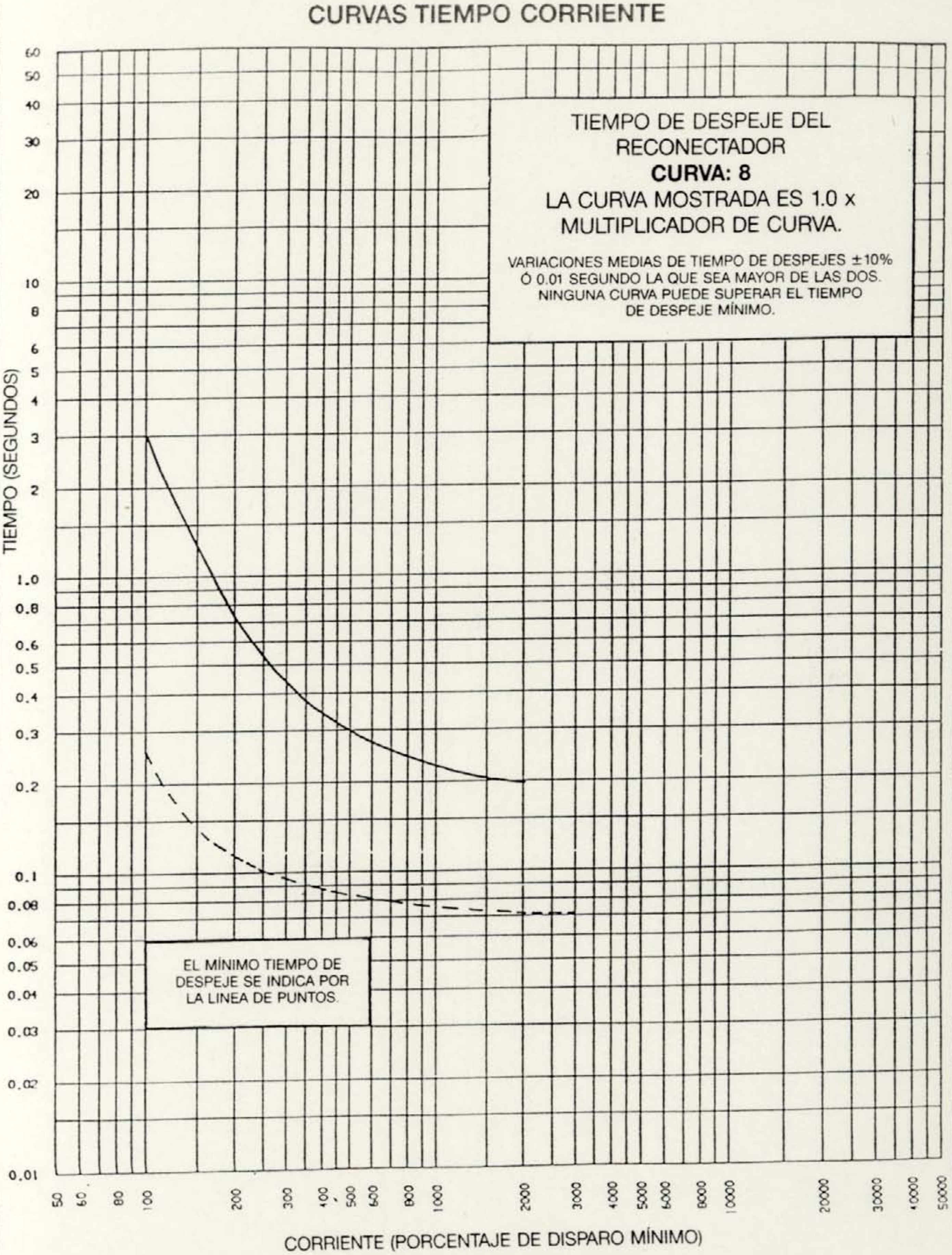


CURVA. 7.

CURVAS TIEMPO CORRIENTE

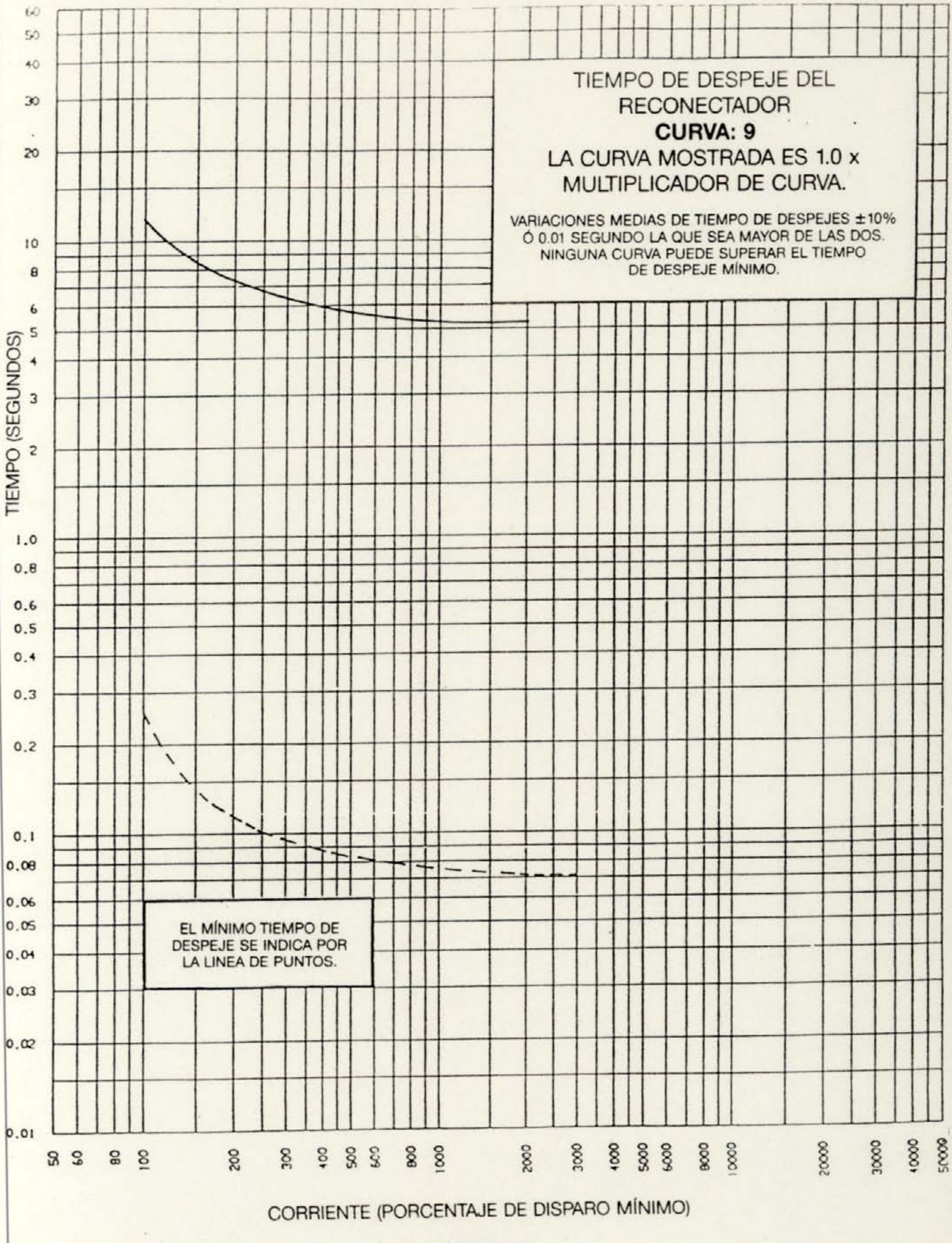


CURVA. 8*.


CURVAS TIEMPO CORRIENTE
TIEMPO DE DESPEJE DEL RECONECTADOR
CURVA: 8
LA CURVA MOSTRADA ES 1.0 x MULTIPLICADOR DE CURVA.
VARIACIONES MEDIAS DE TIEMPO DE DESPEJES ±10% Ó 0.01 SEGUNDO LA QUE SEA MAYOR DE LAS DOS. NINGUNA CURVA PUEDE SUPERAR EL TIEMPO DE DESPEJE MÍNIMO.
EL MÍNIMO TIEMPO DE DESPEJE SE INDICA POR LA LINEA DE PUNTOS.
TIEMPO (SEGUNDOS)
CORRIENTE (PORCENTAJE DE DISPARO MÍNIMO)
60
50
40
30
20
10
8
6
5
4
3
2
1.0
0.8
0.6
0.5
0.4
0.3
0.2
0.1
0.08
0.06
0.05
0.04
0.03
0.02
0.01
50
60
80
100
200
300
400
500
600
800
1000
2000
3000
4000
5000
6000
8000
10000
20000
30000
40000
50000

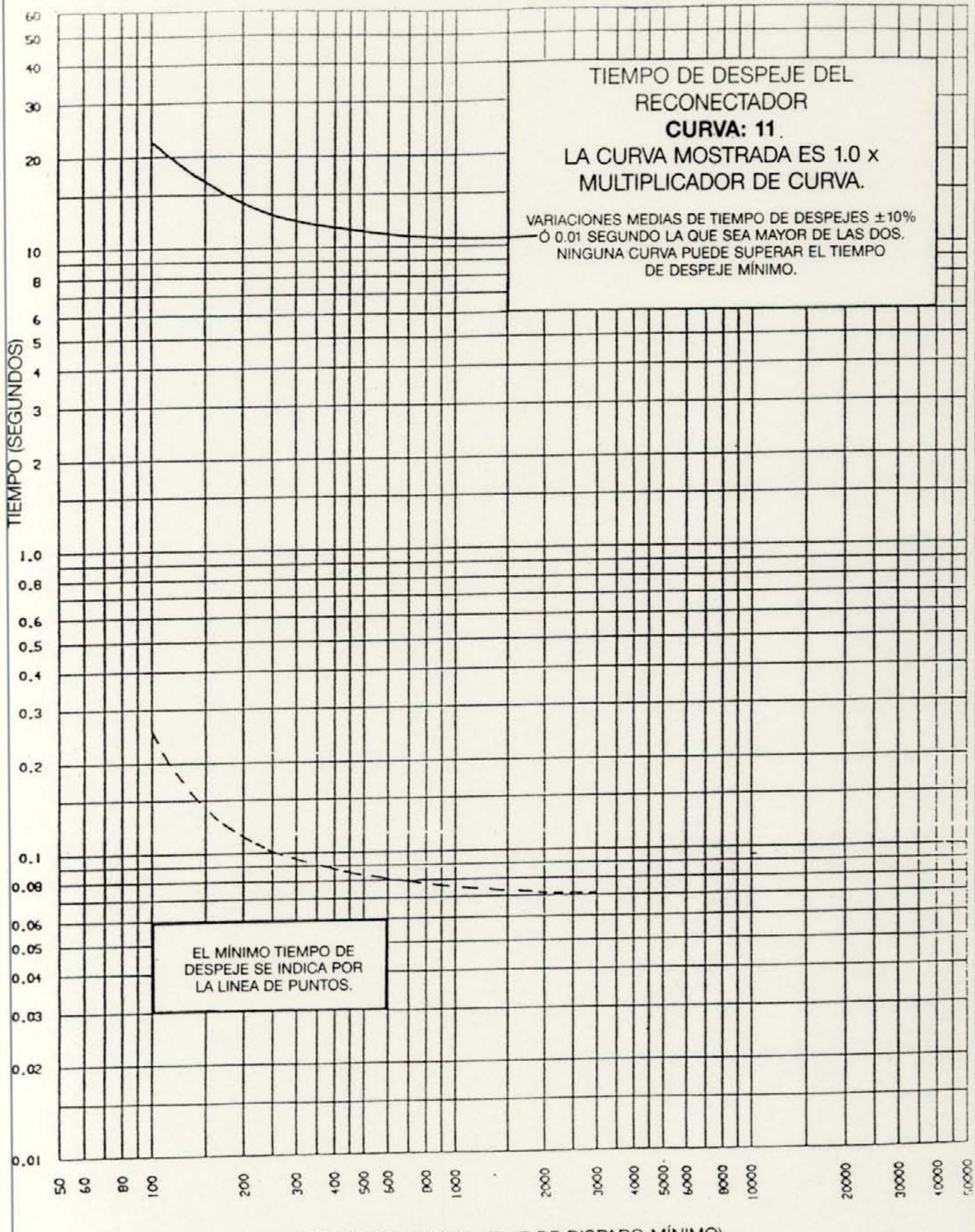
CURVA. 8.

CURVAS TIEMPO CORRIENTE



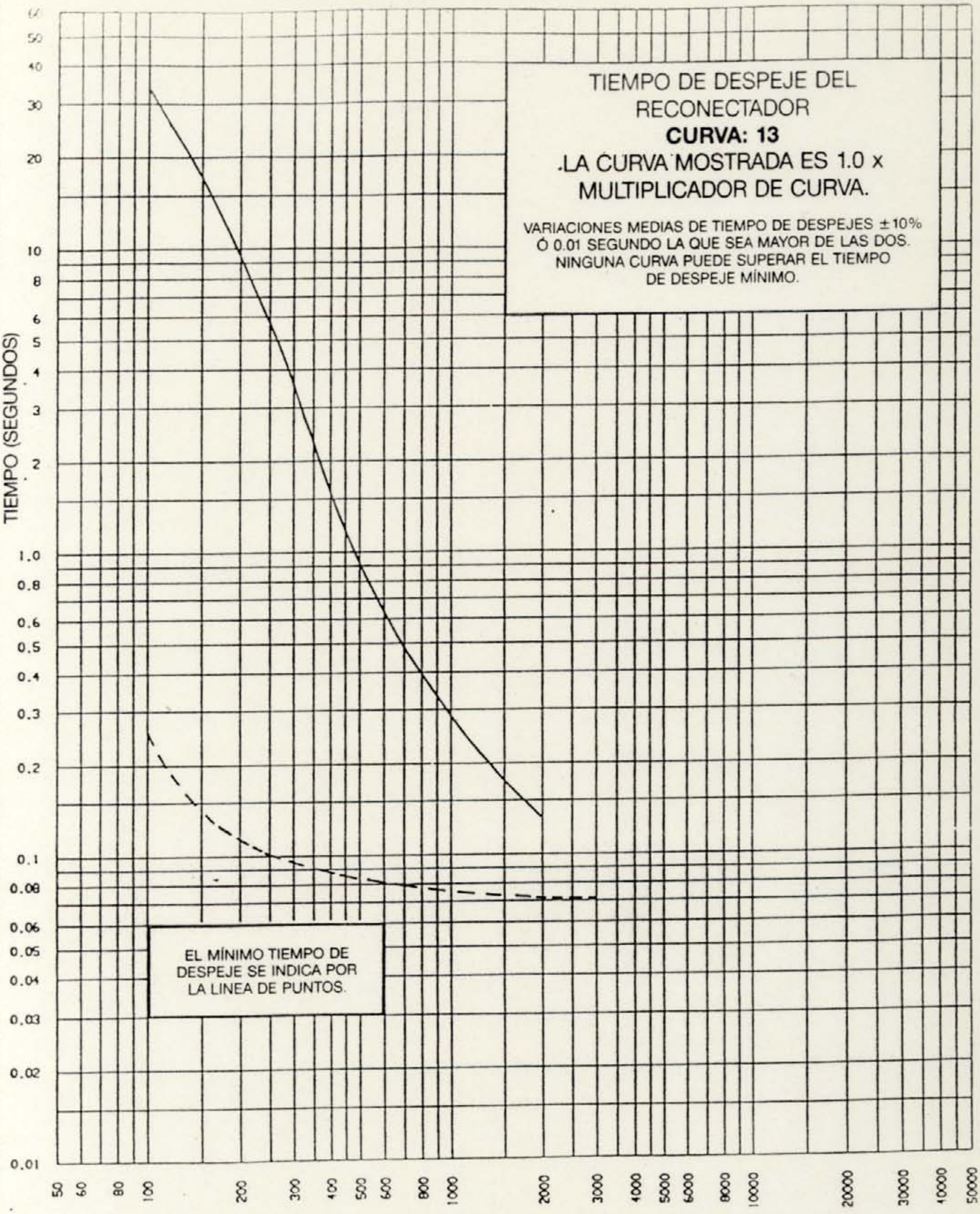
CURVA. 9.

CURVAS TIEMPO CORRIENTE

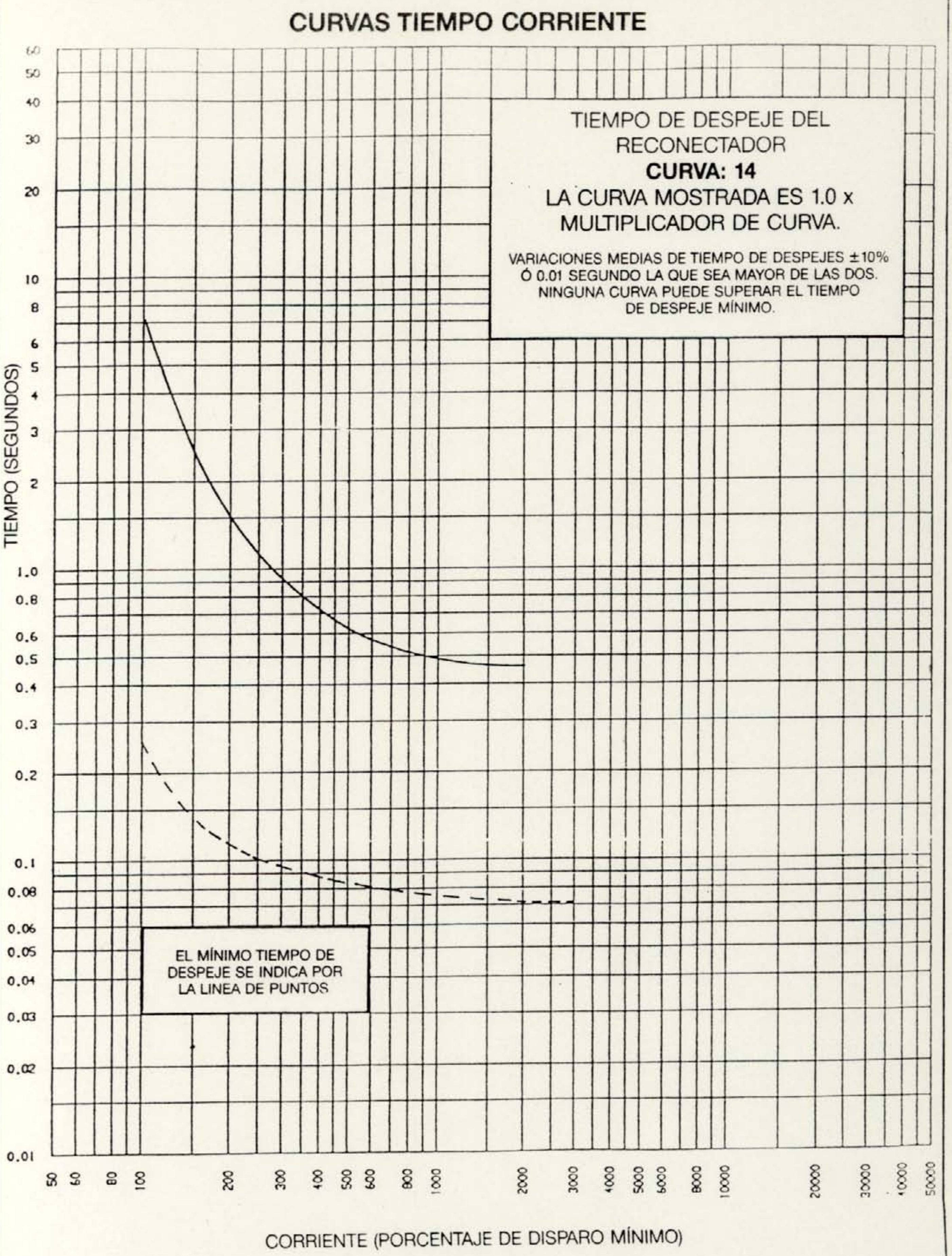


CURVA. 11.

CURVAS TIEMPO CORRIENTE

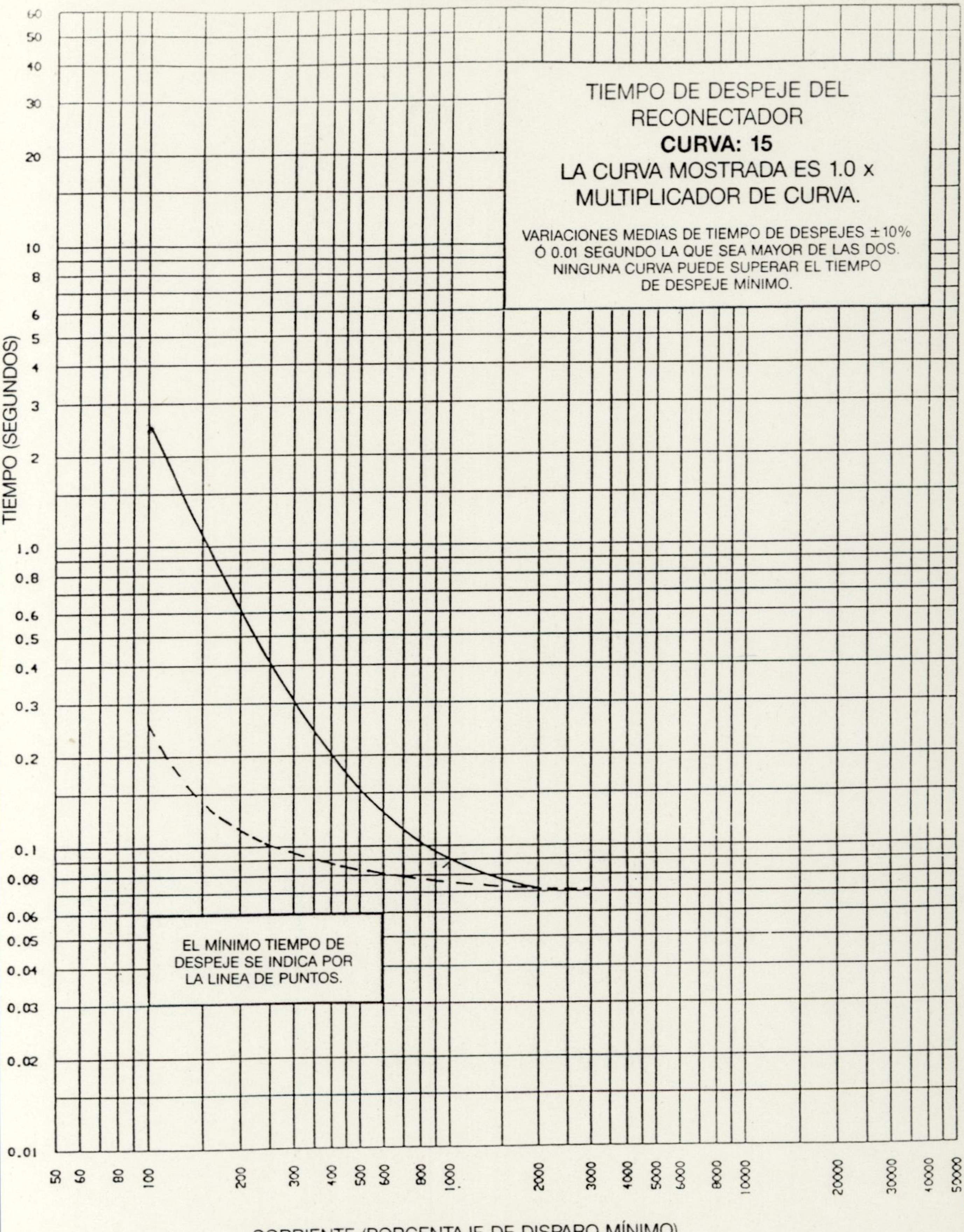


CURVA. 13.

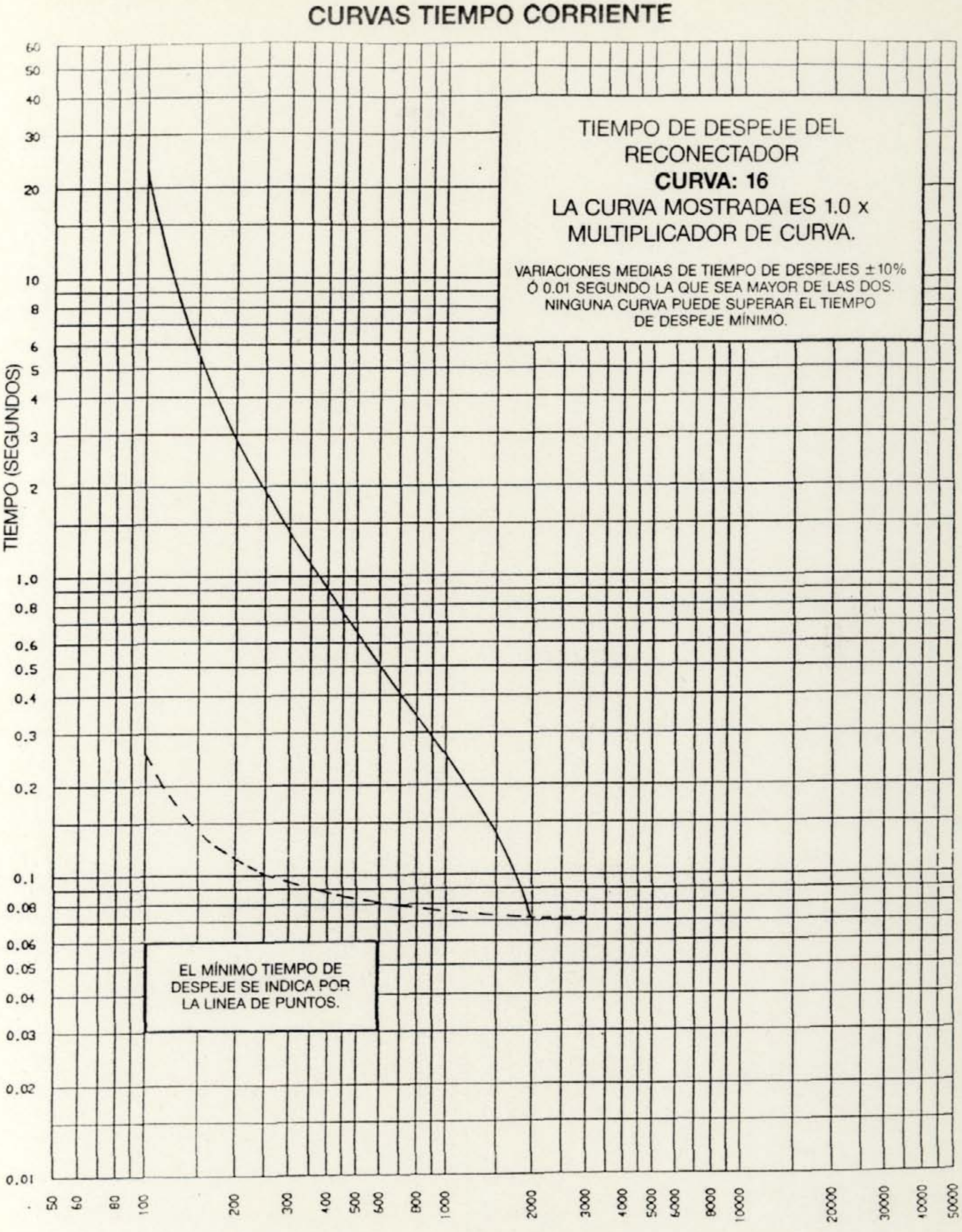

CURVAS TIEMPO CORRIENTE
TIEMPO DE DESPEJE DEL
RECONECTADOR
CURVA: 14
LA CURVA MOSTRADA ES 1.0 x
MULTIPLICADOR DE CURVA.
VARIACIONES MEDIAS DE TIEMPO DE DESPEJES ±10%
Ó 0.01 SEGUNDO LA QUE SEA MAYOR DE LAS DOS.
NINGUNA CURVA PUEDE SUPERAR EL TIEMPO
DE DESPEJE MÍNIMO.
EL MÍNIMO TIEMPO DE
DESPEJE SE INDICA POR
LA LINEA DE PUNTOS
TIEMPO (SEGUNDOS)
60
50
40
30
20
10
8
6
5
4
3
2
1.0
0.8
0.6
0.5
0.4
0.3
0.2
0.1
0.08
0.06
0.05
0.04
0.03
0.02
0.01
50
60
80
100
200
300
400
500
600
800
1000
2000
3000
4000
5000
6000
8000
10000
20000
30000
40000
50000
CORRIENTE (PORCENTAJE DE DISPARO MÍNIMO)

CURVA. 14.

CURVAS TIEMPO CORRIENTE

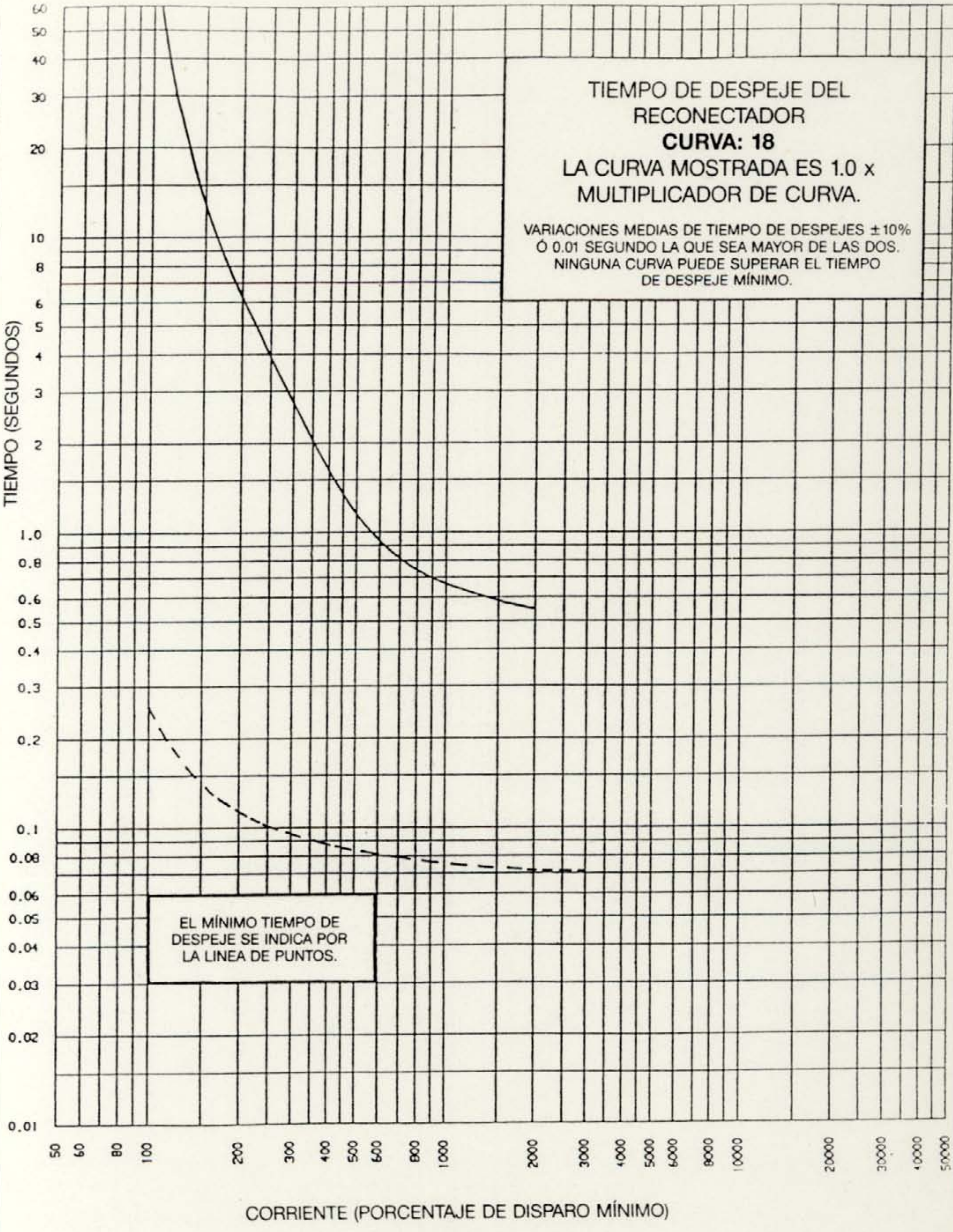


CURVA. 15.


CURVAS TIEMPO CORRIENTE
TIEMPO DE DESPEJE DEL
RECONECTADOR
CURVA: 16
LA CURVA MOSTRADA ES 1.0 x
MULTIPLICADOR DE CURVA.
VARIACIONES MEDIAS DE TIEMPO DE DESPEJES ±10%
Ó 0.01 SEGUNDO LA QUE SEA MAYOR DE LAS DOS.
NINGUNA CURVA PUEDE SUPERAR EL TIEMPO
DE DESPEJE MÍNIMO.
EL MÍNIMO TIEMPO DE
DESPEJE SE INDICA POR
LA LINEA DE PUNTOS.
TIEMPO (SEGUNDOS)
60
50
40
30
20
10
8
6
5
4
3
2
1.0
0.8
0.6
0.5
0.4
0.3
0.2
0.1
0.08
0.06
0.05
0.04
0.03
0.02
0.01
50
60
80
100
200
300
400
500
600
800
1000
2000
3000
4000
5000
6000
8000
10000
20000
30000
40000
50000
CORRIENTE (PORCENTAJE DE DISPARO MÍNIMO)

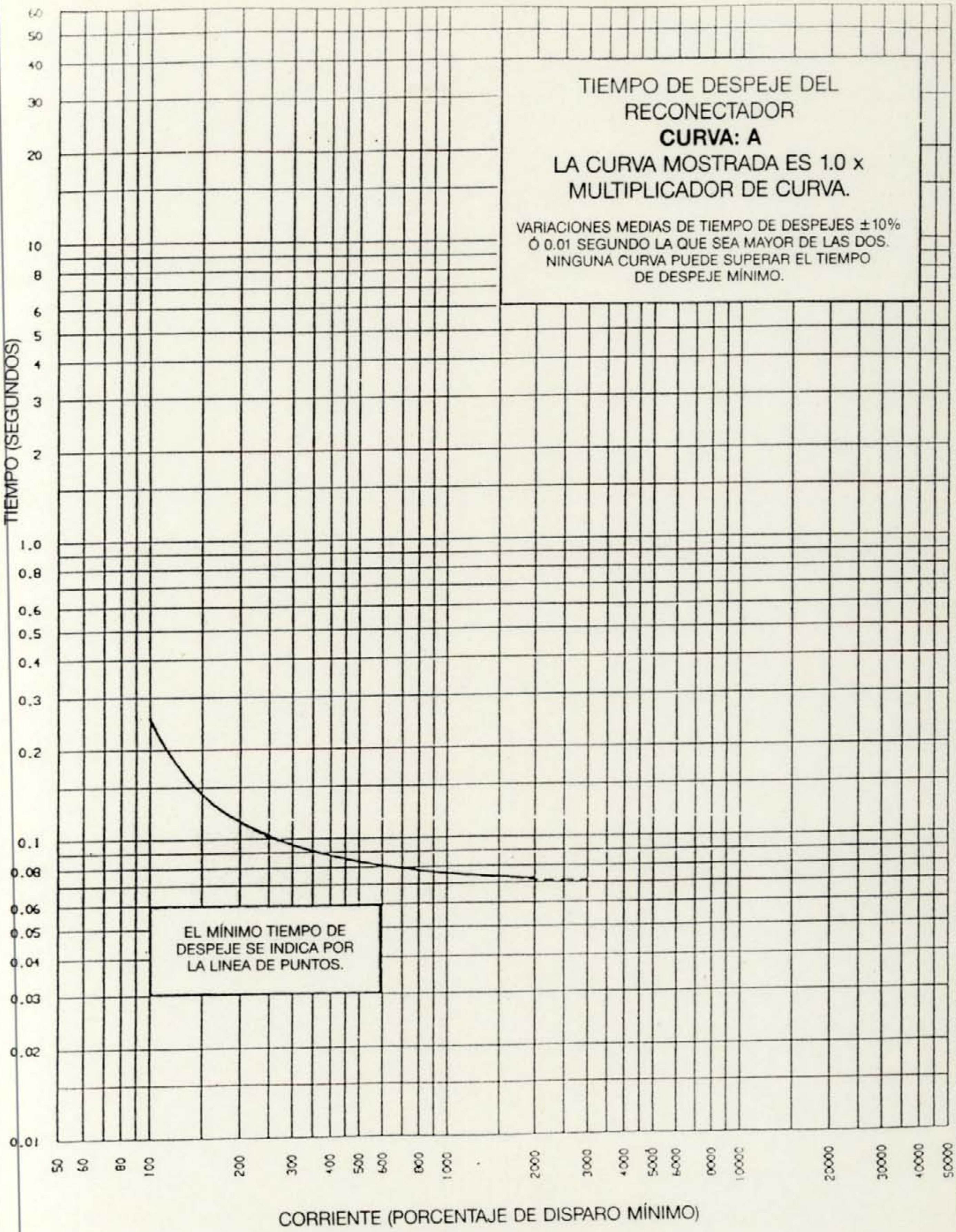
CURVA. 16.

CURVAS TIEMPO CORRIENTE



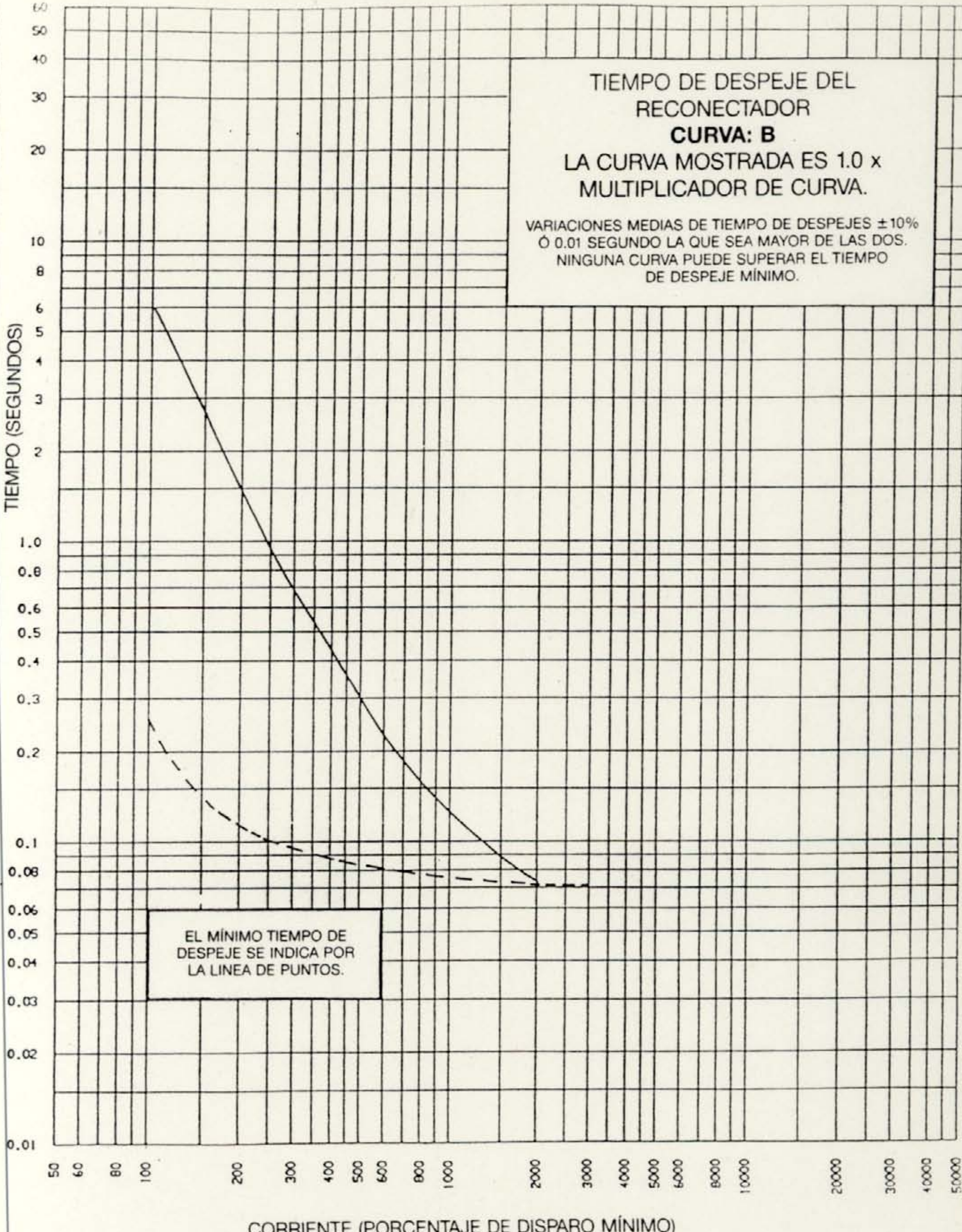
CURVA. 18.

CURVAS TIEMPO CORRIENTE



CURVA. A.

CURVAS TIEMPO CORRIENTE



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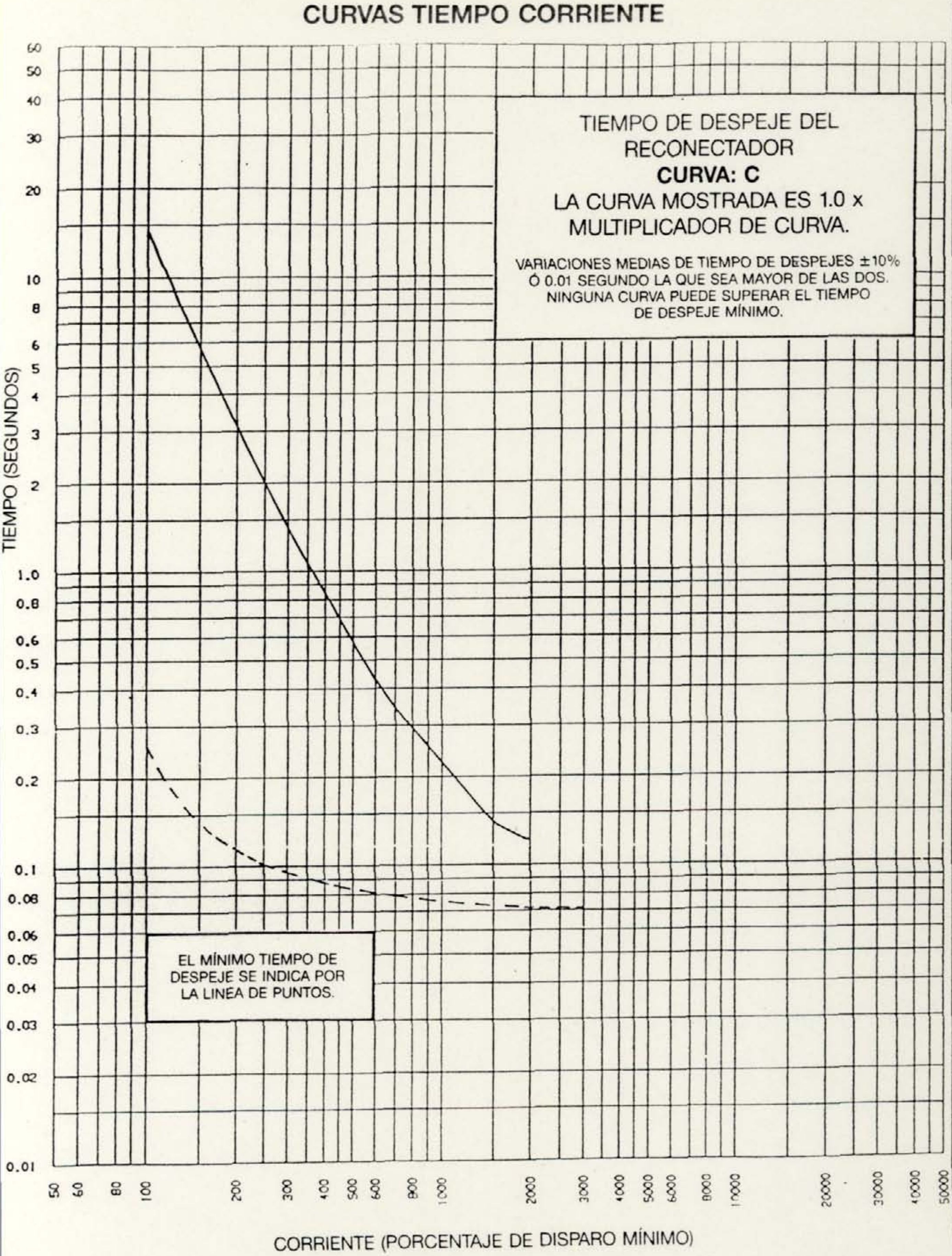
CURVAS TIEMPO CORRIENTE
TIEMPO DE DESPEJE DEL RECONECTADOR
CURVA: C
LA CURVA MOSTRADA ES 1.0 x MULTIPLICADOR DE CURVA.
VARIACIONES MEDIAS DE TIEMPO DE DESPEJES ±10% Ó 0.01 SEGUNDO LA QUE SEA MAYOR DE LAS DOS. NINGUNA CURVA PUEDE SUPERAR EL TIEMPO DE DESPEJE MÍNIMO.
EL MÍNIMO TIEMPO DE DESPEJE SE INDICA POR LA LINEA DE PUNTOS.
TIEMPO (SEGUNDOS)
60
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40
30
20
10
8
6
5
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3
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1.0
0.8
0.6
0.5
0.4
0.3
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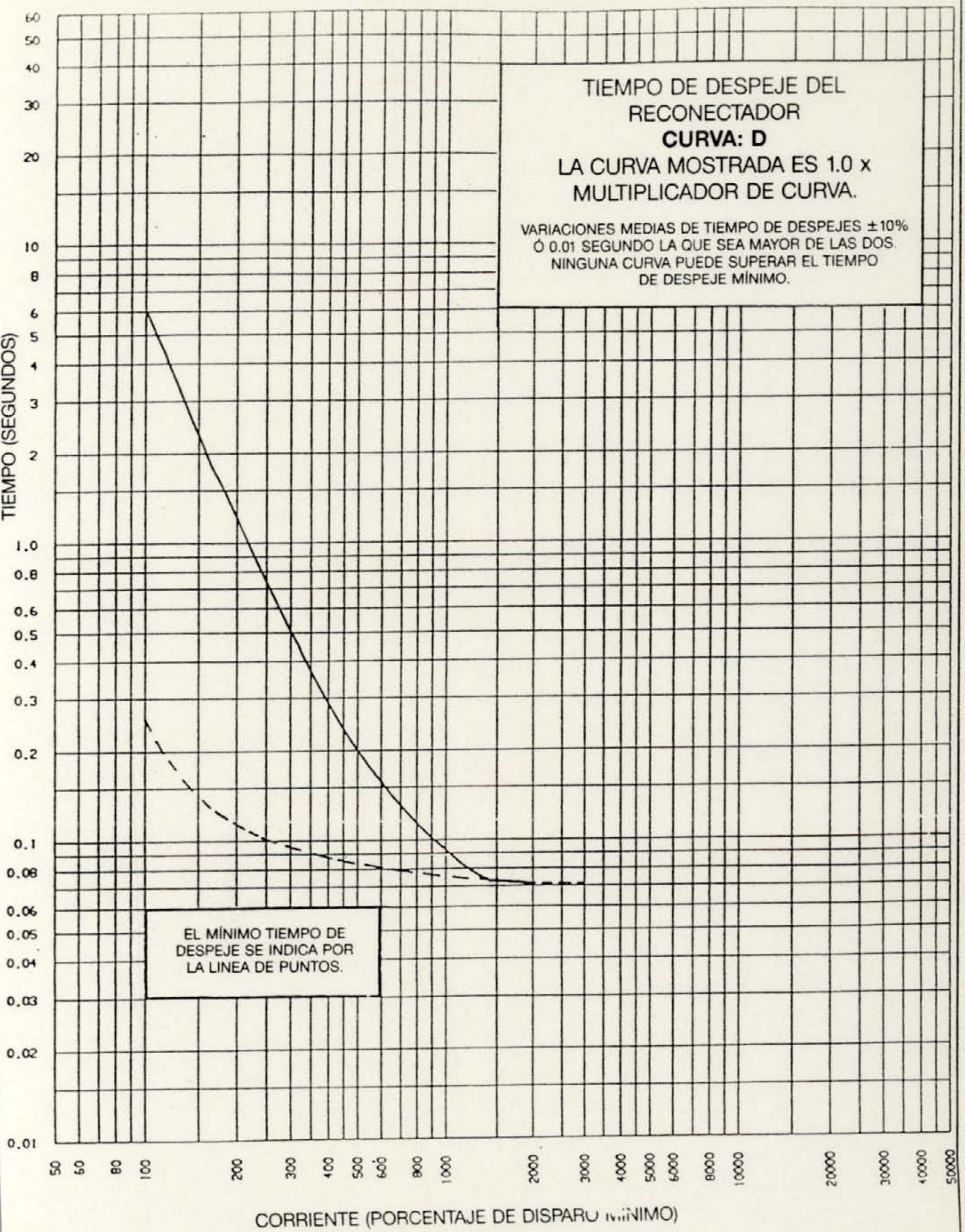
0.08
0.06
0.05
0.04
0.03
0.02
0.01
50 60 80 100 200 300 400 500 600 800 1000 2000 3000 4000 5000 6000 8000 10000 20000 30000 40000 50000
CORRIENTE (PORCENTAJE DE DISPARO MÍNIMO)

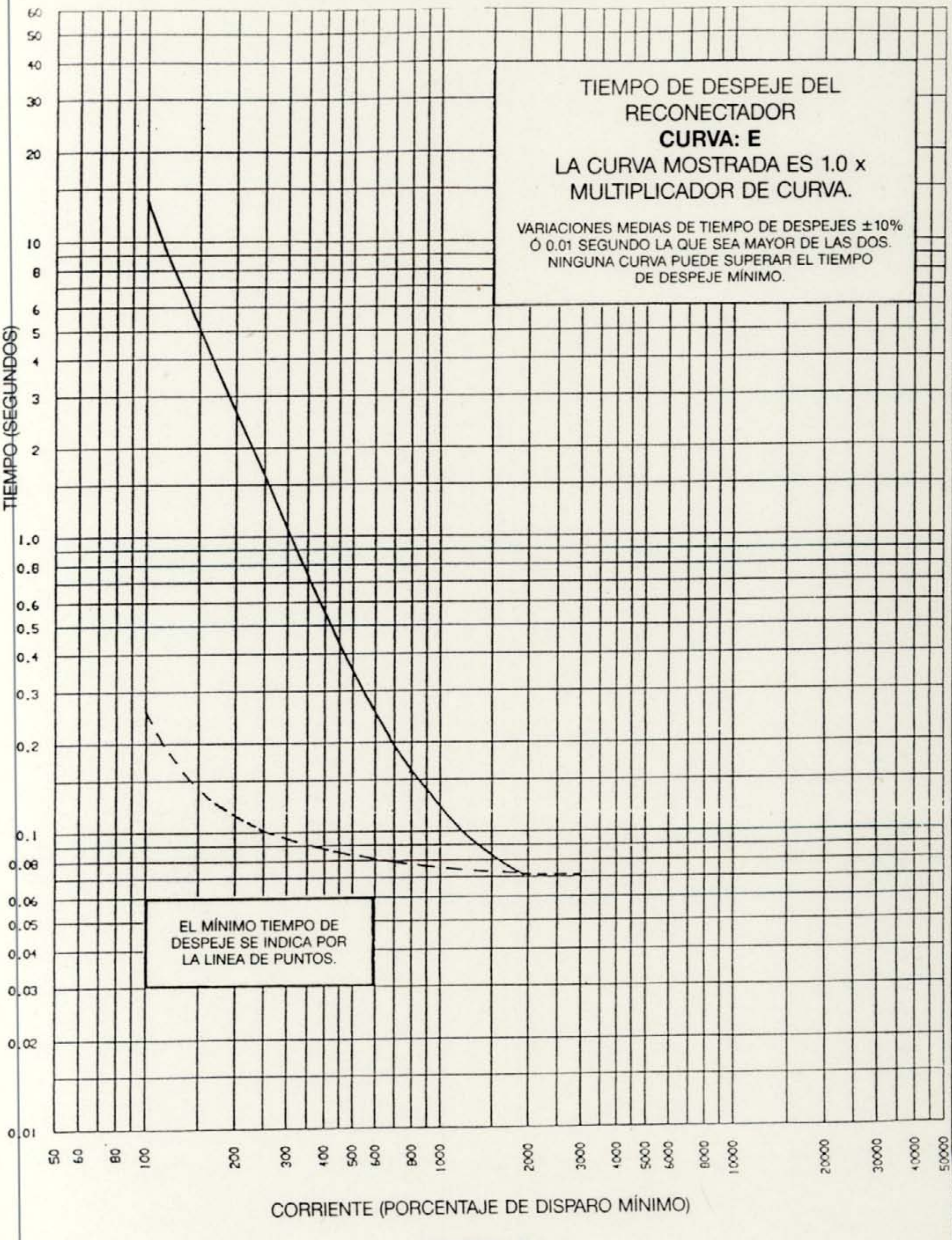
CURVA. C.

CURVAS TIEMPO CORRIENTE

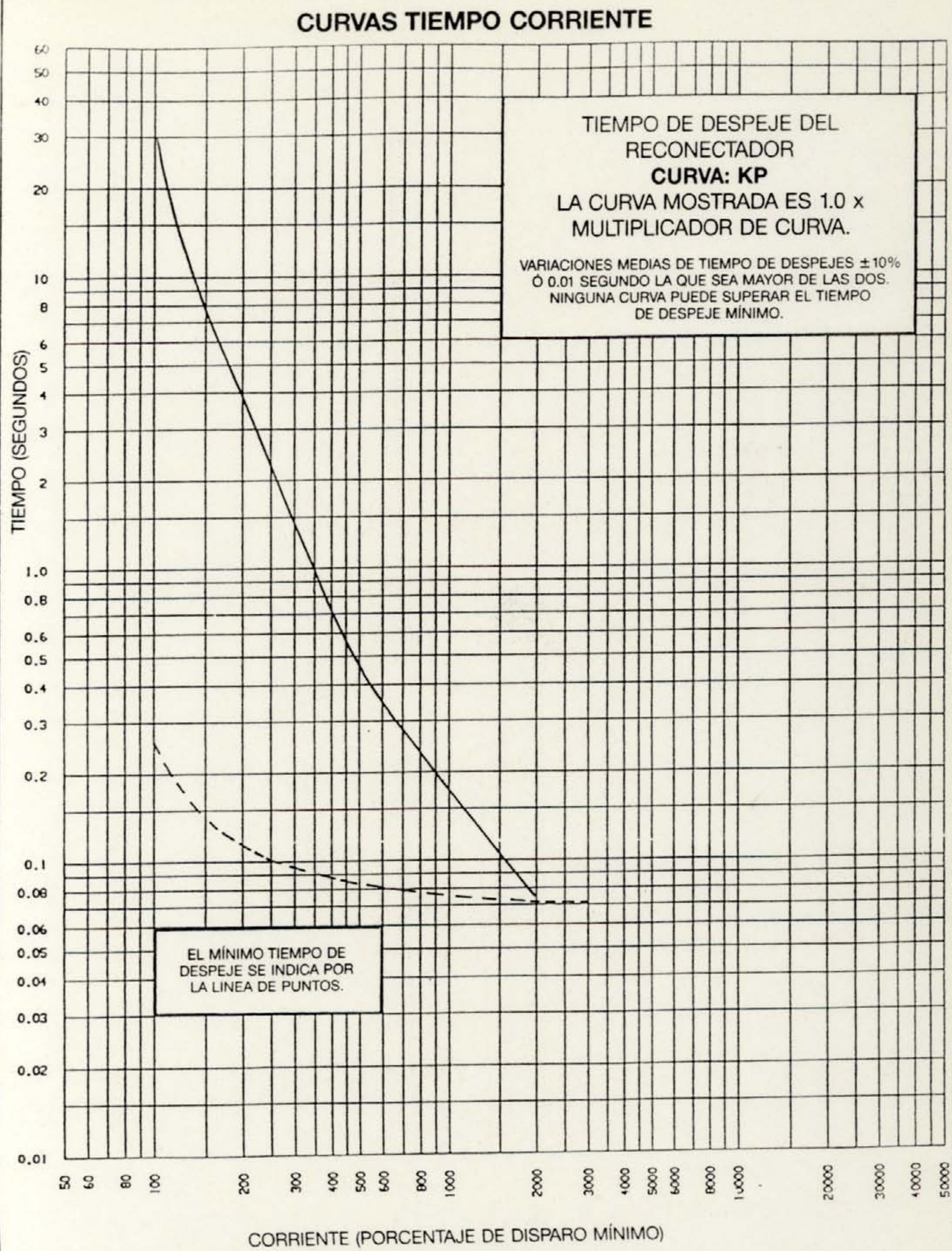


CURVA. D.

CURVAS TIEMPO CORRIENTE



CURVA. E.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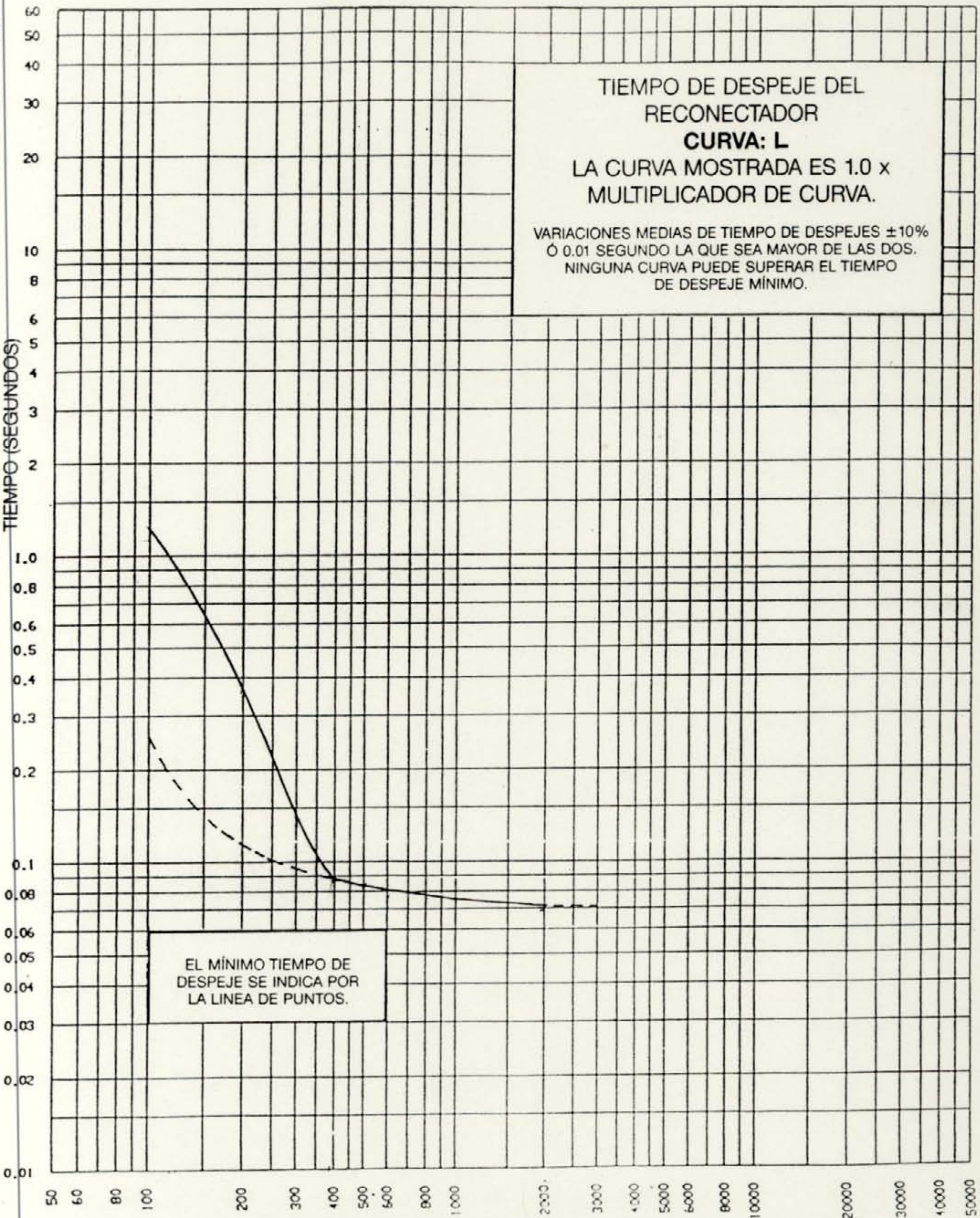
TIEMPO DE DESPEJE DEL RECONECTADOR
CURVA: KP
LA CURVA MOSTRADA ES 1.0 x MULTIPLICADOR DE CURVA.
VARIACIONES MEDIAS DE TIEMPO DE DESPEJES ± 10% Ó 0.01 SEGUNDO LA QUE SEA MAYOR DE LAS DOS. NINGUNA CURVA PUEDE SUPERAR EL TIEMPO DE DESPEJE MÍNIMO.
EL MÍNIMO TIEMPO DE DESPEJE SE INDICA POR LA LINEA DE PUNTOS.
TIEMPO (SEGUNDOS)
CORRIENTE (PORCENTAJE DE DISPARO MÍNIMO)

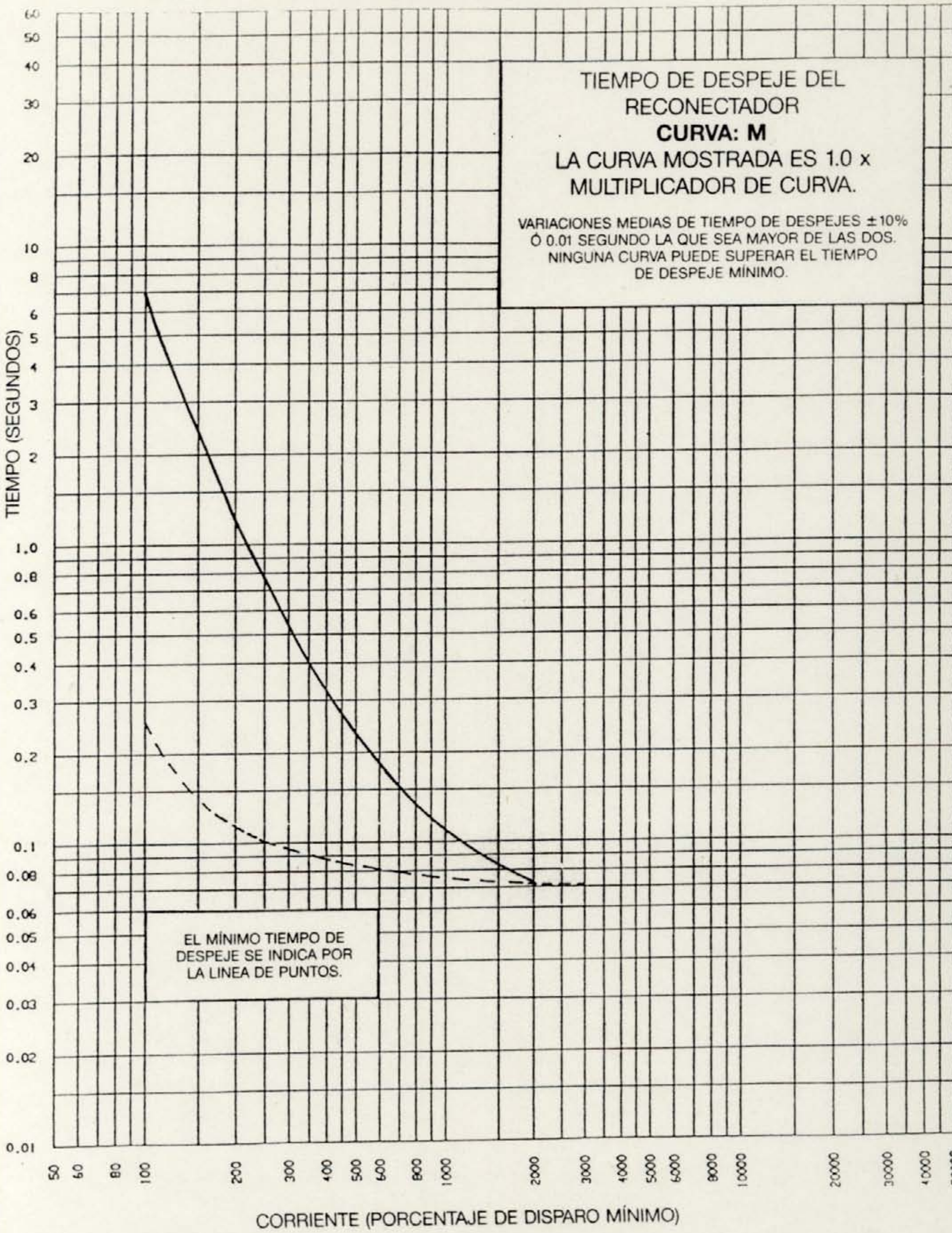
CURVA. KP.

CURVAS TIEMPO CORRIENTE



CURVA. L

CURVAS TIEMPO CORRIENTE



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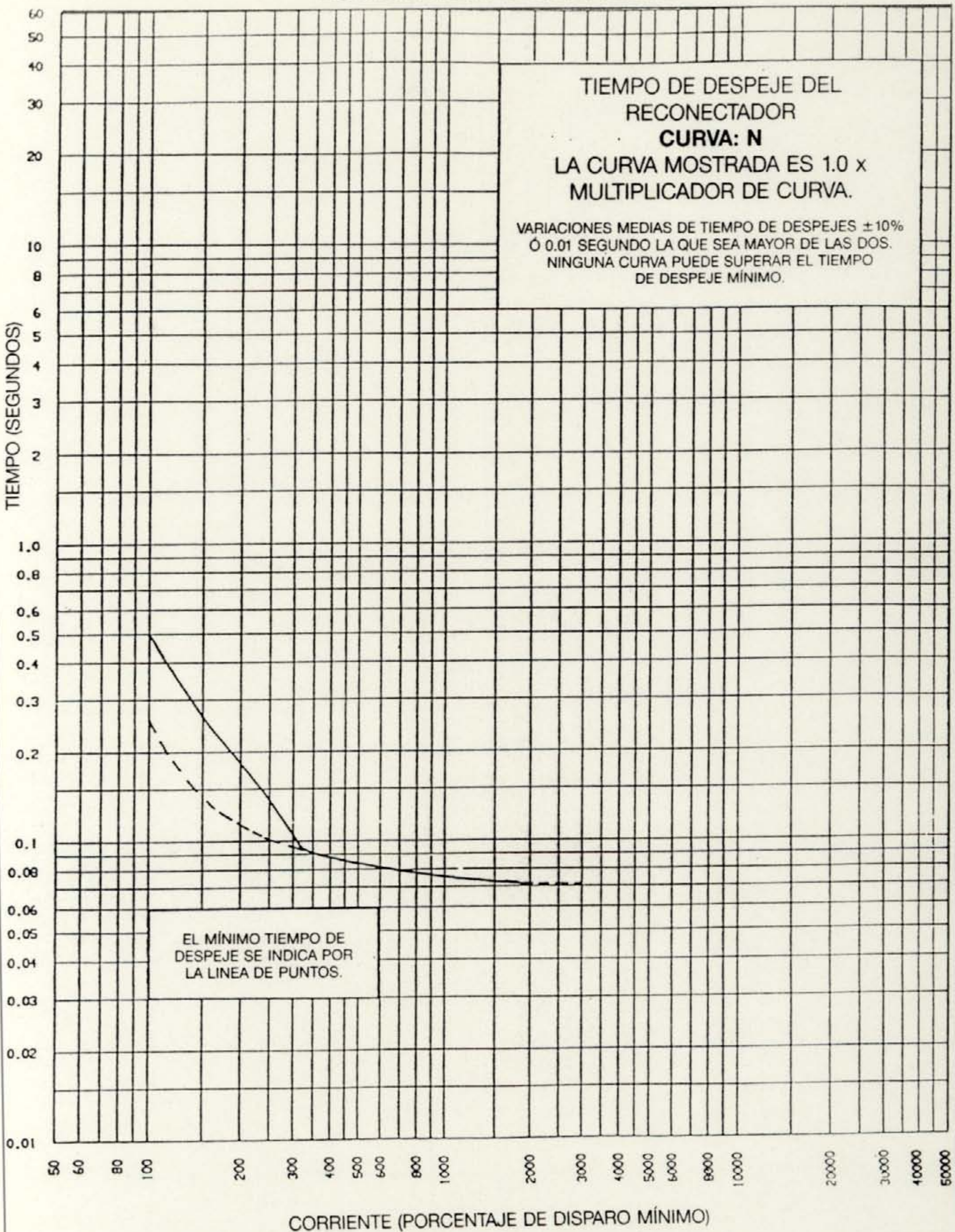
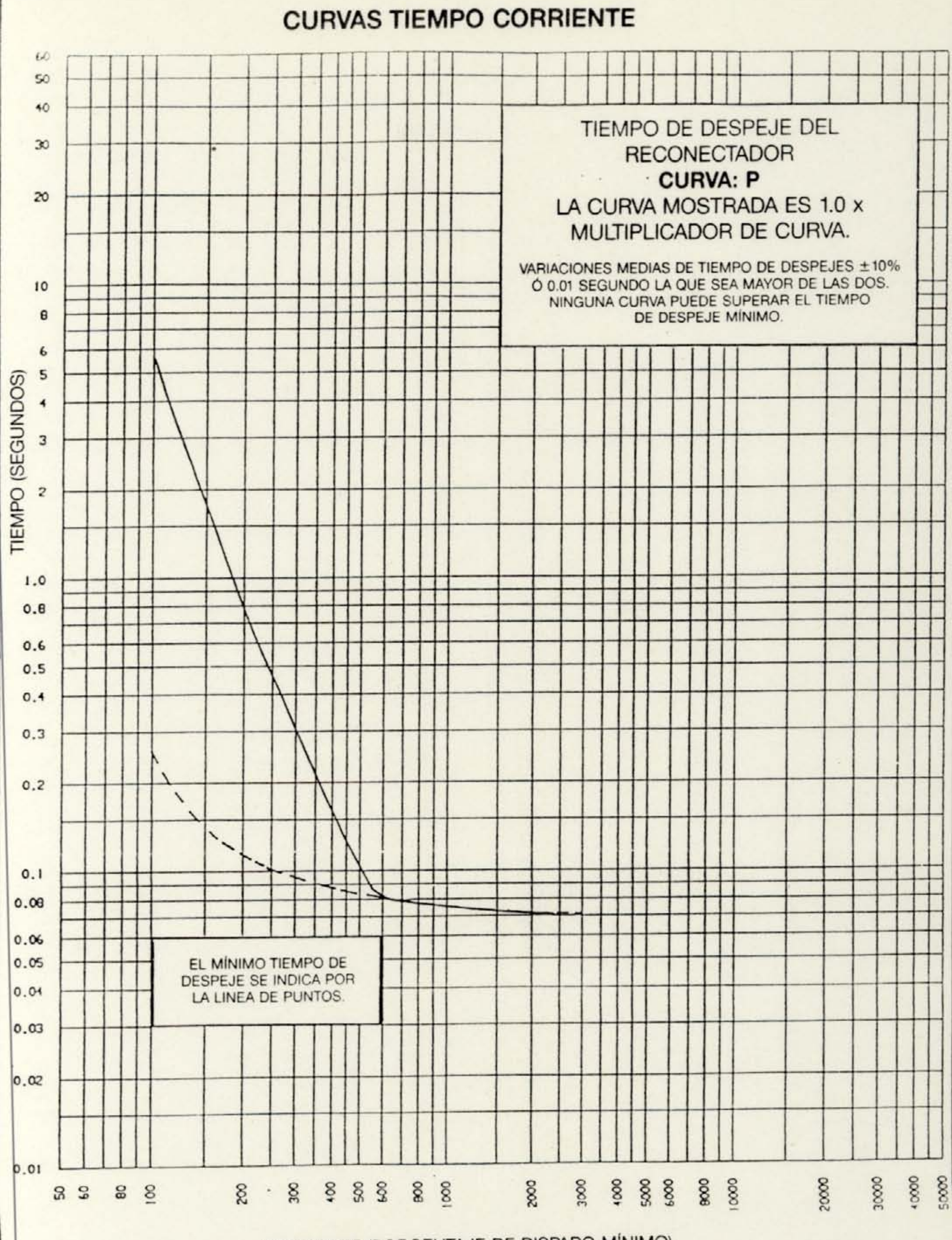
CURVAS TIEMPO CORRIENTE



CURVA. N.


CURVAS TIEMPO CORRIENTE
TIEMPO DE DESPEJE DEL
RECONECTADOR
CURVA: P
LA CURVA MOSTRADA ES 1.0 x
MULTIPLICADOR DE CURVA.
VARIACIONES MEDIAS DE TIEMPO DE DESPEJES ±10%
Ó 0.01 SEGUNDO LA QUE SEA MAYOR DE LAS DOS.
NINGUNA CURVA PUEDE SUPERAR EL TIEMPO
DE DESPEJE MÍNIMO.
EL MÍNIMO TIEMPO DE
DESPEJE SE INDICA POR
LA LINEA DE PUNTOS.
TIEMPO (SEGUNDOS)
60
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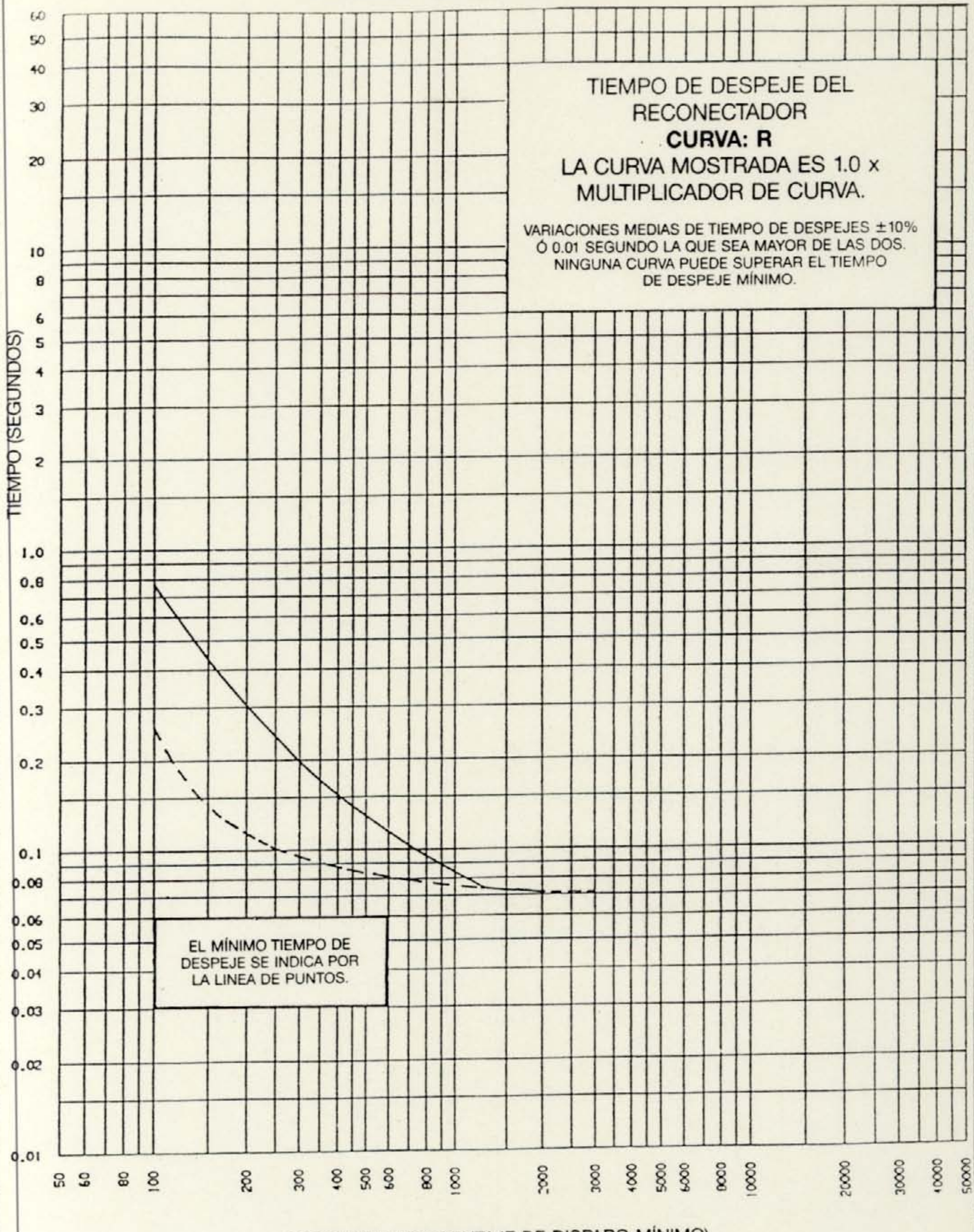
0.04
0.03
0.02
0.01
50 60 80 100 200 300 400 500 600 800 1000 2000 3000 4000 5000 6000 8000 10000 20000 30000 40000 50000
CORRIENTE (PORCENTAJE DE DISPARO MÍNIMO)

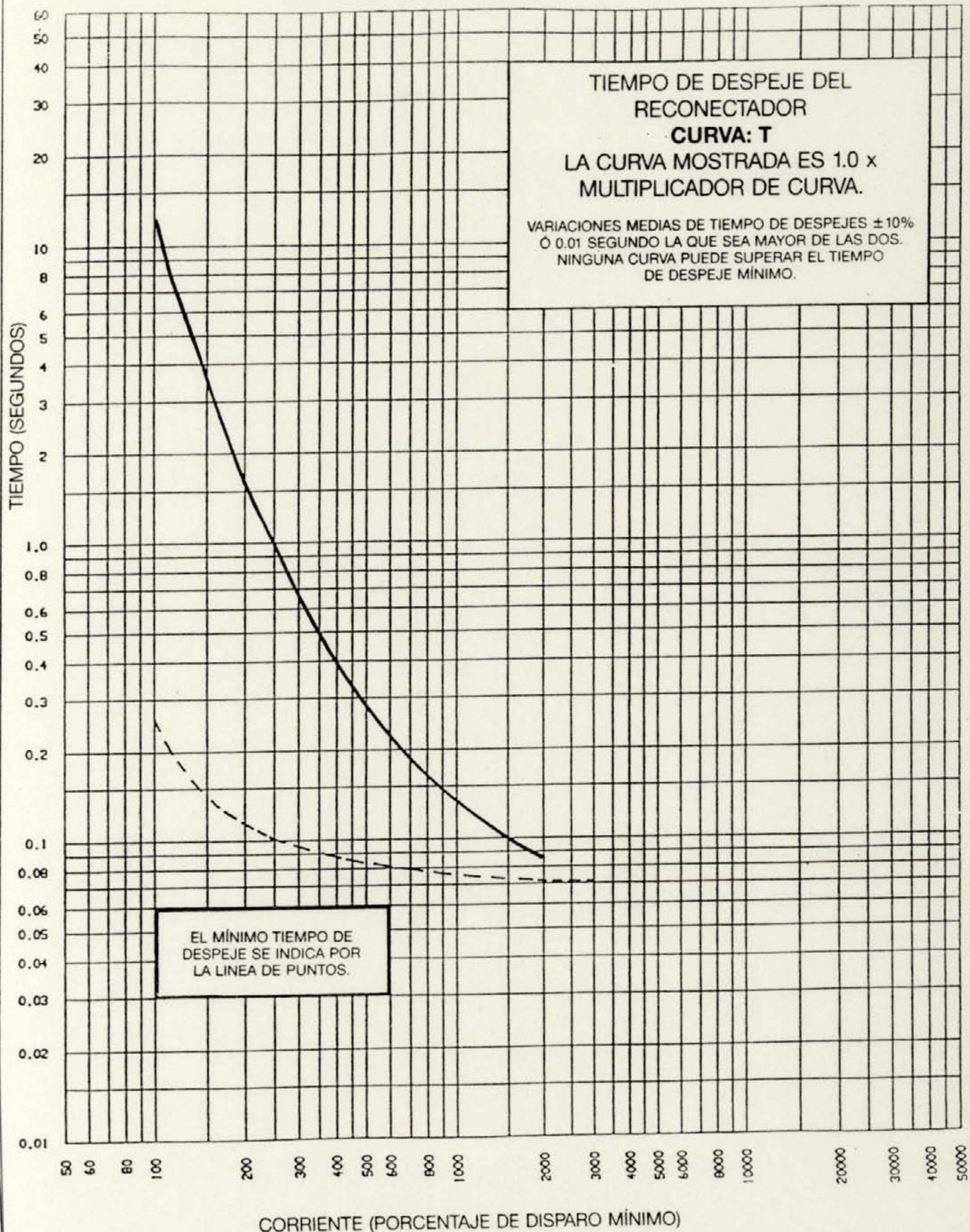
CURVA. P.

CURVAS TIEMPO CORRIENTE



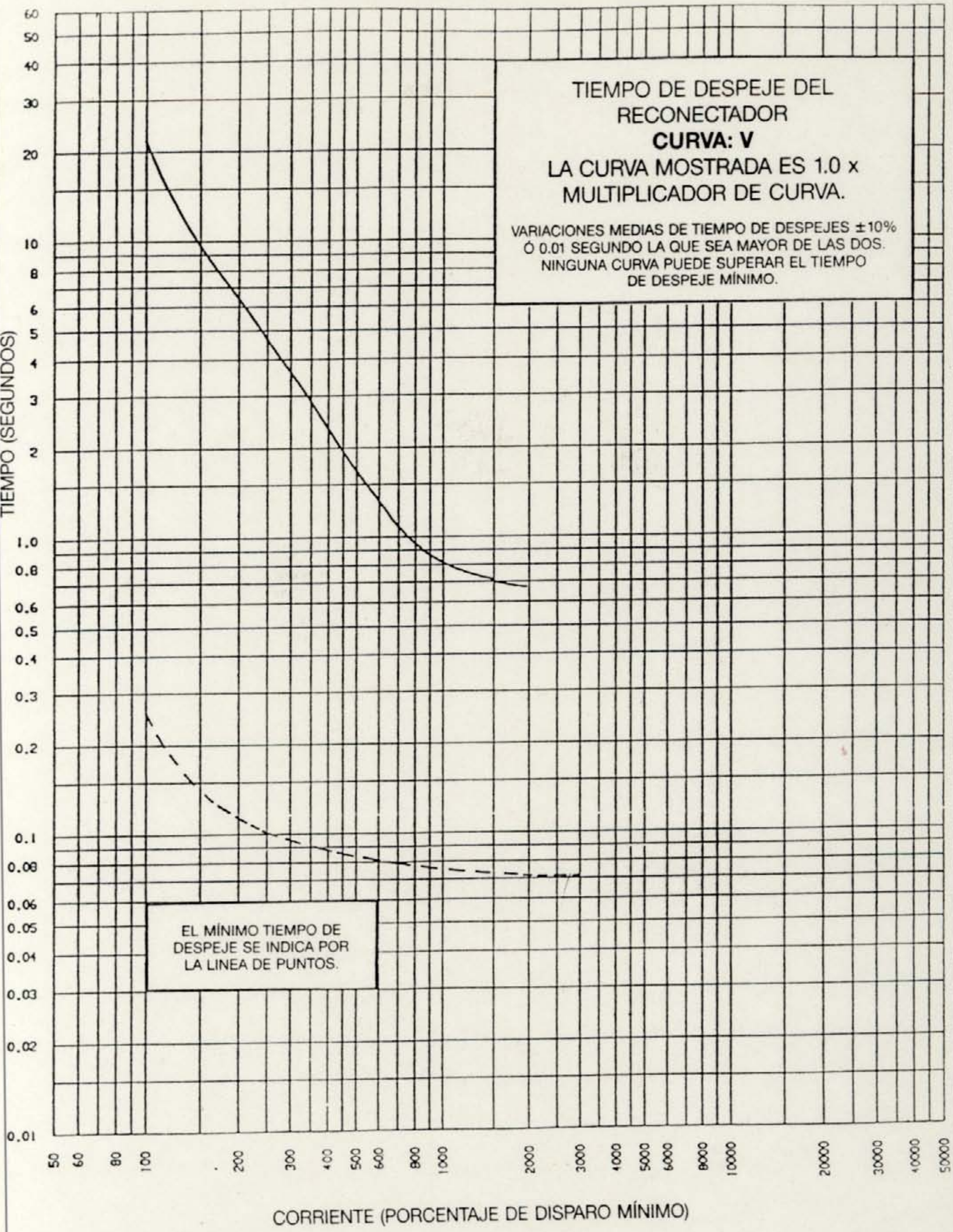
CURVA. R.

CURVAS TIEMPO CORRIENTE

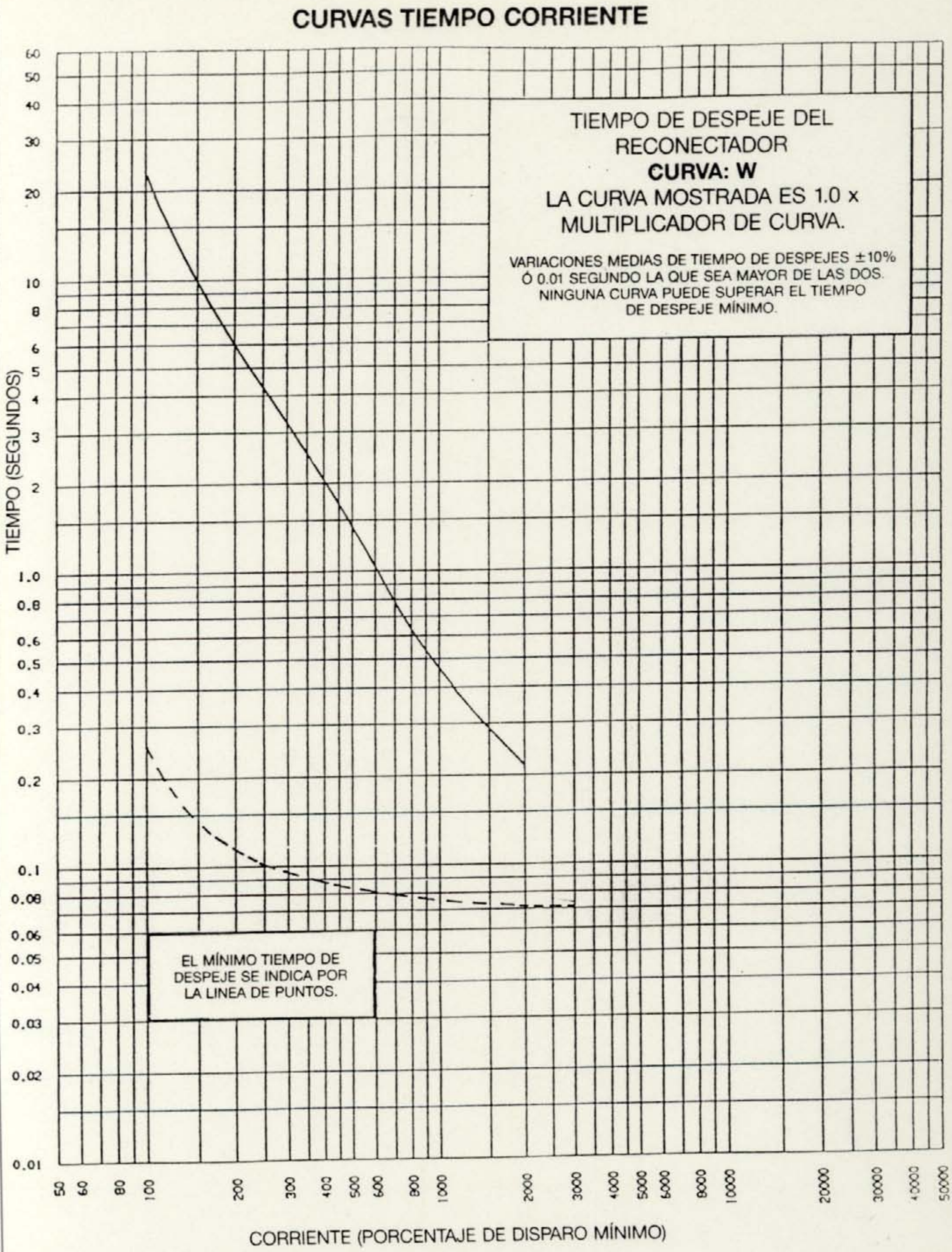


CURVA. T.

CURVAS TIEMPO CORRIENTE



CURVA. V.


CURVAS TIEMPO CORRIENTE
TIEMPO DE DESPEJE DEL RECONECTADOR
CURVA: W
LA CURVA MOSTRADA ES 1.0 x MULTIPLICADOR DE CURVA.
VARIACIONES MEDIAS DE TIEMPO DE DESPEJES ±10% Ó 0.01 SEGUNDO LA QUE SEA MAYOR DE LAS DOS. NINGUNA CURVA PUEDE SUPERAR EL TIEMPO DE DESPEJE MÍNIMO.
EL MÍNIMO TIEMPO DE DESPEJE SE INDICA POR LA LINEA DE PUNTOS.
TIEMPO (SEGUNDOS)
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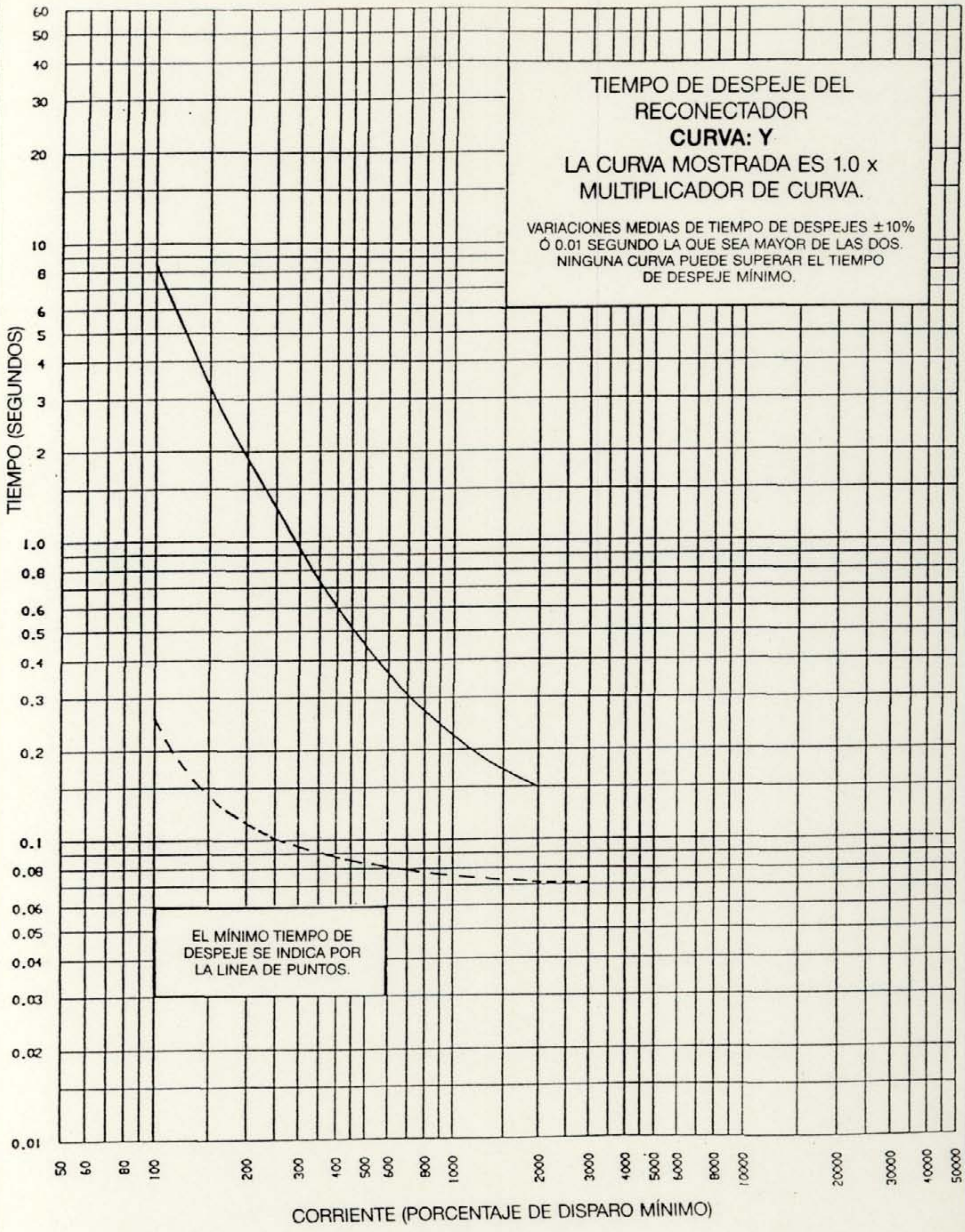
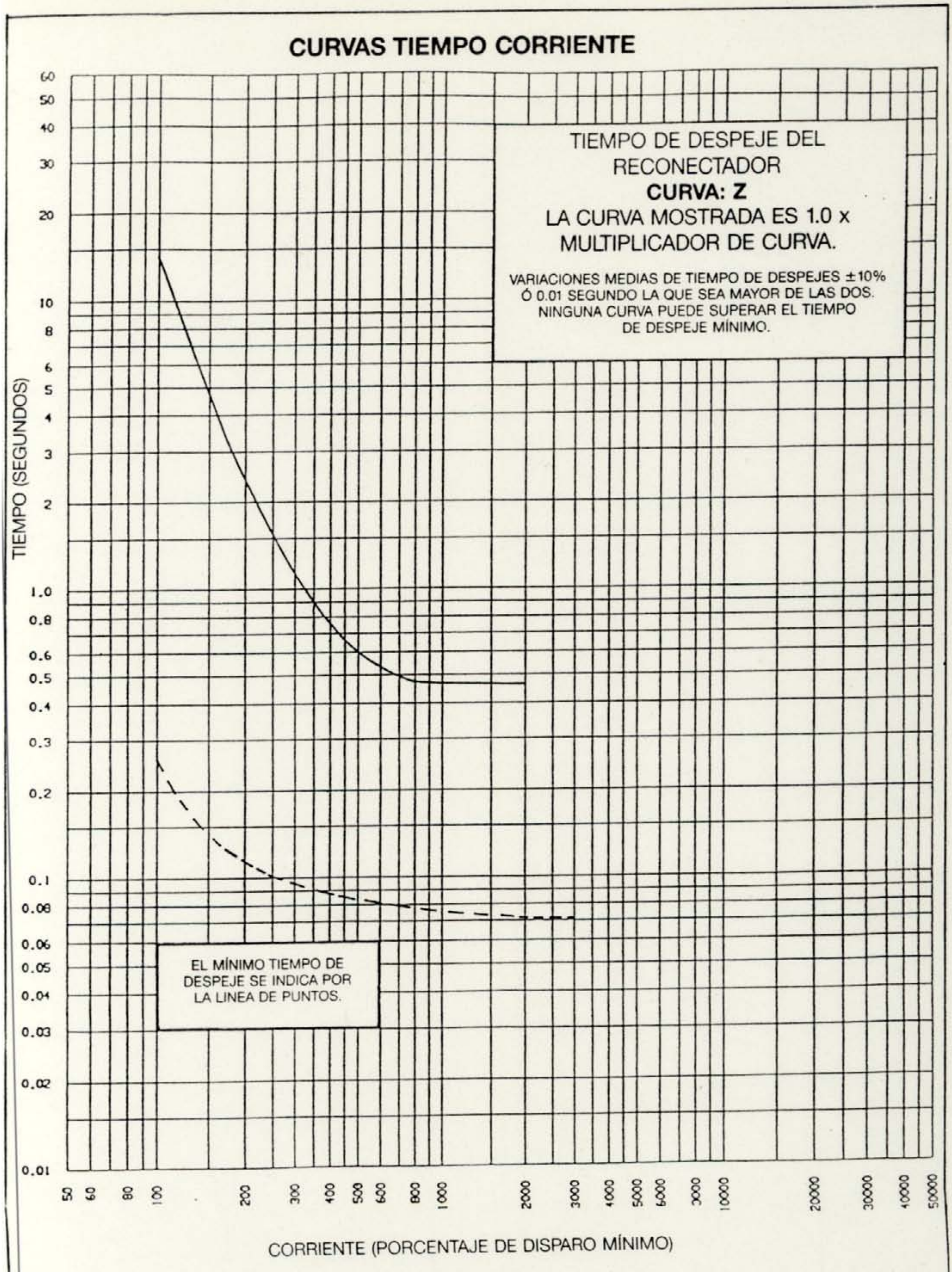
50000
CORRIENTE (PORCENTAJE DE DISPARO MÍNIMO)

CURVA. W.

CURVAS TIEMPO CORRIENTE



CURVA. Y.


CURVAS TIEMPO CORRIENTE
TIEMPO DE DESPEJE DEL
RECONECTADOR
CURVA: Z
LA CURVA MOSTRADA ES 1.0 x
MULTIPLICADOR DE CURVA.
VARIACIONES MEDIAS DE TIEMPO DE DESPEJES ±10%
Ó 0.01 SEGUNDO LA QUE SEA MAYOR DE LAS DOS.
NINGUNA CURVA PUEDE SUPERAR EL TIEMPO
DE DESPEJE MÍNIMO.
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10000
20000
30000
40000
50000
CORRIENTE (PORCENTAJE DE DISPARO MÍNIMO)

CURVA. Z.

ANEXO K

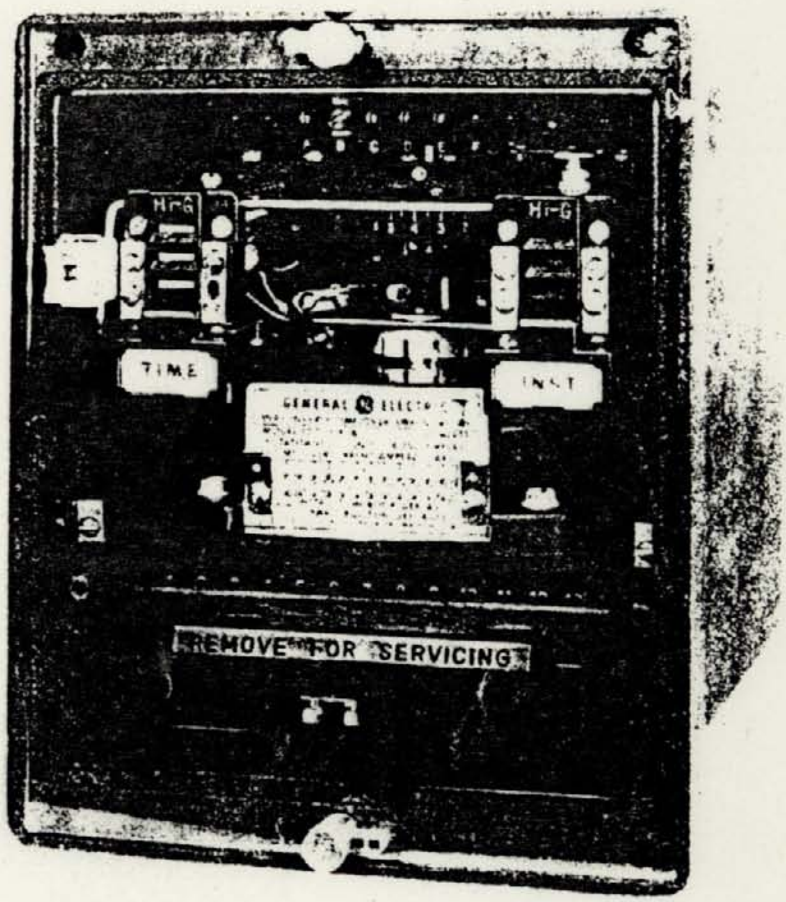
INSTRUCTIONS

GEK-45375 E
Supersedes GEK-45375 D

TIME OVERCURRENT RELAYS

TYPES

IFC51A AND 51B
IFC53A AND 53B
IFC77A AND 77B



GENERAL ELECTRIC

TIME OVERCURRENT RELAYS

TYPES

IFC 51A and 51B
IFC 53A and 53B
IFC 77A and 77B

DESCRIPTION

The type IFC relays covered by these instructions are extended range, single phase, time overcurrent relays. The various time-current characteristics available are as follows:

IFC51A, IFC51B	-	Inverse time
IFC53A, IFC53B	-	Very inverse time
IFC77A, IFC77B	-	Extremely inverse time

The IFC51B, 53B and 77B relays also include a hinged-armature instantaneous overcurrent unit which provides instantaneous tripping at high current levels. The instantaneous unit is not included in the IFC51A, 53A or 77A relays. Both the time overcurrent unit and the instantaneous overcurrent unit are described in detail in the section on CONSTRUCTION. Each relay is equipped with a dual rated target and seal-in unit.

When semiflush mounted on a suitable panel, these relays have a high seismic capability including both the target seal-in unit and the instantaneous overcurrent unit when it is supplied. Also, these relays are recognized under the Components Program of Underwriters Laboratories, Inc.

The relay is mounted in a size C1 drawout case of molded construction. The outline and panel drilling are shown in Figures 23 and 24. The relay internal connections are shown in Figure 4 for the IFC51A, IFC53A and IFC77A, and in Figure 5 for the IFC51B, IFC53B and IFC77B.

APPLICATION

Time overcurrent relays are used extensively for the protection of utility and industrial power distribution systems and frequently for overload backup protection at other locations. The EXTREMELY INVERSE time characteristics, Figure 8 and 22, of the IFC77A and IFC77B relays are designed primarily for use where they are required to coordinate rather closely with power fuses, distribution cutouts and reclosers. They also provide maximum tolerance to allow for cold load pickup. This is the result of an extended service outage which results in a heavy accumulation of loads of automatically controlled devices such as refrigerators, water heaters, water pumps, oil burners, etc. Such load accumulations often produce inrush currents considerably in excess of feeder full load current for a short time after the feeder is energized. The EXTREMELY INVERSE time characteristic often permits successful pickup of these loads and at the same time provides adequate fault protection.

The VERY INVERSE time characteristics, Figure 7 and 21, of the IFC53A and IFC53B relays are likely to provide faster overall protection in applications where the available fault current magnitude remains fairly constant due to a relatively constant generating capacity. The variation in the magnitude of fault current thru the relay is therefore mainly dependent upon the location of the fault with respect to the relay. The INVERSE time overcurrent characteristics, Figure 6 and 20, of the IFC51A and IFC51B relays tend to make the relay operating time less dependent upon the magnitude of the fault current than in the case of VERY INVERSE and EXTREMELY INVERSE devices. For this reason, INVERSE type relays are likely to provide faster overall protection in applications where the available fault current magnitudes vary significantly as a result of frequent changes in the source impedance due to system loading and switching.

The usual application of these relays requires three relays for multiphase fault protection, one per phase, and a separate relay residually connected for single-phase-to-ground faults. Typical external connections for this application are shown in Figure 9. Use of a separate ground relay is advantageous because it can be set to provide more sensitive protection against ground faults.

In the application of these relays with downstream automatic reclosing devices, the relay reset time should be considered. This is the time required for the relay to go from the contacts fully closed position to the fully open position when set at the number 10 time dial. At lower time dial settings the reset times are proportionately lower. The reset time of all VERY INVERSE and EXTREMELY INVERSE relays is approximately 60 seconds. The reset time of all INVERSE relays covered by these instructions is approximately 7 seconds.

These instructions do not purport to cover all details or variations in equipment nor to provide for every possible contingency to be met in connection with installation, operation or maintenance. Should further information be desired or should particular problems arise which are not covered sufficiently for the purchaser's purposes, the matter should be referred to the General Electric Company.

To the extent required the products described herein meet applicable ANSI, IEEE and NEMA standards; but no such assurance is given with respect to local codes and ordinances because they vary greatly.

CONTENTS

When setting these relays to coordinate with downstream relays, a coordination time of from 0.25 to 0.40 seconds is generally allowed, depending on the clearing time of the breaker involved. These coordination times include, in addition to breaker clearing time, 0.10 seconds for relay overtravel and 0.17 seconds for safety factor. For example, if the breaker clearing time is 0.13 seconds (8 cycles), the coordination time would be 0.40 seconds (0.13+0.10+0.17). If the relay time is set by test at the current level in question, the safety factor may be reduced to 0.07 seconds. Then if the downstream breaker time is 5 cycles (0.08 seconds) a minimum of 0.25 seconds (0.08+0.10+0.07) could be allowed for coordination. If relay coordination times are marginal or impossible to obtain, use the relay overtravel curves of Figures 10, 11 or 12 to refine the relay settings. First determine the relay operating time necessary to just match the operating time of the downstream relay with which coordination is desired. Determine the multiple of pickup and the necessary time dial setting to provide this relay operating time. Use the appropriate curve of Figure 10, 11 or 12 to determine the overtravel time in percent of operating time and convert this into real time. Add this time to the breaker time and the safety factor time and the original relay operating time to determine the final relay operating time required. Set the relay to this value.

Once the current in the relay operating coil is cut off the relay contacts will open in approximately six cycles (0.1 second) with normal adjustment of contact wipe. This permits the use of the relay in conjunction with instantaneous reclosing schemes without risk of a false retrip when the circuit breaker is reclosed on a circuit from which a fault has just been cleared.

The instantaneous overcurrent unit present in the IFC51B, IFC53B and IFC77B relays has a transient overreach characteristic as illustrated in Figure 13. This is the result of the DC offset that is usually present in the line current at the inception of a fault. When determining the pickup setting for this unit the transient overreach must be taken into consideration. The percent transient overreach should be applied to proportionately increase the calculated pickup setting so that the instantaneous unit will not overreach a downstream device and thereby cause a loss of coordination in the system protection scheme. The operating time characteristics of this unit are shown in Figure 14.

CONSTRUCTION

The IFC induction disk relays consist of a molded case, cover, support structure assembly, and a connection plug to make up the electrical connection. See Cover Figure and Figures 1,2,3 and 19. Figures 2 and 3 show the induction unit mounted to the molded support structure. This disk is activated by a current operating coil mounted on either a laminated EE or U-Magnet. The disk and shaft assembly carries a moving contact which completes the alarm or trip circuit when it touches a stationary contact. The disk assembly is restrained by a spiral spring to give the proper contact closing current. Its rotation is retarded by a permanent magnet mounted in a molded housing on the support structure.

The drawout connection/test system for the C1 case, shown in Figure 19, has provisions for 14 connection points, and a visible CT shorting bar located up front. As the connection plug is withdrawn, it clears the shorter contact fingers in the output contact circuits first. Thus, the trip circuit is opened before any other circuits are disconnected. Next, current circuit fingers on the case connection block engage the shorting bar (located at the lower front of the case) to short-circuit external current transformer secondary connections. The window provides visual confirmation of CT shorting. The connection plug then clears the current circuit contact fingers on the case and finally those on the relay support structure to completely de-energize the drawout element.

There is a Hi-Seismic target and seal-in unit mounted on the front to the left of the shaft of the time overcurrent unit, see Figure 1. The seal-in unit has its coil in series and its contacts in parallel with the contacts of the time overcurrent unit such that when the induction unit contacts close the seal-in unit picks up and seals in. When the seal-in unit picks up, it raises a target into view which latches up and remains exposed until released by pressing a reset button located on the upper left side of the cover.

The IFC "B" model relays in addition to the above contain a Hi-Seismic instantaneous unit, see Figure 1. The instantaneous unit is a small hinged type unit which is mounted on the front to the right of the shaft of the time overcurrent unit. Its contacts are normally connected in parallel with the contacts of the time overcurrent unit and its coil is connected in series with the time overcurrent unit. When the instantaneous unit picks up it raises a target which latches up and remains exposed until it is released. The same reset button that releases the target seal-in unit also releases the target of the instantaneous unit.

A magnetic shield, depicted in Figure 1, is mounted to the support structure of inverse and very inverse time overcurrent IFC relays, to eliminate the proximity affect of external magnetic materials.

Both the Hi-Seismic target and seal-in unit and the Hi-Seismic instantaneous unit have the letters "Hi-G" molded into their target blocks to distinguish them as Hi-Seismic units. Seismic Fragility Level exceeds peak axial acceleration of 10g's (4g ZPA) when tested using a biaxial multi-frequency input motion to produce a Required Response Spectra (RRS) in accordance with the IEEE Proposed Guide for Seismic Testing of Relays, P501, May, 1977.

RATINGS

The relays are designed for operation in an ambient air temperature from -20°C to +55°C.

TIME OVERCURRENT UNIT

Ranges for the time overcurrent unit are shown in Table 1.

TABLE 1

Relay	Frequency (Hertz)	Current Range (Amperes)
IFC51A & B IFC53A & B IFC77A & B	50 and 60	0.5 - 4.0 1.0 - 12.0

Available taps for the time overcurrent unit are shown in Table 2.

TABLE 2

Range (Amperes)	Taps Available (Amperes)
0.5 - 4.0	0.5, 0.6, 0.7, 0.8, 1.0, 1.2, 1.5, 2.0, 2.5, 3.0, 4.0
1 - 12	1.0, 1.2, 1.5, 2.0, 2.5, 3.0, 4.0, 5.0, 6.0, 7.0, 8.0, 10.0, 12.0

The one second thermal ratings are listed in Table 3.

TABLE 3

Model	Time Overcurrent Unit (Amperes)	One Second Rating Any Tap (Amperes)	K
IFC51	0.5 - 4.0	128	16384
	1.0 - 12.0	260	67600
IFC53	0.5 - 4.0	140	19600
	1.0 - 12.0	260	67600
IFC77	0.5 - 4.0	84	7056
	1.0 - 12.0	220	48400

Ratings less than one second may be calculated according to the formula $I = \sqrt{K/T}$, where T is the time in seconds that the current flows.

The continuous ratings for the time overcurrent unit are shown in Tables 4 and 5.

TABLE 4

0.5 - 4.0 Ampere Range Ratings

Model	Tap										
	0.5	0.6	0.7	0.8	1.0	1.2	1.5	2.0	2.5	3.0	4.0
IFC51	1.6	1.8	2.0	2.1	2.3	2.7	3.0	3.5	4.0	4.5	5.0
IFC53	3.8	4.0	4.2	4.4	4.7	5.0	5.3	5.8	6.2	6.6	7.1
IFC77	2.5	2.7	3.0	3.2	3.6	4.0	4.5	5.2	5.9	6.5	7.5

TABLE 5

1.0 - 12.0 Ampere Range Ratings

Model	Tap											
	1.0	1.2	1.5	2.0	2.5	3.0	4.0	5.0	6.0	7.0	8.0	10.0	12.0
IFC51	3.7	4.1	4.6	5.3	6.0	6.5	7.6	8.5	9.3	10.0	10.8	12.1	13.2
IFC53	6.8	7.1	7.7	8.3	8.8	9.4	10.3	11.0	11.6	12.4	12.6	13.5	14.4
IFC77	5.8	6.4	7.2	8.4	9.4	10.4	12.1	13.6	15.1	16.4	17.6	19.8	21.8

HI-SEISMIC INSTANTANEOUS UNIT

The instantaneous coil is tapped for operation on either one of two ranges (H or L). Selection of the high or low range is determined by the position of the link located on the top of the support structure. See Figure 2 and Table 6.

TABLE 6

Hi-Seismic Instantaneous Unit (Amps)	Link Position	* Range (Amps)	Continuous Rating (Amps)	** One Second Rating (Amps)	K.
2 - 50	L	2 - 10	3.7	130	16,900
	H	10 - 50	7.5		
6 - 150	L	6 - 30	10.2	260	67,600
	H	30 - 150	19.6		

*The range is approximate, which means that the 2-10, 10-50 may be 2-8, 8-50. There will always be at least one ampere overlap between the maximum L setting and the minimum H setting. Whenever possible, always select the higher range, since it has the higher continuous rating.

**Higher currents may be applied for shorter lengths of time in accordance with the formula:

$$I = \sqrt{K/T}$$

Since the instantaneous unit coil is in series with the time overcurrent unit coil, see Tables 3,4, 5 and 6 to determine the current limiting element for both continuous and short time ratings.

HI-SEISMIC TARGET AND SEAL-IN UNIT

Ratings for the target and seal-in unit are shown in Table 7.

TABLE 7

	Tap	
	0.2	2
D.C. Resistance ± 10% (ohms)	8.0	0.24
Min. Operating (Amp.) +0 -60%	0.2	2.0
Carry Continuous (Amperes)	0.3	3
Carry 30 Amps for (Sec.)	0.03	4
Carry 10 Amps for (Sec.)	0.25	30
60 Hz Impedance (Ohms)	68.6	0.73

If the tripping current exceeds 30 amperes an auxiliary relay should be used, the connections being such that the tripping current does not pass through the contacts or the target and seal-in coils of the protective relay.

CONTACTS

The current-closing rating of the contacts is 30 amperes for voltages not exceeding 250 volts. The current carrying rating is limited by the ratings of the seal-in unit.

BURDENS

Burdens for the time overcurrent unit are given in Table 8.

TABLE 8

MODEL	HZ	RANGE	Min Tap Amps	Burdens at Min. Pickup Min. Tap (Ohms)			Burdens in Ohms (Z) Times Pickup		
				R	J_X	Z	3	10	20
IFC51	60	0.5- 4.0	0.5	5.43	21.53	22.20	12.55	5.14	3.29
		1.0-12.0	1.0	1.47	5.34	5.54	3.09	1.28	0.82
IFC53	60	0.5- 4.0	0.5	1.52	4.23	4.50	4.47	3.10	1.93
		1.0-12.0	1.0	0.38	1.06	1.13	1.11	0.78	0.49
IFC77	60	0.5- 4.0	0.5	1.55	2.36	2.82	2.86	2.93	2.76
		1.0-12.0	1.0	0.59	0.43	0.73	0.74	0.75	0.70
IFC51	50	0.5- 4.0	0.5	4.53	17.95	18.50	11.45	4.28	2.70
		1.0-12.0	1.0	1.22	4.45	4.62	2.58	1.07	0.68
IFC53	50	0.5- 4.0	0.5	1.27	3.52	3.75	3.72	2.58	1.61
		1.0-12.0	1.0	0.32	0.88	0.94	0.93	0.65	0.41
IFC77	50	0.5- 4.0	0.5	1.29	1.97	2.35	2.38	2.44	2.30
		1.0-12.0	1.0	0.49	0.36	0.61	0.62	0.63	0.58

Note: The impedance values given are those for minimum tap of each range, the impedance for other taps at pickup current (tap rating) varies inversely, (approximately) as the square of the tap rating. For example, an IFC77 60Hz relay with 0.5 - 4.0 amp range has an impedance of 2.82 ohms on the 0.5 amp tap. The impedance of the 2.0 amp tap is $(0.5/2.0)^2 \times 2.82 = 0.176$ ohms.

The Hi-Seismic instantaneous unit burdens are listed in Table 9.

TABLE 9

Hi Seismic Inst. Unit (Amps)	Hz	Link Position	Range (Amps)	Min Pickup (Amps)	Burdens at Min. Pickup (Ohms)			Burdens In Ohms (Z) Times Pickup		
					R	J_X	Z	3	10	20
2-50	60	L	2-10	2	0.750	0.650	0.992	0.634	0.480	0.457
		H	10-50	10	0.070	0.024	0.074	0.072	0.071	0.070
6-150	60	L	6-30	6	0.110	0.078	0.135	0.095	0.081	0.079
		H	30-150	30	0.022	0.005	0.023	0.022	0.022	0.022
2-50	50	L	2-10	2	0.625	0.542	0.827	0.528	0.400	0.380
		H	10-50	10	0.058	0.020	0.062	0.060	0.059	0.058
6-150	50	L	6-30	6	0.092	0.065	0.112	0.079	0.068	0.066
		H	30-150	30	0.018	0.004	0.019	0.018	0.018	0.018

CHARACTERISTICS

TIME OVERCURRENT UNIT

Pickup

Pickup in these relays is defined as the current required to close the contacts from the 0.5 time dial position. Current settings are made by means of two movable leads which connect to the tap block at the top of the support structure, see Figure 1. The tap block is marked A through J, A through M or A through N. See the nameplate on the relay for tap settings.

Example:

The 2 amp tap for a 1 to 12 IFC77 time overcurrent relay requires one movable lead in position D and the other in position H.

* Operating Time Accuracy

The IFC relays should operate within ±7% or ± the time dial setting times 0.010 seconds, whichever is greater, of the published time curve. Figures 6-8 and 20-22 show the various time-current characteristics for the IFC relays. The setting of the time dial determines the length of time required to close the contacts for a given current. The higher the time dial setting the longer the operating time.

The contacts are just closed when the time dial is set to zero. The maximum time setting occurs when the time dial is set to 10 and the disk has to travel its maximum distance to close the contacts.

Reset

The unit resets at 90% of the minimum closing current. Reset times are proportionate to the time dial settings. The time to reset to the number 10 time dial position when the current is reduced to zero is approximately 60 seconds for the IFC53 and 77 relays. The IFC51 relay will reset in approximately 12 seconds from the same number 10 time dial.

HI-SEISMIC INSTANTANEOUS UNIT

The instantaneous unit has a 25 to 1 range with a tapped coil. There are high and low ranges, selected by means of a link located on the top of the support structure. See Figure 1. The time-current curve for the instantaneous unit is shown in Figure 14.

HI-SEISMIC TARGET AND SEAL-IN UNIT

The target and seal-in unit has two tap selections located on the front of the unit. See Figure 1.

RECEIVING, HANDLING AND STORAGE

These relays, when not included as a part of a control panel, will be shipped in cartons designed to protect them against damage. Immediately upon receipt of a relay, examine it for any damage sustained in transit. If injury or damage resulting from rough handling is evident, file a damage claim at once with the transportation company and promptly notify the nearest General Electric Apparatus Sales Office.

Reasonable care should be exercised in unpacking the relay in order that none of the parts are injured or the adjustments disturbed.

If the relays are not to be installed immediately, they should be stored in their original cartons in a place that is free from moisture, dust and metallic chips. Foreign matter collected on the outside may find its way inside when the cover is removed and cause trouble in the operation of the relay.

ACCEPTANCE TESTS

Immediately upon receipt of the relay an INSPECTION AND ACCEPTANCE TEST should be made to insure that no damage has been sustained in shipment and that the relay calibrations have not been disturbed. If the examination or test indicates that readjustment is necessary, refer to the section on SERVICING.

These tests may be performed as part of the installation or acceptance tests at the discretion of the user.

Since most operating companies use different procedures for acceptance and installation tests, the following section includes all applicable tests that may be performed on these relays.

VISUAL INSPECTION

Check the nameplate to insure that the model number and rating of the relay agree with the requisition.

Remove the relay from its case and check that there are no broken or cracked parts or any other signs of physical damage.

MECHANICAL INSPECTION

1. There should be no noticeable friction when the disk is rotated slowly clockwise. The disk should return by itself to its rest position.
2. Make sure the control spring is not deformed nor its convolutions tangled or touching.
3. The armature and contacts of the seal-in unit as well as the armature and contacts of the instantaneous unit should move freely when operated by hand, there should be at least 1/64" wipe on the seal-in and the instantaneous contacts.
4. The targets in the seal-in unit and in the instantaneous unit must come into view and latch when the armatures are operated by hand and should unlatch when the target release button is operated.
5. Make sure that the brushes and shorting bars agree with the internal connections diagram.
6. CAUTION: Should there be a need to tighten any screws, DO NOT OVER TIGHTEN to prevent stripping.

DRAWOUT RELAY TESTING

The IFC relays may be tested without removing them from the panel by using the 12XCA11A1 four point test probes. The 12XCA11A1 four point test probe makes connections to both the relay and the external circuitry, which provides maximum flexibility, but requires reasonable care since a CT shorting jumper is necessary when testing the relay. The CT circuit may also be tested by using an ammeter instead of the jumper. See the test circuit in Figure 15.

POWER REQUIREMENTS GENERAL

All alternating current operated devices are affected by frequency. Since non-sinusoidal waveforms can be analyzed as a fundamental frequency plus harmonics of the fundamental frequency, it follows that alternating current devices (relays) will be affected by the applied waveform.

Therefore, in order to properly test alternating current relays it is essential to use a sine wave of current and/or voltage. The purity of the sine wave (i.e., its freedom from harmonics) cannot be expressed as a finite number for any particular relay, however, any relay using tuned circuits, R-L or RC networks, or saturating electromagnets (such as time overcurrent relays) would be essentially affected by non-sinusoidal waveforms. Hence a resistance limited circuit, as shown in Figures 16-18, is recommended.

TIME OVERCURRENT UNIT

Rotate the time dial slowly and check by means of a lamp that the contacts just close at the zero time dial setting.

The point at which the contacts just close can be adjusted by running the stationary contact brush in or out by means of its adjusting screw.

With the contacts just closing at No. 0 time setting, there should be sufficient gap between the stationary contact brush and its metal backing strip to insure approximately 1/32" wipe.

The minimum current at which the contacts will just close is determined by the tap setting in the tap block at the top of the support structure. See Characteristic section.

The pickup of the time overcurrent unit for any current tap setting is adjusted by means of a spring-adjusting ring. See Figure 1. The spring-adjusting ring either winds or unwinds the spiral control spring. By turning the ring, the operating current of the unit may be brought into agreement with the tap setting employed, if this adjustment has been disturbed. This adjustment also permits any desired setting intermediate between the various tap settings to be obtained. If such adjustment is required, it is recommended that the higher tap be used. It should be noted that the relay will not necessarily agree with the time current characteristics of Figures 6-8 and 20-22, if the relay has been adjusted to pickup at a value other than tap value, because the torque level of the relay has been changed.

Time Setting

The setting of the time dial determines the length of time the unit requires to close the contacts when the current reaches a predetermined value. The contacts are just closed when the time dial is set on 0. When the time dial is set on 10, the disk must travel the maximum amount to close the contacts and therefore this setting gives the maximum time setting.

The primary adjustment for the time of operation of the unit is made by means of the time dial. However, further adjustment is obtained by moving the permanent magnet along its supporting shelf; moving the magnet toward the disk and shaft decreases the time, while moving it away increases the time.

Pickup Test

Set the relay at 0.5 time dial position and the lowest tap. Using the test connections in Figure 16 the main unit should close the contacts within ±3% of tap value current for 60 Hz relays and within ±7.5% of tap value current for 50 Hz relays.

Time Test

Set the relay at No. 5 time dial setting and the lowest tap. Using the test connection in Figure 16 apply five times tap current to the relay. The relay operating times to close its contact is listed in Table 10.

TABLE 10

Relay	Hz	Time (seconds) Min.	Max.
IFC51	50 and 60	1.75	1.81
IFC53	50 and 60	1.28	1.34
IFC77	50 and 60	0.89	0.95

HI-SEISMIC INSTANTANEOUS UNIT

Make sure that the instantaneous unit link is in the correct position for the range in which it is to operate. See the Internal Connections Diagram Figure 5 and connect as indicated in the test circuit of Figure 17. Whenever possible use the higher range since the higher range has higher continuous rating.

Setting The Hi-Seismic Instantaneous Unit

The instantaneous unit has an adjustable core located at the top of the unit as shown in Figure 1. To set the instantaneous unit to a desired pickup loosen the locknut and adjust the core. Turning the core clockwise decreases the pickup, turning the core counterclockwise increases the pickup. Bring up the current slowly until the unit picks up. It may be necessary to repeat this operation, until the desired pickup value is obtained. Once the desired pickup value is reached, tighten the locknut.

CAUTION - Refer to Table 6 for the continuous and one second ratings of the instantaneous unit. Do not exceed these ratings when applying current to the instantaneous unit.

The range of the instantaneous unit (See Table 6) must be obtained between a core position of 1/8 of a turn of full clockwise and 20 turns counterclockwise from the full clockwise position. Do not leave the core in the full clockwise position.

HI-SEISMIC TARGET AND SEAL-IN UNIT

The target and seal-in unit has an operating coil tapped at 0.2 and 2.0 amperes. The relay is shipped from the factory with the tap screw in the higher ampere position. The tap screw is the screw holding the right hand stationary contact. To change the tap setting, first remove one screw from the left hand stationary contact and place it in the desired tap. Next remove the screw from the undesired tap and place it on the left hand stationary contact where the first screw was removed. See Figure 1. This procedure is necessary to prevent the right hand stationary contact from getting out of adjustment. Screws should never be left in both taps at the same time.

Pickup And Dropout Test

1. Connect relay studs 1 and 2 (See the test circuit of Figure 18) to a DC source, ammeter and load box so that the current can be controlled over a range of 0.1 to 2.0 amperes.

2. Turn the time dial to the ZERO TIME DIAL POSITION.

3. Increase the current slowly until the seal-in unit picks up. See Table 11.

4. Move the time dial away from the ZERO TIME DIAL position, the seal-in unit should remain in the picked up position.

5. Decrease the current slowly until the seal-in unit drops out. See Table 11.

TABLE 11

TAP	PICK-UP CURRENT	DROP-OUT CURRENT
0.2	0.12 - 0.20	.05 or more
2.0	1.2 - 2.0	.50 or more

INSTALLATION

The relay should be installed in a clean, dry location, free from dust, and well lighted to facilitate inspection and testing.

The relay should be mounted on a vertical surface. The outline and panel drillings are shown in Figures 23 and 24. Figure 23 shows the semi-flush mounting and Figure 24 shows various methods of surface mounting.

The internal connection diagrams for the relays are shown in Figures 4 and 5. Typical external connections are shown in Figure 9.

INSTALLATION TESTS

The following tests are to be performed at the time of installation:

Time Overcurrent Unit

Set the tap block to the desired tap setting and the time dial to the 0.5 position. Using the test circuit in Figure 16 gradually apply current until the contacts just close. This value of current is defined as pickup and should be within three percent of tap value for 60 Hz relays and within 7.5 percent of tap value for 50 Hz relays.

Check the operating time at some multiple of tap value and the desired time dial setting. This multiple of tap value may be five times tap rating or the maximum fault current for which the relay must coordinate. This value used is left to the discretion of the user.

Hi-Seismic Target and Seal-In Unit

1. Make sure that the tap screw is in the desired tap.
2. Perform pickup and drop out tests as outlined in the Acceptance Test Section.

Hi-Seismic Instantaneous Unit

1. Select the desired range by setting the link in the proper position. (See Figure 1 and the Internal Connections Diagram). Whenever possible always select the higher range since it has higher continuous rating.
2. Set the instantaneous unit to pick up at the desired current level. See "Setting the Instantaneous Unit" in the "Acceptance Test Section".

All the tests described above under Installation Tests must be performed at the time of installation. In addition, if those tests described under the "Acceptance Tests Section" were not performed prior to installation, it is recommended they be performed at this time.

PERIODIC CHECKS AND ROUTINE MAINTENANCE

In view of the vital role of protective relays in the operation of a power system it is important that a periodic test program be followed. It is recognized that the interval between periodic checks will vary depending upon environment, type of relay and the user's experience with periodic testing. Until the user has accumulated enough experience to select the test interval best suited to his individual requirements it is suggested that the points listed below be checked at an interval of from one to two years.

These tests are intended to insure that the relays have not deviated from their original setting. If deviations are encountered the relay must be retested and serviced as described in this manual.

TIME OVERCURRENT UNIT

1. Perform pickup test as described in the "Installation Section" for the tap setting in service.

2. Perform the time tests as described in the "Installation Section".

HI-SEISMIC INSTANTANEOUS UNIT

1. Check that the instantaneous unit picks up at the desired current level, as outlined in the "Acceptance Test Section".

HI-SEISMIC TARGET AND SEAL-IN UNIT

1. Check that the unit picks up at the values shown in Table 11.

2. Check that the unit drops out at 25% or more of tap value.

CONTACT CLEANING

For cleaning relay contacts, a flexible burnishing tool should be used. This consists of a flexible strip of metal with an etched-roughened surface resembling in effect a superfine file. The polishing action is so delicate that no scratches are left, yet it will clean off any corrosion thoroughly and rapidly. Its flexibility insures the cleaning of the actual points of contact. Do not use knives, files, abrasive paper or cloth of any kind to clean relay contacts.

COVER CLEANING

The lexan cover should only be cleaned with soap and water. If solvents are used that contain hydrocarbons, then the cover may become cloudy.

SYSTEM TEST

Although this instruction book is primarily written to check and set the IFC relay, overall functional tests to check the system operation are recommended at intervals based on the customer's experience.

SERVICING

TIME OVERCURRENT UNIT

If it is found during installation or periodic testing that the time overcurrent unit is out of limits, the unit may be recalibrated as follows:

Pickup Tests

Rotate time dia to No. 0 time dial setting and check by means of a lamp that the contacts just close.

The point at w ic the contacts just close can be adjusted by running the stationary contact brush in or out by means f its adjusting screw. This screw should be held securely in its support.

With the cont cts just closing at No. 0 time setting, there should be sufficient gap between the stationary contac rush and its metal backing strip to insure approximately 1/32" wipe.

The pickup of the unit for any current tap setting is adjusted by means of a spring-adjusting ring. By turning the r ng the operating current of the unit may be brought into agreement with the tap setting employed if for some reason, this adjustment has been disturbed. This adjustment also permits any desired setting intermediate between the various tap settings to be obtained. If such adjustment is required, it is recommended that the higher tap setting be used. It should be noted that the relay will not necessarily agree with the time current characteristics of Figures 6-8 and 20-22, if the relay has been adjusted to pickup at a value other than tap value, because the torque level of the relay has been changed.

Connect the operating coil terminals to a source of the proper frequency and good waveform having a voltage of 110 or more, with resistance load boxes for setting the current. See Test Circuit Figure 16.

With the tap block set for the lowest tap and the time dial set where contacts are just open, adjust the control spring to just close the contacts within the limits given below which are plus and minus 1% of the tap amps. See Table 12.

TABLE 12

Tap Range	Tap	Min. Amps	Max. Amps.
0.5-4	0.5	.495	.505
1.0-12.0	1.0	.99	1.01

It should never be necessary to wind up the control spring adjuster more than 30 degrees (one notch) or unwind it more than 120 degrees (three notches) from the factory setting to obtain the above pickup setting.

Time Tests

With the tap block set for the lowest tap and the time dial at No. 5 setting, apply five times tap current to the relay.

Adjust the position of the drag magnet assembly to obtain an operating time as listed in Table 13.

TABLE 13

Relay	Time (Seconds) Min.	Max.
IFC51	1.76	1.80
IFC53	1.29	1.33
IFC77	0.90	0.94

However, it would be preferable to adjust the operating time as near as possible to 1.78, 1.31 or 0.92 seconds. The drag magnet assembly should be approximately in the middle of its travel. The drag magnet assembly is adjusted by loosening the two screws securing it to the support structure. See Figure 1. Moving the drag magnet towards the disk and shaft decreases the operating time and moving the drag magnet away from the disk and shaft increases the operating time. The screws securing the drag magnet assembly to the support structure must be tight before proceeding with other time checks.

MECHANICAL ADJUSTMENT

The disk does not have to be in the exact center of either air gap for the relay to perform correctly. Should the disk not clear all gaps, the following adjustment can be made.

1. Determine which way the disk must be aligned to clear all gap surfaces by 0.010 inch.
2. Remove the drag magnet assembly by loosening the two screws securing it to the support structure. The screws need not be removed.
3. Loosen the upper pivot bearing set screw (1/16 inch hex wrench) slightly, so the upper pivot can move freely. Do not remove the set screw from the support structure.
4. Loosen the jewel bearing set screw as in 3 above.
5. Apply a slight downward finger pressure on the upper pivot and turn the jewel bearing screw, from the underside of the support structure, to position the disk as determined in 1 above.
6. Turn the jewel bearing screw 1/8 turn clockwise and tighten the upper pivot set screw to 2.5-3.5 inch pounds of torque.
7. Turn the jewel bearing screw 1/8 turn counterclockwise. This will lower the disk and shaft assembly approximately 0.005 inch and permit proper end-play. The shaft must have 0.005-0.010 inch of end-play.

8. Tighten the jewel bearing set screw to 2.5-3.5 inch pounds of torque.

9. Rotate the disk through the electromagnet gap. The disk should clear the gap surfaces by 0.010 inch and be within 0.005 inch flatness. If the disk is not within 0.005 inch flatness the disk should be replaced.

10. Reinstall the drag magnet assembly and check that the disk has at least 0.010 inch clearance from the drag magnet assembly surfaces.

11. Tighten the drag magnet assembly mounting screws with 7-10 inch pounds of torque, after securely seating the assembly and positioning it according to the Time Test above.

HI-SEISMIC INSTANTANEOUS UNIT

1. Both contacts should close at the same time.

2. The backing strip should be so formed that the forked end (front) bears against the molded strip under the armature.

3. With the armature against the pole piece, the cross member of the "T" spring should be in a horizontal plane and there should be at least 1/64" wipe on the contacts. Check this by inserting a 0.010" feeler gage between front half of the shaded pole with the armature held close. Contacts should close with feeler gage in place.

4. Since mechanical adjustments may affect the Seismic Fragility Level, it is advised that no mechanical adjustments be made if seismic capability is of concern.

HI-SEISMIC TARGET AND SEAL-IN UNIT

Check 1 and 2 as described under Instantaneous Unit.

To check the wipe of the seal-in unit, insert a 0.010" feeler gage between the plastic residual of the armature and the pole piece with the armature held closed. Contacts should close with feeler gage in place. Since mechanical adjustments may affect the Seismic Fragility Level, it is advised that no mechanical adjustments be made if seismic capability is of concern.

RENEWAL PARTS

It is recommended that sufficient quantities of renewal parts be carried in stock to enable the prompt replacement of any that are worn, broken or damaged.

When ordering renewal parts, address the nearest Sales Office of the General Electric Company, specify quantity required, name of the part wanted, and the complete model number of the relay for which the part is required.

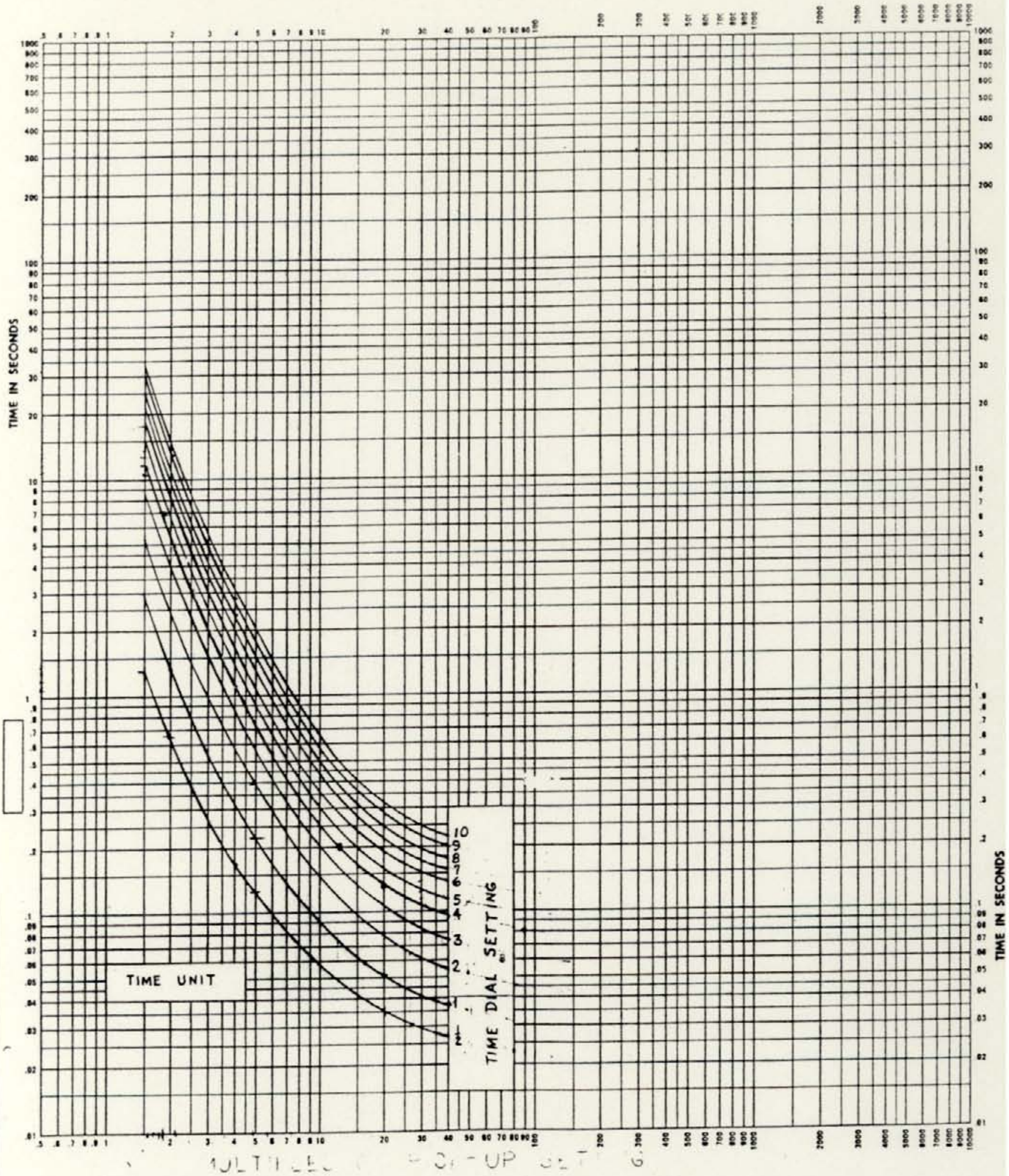


FIGURE 8 (0108B8945-1) 60 HERTZ TIME-CURRENT CHARACTERISTICS FOR RELAY TYPES

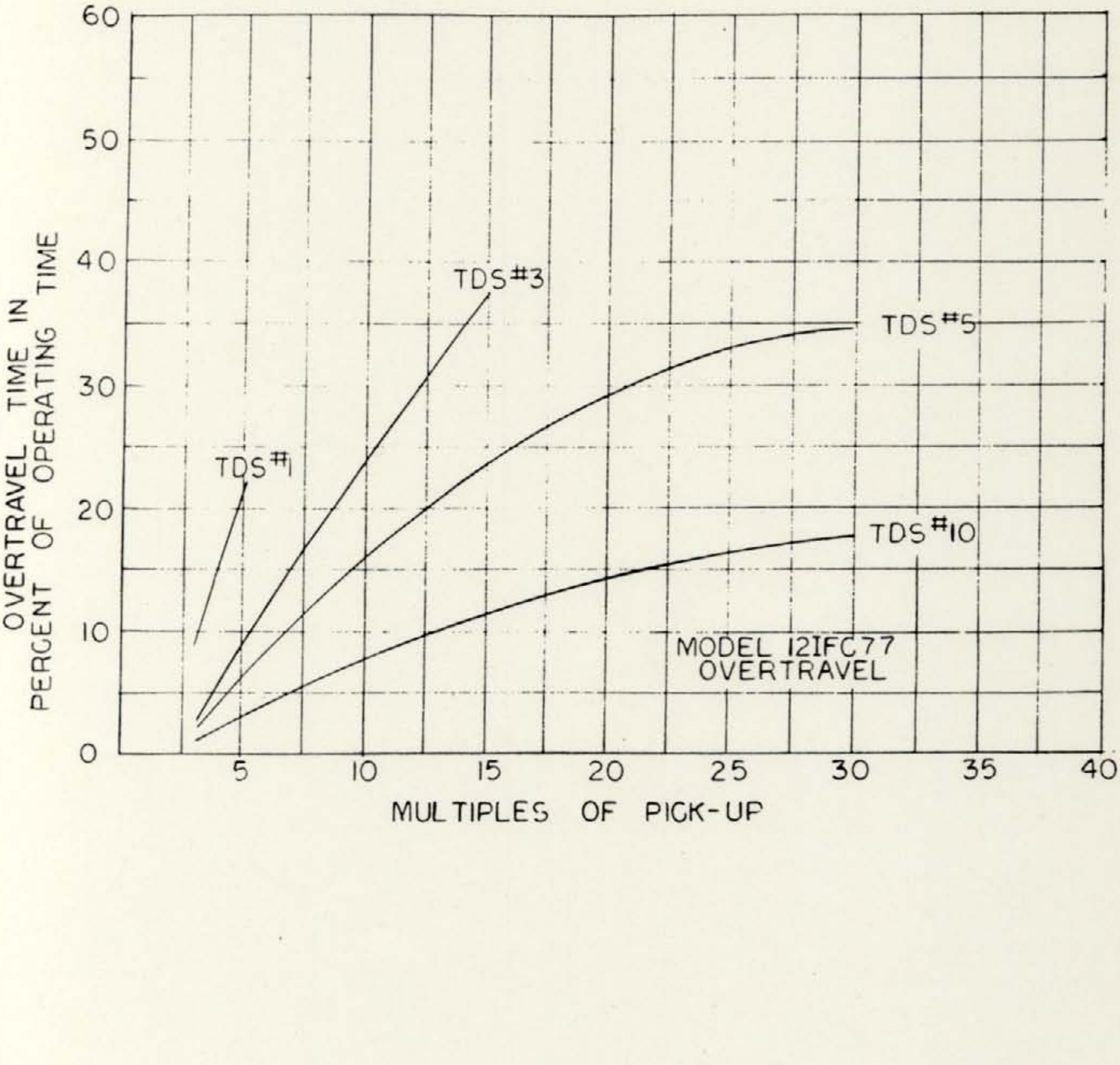


FIGURE 12 (0257A8596-0) OVERTRAVEL CURVES FOR RELAY TYPE IFC77

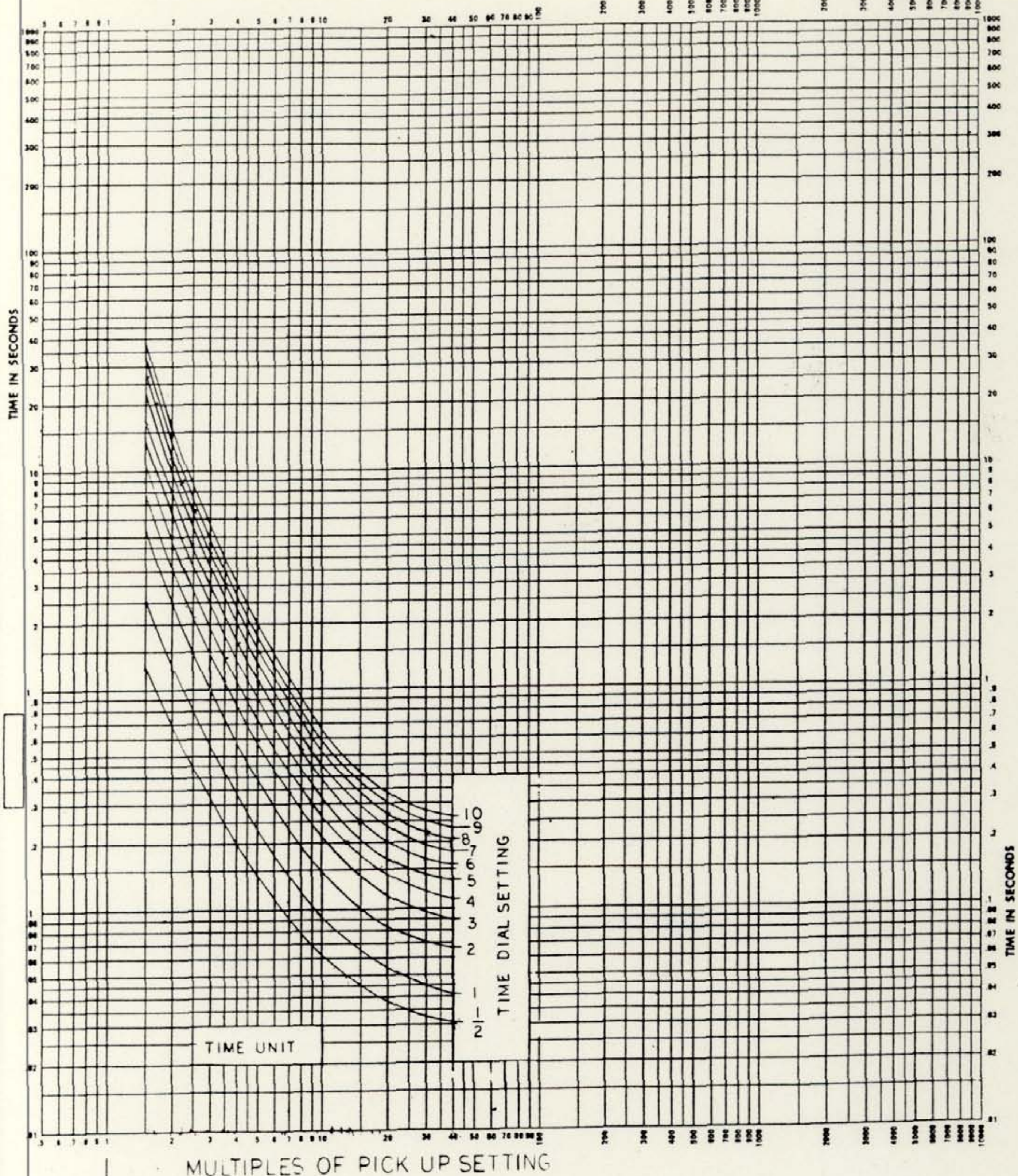


FIGURE 22 (0108B8975-0) 50 HERTZ TIME-CURRENT CHARACTERISTICS FOR RELAY TYPES IFC77A AND ...

ANEXO L

Sectionalizers

COOPER
Cooper Power Systems

Electronically Controlled; Manually Closed Types GN3E and GN3VE

GENERAL

A sectionalizer is an automatic circuit-opening device. After a circuit has been deenergized by a backup protective device—such as a recloser or reclosing breaker—a sectionalizer isolates the faulted portion of a distribution line. After the fault has been isolated, the rest of the circuit is returned to service upon reclosure of the backup.

The sectionalizer counts the overcurrent interruptions of the backup and can be set to open after one, two, or three counts have been registered within a predetermined time span. A sectionalizer opens during the open interval of the backup. Although it cannot interrupt faults, it can be closed into them.

Sectionalizers can be used in place of fuses or between a reclosing device and a fuse. They only detect current interruptions above a predetermined level and have no time-current characteristics, permitting easy coordination with other protective devices on the system. They provide additional protection without adding a coordination step to the protective scheme.

Sectionalizers provide several advantages over fuse cutouts:

- In addition to application flexibility, they offer safety and convenience;
- After a permanent fault, the fault-closing capability of the sectionalizer greatly simplifies circuit testing;
- If a fault is still present, interruption takes place safely at the backup recloser;
- Replacement fuse links are not required so the line can be tested and service restored with more speed, convenience, and economy;
- Sectionalizers do not open accidentally under load due to a damaged link;
- The possibility of error in the selection of the correct fuse link size and type is eliminated.

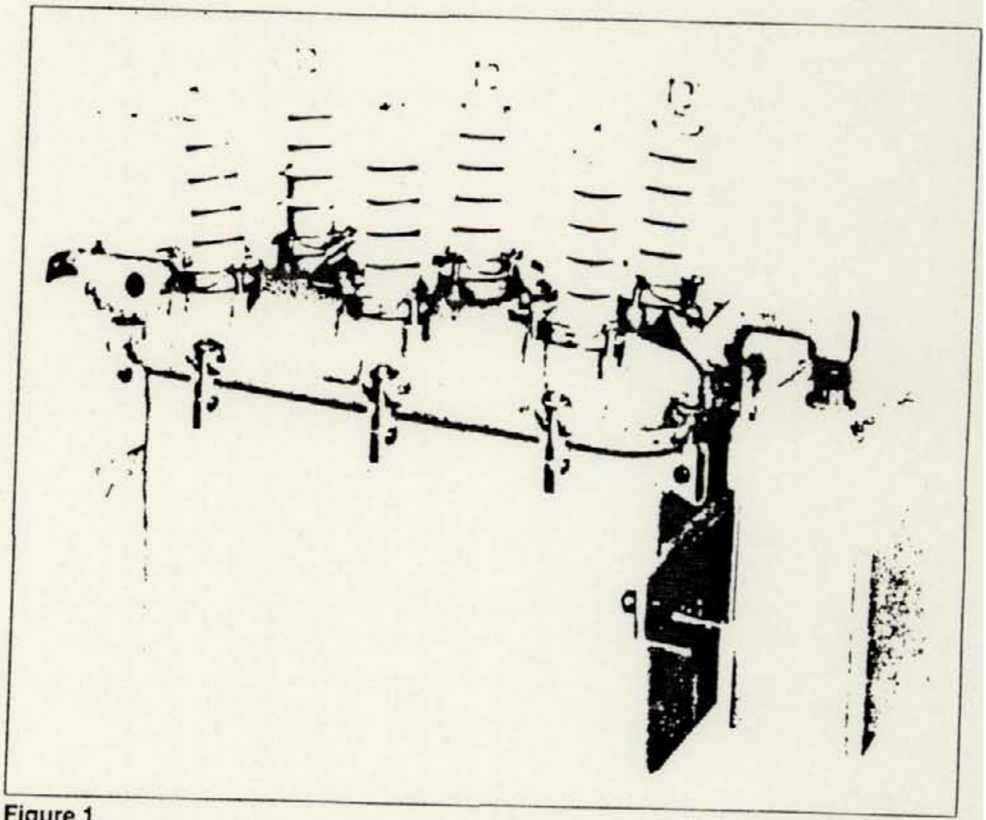


Figure 1.
Kyle® Type GN3E three-phase electronically controlled sectionalizer.

TABLE 1
Basic Ratings of Types GN3E and GN3VE Sectionalizers

Type	Nominal Voltage (kV)	Rated Max Voltage (kV)	Max Continuous Current (amps)	Max Interrupting Loadbreak Current (amps)	Max Momentary and Making Current (asymmetrical amps)	BIL (kV)
GN3E	14.4	15.5	200	440	9000	110
GN3VE	24.9	27	200	440	9000	125

SUMMARY OF RATINGS

The solid-state electronic control used in the Type GN3E (Figure 1) and GN3VE three-phase sectionalizers provides accurate and reliable operation down to 16 amps on phase-fault and 3.5 amps on ground- (earth-) fault detection. Operation is unaffected over a wide range of ambient temperatures. Basic ratings are shown in Table 1.

The sectionalizer is self-contained. Current transformers—internally mounted on the bushings—provide power to operate the electronic control and the trip mechanism. Since these CTs obtain power from the line, no external source of auxiliary power is required.

ORDERING INFORMATION

When ordering a Type GN3E or a GN3VE sectionalizer, include catalog number and description of basic sectionalizer and the phase and ground minimum-actuating-current plug-in resistors. A set (one each) of the phase and ground minimum-actuating-current plug-in resistors is included in the price of the basic sectionalizer. Also specify the operating settings for the inrush-current restraint. If accessories and/or mounting equipment are required, specify by catalog number and description. Prices of the sectionalizers, accessories, and mounting equipment are in Catalog 270-01, Part 15.

Types GN3E and GN3VE Sectionalizers

TABLE 2
Basic Types GN3E and GN3VE Sectionalizers

Description	Catalog Number
Type GN3E sectionalizer set for:	
One count to open........	KGN3EB1
Two counts to open	KGN3EB2
Three counts to open	KGN3EB3
Type GN3VE sectionalizer set for:	
One count to open........	KGN3VEB1
Two counts to open	KGN3VEB2
Three counts to open	KGN3VEB3

TABLE 3
Phase and Ground Minimum Actuating-Current Plug-In Resistors

Type	Minimum Actuating Current Rating (amps)	Catalog Number
Phase	16, 24, 40, 56, 80, 112, 160, 224, 256, 296, or 320	KGN123E_*
Ground	3.5, 7, 16, 28, 40, 56, 80, 112, 160, 224, 320, or BLO (block) ..	KGN124E_*

*Complete the catalog number by inserting the value (amps) of the required minimum-actuating current

TABLE 4
Operating Settings for Inrush-Current Restraint

Description	Available Settings
Phase-actuating current multiplier	2X, 4X, 6X, 8X, or BLOCK
Phase-inrush reset (duration the phase actuating current is to be raised)	5, 10, 15, or 20 cycles (60 Hz base)
Ground inrush reset (duration the ground sensing is to be blocked)	0.3, 0.7, 1.5, 3.0 or 5.0 seconds

ACCESSORIES AND MOUNTING EQUIPMENT

TABLE 5
Bushings; Factory-Installed

Description	Catalog Number
17-inch creepage bushings	KA18GN3

TABLE 6
Multi-Ratio Bushing-Current Transformers for Field Installation; 600:5 for Metering

Description	Catalog Number
Slip-on bushing current transformer kit; one BCT per kit	KA712L1

TABLE 7
Mounting Equipment

Description	Catalog Number
Double-crossarm bracket or substation hanger	KA19H3
Broad-side pole-mounting hanger	
Type GN3E	KA116H3
Type GN3VE	KGN50E
Surge arrester mounting bracket for KA116H3 hanger	KA126H3

Features and Detailed Description

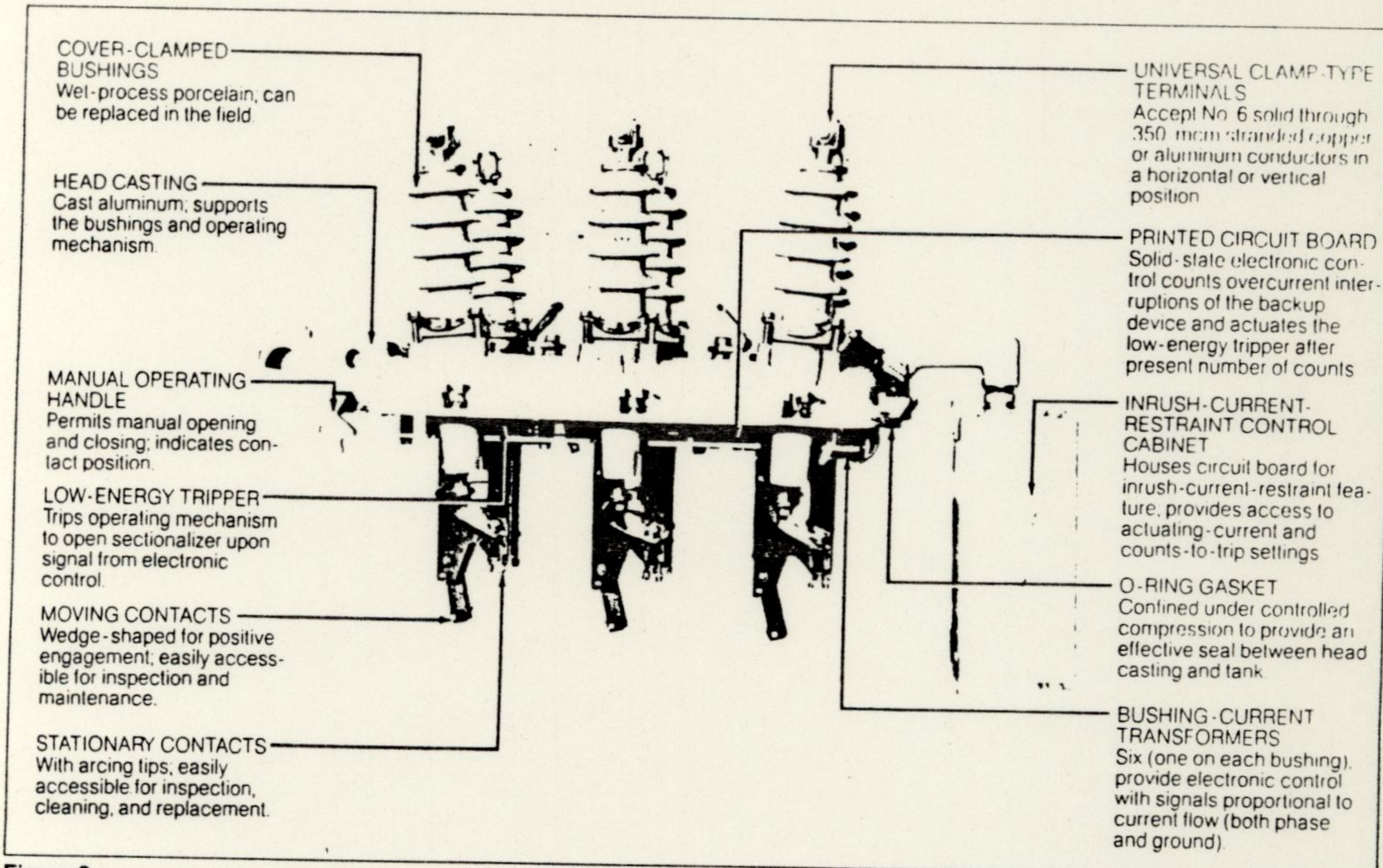


Figure 2.
Untanked Type GN3E sectionalizer.

Sectionalizers provide an economical method to further improve service on distribution lines equipped with reclosers or reclosing circuit breakers by isolating permanent faults, thus confining outages to smaller sections of line.

Sectionalizers are applied on the load side of the fault-interrupting device and count its fault-trip operations. They open during the first, second, or third open interval of the backup protective device, depending upon the coordination scheme selected. Sectionalizers are not designed to interrupt fault currents. They can, however, be closed in against a fault. The sectionalizer will forget counts that do not reach its counts-to-open setting due to clearing of temporary faults.

When properly applied, a sectionalizer will respond to downline fault currents that are interrupted by its backup protective device. However, as with any other protective device, system conditions may produce unexpected and unwanted sectionalizer operation.

Overcurrents interrupted by a downline protective device are one cause for these occurrences; inrush current is another. Count-restraint and inrush-current restraint features are built into the electronic control to block the sectionalizer's response to these system conditions.

OPERATION

The Type GN3E or GN3VE sectionalizer is a three-phase device that opens all three phases simultaneously for either a phase or ground fault or when used as a loadbreak switch. Three sets of oil-insulated contacts are connected by bellcranks to a common operating mechanism. A low-energy tripping mechanism—operated by the electronic control—initiates opening. Opening energy is provided by springs, charged when the sectionalizer is manually closed.

The sectionalizer senses overcurrent interruptions and opens after one, two, or three such interruptions have occurred. When a current above the preset actuating level of the sectionalizer is interrupted by a backup protective device, a count pulse is generated and registered in the electronic control. If the preset number of counts is registered within one minute, the sectionalizer will open during the open interval of the backup device (when no current is flowing in the circuit).

The sectionalizer is completely self-contained. Power to operate the control and low-energy tripper is obtained from the line through bushing current transformers (mounted under the head) which sense the phase- and ground-fault currents. No auxiliary power supply is required.

The solid-state electronic control provides the operating logic for automatic opening. Closing is accomplished by manually closing the yellow operating handle under the sleet hood. The sectionalizer may also be manually opened with this handle which also provides a positive visual indication of contact position.

ELECTRONIC CONTROL

A functional block diagram of the electronic control circuitry is shown in Figure 3.

Bushing current transformers (BCTs) sense the current flowing through the sectionalizer. Three transformers connected in a wye (star) configuration sense phase currents. Three additional BCTs, connected in parallel, sense the ground- (earth-) or zero-sequence current. By selecting the proper plug-in resistors, these signals can be rectified and adjusted to the desired minimum actuating-current level.

To generate and register a count pluse, a current above the preset minimum actuating level must be flowing through the sectionalizer (downline fault). This overcurrent must drop to zero (fault interrupted by the backup protective device). The pulse counter provides storage for up to three pulses. Depending upon the counts-to-open setting, the tripping circuit will turn on after one, two, or three count pulses have been registered. When turned on, the tripping circuit completes the discharge path for the trip-energy-storage capacitors through the coil of the low-energy tripper which, in turn, trips the sectionalizer mechanism to open the sectionalizer contacts.

The pulse counter has a 60-second memory for each count. Thus, the preset number of counts must be registered within one minute for the sectionalizer to open. The control will reset (completely forget the registered count pulses that do not reach the preset number) within 7 minutes.

Types GN3E and GN3VE electronic sectionalizers contain a count-restraint feature. This feature prevents the sectionalizer from counting fault currents interrupted by a downline protective device. The current restraint will block the generation of a count pulse as long as at least 3½ amps of load current are flowing through the sectionalizer after the fault current disappears.

The sectionalizer is also equipped with an inrush-current restraint feature which distinguishes between inrush current and fault current by a logic circuit functionally diagrammed in Figure 4.

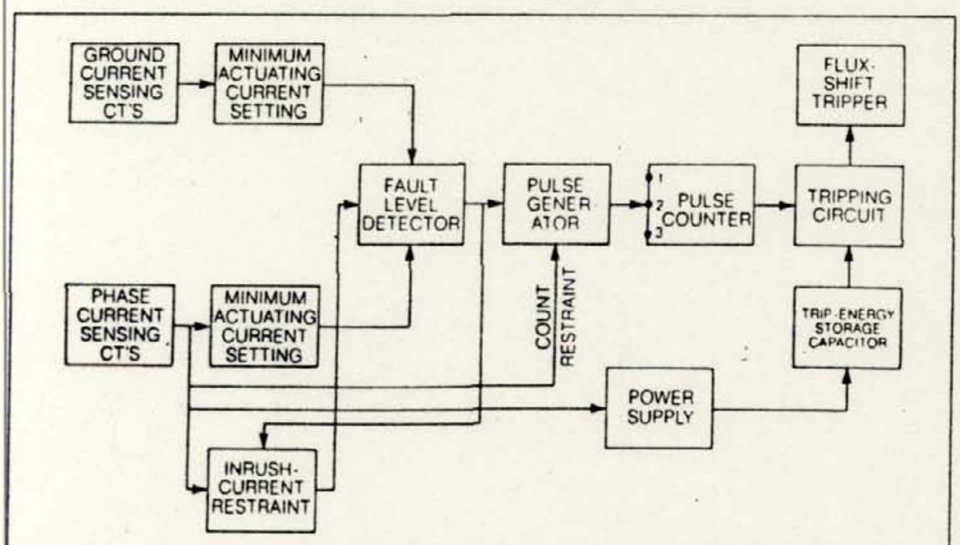


Figure 3.
Functional block diagram of electronic control for Types GN3E and GN3VE sectionalizers.

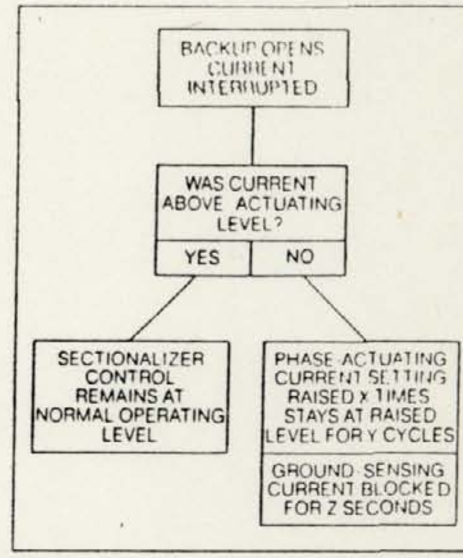


Figure 4.
Logic diagram for inrush-current-restraint feature.

If an overcurrent is present through the sectionalizer when the backup protective device opens (current is interrupted), the overcurrent present upon reclosing is assumed to be fault current and the sectionalizer control operates in its normal manner. If, however, there is no overcurrent detected by the sectionalizer when the current is interrupted, the overcurrent present upon reclosing is assumed to be inrush current. To prevent the sectionalizer from counting this inrush current, the fault-level detector circuit is modified to raise the phase-actuating level by a multiple of 2X, 4X, 6X, or 8X the normal setting (or current detection can be blocked entirely) for a time (Y) of 5, 10, 15, or 20 *cycles* after current flow through the sectionalizer is restored. After this time, the sectionalizer control returns to normal operating settings. At the same time, ground overcurrent detection is blocked entirely for a period (Z) of 0.3, 0.7, 1.5, 3, or 5 *seconds* after current flow through the sectionalizer is restored.

On multi-grounded-wye systems, the entire transient inrush of a particular phase could flow in the neutral. Typical settings for ground-fault sensing on these systems is one-half or less of phase-fault sensing. This could result in values at least twice those necessary for phase magnitude and duration (X and Y). With the improved ground inrush logic, ground sensing is simply blocked for the duration of the Z selected.

Trip-Energy Storage Capacitors

The control is powered by the load and/or fault current flowing through the sectionalizer. This also charges the trip-energy-storage capacitors. For most cases, the charging time of the capacitors (Figure 5) is less than the clearing time of the Kyle® three-phase reclosers with which the GN3E and GN3VE sectionalizers are specifically intended to coordinate. Some recloser fast-trip curves may have a faster clearing time at their low end than the capacitor charging time. These exceptions are listed in Table 8 (Phase Trip Coordination) and Table 9 (Ground Trip Coordination).

To verify proper coordination between the sectionalizer and its backup protective device, the charge time of the trip-energy-storage capacitors (Figure 5) can be plotted against the clearing-time curve of the backup device. Note that the capacitor charge-time curve is plotted in amps, **not** in % of minimum actuating current.

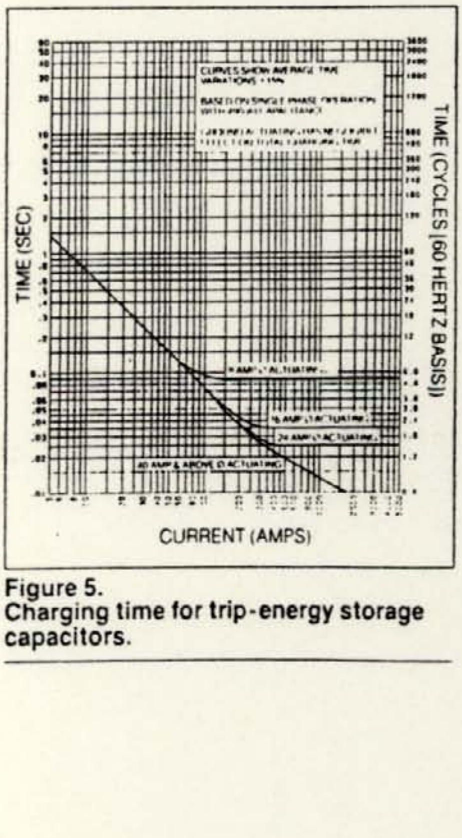


Figure 5.
Charging time for trip-energy storage capacitors.

Count-Restraint Feature

The count-restraint feature blocks the sectionalizer from generating a count pulse as long as some load current flows through the sectionalizer. Thus, the sectionalizer does not count or operate when a load-side device interrupts the overcurrent.

Figure 6 shows a typical application with the sectionalizer located between two reclosers.

For a fault (F1) beyond the load-side recloser (ACR2), only the load-side recloser operates. The sectionalizer does not generate a count because the load current through the sectionalizer is not interrupted. For a load-side fault (F2) interrupted by the source-side recloser (ACR1), the sectionalizer counts the fault interruption since the load current through the sectionalizer is interrupted.

The count-restraint feature is designed to operate with a minimum of 3½ amps load current through the sectionalizer. It is a standard feature of all GN3E and GN3VE electronically controlled sectionalizers.

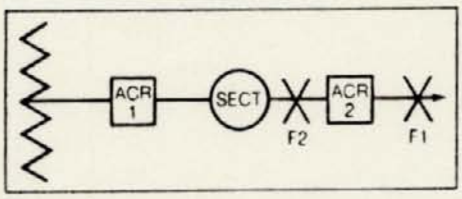


Figure 6.
Typical application of sectionalizer located between two reclosers.

Inrush-Current Restraint Feature

One of the principal causes for unwanted sectionalizer operation is inrush current. If the backup device interrupts a fault on the downline side of the sectionalizer, the sectionalizer will generate and register a count pulse in the normal manner. If the fault is interrupted by a downline protective device, the count-restraint feature will block the generation of a count pulse if at least 3½ amps of uninterrupted load current flows through the sectionalizer.

For a fault on the source side of the sectionalizer (Figure 7), the backup device will trip and deenergize the circuit. However, if upon circuit reenergization, the inrush current through the sectionalizer is greater than its minimum actuating current setting, a second trip operation of the backup device will defeat the count-restraint feature (load current is interrupted) and cause the sectionalizer to generate and register a count.

The inrush-current restraint feature distinguishes between inrush current and fault current by means of a logic circuit previously described. It prevents false counting and operation of the sectionalizer due to inrush currents through the sectionalizer during operation of the source-side protective device.

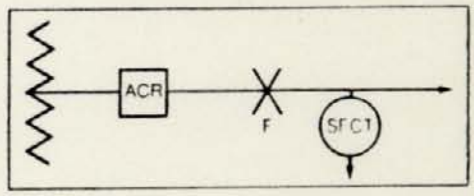


Figure 7.
Typical application showing a fault on the source side of the sectionalizer.

Low-Energy Tripping Mechanism

The low-energy tripping mechanism, operated from the electronic control, initiates the automatic-opening operation. The mechanism consists of a permanent magnet, and a solenoid and coil assembly which operate a trip lever (Figure 8).

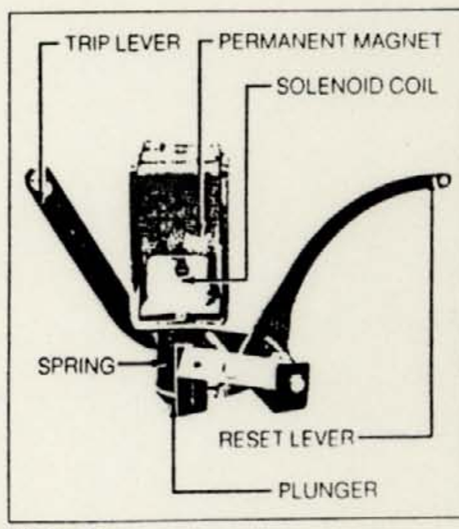


Figure 8.
Low-energy tripping mechanism.

When the sectionalizer is closed, the solenoid's plunger is held by the magnetic force produced by the permanent magnet. In this position, the compressed spring is acting to release the plunger.

During the opening operation, the trip-energy-storage capacitors are connected across the coil of the solenoid. The counter-magnetic flux produced by the discharge of the capacitors is great enough for the compressed spring to override the net magnetic force, pull down the plunger to operate the trip lever, and open the sectionalizer contacts. As the sectionalizer contacts are opened, the spring-biased reset lever of the tripping mechanism is released to return the solenoid plunger and reset the assembly for the next opening operation.

APPLICATION REQUIREMENTS

The following basic coordinating principles should be observed in the application of Types GN3E and GN3VE electronically controlled sectionalizers:

1. For both phase and ground currents, the minimum actuating-current setting of the sectionalizer should be approximately 80% of the minimum trip-current setting of the backup recloser or reclosing breaker.
2. The counts-to-open setting of the sectionalizer must be at least one less than the number of operations to lockout of the backup device.
3. Total accumulated time (TAT) for the operation of the backup fault-interrupting device must not exceed one minute betweeen each operation. TAT is counted from the backup device's first trip operation to the trip operation which causes the sectionalizer to open.
4. To assure that the trip-energy-storage capacitors are fully charged before the backup trips, the clearing time of the backup device must be greater than the charging time of the trip-energy-storage capacitors. The charging time-current curve for the trip-energy-storage capacitors is shown in Figure 5.
5. To operate the count-restraint feature, a minimum of 3½ amps of load current must normally flow through the sectionalizer.
6. The momentary and short-time ratings of the sectionalizer must not be exceeded.
7. Three-phase sectionalizers must be used with backup breakers or reclosers in which all three phases open simultaneously. The counting functions of the sectionalizer do not recognize a signal as originating in a particular phase, but total the overcurrent interruptions in all three phases. Non-simultaneous three-phase tripping of the backup device could result in the sectionalizer interrupting fault current in one or more phases.
8. Application on multi-grounded-wye systems generally requires ground-fault sensing and inrush-current restraint. Setting the phase actuating level to the ground setting of the backup device may result in erroneous counts due to inrush currents and incorrect opening of the sectionalizer for source-side faults.

Application of Inrush-Current Restraint

Sectionalizers can be applied where the main feeder is divided into two feeders close to the substation (Figure 9). Inrush current will be a problem here, since the load current (and connected transformer capacity) is close to the operating settings of the sectionalizer.

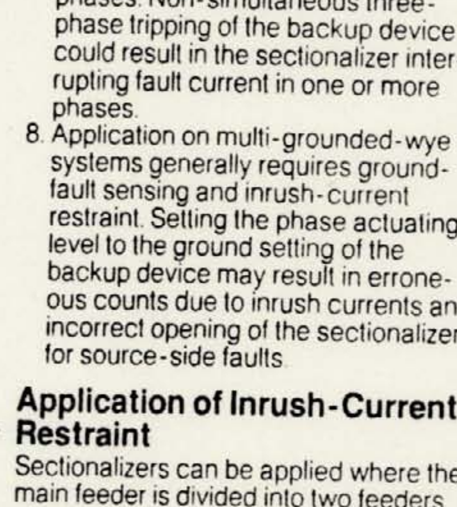


Figure 9.
Sectionalizer application: Main feeder is divided into two feeders close to the substation.

A sectionalizer may also be applied to protect an important branch which may be carrying only a small portion of the total load (Figure 10). Although this example will result in fewer inrush-current problems that the previous application, inrush-current considerations should not be ignored here.

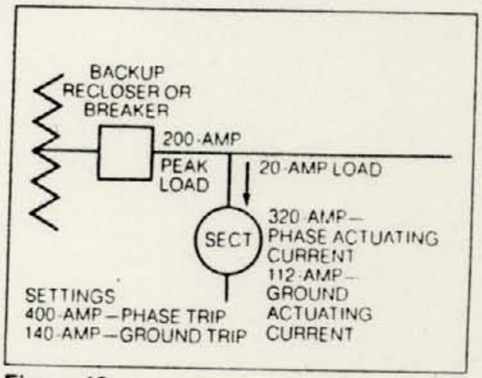


Figure 10.
Sectionalizer application: Sectionalizer protects a branch which carries only a small portion of the total load.

The typical sectionalizer settings shown in these illustrations are identical for both applications since they are based on the settings of the backup device.

To prevent false operation, the inrush-restraint function should be programmed so that:

1. The Multiplier setting exceeds the expected inrush current (cold-load pickup and/or transformer magnetizing);
2. The inrush current decays to below the normal actuating current setting of the sectionalizer within the duration of the Reset setting.

SECTIONALIZER SETTINGS

For proper sectionalizer operation, the following settings must be specified on the order:

- Minimum phase-actuating current.
- Minimum ground-actuating current.
- Number of overcurrent counts to open.
- Multiple of phase minimum-actuating current.
- Duration of raised phase current sensing.
- Duration of ground current-sensing block.

Minimum-Actuating Current

To assure that the sectionalizer will sense and count every fault-trip operation of its backup protective device, the minimum-actuating phase- and ground-trip setting should be approximately 80% of the comparable minimum-trip values of the backup device. However, in a few instances, the lower end of the backup recloser's fast-trip curve may be faster than the charging time of the trip-energy-storage capacitor, and proper coordination may not be attained.

The minimum-trip levels of the recloser fast curves in question and the comparable minimum-actuating levels of the sectionalizer to attain proper coordination are listed in Tables 8 and 9. Below these levels, the Type GN3E or GN3VE sectionalizer may not count the fast-curve operation.

The minimum actuating-current level is determined by plug-in resistors located on the inrush-current-restraint circuit board housed in the control cabinet (Figure 11).

TABLE 8
Phase Trip Coordination

Recloser Type	Recloser Minimum-Trip Current (amps)	Sectionalizer Minimum-Actuating Current (amps)
R, RX, RV, W, WV, VW, VWV	100 (A Curve)	80
RE, RXE, RVE, WE, WVE, VWE, VWVE	100 (A Curve)	80

TABLE 9
Ground Trip Coordination

Device	Minimum-Trip Current (amps)	Sectionalizer Minimum-Actuating Current (amps)
Hydraulic recloser with KA510R hydraulic ground-trip accessory	110 (1 Curve)	80
Hydraulic recloser with KA1144R electronic ground-trip accessory	100 (1 Curve) 50 (2 Curve) 20 (3 Curve) 10 (4 Curve)	80 40 16 7
Electronic recloser with ground trip on ME control	100 (1 Curve) 50 (4 Curve)	80 40

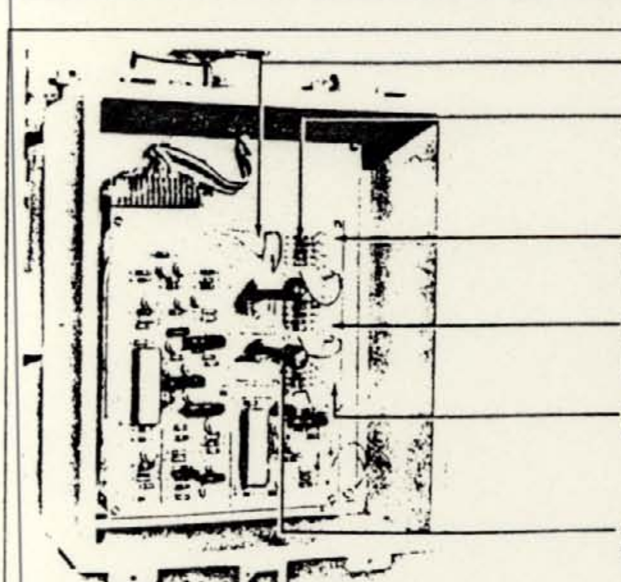


Figure 11.
Sectionalizer settings are located on the printed circuit board in the control cabinet.

The available minimum actuating-current-level values for both phase and ground have been selected to coordinate with the more popular recloser trip settings. The following values are available for phase sensing: 16, 24, 40, 56, 80, 112, 160, 224, 256, 296, and 320 amps. For ground sensing, the values available are 3.5, 7, 16, 28, 40, 56, 80, 112, 160, 224, and 320 amps.

NOTE: If the backup protective device does not include ground-fault trip, a dummy plug-in resistor is used to deactivate the ground-sensing circuits of the sectionalizer control. See ORDERING INFORMATION for proper catalog number.

Number of Counts to Open

The number of overcurrent counts to open should be at least one less than the number of trips to lockout of the backup device. One, two, or three counts are available.

This setting is determined by attaching the jumper wire to the proper terminal tab on the same printed-circuit board that holds the phase and ground plug-in resistors (Figure 11).

Inrush-Current Restraint

Whenever circuit logic determines that the overcurrent is inrush current, this feature raises the minimum phase-actuating-current level of the sectionalizer by a multiple X (2, 4, 6, or 8 times) or blocks overcurrent detection entirely for a period of time Y (5, 10, 15, or 20 cycles) after current flow through the sectionalizer is restored. At the same time, ground overcurrent detection is also blocked entirely for a period Z (0.3, 0.7, 1.5, 3, or 5 seconds). To operate effectively, the values selected for X, Y, and Z should exceed the time-current parameters of the expected inrush currents.

With the inrush-current restraint set on BLOCK for phase-sensing and the ground-sensing circuit normally operating on block, the sectionalizer will not count a system fault interrupted by the backup device within the block time span.

The settings for raising the phase-current-actuating level, the duration of this raised level, and the duration of ground-current block are made by attaching jumper wires to the proper terminal tabs on the inrush-current restraint circuit board. This circuit board is housed in the control cabinet at the back of the sectionalizer (Figure 11).

RATINGS AND SPECIFICATIONS

TABLE 10
Basic Data for Types GN3E and GN3VE Sectionalizers

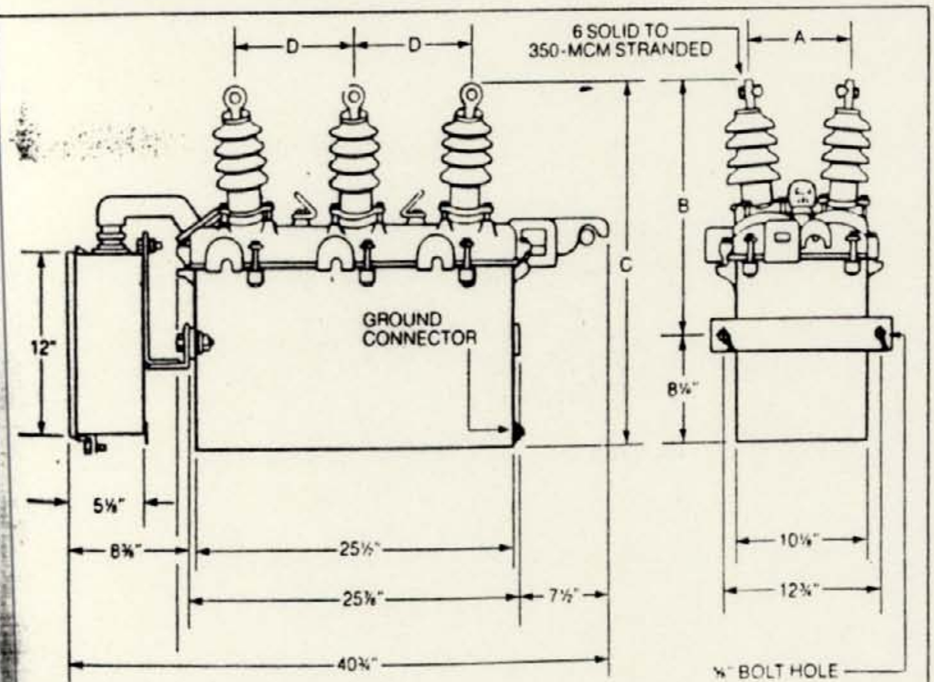
	Type GN3E	Type GN3VE
Nominal operating voltage (kV rms)	14.4	24.9
Max rated voltage (kV rms)	15.5	27
Impulse withstnad (BIL) 1.2 x 50μsec wave (kV crest)	110	125
60 Hz withstand (kV rms)		
Dry, 1 min	50	60
Wet, 10 sec	45	50
Rated continuous current (amps)	200	200
Rated symmetrical load interrupting current (rms amps)	440	440
Rated making current (rms amps; asymmetrical)	9000	9000
Short-time ratings (rms amps)		
10 sec, symmetrical	2600	2600
1 sec, symmetrical	5700	5700
Momentary, max, asymmetrical	9000	9000

TABLE 11
Control Data for Types GN3E and GN3VE Sectionalizers

Minimum Actuating-Current Settings (amps)		Number of Counts to Open	Memory Time* (sec)	Reset Time** (minutes)
Phase-Sensing	Ground-Sensing			
16, 24, 40, 56, 80, 112, 160, 224, 256, 296, 320	3.5, 7, 16, 28, 40, 56, 80, 112, 160, 224, 320	1, 2, or 3	60	7

*Period of time sectionalizer will retain its count.
**Time required for all count retention to be lost for sectionalizer control operations that do not total the required number of counts to open.

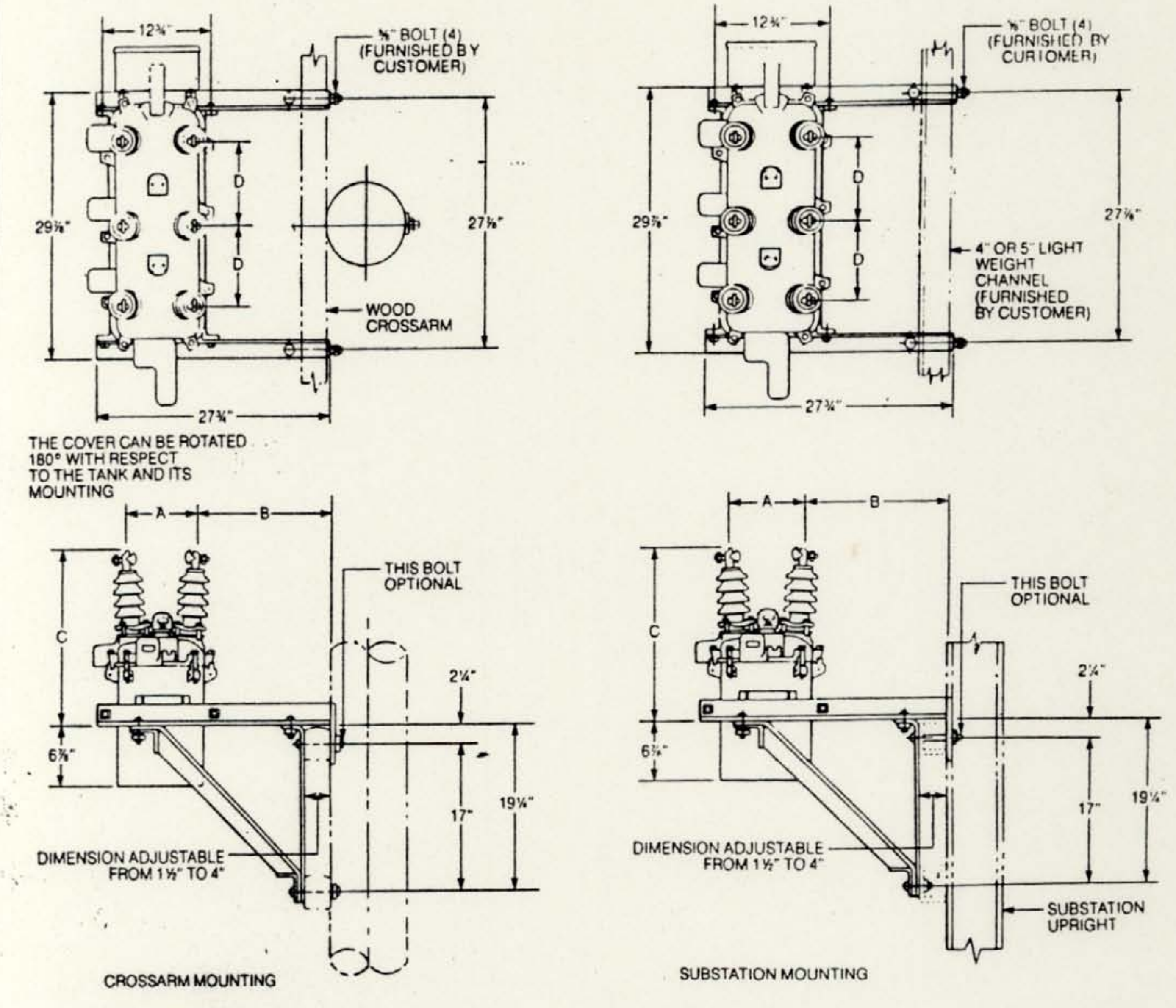
DIMENSIONS AND WEIGHTS



Section-alizer Type	Dimensions (in.)			
	A	B	C	D
GN3E	8¾	19⅝	27¼	9½
GN3VE	9¼	22½	30⅝	9⅞

10 SOLID TO NO 2 STRANDED

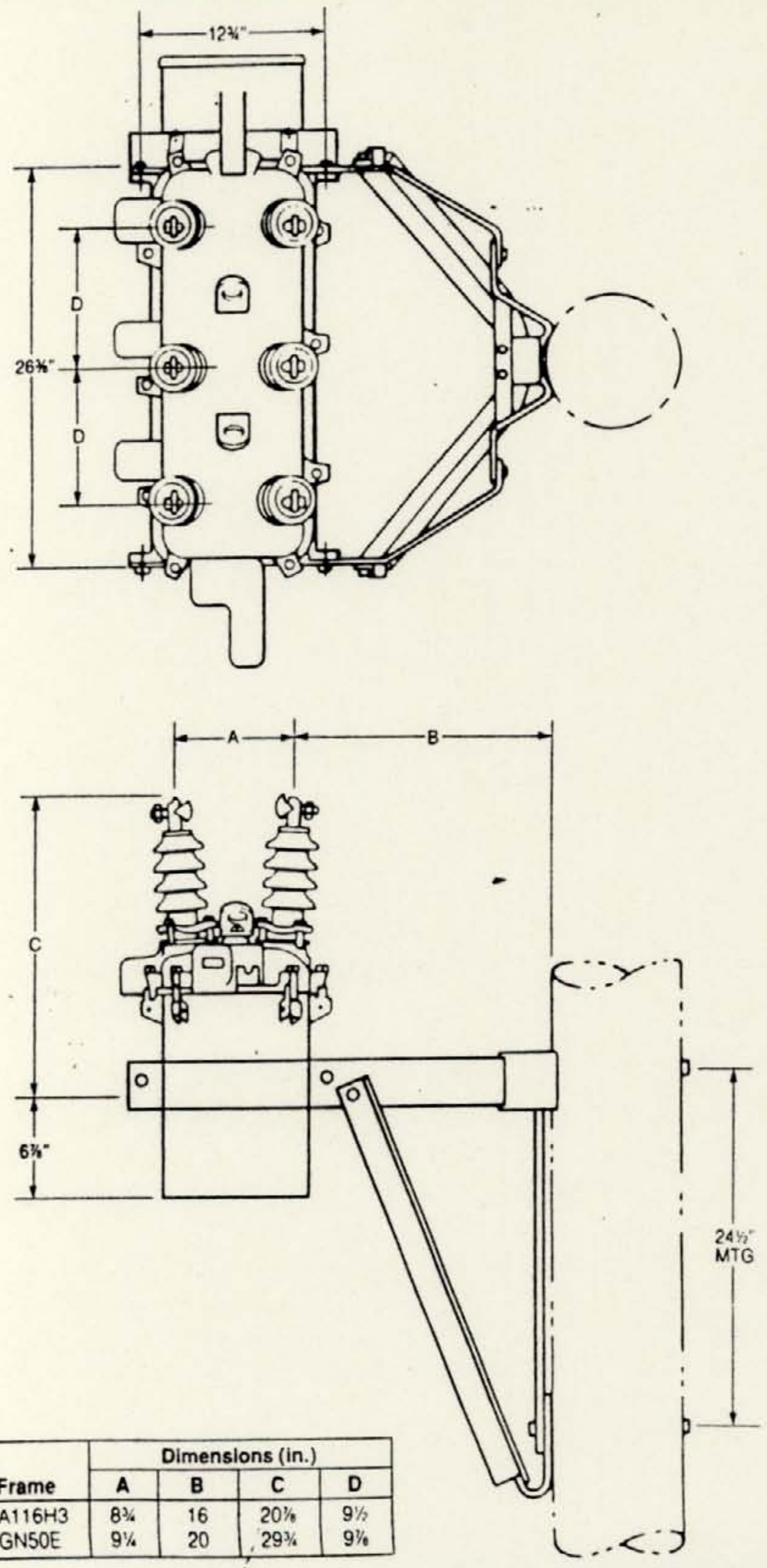
Figure 12.
Dimensions for Types GN3E and GN3VE sectionalizers.



Section-alizer Type	Dimensions (In.)			
	A	B	C	D
GN3E	8¾	16	20⅞	9½
GN3VE	9¼	15¾	29¾	9⅞

Figure 13.
KA19H3 double-crossarm bracket.

Types GN3E and GN3VE Sectionalizers



Frame	Dimensions (in.)			
	A	B	C	D
KA116H3	8¾	16	20⅞	9½
KGN50E	9¼	20	29¾	9⅞

Figure 14.
KA116H3 pole-mounting frame for Type GN3E and KGN50E pole-mounting frame for Type GN3VE sectionalizers.

TABLE 12
Weights and Oil Capacity

Sectionalizer Type	Without Oil (lb)	With Oil (lb)	Oil Capacity (gal)
GN3E	156	250	12½
GN3VE	166	260	12½

ANEXO M

POWER
MEASUREMENT
LTD.

3720 ACM

Advanced Digital Power Instrumentation Package

Installation And Operation Manual

Manual Revision Date:
September 15, 1993

1. INTRODUCTION

High Performance Power Instrumentation

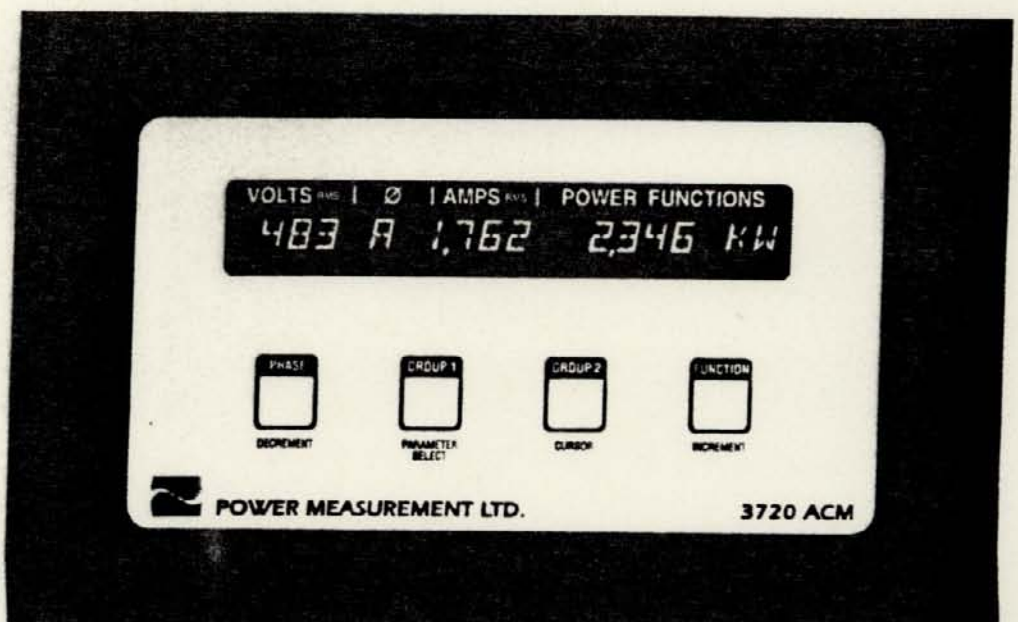
The 3720 ACM is a microprocessor-based, digital 3-phase "Smart Power Monitor/Meter" designed for use in industrial, commercial, and utility power distribution switchboards and substations. The 3720 ACM answers the ever-increasing concern for 'clean', reliable power by integrating the many critical aspects of power monitoring, protection, and control into one simple and economical instrument. It is a state of the art alternative to traditional analog electro-mechanical metering devices, replacing numerous individual transducers and meters.

The 3720 ACM offers the high accuracy, reliability, and ruggedness of its companion product, the successful 3710 ACM, while adding many new measurements and advanced features. The 3720 ACM also matches the 3710 ACM in its mounting dimensions and installation requirements, and in its straightforward and flexible user interface. Refer to Figure 1.1.1 for a comparison of features.

The unit is based around a 12 MHz, 16 bit microcontroller chip. This provides very high computational throughput, allowing the unit's sophisticated software to process information in real time. The unit is self contained and its readings and set up parameters are maintained in nonvolatile memory. An internal 16-bit CPU gives the 3720 ACM the processing capability to be used as a stand-alone power monitoring and control station or as a *smart RTU* in a large energy monitoring network.

Easy Installation and Exceptional Ruggedness

The 3720 ACM is panel-mountable and provides rear-mounted, utility approved terminal strips rated at 600V. The 3720 ACM has been designed to be exceptionally rugged, with a high tolerance to electrical disturbances and temperature extremes. Many special design features guarantee performance in electrically harsh environments. The voltage, current, status (digital), relay, supply power, and communications inputs have been designed to withstand hipot, C37.90A SWC, and fast transient tests. The 3720 ACM transformer-coupled current inputs are fully isolated with respect to the chassis of the unit, and provide 300 Amp surge protection.



	3710 ACM	3720 ACM
INPUTS & OUTPUTS	3 phase voltage inputs, 3 phase current inputs, neutral/ground current input, 3 relay outputs, 4 digital inputs with pulse counter on 1 input (max.count frequency: 0.3 Hz), 1 analog voltage input, 1 analog current output.	3 phase voltage inputs, 3 phase current inputs,neutral/ground current input, 3 relay outputs, 4 digital inputs with pulse counters on all 4 inputs (max. count frequency: 10 Hz), 1 analog voltage input, 1 analog current output.
MEASURED PARAMETERS	37 real-time, 21 min/max, 25 status	369 real-time (including harmonic distortion), 360 min/max, 28 status.
WAVEFORM CAPTURE	Yes. Triggers: comm. port.	Yes. Triggers: comm. port or setpoint*.
WAVEFORM RECORDING	No.	Yes. Triggers: comm. port or setpoint.
SNAPSHOT (TREND) LOGS *Note: Capacity is dependent on number of parameters and triggering method assigned to each log.*	*Basic model:* 1 preset log , 12 parameters, capacity: 100 records, triggering: time interval. *EMEM option:* 1 programmable log, up to 12 parameters, capacity: up to 11520 individual data items (example: 3 parameters @ 15 min. intervals = 40 days), triggering: time interval.	8 programmable logs, up to 12 parameters per log, combined capacity: 11520 individual data items, triggering: time interval or setpoint.
EVENT LOG	*Basic model:* 50 records, resolution: 1 sec. *EMEM option:* 100 records.	100 records, resolution: 1 msec.
MINIMUM / MAXIMUM LOGS	1 preset log: 17 parameters	1 preset log, over 100 parameters. 16 programmable logs each with 1 trigger parameter plus 15 coincident parameters.
SETPOINTS	17 standard speed. Trigger event log or relay control.	17 total: 11 standard speed, 6 high speed. Trigger event log, relay control, snapshot log, waveform capture*, or waveform recorder.
COMMUNICATIONS	Selectable RS-232 / RS-485 port.	Selectable RS-232 / RS-485 port.

Figure 1.1.1 3710 ACM vs. 3720 ACM Feature Comparison

* Setpoint-triggered waveform capture will be available 1st quarter 1994.

Inputs and outputs support a wide variety of applications

The 3720 ACM supports a variety of power distribution configurations, including 4-wire Wye, 3-wire Delta, and Single Phase systems. 3 phase voltage and 3 phase current inputs are provided, as well as an additional current input. In installations with non-linear loads, where odd harmonics can fail to cancel, significant currents in the neutral conductor can be produced. The 3720 ACM fouth current input can be used optionally for monitoring current in the neutral conductor, or for ground current monitoring. Used in conjunction with its high-speed setpoint system, the 3720 ACM can provide reliable ground fault protection.

No intermediate transducers are required on phase voltage and current inputs. No PTs are required on the voltage inputs for systems up to 347/600 Volts. For higher voltage systems, PTs equipped with 120 VAC secondaries can be used. The transformer-coupled current inputs accept CTs with 5 Amp full scale outputs. A 1 Amp input version is also available. Overrange measurement options include 125% to 1000%.

An auxiliary voltage input can be used to measure an external variable such as transformer temperature or battery voltage. Input range is 0 to 1 VAC. An auxiliary analog current output can provide 0-20 or 4-20 mA proportional to any measured parameter.

Four digital inputs can be used to monitor breaker status, ground fault relay status, or any other external dry contact. These inputs can also be used as pulse counters to measure device cycles, running hours, etc. An internal 30 VDC supply provides self-excitation for "volts free" contact sensing.

Outputs include three on-board relays that can be automatically controlled by an extensive user-programmable setpoint system, or manually operated by commands made via the communications port. Relays can perform operations ranging from simple alarm activations to fully automated demand, power factor, or load control. Relays can operate in a *latched* or *pulse* mode, and can also be programmed to provide kWH, kVARH, or kVAH output pulsing. The basic 3720 ACM provides 10 Amp, Form C electromechanical relays. The -SSR option provides 1 Amp, SPST solid state relays which offer longer lifetimes in continuous pulsing applications.

Displays and measurements

The 3720 ACM offers more than 300 high accuracy real-time, 3-phase measured parameters, and over 20 status parameters. All parameters are quickly accessible via the front panel display or through the meter's communications port.

Real-time measurements include: Volts, Amps, Neutral/Ground Current, kW, kVA, kVAR, Power Factor, and Frequency. On-board power quality analysis capability offers total and individual harmonic distortion values for all eight voltage and current inputs (to the 15th harmonic). Demand and minima/maxima values are also provided on all measurements. Energy values include kWH, kVAH, and kVARH. All energy readings provide bi-directional (import/export) indication. All voltage, current, power and energy readings are true RMS, including harmonics.

Status information includes real-time conditions for the three on-board relays, four status inputs, and seventeen user-programmable setpoints. Also included is internal self-diagnostic information.

A unique and flexible user interface

The 3720 ACM front panel features a large, high-visibility, 20-character vacuum fluorescent display. Volts, Amps and Power Functions can all be displayed together for the selected phase. Very large measured values with up to 9 digits of resolution (ex. kWH) are presented using the entire display. Concurrent display of all three phases of Volts or Amps readings is also possible.

The 3720 ACM uses four long-life, stainless steel membrane switches to access all measured parameters and status information, and for programming functions. Using the GROUP buttons, the user can define convenient *custom groupings* of important parameters for quick viewing.

Programming the basic setup parameters of the 3720 ACM can be performed quickly and easily from the front panel. Basic parameters include volts and amps scales, volts mode (wye, delta, etc.), baud rate, etc. Programming for many of the advanced features of the 3720 ACM must be performed via the communications port using a portable or remotely located computer running Power Measurement's

M-SCADA or L-SCADA software, or any compatible third-party software. These parameters include setup for waveform, data logging, and setpoint functions. Setup and other critical information is saved when power is turned off. All programming is password protected.

A powerful high-speed setpoint system for protection and control applications

The comprehensive on-board setpoint system of the 3720 ACM provides extensive control over the three on-board relay outputs, as well as triggering capabilities for the waveform capture*, waveform recorder, and snapshot logging features.

Seventeen user-programmable setpoints are provided, six of which offer high-speed (67 msec / 4 cycle) capabilities. Setpoints can be activated by a wide variety of user-defined conditions, including voltage, current or power levels, harmonic distortion (HD) levels, time-overcurrent characteristics, and external equipment status.

An active setpoint condition can be used to simultaneously trigger up to two separate functions. For example the user may wish to operate a relay and perform a waveform recording when an overcurrent condition occurs.

All setpoint activity is recorded automatically in the on-board Event Log.

Extensive power quality monitoring and fault recording capabilities

Beyond its on-board harmonic distortion measurements, the 3720 ACM has also been equipped with digital waveform sampling capabilities for power quality monitoring and fault analysis. The 3720 ACM provides two powerful methods for acquiring waveform data: *waveform capture* and *waveform recording*.

Waveform capture allows the user to perform high-speed (128 samples/cycle) sampling of the eight voltage and current inputs, providing high-resolution data which can be used for detailed power quality analysis. Capture can be triggered either through user-defined setpoint conditions*, or commands via the meter's communications port. Sampled waveform data is stored in on-board memory and can be read via the communications port. Power Measurement's M-SCADA / L-SCADA PC-based software can be used to upload captured waveform data, display the waveforms, and provide an indication of total harmonic distortion and a breakdown of individual harmonic components (to the 63rd harmonic) both in graphical and tabular form.

Waveform recording allows the user to analyze the conditions occuring before, during, and after a power fluctuation or failure and is ideal for fault and surge analysis, and to aid in fault location. Waveform recording runs continuously at 16 samples/cycle on all eight voltage and current inputs. A trigger by a user-specified setpoint condition or a command made via the meter's communications port freezes 12 cycles of each waveform in memory along with a time stamp. A programmable trigger delay allows pre-event or post-event data to be recorded. The recorded data is saved until uploaded to a master station for analysis. M-SCADA / L-SCADA can be used to display the waveforms together on the computer screen, presenting a comprehensive picture of the power line conditions surrounding the disturbance.

Remote communications makes power quality evaluation and fault analysis fast and economical. Using the M-SCADA / L-SCADA system, harmonic or fault analysis can be performed concurrently with other system supervisory functions, eliminating the need for costly manual surveys using portable instruments.

* Setpoint-triggered waveform capture will be available 1st quarter 1994.

Extensive on-board data logging offers many flexible features

The 3720 ACM supports three types of on-board data logging. Logged data can be extremely useful in the study of growth patterns, for scheduling loads and for cost allocation, for isolating problem sources, or for analysing a variety of power system operating conditions.

The Event Log provides 100 date and time-stamped records. Digital input changes are recorded with 1 millisecond accuracy, ideal for sequence-of-event recording. The log also records all relay operations, setpoint/alarm conditions, setup changes, and self-diagnostic events.

A Preset Min/Max Log records the extreme values for all parameters measured by the 3720 ACM, including all voltage, current, power, frequency, power factor, harmonic distortion, and demand values. Minima/maxima for each parameter are logged independently with date and time stamp, with 1 second resolution.

16 Programmable Min/Max Logs allow the user to define up to 16 separate logs, each containing up to 16 time-stamped parameters. Each log is triggered by the first parameter in its list. When a new minimum or maximum for the trigger parameter is recorded, coincident real-time values for all other parameters in the list are simultaneously stored. For example, the user could program a log to record all per-phase kW, kVAR, and PF demand values when total kW demand peaks. Independent reset functions for the preset and programmable min/max logs are performed either from the front panel or via communications.

The 3720 ACM Snapshot Logs are *historical* or *trend* logs. Up to 8 logs may be defined, each recording up to 12 channels of time-stamped data. The measured parameters recorded by each log are user-programmable. Each snapshot log can be triggered in one of three possible ways. A user-defined *time interval* basis provides an interval range from 1 second to 400 days. A *1-shot* method allows any standard setpoint to automatically trigger a snapshot recording when an active condition occurs. Setpoint conditions can include harmonic distortion levels, status input changes, and more. Finally, a *gated* method allows readings to be recorded on a time interval basis only during the time that a setpoint remains active. This method is ideal for logging voltage and current extremes following a breaker trip, for example. Trigger functions are assigned independently for each log.

Alarm conditions, events, min/max levels, and snapshot interval readings are all automatically time-stamped and logged into on-board non-volatile memory and are accessible via the communications port. Min/max values can also be viewed via the front panel. Power Measurement's M-SCADA / L-SCADA software can be used to program all log setup parameters, and to display all logged data. Historical snapshot data can be displayed graphically as a trend graph. M-SCADA / L-SCADA will also automatically archive to disk all logged data retrieved from each remote device.

Remote communications

The 3720 ACM is equipped with a selectable RS-232C or RS-485 communications port which allows the 3720 ACM to be integrated within large energy monitoring networks. 3720 ACM communications uses an advanced object and register based open protocol which allows the 3720 ACM to be easily adapted to third-party PLC, DCS, EMS, and SCADA systems. The 3720 ACM maintains compatibility with Power Measurement's PC-based M-SCADA / L-SCADA power monitoring software, and the entire family of 3000 series digital instrumentation, which includes power meters, power demand controllers, and smart transducer interfaces. A single M-SCADA station can support up to 99 remote sites with a total of 3168 devices. L-SCADA supports 1 site with 12 devices. Systems are easily expandable, and very large systems can be built by linking multiple master stations. M-SCADA / L-SCADA provides extensive full-colour data display options, automated data handling and system control features including: real-time data display for all or part of the power system; display of captured waveforms and harmonic analysis; historical trend graphing; detection, annunciation, display and logging of alarm conditions; and automatic retrieval and disk archival of data logs from remote devices.

The Power Measurement approach to power monitoring guarantees consistently accurate data retrieval by delegating extensive data acquisition, data logging, and control capabilities to the remote meter/RTU sites. Less processing requirements at the master station means high reliability and performance. Non-volatile data logs ensure data is always retrievable following a temporary power or communication failure.

System applications

Because of its unique measurement, storage, setpoint control (load shedding) and display characteristics the 3720 ACM should be considered for use in:

a) Utility Installations
b) Industrial Buildings
c) Office Buildings
d) Commercial Buildings
e) Hospitals
f) Telephone Exchanges
g) Factories
h) Pulp Mills
i) Saw Mills
j) Shopping Centres
k) Large Stores
l) Hotels
m) Substation Metering
n) Co-generation Systems
o) Chemical Process Plants
p) Multi User Sites where allocation of electrical costs is desirable
q) Any other installation which uses significant amounts of electrical energy.
r) Any other installation which is experiencing power quality problems.
s) Any other locations where remote power monitoring, control, or analysis is needed.

2.6.4 RS-232C CONNECTIONS

Figure 2.6.4a illustrates the wiring requirements for connection of the 3720 ACM using RS-232C communications. This can include a local direct connection to a computer or other device, or a remote connection via modem .

The RS-232C standard allows only a single point-to-point communications connection. Using this method, only one RS-232C equipped device may be connected to the serial port of the computer, modem, or other device.

The cable used between the computer and the modem (if used) is a standard RS-232C communications cable with a maximum length of 50 feet (15.2 m). Refer to the installation manuals for each device for cable requirements.

The cable used between the computer or modem and the 3720 ACM is a custom RS-232C cable. One end is equipped with a DB25 or DB9, male or female connector. The connector required depends on the mating computer or modem serial port connector. The other end of the cable consists of discrete wires which connect to the RS-232C terminals of the the ISOCOM2 card of the 3720 ACM. Cable length is 50 feet (15.2 m) maximum.

Figure 2.6.4b illustrates all RS-232C cable configurations and wiring connections.

If connected directly to an IBM PC RS-232C port, the Tx and Rx leads may need to be reversed at the remote device, depending on whether the PC RS-232C port is configured as DCE or DTE.

Refer to Chapter 8 for information regarding the use of the RTS line of the 3720 ACM.

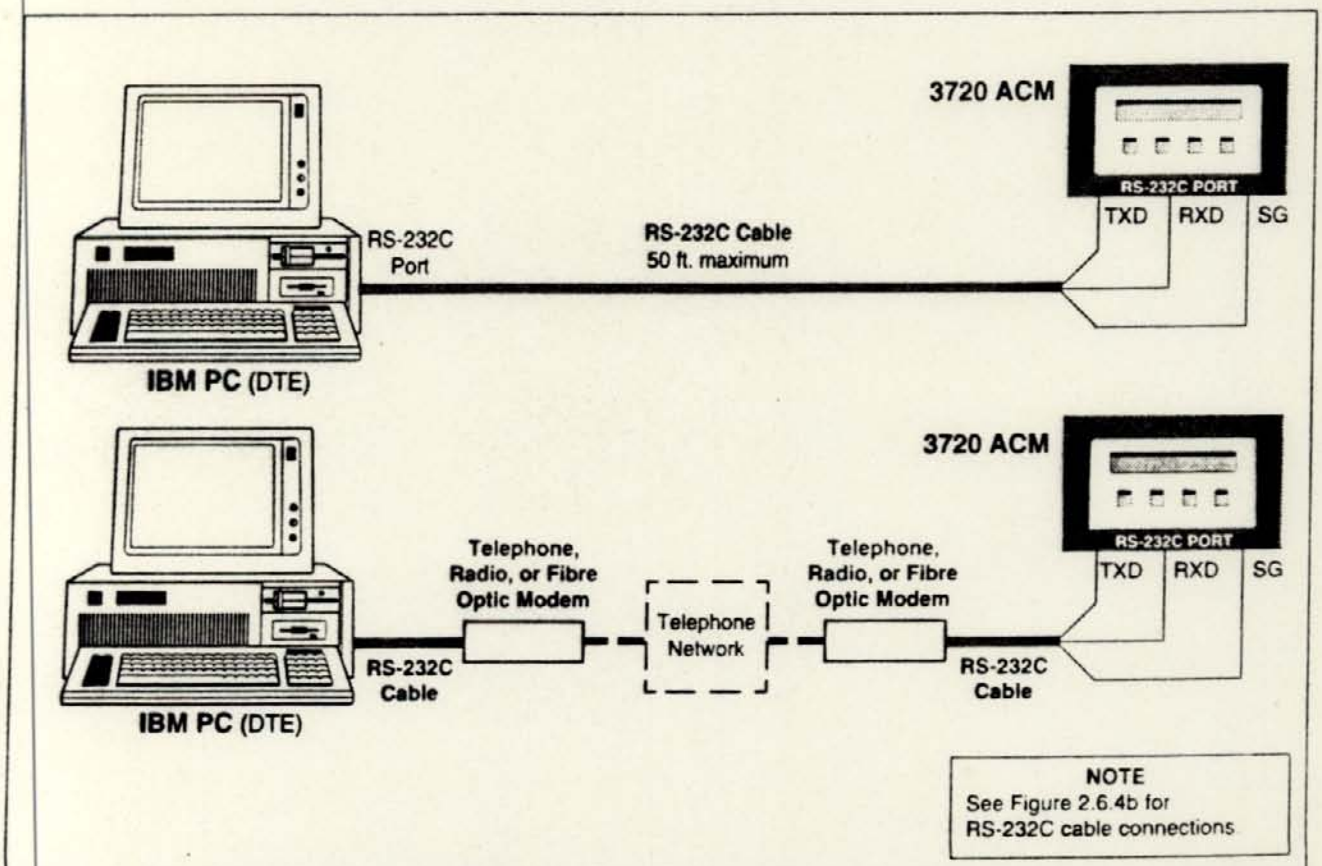


Figure 2.6.4a RS-232C Communications Connections