A STUDY ON SECTIONALIZING AND COORDINATION OF PROTECTIVE DEVICES AND VOLTAGE DROP COMPENSATION OF RURAL DISTRIBUTION SYSTEM

A thesis submitted to Bangladesh Institute of Technology, Khulna for the partial fulfillment of the degree of

Master of Science in Engineering

By

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CERTIFICATE

This is to certify that the thesis entitled-"A Study on Sectionalizing and Coordination of Protective Devices and Voltage Drop Compensation of Rural Distribution System" was performed by me and it has not been submitted elsewhere for award of any degree or diploma.

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This is to certify that the thesis entitled- "A Study on Sectionalizing and Co-ordination of Protective Devices and Voltage Drop Compensation of Rural Distribution System" Submitted by Santosh Kumar Das to the Department of Electrical & Electronic Engineering, Bangladesh Institute of Technology, Khulna, for the partial fulfillment of the degree of Master of Science in Engineering, is a record of bonafide research work carried out by him under our supervision.

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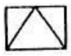
Abstract

Methodologies are presented in this thesis to study the coordination among the protective devices and voltage drops at different points of a radial distribution system. Maximum and Minimum values of currents due to different types of faults occurring at various points of the distribution system are calculated. The inverse time relays and fuses are modeled by nonlinear time current relations. The definite time relays are modeled by constraint conditions. Impedance model for the radial distribution system is considered to find the fault currents. The effectiveness of the protection scheme is studied using different sets of minimum and maximum values of fault currents for all concerned fuses and relays acting as primary and backup protective devices. In the case of any miscoordination or improper coordination the CT plug multiplier setting and relay time dial setting are proposed to adjust. The optimal coordination of the radial distribution system is carried out using two- phase technique. In phase I, the constraints for protecting the lines and equipment of the distribution system for primary and back up protection is tested for feasibility of the constraint conditions for protection. In this phase the relay and fuse time-current characteristic curves are superimposed to visualize and ensure coordination graphically. Phase II endeavors to find out the optimal settings of relays to ensure minimum power interruption. Voltage drops under specified loading at different points are calculated to have an idea about the condition of power at different distribution points of the feeder. As case study, the radial distribution feeders of the Topshidanga 33/11 KV S/S and the Baganchra 33/11 KV S/S, under Jessore PBS-1, a project of Rural Electrification Board is considered for study on sectionalizing and coordination of protective devices and voltage drop compensation. The proposed methodology is tested in a Pentium III PC-based digital computer environment.

List of Symbols

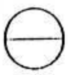
PDB	Power Development Board
REB	Rural Electrification Board
PBS	Pally Bidyut Samity
S/S	Sub-Station
KV	Kilo Volt
KVA	Kilo Volt Ampere
MVA	Mega Volt Ampere
KW	Kilo Watt
KWh	Kilo Watt Hour
KM	Kilo Meter
HP	Horse Power
CT	Current Transformer
PT	Potential Transformer
HT	High Tension
LT	Low Tension
PSM	Plug Setting Multiplier
TMS	Time Multiplier Setting
CTI	Coordinating Time Interval
OCR	Oil Circuit Recloser
OCB	Oil Circuit Breaker
ACR	Automatic Circuit Recloser
1 Ǿ	Single Phase
3 Ǿ	Three Phase
Y⊥	Grounded Y Connection
T1	Transformer-1
T2	Tranformer-2
X-former	Transformer
E / F	Earth Fault
G /F	Ground Fault
T.D	Time Dial
Inst.	Instantaneous
PU	Per Unit
RE	Rural Electrification
DSP	Digital Signal Processor

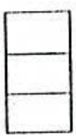
LEGEND USED IN SECTIONALIZING STUDY :

 ---------------------- PBS SUB-STATION

 ---------------------- AUTOMATIC CIRCUIT RECLOSER (ACR)

 ---------------------- FUSE CUT-OUT


---------------------- VOLTAGE DROP
---------------------- DISTANCE FROM SUB-STATION IN KM.


---------------------- THREE PHASE FAULT CURRENT (MAX.)
---------------------- LINE TO GROUND FAULT CURRENT (MAX.)
---------------------- LINE TO GROUND FAULT CURRENT (MIN.)

 ---------------------- LOAD CURRENT IN AMPERE

 ---------------------- NODE NUMBER

 ---------------------- TRANSFORMER

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CHAPTER-I

Introduction

1.1 General Background

Rural electric supply systems are generally radial distribution type. This is due to the population density distribution within the area under consideration. The distribution system, in many cases, has multiple branch lines and resembles a "tree" structure. The major loads are domestic and the load per kilometer of the distribution feeder is much lower than that exists in urban area. The power suppliers' concern is to provide a long distribution system with relatively lower cost. And in general, the protective schemes are designed with OCRs and fuses. The rural distribution system has another important feature that they are subjected to easy ground fault environment due to near by trees. In Bangladesh the rural electrification authorities purchase electricity from the Power Development Board, which has its own protection system.

The protection scheme of a rural distribution system is subjected to problems of miscoordination of the devices. This is due to large number of protective devices in a very long distribution feeder, lack of adjustment due to extension of feeders in different times due to load growth and use of different types of relays and fuses in a system. Sometimes lack of coordination between selling and purchasing companies causes miscoordination. Normally, the power security is not considered with great care, which results in miscoordination of protective devices. This causes improper operation of circuit breakers and some loads may be disconnected from the system without appreciable reason. Since rapid and continuous maintenance in rural distribution system is not always possible, the system itself must be sound and promptly coordinated to avoid any unwanted interruption.

1.2 Brief Literature Survey

The distribution portion is a vital part for proper functioning of the power system. Specially the rural power distribution system is subjected to common faults due to proximity of earth objects to the distribution lines. Sometimes the distribution lines are extended and load is increased to them without proper technical justification of the system protection scheme. All the three parts of the power system should function as integrated units and proper coordination of protective relays and other protective devices is essential to ensure the reliability of any power system. The objective of selecting the relay settings is to achieve the minimum possible operating times while maintaining coordination among the relays. For proper coordination between relays connected in series on a radial feeder, TMS of the farthest relay from the source should be set at a minimum value so that it operates at a minimum possible time. The TMS of the succeeding relays towards the source should be increased for selective operation. Proper coordination of primary and secondary protective devices is a problem associated with relay setting calculations [1,2]. Coordination problems are generally solved in digital environment. Generally topological techniques [3] and linear programming techniques [4] are applied to solve coordination problems of transmission and distribution system. A complete survey of the techniques is presented in the IEEE committee report [5]. Transient effect on the coordination of protective devices of a power system is reported in [6]. The study considers the effect of changes in network topology in the case of a protecting device operating without selectivity. Successive linear programming technique is described in [7]. Simplex two-phase optimization technique is described in [8]. A mathematical model on DSP is reported to work properly for this technique.

In [9] an approach for simulation of interactive protection system is provided. It uses an electromagnetic transient program to simulate electrical transients. A mathematical model of relay is developed to remove the dc offset. A report on relay performance testing is provided by a power system relaying committee in[10]. The paper describes analog and digital simulation methods of relay tripping.

The voltage that is available to the lines of a power system will vary from time to time because of the voltage drop due to load, the voltage rise caused by capacitors or a voltage change (rise or fall) made by voltage regulators. The voltage served to customers of the distribution system is considered to be acceptable when it is adequate for the proper operation of connected lights, appliances, and equipment.

A voltage drop distribution system model has been given in [11]. The study considers the effect of cascaded on-load tap changers on the stability of a radial distribution feeder. A transfer function model of the system is considered for analysis. Optimum operation of distribution networks is proposed in [12] to minimize voltage drops and power loss. They propose tie lines in proper places to improve reliability indices. An improved design for urban power distribution is given in [13]. The paper has introduced indices for serviceability and proposed heuristic rules for proper functioning of open loop distribution network. Standard load models, specially for electrical motors are given in [14]. Here R-L network equivalent to motor loads for dynamic performance analysis of distribution system is considered. Classification of faults and their role on distribution system is discussed in [15]. They also suggest paradigm for fault prevention. It has been reported that voltage that is too high shortens the life of lights and equipment and also voltage that is too low results in dim lights, improper operation of appliances, and motor failure due to overheating. Good service voltage benefits the utility through increased revenue, customer satisfaction and increased usage. As a result increased efficiency of distribution equipment and decreased investment / KVA supplied [18] is attained. Effect of non-linear loads on voltage distortion of distribution feeder is given in [16]. Equivalent harmonic voltage components due to non-linear loads are considered in it as the source of voltage distortion of a distribution network. Impedance models for a distribution network is described to calculate loss in distribution system in [17]. The study gives an inherent to the reduction of system loss of distribution systems.

1.3 Objectives of the Present Work

The main objective of the present study is to analyze the coordination of protective devices in radial distribution system. At first a methodology to calculate fault current in a radial distribution system with impedance model is provided. Also the nominal load currents of different sections of distribution system are calculated by the same program supplied with load data. The relay and fuses are modeled with their time current characteristics. The protective devices are normally coordinated in pair. The objective of selecting the relay setting is to achieve the minimum possible operating times while maintaining coordination among all relays. For optimal coordination, simplex two-phase technique of linear programming is applied in a graphical environment. In the first phase feasibility of the scheme is ensured and optimal solution is ensured by final adjustment of the relay settings. The two-phase simplex method is applied to find feasible and optimal solution. The methodology presented endeavors to bridge the gap between the topological and mathematical approaches of protective device coordination.

The methodology is applied to study the effectiveness of coordination scheme of existing Jessore PBS-1, a project of Bangladesh Rural Electrification Board. The miscoordinating components are detected and suggestions are given for coordinating them.

The study also considers voltage drop calculation of radial distribution system. The magnitude of the voltage at the load ends is calculated under full load conditions. The load points subjected to under voltages are detected and suggestions are given to improve the voltage levels for those points.

1.4 Contents of the Thesis in Brief

The thesis consists of seven chapters. An over view of the contents of each chapter are indicated below:

Chapter-I gives the brief description of the problem of rural distribution system. It also contains a brief review of literature available on protection scheme coordination and voltage drop calculation. It endeavors to discuss on the selection of the topic as a subject matter for research study.

Chapter-II gives a brief description of power system and common types of faults associated with it. The methodology for calculating fault current and a brief idea about the protective devices is also given in this chapter.

A brief description on voltage levels is provided in chapter-III. It also contains the methodology and procedure for calculating voltage drops of distribution system. The steps of voltage drop calculation are also described.

Chapter IV gives a brief description about the protection of radial distribution system. It endeavors to discuss on the procedure of coordination and selection of protective devices. It also contains OCR-OCR & OCR-Fuse coordination charts and coordination principal.

Description about the technique of selection of fuses in lateral lines and coordination of two fuses in series are given in it.

A procedure to coordinate 33KV over current protective devices is given in chapter-V. It shows a method to coordinate the PDB and PBS protection schemes.

In chapter VI the fault currents and voltage drops at different nodes of two existing radial distribution systems (Topshidanga 33/11 KV S/S and Baganchra 33/11 KV S/S) of Rural Electrification Board are calculated based on the present system data. Proposal for coordination scheme and voltage drop improvement along with justification are given in this chapter.

Finally, some conclusions are given in chapter-VII. It also includes suggestions for extended research in this field.

CHAPTER-II

Fault Current Calculation & Protection of Distribution System

2.1 Introduction

Fault Currents flowing through different protective devices are calculated on the basis of fault level of source, line impedance, distance of the fault from source and nature of fault. The optimal coordination of the radial distribution system is carried out using two-phase technique of linear programming. In phase I, the constraints for protecting the lines and equipments of the distribution system for primary and back up protection are tested for feasibility of the constraint conditions for protection. For feasibility study of the protective devices fault current calculation is required. All protective devices should have minimum tripping capacity, continuous current carrying capacity and maximum interrupting capacity. So, an OCR selected for a particular position will be feasible only when its minimum tripping capacity is equal to or higher than the minimum fault current, continuous current carrying capacity is equal to or higher than the section load current and maximum interrupting capacity is equal to or higher than the maximum fault current. The minimum and maximum fault currents are utilized for checking coordination of protective devices. Relay Plug setting multiplier (PSM) and time multiplier setting (TMS) are used for coordinating a relay with other relays and fuses maintaining a suitable coordination interval.

2.1.1 Present Status of Power Development Board

An electric power system consists of three major parts: Generation, Transmission and Distribution. Electric power is generated in hydroelectric, thermal and nuclear plants. In Bangladesh power generation by nuclear plant is not in practice. The major power stations of our country are situated at Kaptai, Rawjan, Shiddirganj, Shahajibazar, Ashuganj, Ghorashal, Baghabari, Bheramara, Khulna and Barisal. Also there are some small plants in some other places of the country.

Transmission lines are the connecting links between the generating stations and the distribution systems and lead to other power systems over interconnections. Modern electrical power systems are large interconnected AC networks. The total network is divided into a few regional zones. Each zone controls its own load, frequency and generation. All the zones are interconnected to form a National Grid.

For example: Power map of Bangladesh is covered by the following regional zones.

- Central zone
- Eastern zone
- Western zone
- Northern zone

In an interconnected network the National Load control centre determines the exchange between Regional zone. Regional load control centres control generation in the respective zone to match the prevailing load so as to maintain the regional frequency within target limits (50.5 to 49.5). During the low frequency high load; the region imports power from adjacent surplus region. During low load/high frequency the region exports power.

Advantages of Interconnections

- Lower spinning reserves
- Economic generation
- A justified minimum installed capacity
- Minimum operational costs, maximum efficiency
- Better use of energy reserves
- Better service to consumers

The main task of an interconnecting transmission system is to transfer adequate power from one system to other system during normal and emergency conditions and to maintain system security. In Bangladesh 132KV AC lines have been used for interconnection excepting a small section from Ghorashal to Ishwardi via Ashuganj and Tongi which is 230KV.

A distribution system connects all the individual loads to the transmission lines at substations, which perform voltage transformation, switching and related protective functions.

2.1.2 Feeders of Distribution Systems

The feeders of distribution system may be of three types. They are

i. Radial feeders

ii. Parallel feeders and

iii. Ring mains

The radial feeders of distribution system is used if power system is small. This system is adopted only from economic point of view and it is understood that continuity of supply is not of paramount importance. REB uses radial feeders. In this system some time one radial feeder of a s/s is interconnected to the another radial feeder of other sub-station. The point of interconnection between two sub-stations is normally kept open and function during emergency conditions. The single line diagram of a typical radial feeder system is illustrated in Figure 2.1.

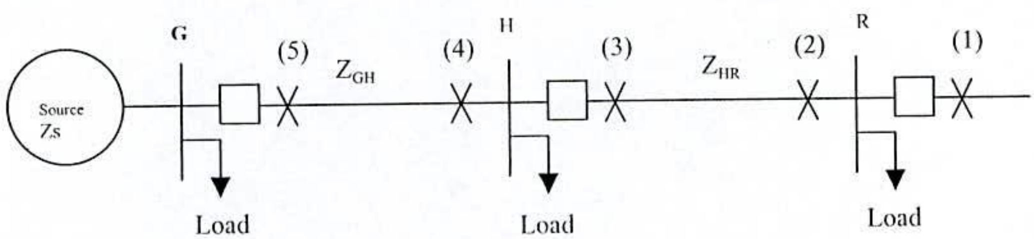


Figure 2.1 :A typical radial feeder.

2.2 Faults in Power System

A fault proof power system is neither practical nor economically feasible. Modern power systems are constructed with as high an insulation level as practical have sufficient flexibility so that one or more components may be out of service with minimum interruption of service. In addition to insulation failure, faults may result from electrical, mechanical and thermal failure or any combination of these.

2.2.1 Major Types and Causes of Failure

Type	Causes
Insulation	Design defects or errors.
	Improper manufacturing
	Improper Installation
	Aging of insulation
	Contamination
Electrical	Lightning surges
	Switching surges
	Dynamic over voltages
Thermal	Coolant failure
	Over current
	Over voltage
	Ambient temperatures
Mechanical	Over current forces
	Earthquake
	Foreign object impact
	Snow or ice
Earthed object	Trees
Living beings	Birds
	Bats
	Snakes
	Human beings

2.2.2 Basic Type of Faults

Basically, faults are of four types. These are:

Three phase (a-b-c, a-b-c-g)

Line to line (a-b, b-c, c-a)

Single line to ground (a-g, b-g, c-g)

Double line to ground (a-b-g, b-c-g, c-a-g)

here, a,b,c are the three phases and g is the ground.

2.2.3 Symmetrical Components

The method of symmetrical components is the foundation for obtaining and understanding fault data on three-phase power systems. Formulated by Dr. C.L. Fortescue in a classic AIEE paper in 1918.

Basic Concepts

The method of symmetrical components consists of reducing any unbalanced three-phase of phasors into three balanced or symmetrical systems of phasors. The balanced sets of components are:

(a) Positive-sequence components consisting of three phasors equal in magnitude, displaced from each other by 120° in phase, and having the same phase sequence as the original phasors.

(b) Negative-sequence components consisting of three phasors equal in magnitude, displaced from each other by 120° in phase and having the phase sequence opposite to that of the original phasors.

(c) Zero-sequence components consisting of three phasors equal in magnitude and with zero phase displacement from each other.

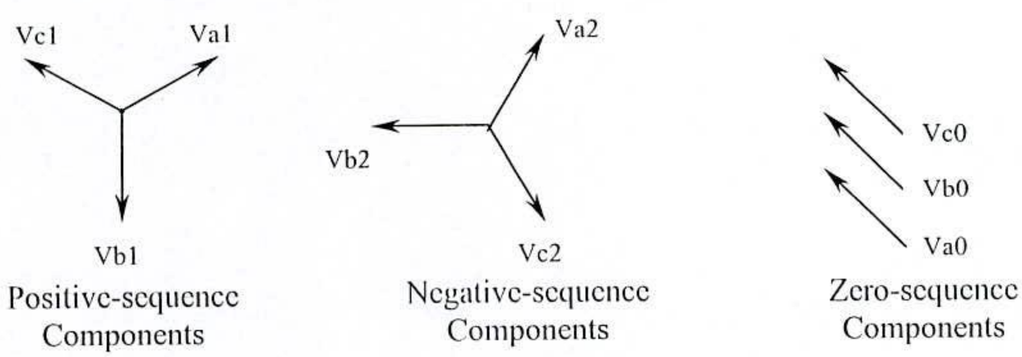


Figure 2.2: Sequence components of voltages

The subscript 1 identifies the positive sequence component, the subscript 2 the negative sequence component and the subscript 0 the zero sequence component. All phasers rotate in counter clockwise direction.

2.2.4 Operators

Because of the phase displacement of the symmetrical components of the voltage and currents in a three-phase system, it is convenient to have a shorthand method of indicating the rotation of a phasor through 120°.

The letter **a** is commonly used to designate the operator that cause a rotation of 120° in the counter clockwise direction. Such an operator is a complex number of unit magnitude with an angle of 120° and is defined by

$$\mathbf{a} = 1\angle\ 120^{\circ} = -\ 0.5 + j0.866$$

If the operator '**a**' is applied to a phasor twice in succession, the phasor is rotated through 240° . Three successive applications of a rotate the phasor through 360°.

Thus,

$$\mathbf{a}^{2} = 1\angle\ 240^{\circ} = -\ 0.5 - j0.866$$

and $\mathbf{a}^{3} = 1\angle\ 360^{\circ} = 1\angle 0^{\circ} = 1$

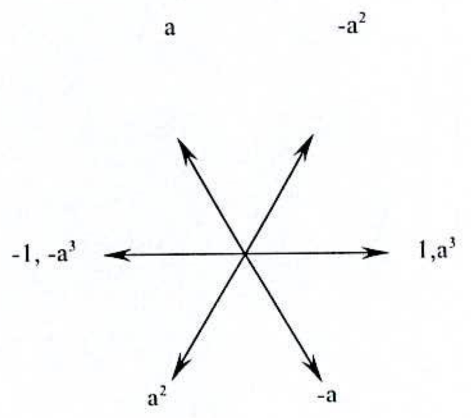


Figure 2.3: Phasor diagram of the various powers of operator **a**.

2.2.5 The Symmetrical Components of Unsymmetrical Phasors

The original phasors expressed in terms of their components are

$$V_a = V_{a1} + V_{a2} + V_{ao} \tag{2.1}$$

$$V_b = V_{b1} + V_{b2} + V_{bo} \tag{2.2}$$

$$V_c = V_{c1} + V_{c2} + V_{co} \tag{2.3}$$

The number of unknown quantities can be reduced by expressing each component of V_b and V_c as the product of some function of the operator '**a**' and a component of V_a. Fig. 2.2 verifies the following relations :

$$\begin{aligned} V_{b1} &= \mathbf{a}^2 V_{a1} & V_{c1} &= \mathbf{a} V_{a1} \\ V_{b2} &= \mathbf{a} V_{a2} & V_{c1} &= \mathbf{a}^2 V_{a2} \\ V_{bo} &= V_{ao} & V_{co} &= V_{ao} \end{aligned} \tag{2.4}$$

Repeating equation 2.1 and substituting equations 2.4 in Equations 2.2 and 2.3 yield

$$V_a = V_{a1} + V_{a2} + V_{a0} \tag{2.5}$$

$$V_b = \mathbf{a}^2 V_{a1} + \mathbf{a} V_{a2} + V_{ao} \tag{2.6}$$

$$V_c = \mathbf{a} V_{a1} + \mathbf{a}^2 V_{a2} + V_{ao} \tag{2.7}$$

Or in Matrix form

$$\begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} V_{ao} \\ V_{a1} \\ V_{a2} \end{bmatrix} \tag{2.8}$$

$$\text{Let } A = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \qquad \textit{then } A^{-1} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \tag{2.9}$$

Multiplying both sides of equation 2.8 by A^{-1} yields

$$\begin{bmatrix} V_{ao} \\ V_{a1} \\ V_{a2} \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} \qquad (2.10)$$

Similarly

$$\begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} = \begin{bmatrix} 1\,1\,1 \\ 1\,a^2\,a \\ 1\,a\,a^2 \end{bmatrix} \begin{bmatrix} I_{ao} \\ I_{a1} \\ I_{a2} \end{bmatrix} \text{ And } \begin{bmatrix} I_{ao} \\ I_{a1} \\ I_{a2} \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1\,1\,1 \\ 1\,a\,a^2 \\ 1\,a^2\,a \end{bmatrix} \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} \qquad (2.11)$$

In the three phase system the sum of the line currents is equal to the current $\mathbf{I}_n$

Thus $I_a + I_b + I_c = \mathbf{I}_n$ or $\mathbf{I}_n = 3I_{ao}$ (2.12)

2.3 Per Unit Quantities

The per unit value of any quantity is defined as the ratio of a quantity to its base value expressed as a decimal. The ratio in percent is 100 times the value in per unit. Both the percent and per unit methods of calculation are simpler than the use of actual amperes, ohms and volts. The per unit method has an advantage over the percent method because the product of two quantities expressed in per unit is expressed in per unit itself, but the product of two quantities expressed in percent must be divided by 100 to obtain the result in percent. Voltage, current, KVA and impedance are so related that selection of base values for any two of them determines the base values of the remaining two. If we specify the base values of current and voltage, base impedance and base KVA can be determined. The base impedance is that impedance which will have a voltage drop across it equal to the base voltage when the current following in the impedance is equal to the base value of the current. The base KVA in single-phase system is the product of base voltage in KV and base current in amperes. Usually the base KVA and base voltage in KV are the quantities selected to specify the base.

2.3.1 Base Values for Single-phase System

For a single-phase system or three-phase system where the term current refers to line current, where the term voltage refers to voltage to neutral and whère the term KVA refers to KVA per phase, the following formulas relate the various quantities:

Base current in amperes = Base $KVA_{1\phi}$ /Base voltage, KV_{LN}

Base impedance = Base voltage, KV_{LN}/ Base current, A

= (Base voltage $KV_{LN})^2$ x 1000 /Base KVA $_{1\phi}$

= (Base voltage $KV_{LN})^2$ /Base MVA $_{1\phi}$ (2.13)

Base power, $KW_{1\phi}$ = Base $KVA_{1\phi}$

Base power, $MW_{1\phi}$ = Base $MVA_{1\phi}$

$$Per\ unit\ impedance\ \ of\ a\ circuit\ \ element = \frac{Actual\ impedance, \Omega}{Base\ impedance, \Omega}$$

$$= \frac{(Actual\ impedance) \times (Base\ KVA)}{(Base\ impedance, KV_{LN})^2\ x1000} \quad (2.14)$$

2.3.2 Base Values for Three-phase System

For three phase if we interpret base KVA and base voltage in KV to mean base KVA for the total of the three phase and base voltage from line to line, we find :

$$Base\ current\ in\ Amp. = \frac{Base\,KVA_{3\phi}}{\sqrt{3} \times Base\,voltage, KV_{LL}} \quad (2.15)$$

$$\text{Base impedance} = \frac{(\text{Base voltage, } KV_{LL}/\sqrt{3})^2 \times 1000}{Base\,KVA_{3\phi}/3} \quad (2.16)$$

$$= \frac{(\text{Base voltage, } KV_{LL})^2 \times 1000}{Base\,KVA_{3\phi}}$$

$$= \frac{(\text{Base voltage,} KV_{LL})^2}{\text{Base } MVA_{3\phi}} \quad (2.17)$$

To change from per-unit impedance on a given base to per-unit impedance on a new base, the following equation applies :

$$Perunit\ Z_{new} = Perunit\ Z_{given}\left(\frac{BaseKV_{given}}{BaseKV_{new}}\right)^2\left(\frac{BaseKVA_{new}}{BaseKVA_{given}}\right) \tag{2.18}$$

2.4 Fault Detection

Most of the faults on power lines can be detected by applying over current relays. The fault currents are normally higher than the load current.

Radial circuits can be protected by non-directional over current relays. Figure 2.4 shows several sections of a typical radial circuit. Because of the circuit is radial, each section requires only one circuit breaker at the source end. To clear a fault at (1) and other faults to the right then, only the breaker at R needs to be tripped. To clear fault at (2) and (3) and in the area between them, the breaker at H must be tripped. Likewise, to clear faults at (4) and (5) and between them, the breaker at G must be tripped.

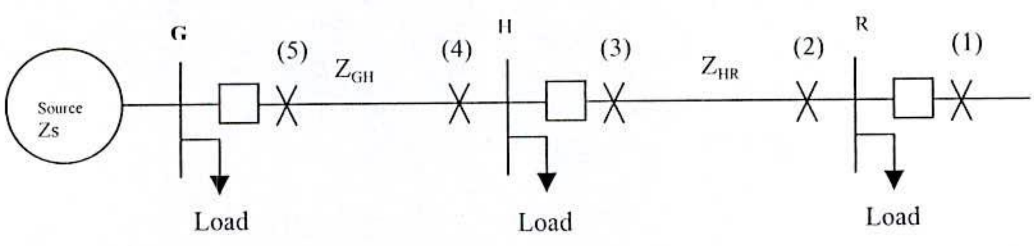


Figure 2.4: A typical radial circuit.

However, none of the relays at the breaker locations can distinguish whether the remote fault is on the protected line, the remote bus, or an adjacent line. To solve this problem time delay technique is to be applied.

2.4.1 Time-Delay Relaying

Time relaying delays the operation of the relay for a remote fault, allowing relays and breakers closer to the fault to clear it, if possible. In the example shown in Fig. 2.4, relays at H will delay for faults at (1) or (2). If the fault is at (1), this delay will allow the R relays and breaker to operate before H. Thus, although H would not open for a fault at (1) (unless the R relay or associated breaker failed), it would operate for a fault at (2).

2.5 Fault Current Calculation

The type of fault that may occur depends upon the distribution system and the circumstances. Line-to-ground, line-to-line and double line-to-ground faults are common to single, two and three phase systems. The three-phase fault, naturally, is a characteristic only of the three-phase system.

For proper selection of the protective devices, short circuit studies are to be carried out. In most of short circuit studies, only three-phase and single line-to-ground fault currents are calculated. The reason for this is that a three-phase fault normally produces the maximum fault current on lines, and the single line-to-ground fault is a common type of fault.

Equations for calculating short circuit currents:

i) Maximum three phase symmetrical fault levels in MVA and in Amperes on the secondary terminal of a sub-station :Fault MVA $= \dfrac{Base\ MVA}{z_1}$ (2.19)

z_1 is the summation of the per unit value of the impedance of the source system and the power x-former.

$$\text{i.e. } z_1 = z_{11} + z_{12} \tag{2.20}$$

z_{11} = Per unit value of the source impedance.

z_{12} = Per unit value of the x - former impedance.

$$\text{Three phase fault current} = \left(I_{3\phi}\right) = \frac{Base\ MVA_{3\phi} \times 1000}{\sqrt{3} \times Base\ KV_{LL} \times z_1} \tag{2.21}$$

ii) Maximum single line-to-ground fault level in amperes on the secondary terminals of power transformers :

Maximum single line-to-ground fault level in Amperes:

$$I_{(L-G)\max} = \frac{\sqrt{3} \times BaseMVA \times 1000}{BaseKV(z_1 + z_2 + z_o + 3z_f)} \tag{2.22}$$

z_1 = Positive sequence impedance of the system source in per unit plus the positive sequence impedance of the x-former in per unit.

z_2 = Negative sequence impedance of the system source in per unit plus the negative sequence impedance of the x-former in per unit.

z_o = Zero sequence impedance of the system source in per unit plus the Zero sequence impedance of the x-former in per unit.

z_f = Fault impedance = 0 (for maximum single line-to-ground fault calculation).

iii) Maximum three-phase symmetrical fault levels in amperes on lines :
Maximum three-phase symmetrical fault levels in

$$\text{Amperes on lines} = \left(I_{3\phi}\right)_{\max} = \frac{BaseMVA \times 1000}{\sqrt{3} \times BaseKV_{LL} \times z_1} \tag{2.23}$$

z_1 = Positive sequence impedance of the source in per unit plus the positive sequence impedance of the x-former in per unit plus the positive sequence impedance of the line per unit.

iv) Maximum single line-to-ground fault levels in Amperes on the lines:
Maximum single line-to-ground fault level in Amperes on lines is given by

$$I_{(L-G)\max} = \frac{\sqrt{3} \times Base\ MVA \times 1000}{BaseKV(z_1 + z_2 + z_o + 3z_f)} \tag{2.24}$$

z_1 = Positive sequence impedance of the source line per unit plus the positive sequence impedance of the x-former per unit plus the positive sequence impedance of the line per unit.

z_2 = Accumulative per unit negative sequence impedances of source line, x-former and line.

z_o = Accumulative per unit zero sequence impedances of source line, x-former and line.

z_f = Fault impedance = 0 (for maximum line-to-ground fault current calculation).

The above equations are sufficient to calculate the fault current at any point of the transmission and distribution circuit. To calculate the fault current on the 33KV side of a 33-11KV step down transformer, the above equations can be used. But our most frequent activity will be to calculate fault current on 11KV side of the x-former and at various locations along the 11KV distribution circuit. When we want to calculate the fault current at different nodes on the distribution circuit, instead of using the above equations it would be much easier to calculate the fault current by simplifying the circuit and considering the 33/11KV substation as part of the source system. The impedance of the source is to be calculated and then the following equations can be applied:

i) Three-phase fault $= I_{3\phi} = \dfrac{V_f}{(z_1 + z_f)}$ (2.25)

ii) Single line -to-ground fault$= I_{(L-G)} = \dfrac{3V_f}{(z_1 + +z_2 + z_o + 3z_f)}$ (2.26)

Where, I = the R.M.S value of the steady state symmetrical AC phase current following in to the fault.

V_f = The R.M.S value of the steady state AC voltage to ground at the fault prior to the occurrence of the fault.

z_1, z_2, z_o are total positive, negative and zero sequence impedance of the system viewed from the fault and z_f is the fault impedance associated with a given type of fault.

2.6 Over Current Protection Equipment

Commonly used over current protection equipments are circuit breakers, oil circuit reclosers and fuses. A brief description about them are given below:

2.6.1 Circuit Breakers

Substation circuit breakers are heavy-duty pieces of equipment, which are mounted on the ground, require auxiliary equipment to operate and are used primarily in sub-stations.

The actual opening of the breaker is usually done by a heavy coil spring, which was compressed during the previous closing.

The actual closing of the breaker is done by a heavy duty closing mechanism, which may be operated by various different methods; for example, an electrical motor, an electrical solenoid, a tank of compressed air, etc.

The most common types of auxiliary equipment used with substation CBs are the followings:

(a) Current transformers (b) tripping relays (c) closing relays (d) a source of AC power (e) a source of DC power.

(a) Current Transformers

Current transformers, also known as CTs, are of the external wound type, which are mounted external to the CB and the bushing CTs, which are mounted inside the CB and are an integral part of it. Many CTs are of multi-ratio and provide several ratios of the primary and secondary currents such as 100/5, 200/5, 400/5, 600/5 etc.

To determine the line amperes, which will trip an OCB, the current tap or pick up value of the relay is multiplied by the CT ratio.

(b) Tripping relays

The tripping relays used for fuse coordination include the following types: Phase time-delay relays, phase instantaneous relays, ground time-delay relays and ground instantaneous relays.

All phase relay will see all types of faults, while ground relays will see only faults involving ground. Most time delay relays are induction disc-type relays which operate in the same manner as a watt-hour meter except in the following cases : (1) the disc does not begin to turn until the current through the relay exceeds a value equal to the current tap for which the relay is set; (2) the disc only makes a part of one revolution until it operates its contacts (either opening or closing); (3) the time-dial number is a measure of the angular distance the disc turns in going from rest to the operation of the contacts.

(c) Closing relay

The closing relay (more commonly called reclosing relay) automatically energizes the closing mechanism of the breaker at pre-determined time intervals after an automatic tripping of the OCB. If the OCB trips again the reclosing relay may close the OCB again. In any case, after a pre-determined number of reclosings and trips, the reclosing relay will de-energize itself and the OCB will open. This is known as lockout. If the OCB does not trip again when reclosed, then after a predetermined time interval the reclosing relay will automatically restore itself to its original condition and the OCB will be closed. This is known as reset.

One other function of the reclosing relay is that after the initial trip, it operates a contact, which prevents operation of the instantaneous relays from tripping the OCB. The instantaneous relays are cut back into service when the reclosing relay resets.

(d) Source of AC power

The source of AC power may be the sub-station service transformers or potential transformers, which are connected to the bus of the substation ahead of CB.

(e) Source of DC power

The source of DC power will be the station batteries if available.

2.6.2 Oil Circuit Reclosers

Oil circuit reclosers are defined as self contained devices for automatically interrupting and reclosing an alternating current circuit. OCRs are generally, but not always, lighter duty than OCBs and are pole mounted in distribution lines at locations relatively remote from the substations. Within the PBS systems they are used in the substations in the place of OCBS.

OCR Operational Specifications

The requirements of the OCR's operation will determine its specifications. The size is determined by the current, which the recloser can carry continuously without any overheating. The minimum trip current is the minimum current at which the solenoid will operate its plunger to open the recloser and is generally, but not always, twice the continuous current rating. The maximum interrupting capability of a recloser is the maximum RMS symmetrical current which the recloser must interrupt under the operating duty specified.

OCR Operation

In operation, the reclosers use a series-trip coil to each phase which must be insulated for the full line voltage and must withstand the full fault current. In some heavy-duty reclosers, the ground current from the CTs may be used to trip the OCR. In addition energy is taken from the current and stored in a spring until the fault has been cleared, and then the spring recloses the OCR.

During the first and second trips of an OCR, there is no intentional time delay in opening, but by means of hydraulic, mechanical or electronic timing devices an intentional time delay is introduced in the third and fourth trips.

2.6.3 Fuses

Fuses are weak links in an electrical circuit, which are designed to melt if their temperature exceeds a given value. The temperature is determined primarily by the construction of the fuse, the current flowing through the fuse, and the length of time the current is flowing. Thus by changing the material and the shape of a fuse, it can be made into an accurate timing device for over current protection.

Speed ratios for Fuses

Fuses may have fast slow and extra slow characteristics depending on the speed ratio of the fuses. Speed ratio of a fuse is defined as the ratio of the current at the intersection of the minimum melting curve and the 0.1 second line to the current at the intersection of the minimum melting curve and the 300 second line for fuses 6 through 100 amperes. The 600-second line is used for fuses over 100 Amps.

Types of Fuses

There are mainly two types of fuses, the K and T. The K or fast fuse has a speed ratio of 6 to 8. The T or slow fuse has a speed ratio of 10 to 13. The Kearney type KS fuse has a speed ratio of 17 to 22.

2.6.4 Sectionalizers

Sectionalizers are mechanical devices for automatically isolating faults on distribution systems. It should not be confused with a line fuse because a sectionalizer does not interrupt fault current and does not automatically reclose after tripping. Sectionalizer counts the surges of current through it and, after a pre-set number of surges, it opens while the backup recloser has de-energized the circuit and thus isolates the fault. The reclosing of the backup recloser energizes the line up to the sectionalizer.

2.7 Protection Scheme

Introduction: Earliest protective system was evolved from the idea of protection against excessive current. From this basic principle the graded current system i.e a discriminative fault protection has been evolved.

2.7.1 Overload protection

It is that protection in which relay operates in a time related in some degree to the thermal capacity of the plant to be protected.

2.7.2 Over current protection

This protection is devoted entirely to the clearance of faults although with this setting usually adopted some measure of overload protection is obtained.

The operating time of all over current relays tends to become asymptotic to a definite minimum value with increase in current. This is inherent in electromechanical relays due to saturation of the magnetic circuit. So by varying the point of saturation different characteristic are obtained.

These are

(1) Definite time.

(2) Inverse definite minimum time (IDMT).

(3) Inverse

(4) Very inverse.

(5) Extremely inverse.

These characteristics obtained by induction disc or induction cup relays are shown below:

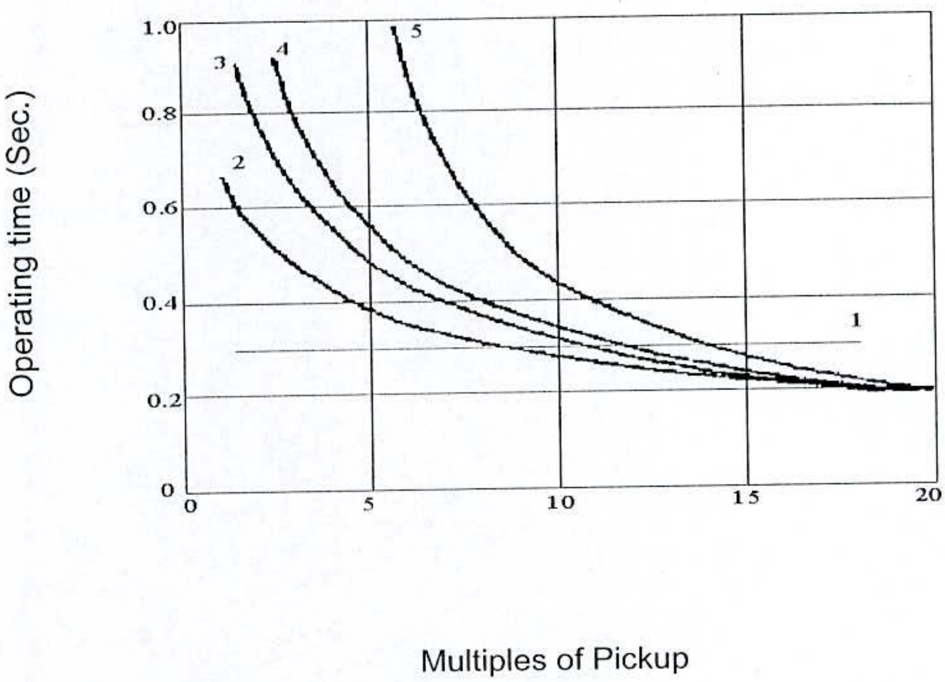


Figure 2.5:Time current characteristic curve shape comparison

The torque of these relays is proportional to $\phi_1\phi_2 \sin\theta$, where ϕ_1 and ϕ_2 are the two fluxes cutting the disc or cup and θ is the angle between them. If both fluxes are produced by the same quantity current or voltage operated relays, then below saturation the torque is proportional to I^2, the coil current i.e $T = KI^2$. If the core is made to saturate at very early stage with the result that by increasing I, K decreases so that the time of operation remains the same over the working range. This type of characteristic is shown by curve (1) and is known as definite time.

If the core is made to saturate at a later stage, the characteristic assumes the shape of curve (2), known as IDMT. The time current characteristic is inverse over some range and then after saturation assumes the definite time form. At low values of operating current the shape of the curve is determined by effect of the restraining force of the control sparing, while at high values, the effect of saturation predominates.

Different time setting multipliers (TSM) are obtained by varying the travel of the disc required to close the contracts. The higher the TSM, the greater will be the spring restraining force. As the disc moves in the tripping direction, winding up the spring, more and more conducting metal of the disc comes into play in active air gap of the electromagnet to increase the electric torque, thus compensating the increasing spring torque.

If the saturation occurs at a still later stage, the characteristic becomes very inverse, shown in curve (3). The curve (4) shows the extremely inverse characteristic.

2.7.3 Instantaneous Over Current Relay

In this type of relay no intentional time delay is provided for the operation. The time of operation of such relay is approximately 0.01 sec. This characteristic is achieved by hinged attracted armature relay. The instantaneous relay is more effective when the impedance z_s between the source and the relay is small compared with impedance z_l of the section be protected. With so fast is operation it is likely that the relay may operate as transients beyond the normal range of setting.

2.7.4 Standard IDMT Over Current Relay

IDMT relays with different operating characteristics are available to suit different requirements. The standard IDMT relay characteristic is shown in fig. 2.6. The relay has two controls, plug setting and time setting multiplier (TSM). The plug setting is a device used to provide a range of current setting at which the relay starts to operate. The setting ranges from 50% to 200% in the steps of 25% of the relay rated current. The TSM varies the time at which the relay closes its contract for given values of fault current. TSM ranges from 0 to 1 in steps of 0.05. The characteristic curve moves horizontally with the variation of plug setting and moves vertically with the variation of TSM.

To obtain the actual operating time of a relay with TSM other than 1, the characteristic operating time obtained from curve (fig. 2.6) is multiplied by the TSM of the relay.

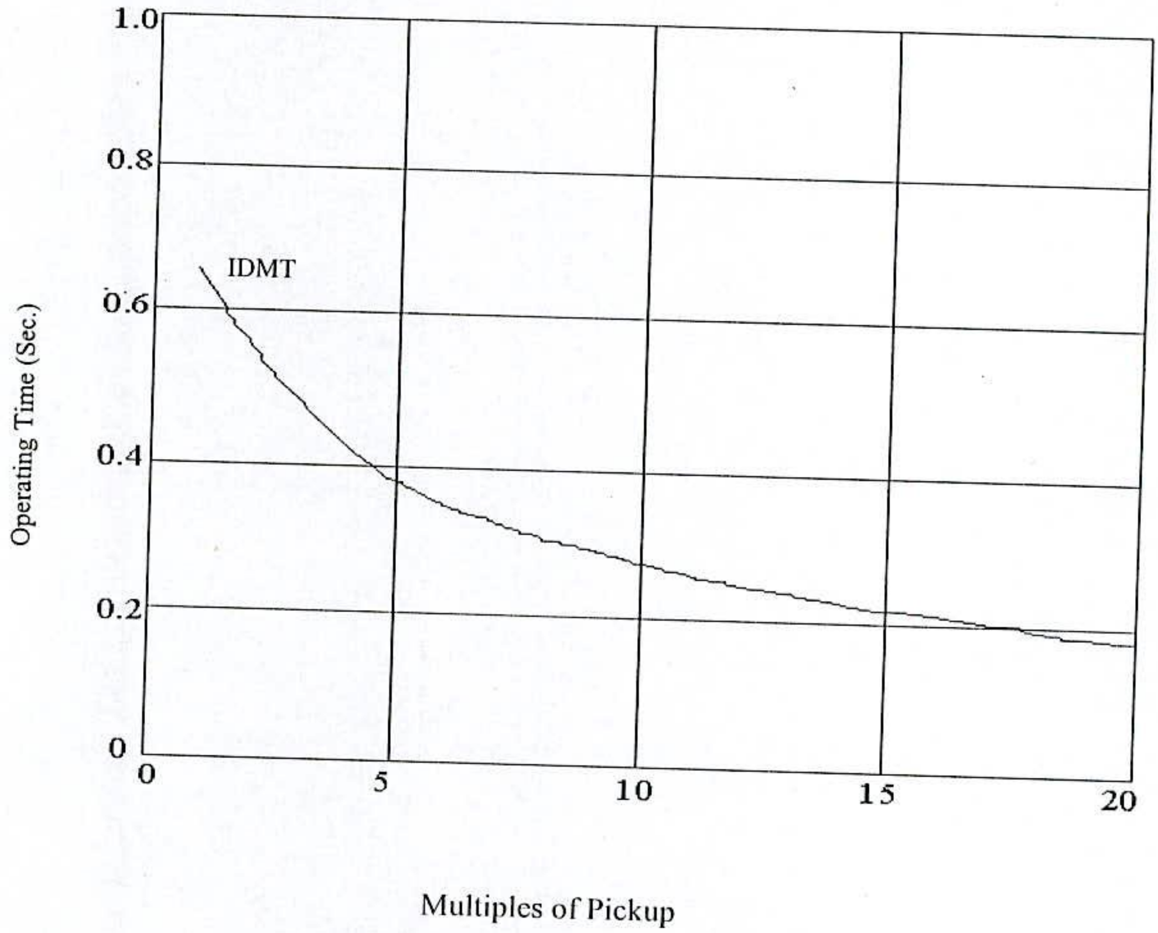


Figure 2.6: Standard IDMT curve

The characteristic curve of this relay is modeled mathematically by

$t = 0.0718\ e^{-0.0004\,i}$ (Exponential form)

$t = -0.0207\ \ln(i) + 0.1804$ (Logarithmic form)

Where,

t = Operating time in Second.

i = Fault current in Ampere

2.7.5 Over current Ground Relay

Ground overcurrent relays are for faults involving zero sequence quantities, primarily single-phase-to-ground faults and sometimes two-phase-to-ground faults. With a few significant differences, the general application rules for phase relays also can be applied to ground relays.

Ground relays usually can be set and coordinated independently of phase relays, even though the faulted phase current does flow through the one or more phase relays for a single-phase-to-ground fault. The primary reason for this independence is that ground relays are set at one-fifth to one-tenth of the sensitivity of phase relays.

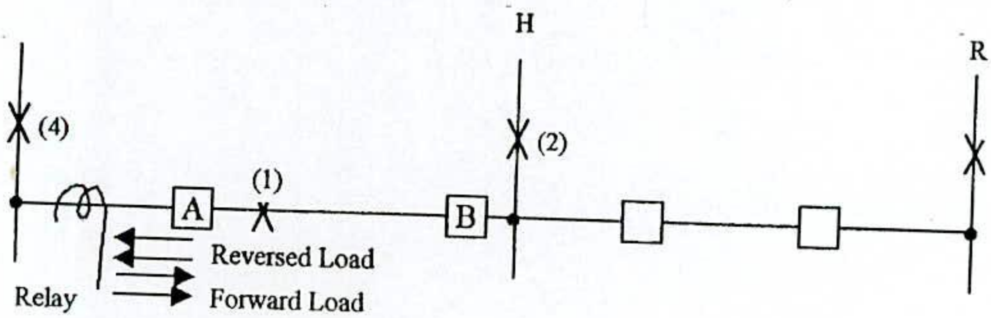


Figure 2.7:Criteria for a directional unit requirement at relay breaker "A"

A circuit may be protected with a single, non-directional over current ground relay, as shown in figure 2.7 Positive and negative sequence currents are balanced out at the current transformer neutral, so only $3I_o$ currents pass through the ground relay. Since under normal balanced conditions, $3I_o$ is at or approaches 0, a very low pickup current is used, typically 0.5 to 1.0 A. Although ground-fault currents on distribution circuits are generally higher at the substation than phase fault currents, they decrease at a much greater rate with the distance from the sub-station, because X_o is considerably larger than X_1 for the feeder circuits.

CHAPTER-III

Voltage Drop Calculation

3.1 Introduction

Rural distribution systems in Bangladesh are designed so that acceptable standards of service are maintained in operation of the system. This section is a guide to making voltage drop calculations on distribution primary lines of standard Rural Electrification designs. Examples of voltage drop calculations have been included to facilitate a more complete understanding of the procedures and methods given in this chapter.

3.2 Voltage Levels

The voltage that is present on the lines of a power system will vary from time to time because of the voltage drop due to load, the voltage rise caused by capacitors or a voltage change (rise or fall) made by voltage regulators. The voltage served to customers of the system is considered to be acceptable when it is adequate for the proper operation of connected lights, appliances, and equipment.

Voltage that is too high will shorten the life of lights and equipment, voltage that is too low will result in dim lights, improper operation of appliances, and motor failure due to overheating. Good service voltage benefits the utility through increased revenue, customer satisfaction, increased usage because of satisfaction, increased efficiency of distribution equipment and decreased investment/KVA distributed [18].

Allowable variation	Phase to Neutral	Phase to phase(L-L)
Maximum (105%)	241.5 Volts	418.3 Volts
Normal (100%)	230.0 Volts	400.0 Volts
Minimum (96.5%)	221.9 Volts	386.0 Volts

The total system voltage drop permitted on the distribution system is determined as the difference in voltage between the maximum service voltage delivered at the customer nearest the 11KV power supply substation and the minimum service voltage delivered to the customer located furthest away from the substation. The maximum voltage drop on a 230-Volt base is 19.6 Volts (241.5-221.9). The distribution of this voltage drop among the various components of the system is shown below:

TABLE-3.1: Allowable voltage drops-maximum load conditions [18]

241.5 Max. voltage on a 230 volt base

Sl.No.	Description of the system	Max. Volts Drop	% Volt Drop
1.	Primary line	6.9	3.0
2.	Distribution Transformer	3.5	1.5
3.	Secondary Main	4.6	2.0
4.	Secondary Branch/Service	4.6	2.0
5	Total Voltage drop at Customer's service entrance	19.6	8.5%

3.3 Basis for Voltage Drop Calculation

As a basis for the preparation of voltage drop calculations, the following information relative to the system or portion of the system should be on hand:

i) A Circuit Diagram showing all areas and loads which are to be served by the system for which the voltage drop calculations are being made. Although a circuit diagram may serve the dual purpose of voltage drop calculations and sectionazing studies, a separate circuit diagram for the voltage drop calculation is recommended.

ii) The number of consumers for each section of each circuit of a balanced design.

iii) The number of consumers for each phase of each section of each circuit of an unbalanced design.

Basis of Calculation

Individual line voltage drop calculation should be based upon relative load levels, which are consistent with the overall system design level. Voltage drop calculations are referred to a 230-volt base.

$$\text{Voltage Drop (230 volt base)} = \frac{ActualVoltageDrop}{SystemNominalVoltage}(230)\ V \qquad (3.1)$$

For example:

Nominal system voltage = 11 KV GRD.Y

Actual voltage drop = 360 Volts/phase

$$\text{Voltage Drop (230 volt base)} = \frac{360 \times 230}{6350} = 13.04 volts/\text{phase}$$

In these calculations all lines are assumed to be operated at 95% lagging power factor. The lines on the circuit diagram are divided into sections with the ends of the sections at the following points:

1. Substations
2. Major taps and at the end of such taps, (A major tap is defined as a tap having a load which is estimated to be equal to 20 percent of line load at that point).
3. Phase changes
4. Conductor size changes
5. Concentrated loads- (A concentrated load is defined as a load, which is estimated to be more than 25 KW).

Balanced circuit calculation

The following assumptions are made for completing the voltage drop work sheet when calculating voltage drop on balanced circuits. A balanced circuit is defined as a multi-phase line loaded such that the estimated load of any phase is not less than 80 percent or not greater than 120 percent of the average per phase load.

Unbalanced Circuit Calculation

On unbalanced circuits the voltage drop is calculated for each phase separately for the loads on that particular phase. An unbalanced circuit is defined as a multi-phase line loaded such that the estimated load of any phase is less than 80 percent or greater than 120 percent of the average per phase load. On unbalanced circuits the voltage drop factor for "V" phase lines is the single-phase voltage drop factor and on three-phase lines it is three times the voltage drop factor for three-phase balanced circuits.

3.4 Voltage Drop Calculation Method

Voltage drop for known source end and lagging power factor conditions may be calculated from the following equation:

$$\text{Voltage drop} = I\,(R\cos\theta + X\sin\theta) \tag{3.2}$$

Where, I = Line current in amperes

θ = Phase angle between voltage and current

R = Resistance of line in ohms

X = Reactance of line in ohms

It can be seen from the vector diagram that this approximate equation is sufficiently accurate for the magnitude and phase angle of the vectors resulting from normal system designs.

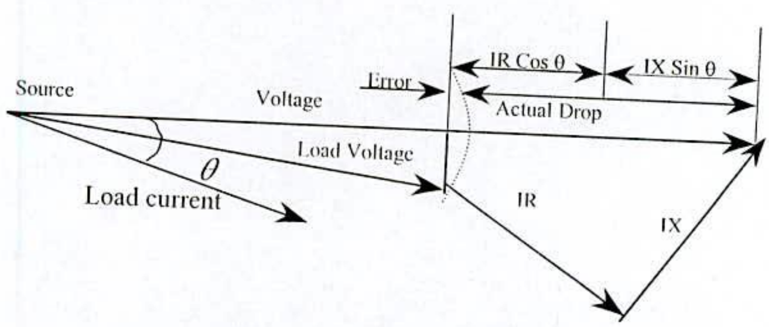


Figure 3.1 : Vector diagram

Line current may be expressed in terms of kilowatts and voltage as follows:

$$I = \frac{KW}{(KV)(Cos\,\theta)(P)} \quad Amps. \tag{3.3}$$

Where, KW = Circuit load in kilowatts

KV = System nominal phase to ground voltage in kilovolts

P = Number of phase

Voltage drop(VD) referred to a 230-volt base is expressed as follows:

$$VD = \frac{Actual\,Voltage\,Drop(230)}{System\,Nominal\,Voltage} \quad Volts \tag{3.4}$$

Using the above equations for line current and voltage drop referred to on a 230-volt base, the equation for voltage drop (VD) becomes:

$$VD = \frac{(KW)(RCos\theta + XSin\theta)(230)}{(KV^2)(Cos\theta)(P)(1000)} \quad Volts \tag{3.5}$$

The equation for (VD) expressed in per KM units written as follows:

$$VD = \frac{(KW)(r\,Cos\,\theta + x\,Sin\,\theta)(S)(230)}{(KV^2)(Cos\,\theta)(P)(1000)} \quad Volts \tag{3.6}$$

Where, r = Resistance in ohms per phase per KM of line

x = Reactance in ohms per phase per KM of line

S = Line distance in KM

Letting the following factor be designated the voltage drop factor (VDF)

$$\text{VDF} = \frac{(rCos\theta + xSin\theta)(230)}{(KV^2)(Cos\theta)(P)} \tag{3.7}$$

The equation for VD becomes:

$$VD = \frac{(KW)(S)(VDF)}{1000} \quad Volts \tag{3.8}$$

3.5 Steps of Voltage Drop Calculation

A complete procedure for the calculations of voltage drop in a radial feeder should consist of the following:

1. Basic Data

   a) Tabular summary of all-consumers by classifications.

   b) Tabular summary of the number of concentrated loads (such as large Industrial, Tea Gardens, etc.) with their KW demands.

   c) Design KWh/month/consumer for all consumers except for those included in (b) above.

Demands are based on the following formula[18]:

Demand $=C[1-0.4C+0.4\sqrt{(C^2+40)}]\times 0.005925(\text{KWH/CUSTOMER /MONTH})^{0.885}$

Where C =Number of Customer and <1400

Demand $=C\times 0.005925\times(\text{KWH/CUSTOMER /MONTH})^{0.885}$ for $C \geq 1400$

Generally for PBS distribution system, 20 KWH/CUSTOMER /MONTH for domestic consumers and 30 KWH/CUSTOMER /MONTH for commercial consumers are assumed. Higher values may be taken for any PBS if it is justified by the statistics.

2. Completed voltage drop circuit diagrams.

3. Voltage drop work sheets.

4. Explanatory comments :

   a) Basis for design kwh/mo/consumer for the system.

   b) Basis for design kwh/mo/consumer for the substations and feeders.

   c) Basis for calculating contributing demand of such loads as large industrial loads, teagardens, etc.

The basic data should be developed and presented in such a manner as to show the number and sizes of all loads considered and as to facilitate future voltage analysis required due to unforeseen changes in loading

The per phase per KM resistance and reactance of distribution lines, the voltage drop factor (VDF) for calculating voltage drop of distribution lines and the voltage drop factor (VDF) for calculating voltage drop of distribution lines constructed in accordance with REB standard can easily be obtained from table- 3.2,3.3 and 3.4 respectively [18].

PER KM RESISTANCE AND REACTANCE OF 6.35/11 (GRD.Y) KV DISTRIBUTION LINE

TABLE –3.2

Conductor Size	Ohms per circuit-KM of line					
	Single-Phase		"V"-Phase		Three-Phase	
	r	x	r	X	r	x
#4/0 AWG ACSR - "PENGUIN"	0.4737	0.6631	0.4737	0.6631	0.3522	0.4001
#1/0 AWG ACSR - "RAVEN"	0.7982	0.7625	0.7982	0.7625	0.6709	0.4392
#3 AWG ACSR - "SWALLOW"	1.3946	0.7650	1.3946	0.7650	1.2673	0.4417
336.4 MCM - "MERLIN"					0.1900	0.3389
30(2.59)/7(2.59) - "WOLF"					0.2069	0.3353
6(4.72)/7(1.57) - "DOG"					0.3386	0.3875
6(3.35)/1(3.35) - "RABBIT"					0.6206	0.4102
6(2.36)/1(2.36) - "GOPHER"					1.2306	0.4275
477 MCM-26(3.44)/7(2.67) - "HAWK"					0.1342	0.3218

Equivalent spacing =1482.6 mm

Note: i) Resistances are A.C values @50Hz and 50°C

ii)Reactances are @50Hz and standard REB spacing

PER KM VOLTAGE DROP FACTORS OF 6.35/11 GRD. Y: KV[18]
DISTRIBUTION LINE (230 VOLT BASE)

$$VD = \frac{(KW)(RCos\theta + XSin\theta)(230)}{(KV^2)(Cos\theta)(P)(1000)}$$ for Cos θ = 0.95

TABLE –3.3

Conductor size/ Copper Equivalent	Single-Phase	"V"-Phase	Three-Phase
#4/0 AWG ACSR - "PENGUIN"	3.9452	1.9726	0.9197
#1/0 AWG ACSR - "RAVEN"	5.9825	2.9912	1.5501
#3 AWG ACSR - "SWALLOW"	9.3890	4.6945	2.6856
DOG	-	-	0.8860
RABBIT	-	-	1.4363
GOPHER	-	-	2.6069

PER KM DROP RESISTANCE AND REACTANCE OF 33 KV LINES[18]
AND VOLTAGE FACTOR AT PF = 0.95

TABLE –3.4

Conductor Size	Three Phase r	Three Phase x	Voltage Drop Factor (33KV)
MERLIN	0.1900	0.3484	0.0643
WOLF	0.2069	0.3449	0.0677
477 MCM, HAWK	0.1342	0.3314	0.0514
4/0, PENGUIN	0.3522	0.4096	0.1028

*Equivalent spacing = 1720.5 mm

3.6 SAMPLE VOLTAGE DROP CALCULATION

A sample voltage drop calculation for the system whose single line diagram is shown in the figure below and voltage drop calculation chart is also shown below.

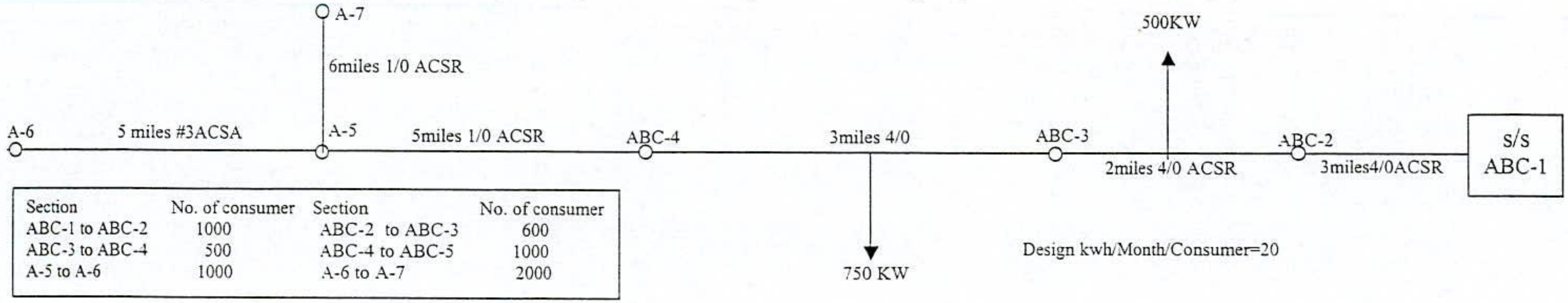


Figure 3.2: Single line diagram for sample voltage drop calculation

Table-3.5

Rural Electrification Board					Name of Area :X					Substation :Y					System Design 20 KWH/MONTH/CUST				
Voltage Drop Work Sheet					System Eng. CAI					Circuits ABC					Date March. 2002				
Section		Load								Line									
		Consumers					Concentrated										Volt Drop		
Source End	Load End	Within this Sect.	Past this Sect.	Equiv. this Sect. .5x3+4	KWH/ Mon/ Cust	KW this Sect.	KW this Sect.	KW past this Sect.	Equiv. KW This Sect. .5x8+9	Total KW 7+10	Wire Size	Phase	KV	Volt Drop Factor	Line Miles this Sect.	KW Miles 11x16	This Sect. 15×17/1000	Total	At Point
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
A-5	A-7	2000	-	1000	20	84.6	-	-	-	84.6	1/0ACSR	1	6.35	10.7199	8	676.8	7.26	40.0	A-7
ABC-4	A-5	1000	3000	3500	20	294	-	-	-	294	1/0ACSR	1	6.35	10.7199	5	1470	15.76	32.74	A-5
ABC-3	ABC-4	500	4000	4250	20	357	750	-	375	732	4/0ACSR	3	6.35	1.6711	3	2196	3.67	16.98	ABC-4
ABC-2	ABC-3	600	4500	4800	20	403	500	750	1000	1403	4/0ACSR	3	6.35	1.6711	2	2806	4.69	13.31	ABC-3
ABC-1	ABC-2	1000	5100	5600	20	470	-	1250	1250	1720	4/0ACSR	3	6.35	1.6711	3	5160	8.62	8.62	ABC-2

3.7 Column Explanation for Voltage Drop Worksheet

Columns 1 & 2 -	Starting at the farthest ends of the circuit from the substation, designate the section being considered by letters corresponding to the points previously marked on the circuit diagram to indicate the ends of the sections. For example, "ABC-5 to A-7" designates the single-phase line composed of phase A between points 5 and 7.
Column 3 -	The column shows the number of consumers (corresponding to the system design) in the section. (Concentrated loads are not included)
Column 4 -	This column shows the number of consumers who are supplied power, which must flow all the way through the section being considered. These figures are obtained by adding the figures in column 3, which pertain to sections beyond the section being considered.
Column 5 -	This column shows the equivalent of consumers that are supplied through the section being considered. These figures are obtained by adding one-half the consumers shown in column 3 to the number of consumers showing in column 4.
Column 6 -	This column shows the average kilowatt hour consumption per consumer per month used for the circuit.
Column 7 -	The peak kilowatt demand for the number of consumers shown in column 5 is entered in this column. Peak kilowatt demand is read directly from the appropriate demand table.
Column 8 -	The contributing peak load of the concentrated loads within the section being considered is to be entered. Concentrated loads are considered to be those customers with a KW demand greater than 25 KW.
Column 9 -	The contributing peak load at the end and beyond the section being considered is to be entered.
Column 10 -	The total equivalent contributing peak load of the concentrated loads, column 9 plus one-half of column 8 is to be entered.
Column 11 -	The total equivalent load for the section, column 10 plus column 7 is to be entered.
Column 12 -	The conductor size used in the section is to be entered.
Column 13 -	The number of phases in the section being considered is to be indicated.

Column 14 - The line-ground kilovolts of the line is to be indicated.

Column 15 - These values are taken from Table-2, this section. Voltage drop factors, for the conductor size, number of phases and voltage given in columns 12, 13 and 14.

Column 16 - The total length in kilometers, of the section being considered is to be showed.

Column 17 - The kilowatt-kilometers, which are the product of the figures in columns 11 and 16 are to be showed.

Column 18 - The voltage drop in the section is to be entered. These values are obtained applying the equation.

Voltage Drop (230 volt Base)

$$= \frac{(Total KW)\,(Kilometers)\,(Voltage\ \ Drop\ \ Factor)}{1000}$$

$$= \frac{(Column\ \ 17)(Column\ 15)}{1000}$$

Column 19 - This column shows the voltage drop at the load end of each section. The values are found by starting with the section nearest to the source and summing up the voltage drops in all the sections between the source and the section being considered, including the voltage drop in this section. The voltage drop thus calculated applies at the load end of each section being considered.

Column 20 - This column shows the point at which the calculated voltage drop applies. The letters designate the load end of the respective sections, same as column 2.

3.8 Voltage Level Improvement

To improve system voltage conditions, voltage regulators or shunt capacitors may be used, often both are necessary to have a well-balanced system operating at maximum efficiency. In general, it can be said that the voltage regulators should be used to maintain accurate control of the voltage throughout the load cycle and shunt capacitors should be used to correct low power factors, which rob the capacity of system and decrease voltage levels. Improvement of power factor will raise the overall system voltage level. Voltage level of a distribution system can also be improved by changing lower size conductors by higher ones.

CHAPTER-IV

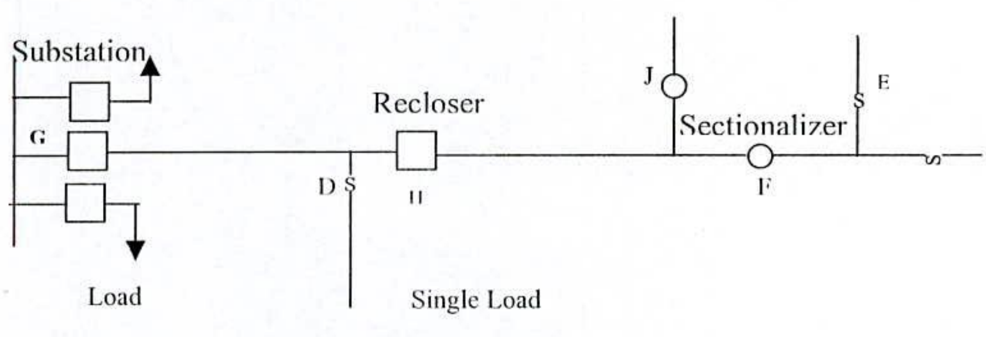
Over Current Protection Coordination

4.1 Introduction

Proper coordination of protective relays and other protective devices is essential to ensure the reliability of any power system. The objective of selecting the relay setting is to active the minimum possible operating times while maintaining coordination among all relays. For proper coordination between relays, connected in series on a radial feeder TMS of the farthest relay from the source should be set at a minimum value so that it operates at a minimum possible time. The TMS of the succeeding relays towards the source should be increased for selective operation

4.2 Protection of Radial Distribution System

Radial circuits can be protected by non-directional over current relays. Figure 4.1 shows a typical feeder circuit using a circuit breaker, recloser, sectionalizers, and fuses. The three reclosers of breaker G should be time-delayed to allow clearing of faults beyond recloser H. The first recloser can be instantaneous, however, if the instantaneous trip units of the relays can be short of H, and the reclosing relay can lock out subsequent instantaneous trip operations after the first recloser.The recloser at H can be set for either one or two instantaneous reclosers; the other two or three should be time-delayed.



G=Circuit Breaker H=Circuit Recloser C,D & F=Fuses J & F=Sectionalizers

Figure 4.1 Typical distribution feeder protection.

4.3 Algorithm for Optimal Relay Coordination

For determining coordinated relay setting the simplex two-phase method is used. Phase-I determines whether the selected operating conditions between primary and back up relays are feasible and phase-II finds the optimum relay settings. The operating conditions that are detected in phase-I to be "not valid" are excluded at the beginning of phase-II.

For a network consisting of m relays, the operating times of the primary relays for near end faults can be expressed as:[8]

$$z = \sum_{i=1}^{m} t_{i,i} \qquad (4.1)$$

Where, t_{ii} is the operating time of the primary relay at i for near-end fault at i.
The operating times of the back-up relays must be more than the sum of the operating times of the
primary relays and the coordination margin. This can be expressed as

$$t_{bi,i} \geq t_{i,i} + \Delta t, \qquad for\ i = 1\ to\ m, \qquad (4.2)$$

Where, t_{ii} is the operating time of the primary relay for near-end fault,
t_{bii} is the operating time of the backup relay for same near-end fault and
Δt is the coordination time interval (CTI).

In the application reported in this thesis, overcurrent relays conformed to the following IEC characteristic [8].

$$t = \frac{k \times TMS}{I_{mpu}^{\ n} - 1} \qquad (4.3)$$

Where, k is a constant,
n is a characteristic index,
I_{mpu} is the multiple of pick-up current and
TMS is the time multiplier setting.

Since the pickup currents of the relays are pre-determined from the system requirements, Equation 4.3 becomes

$$t = a \times TMS \qquad (4.4)$$

$$Where,\ a = \frac{k}{I_{mpu}^{\ n} - 1}$$

By making this substitution in Equation 4.1, the objective function becomes

$$z = \sum_{i=1}^{m} a_i \; TMS_i ,$$

In this equation all a_i.s are known ; values of TMS_i are determined by minimizing z and satisfying the coordination between the primary and backup relays. This equation is optimized using simplex two-phase method [20] subjected to condition that the operation of the backup relays remains properly coordinated.

4.4 Coordination

In a coordinated protective system the load side device interrupts the fault before the source side device. The first coordination occurs on the temporary fault. With this temporary fault the OCB or OCR should clear the fault so that, even if the fault is beyond a lateral fuse, the fuses will not even being to melt. The second coordination occurs when the fast trip has been disabled, on the second or third trip, then it is wanted that the OCB or OCR to have enough time delay before tripping so that, if the fault is beyond a fuse then the fuse will totally clear the fault before the OCB or OCR will trip. In the example shown in fig. 4.1, relays at H will delay for faults at (1) or (2). If the fault is at (1), this delay will allow the R relays and breaker to operate before H. Thus, although H would not open for a fault at (1) (unless the R relays or associated breaker failed),it would operate for a fault at (2). Relays are coordinated in pairs. If, in figure 4.1, breaker H relay tripping characteristics have already been coordinated with whatever protective devices exist at R and beyond, the breaker at G must then be coordinated with those at H.

The following data are required for coordination setting for relays at breaker "G" (fig.4.1) of the three critical fault points (5), (3) and (2).

1. Fault at (5). Maximum and minimum fault currents.
2. Fault at (3). Maximum fault current, which determines the required coordination between breakers G and H.
3. Fault at (2). Minimum fault current, which determines when the G relays must operate to provide backup protection for faults on line HR not cleared by the breaker at H.

Relays are coordinated in pairs. If, in fig. 4.1, breaker H relay tripping characteristics have already been coordinated with whatever protective devices exist at R and beyond, the breaker at G must then be coordinated with those at H

Relays within a system can be coordinated using graphs or tables, although graphs are generally more useful for radial systems. Semi-log (log abscissa for current and linear ordinate for time) or log-log paper can be used. Log-log is preferred when a number of different types of devices, including fuses, are being coordinated in one graph. The current scale can be in primary amperes or per unit. Any difference in current transformer ratios must be taken into consideration when determining actual relay currents at different Locations. The relay curves can be moved either along X (current) axis and Y (time) axis. The relay curves can be related to CT ratio or change in plug setting multiplier (PSM) (X-axis shifting) or they can be related to change in Time Multiplier Setting (TMS) (Y-axis shifting). A coordinating time interval (CTI) of 0.25 sec. is to be considered.

4.4.1 Coordinating Time Interval (CTI)

The coordinating time interval is the minimum interval that permits the remote (upstream) relay and breaker to clear a fault in its operating zone. Factors influencing the CTI are as follows:

1. Breaker fault interruption time

2. Relay-impulse-time over travel of the induction disk or solid-state relay after the fault current has been interrupted

3. Safety margin to compensate for possible deviations in calculated fault currents, relay tap selection, relay operating time and current transformer ratio errors

For coordinating at above approximately three times minimum trip current (at least two times the setting value), the CTI should be in the range of 0.2 to 0.5 sec. [21].

4.4.2 Coordination Procedure

The coordination procedure is conducted as follows:

First, the desired relay type is assumed and current transformer ratio is to be determined. Then the following steps are to be performed.

1. The circuit fault locations and fault current values are determined.

2. These variables are plotted on the time current graph, drawing vertical lines at the various values.

3. The setting of the most downstream relay for the maximum and minimum fault currents is determined. The relay is set as sensitive and fast as possible if there is no other device downstream that has to be coordinated with. If there is some other device, such as a power fuse, to the right of this relay, then this relay should be coordinated with power fuse first. If there is no other device to coordinate with down stream, the over current relay is to be set equal to or greater than 2 times maximum load.

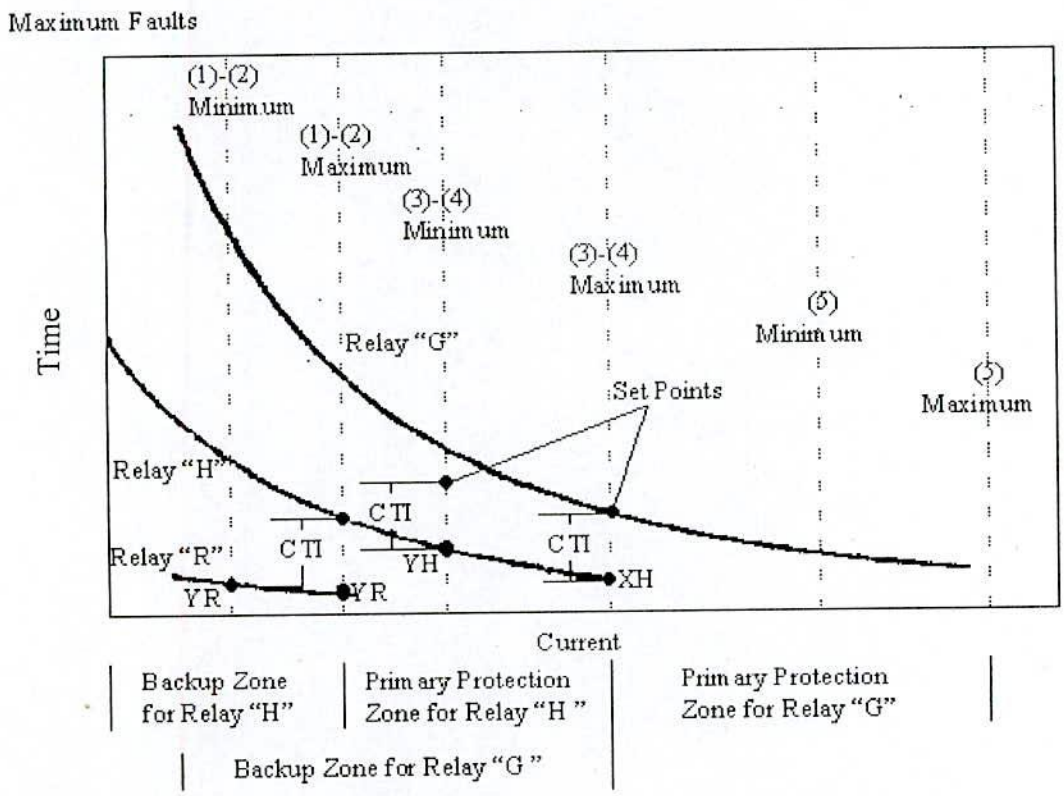
4. The operating time of relay R (figure 4.1) is to be plotted on the time current graph, shown as XR and YR points in Figure 4.2, respectively.

5. A one step coordinating time interval (CTI) is added to points XR and YR. This step gives two set points for the characteristic curve of the relay at H (Figure 4.1).

6. A tap for relay H is selected to operate for fault (1) minimum and, for a phase relay, not to operate on maximum load. The fault (1) minimum should operate the relay on at least twice pickup, although compromises may be necessary. For phase relays, setting must always be above the maximum load.

7. A time lever is selected such that the relay H time-current curve passes through or above one or both of set points XR and YR and provides the minimum operating time for maximum and minimum fault.

8. The above steps are to be repeated for each time section "up-stream". For example, a one step CTI is added to XH and YH in Figure 4.2 for relay H, respectively, then a tap and time lever for relay H is to be selected.



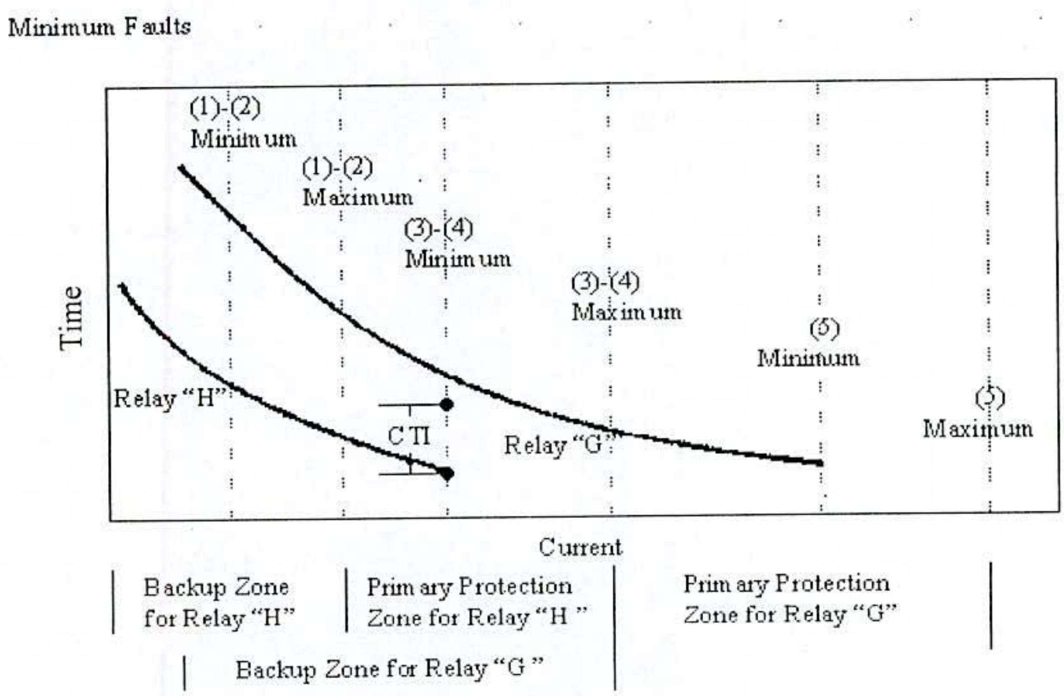


Figure 4.2: Coordination Setting Procedure for Relays at Breaker "G" of figure 4.1

4.5 Fault Calculations

The knowledge of fault currents is necessary for selecting the circuit breakers of adequate rating, designing the sub-station equipment, determining the relay settings, etc. The fault calculations provide the information about the fault currents and the voltages at various points of the power system under different fault conditions.

The per unit system is normally used for fault calculations. The symmetrical faults such as three phase faults are analyzed on per phase basis, for calculations on unsymmetrical faults; the method of symmetrical components is adopted. The network analyzer and digital computers are used for fault calculations of large systems.

4.5.1 Approaches to Short Circuit Calculations

(a) Drawing a Circuit Diagram

i. The points (nodes) are labeled on the diagram where fault currents are to be calculated.

ii. The different types of wires or cables used are identified.

iii. For each line section on the diagram, the circuit type and its length in meter are shown.

(b) Calculation of the Source Impedances

Using the 132 KV Transmission system three phase symmetrical fault level as 900 MVA and knowing the 132/33KV transformer KVA and % impedance, the length and size conductor of the 33KV feeder, and the distribution substation 33/11KV transformer KVA and % impedance, the distribution substation 11KV bus three phase and line-to-ground fault currents are calculated.

(c) Determination of the Line Section Impedances by Type of Line in Ohms per Km.

For each identified type of line, the attached wire table is used to find the positive and zero sequence impedances on ohms per Km.

(d) Determination of Line Section Impedances in Ohms

For each line section shown on the Diagram, the section length in Km. are multiplied by the positive and zero sequence values from step 3 in ohms per Km.

(e) **Selection of Fault Impedance**

In general, the fault impedance of a three-phase fault is considered to be zero (0), likewise, faults in substation or underground cable sections would be calculated with fault impedance of zero (0). Line-to-ground faults in an overhead line section would be calculated with fault impedance of 40-ohm.

(f) **Calculation of Total Impedance at Node of Fault**

Add the positive sequence impedances from step 4 of all the line sections connecting the node of the fault to the source including the positive sequence source impedance developed in step 2. The negative sequence impedances are equal to the positive sequence impedances. The procedure is repeated for the zero sequence impedances.

(g) **Recording the Fault Currents on the Diagram**

The maximum and minimum fault currents are shown on the circuit diagram at each node where the fault currents have been calculated.

The following is an example of fault current calculations for typical rural line:

4.5.2 Simplified Short Circuit Calculations

(a) Determination of the three phase and line-to-ground short circuit currents available on the 11KV bus at the 33/11KV distribution substation.

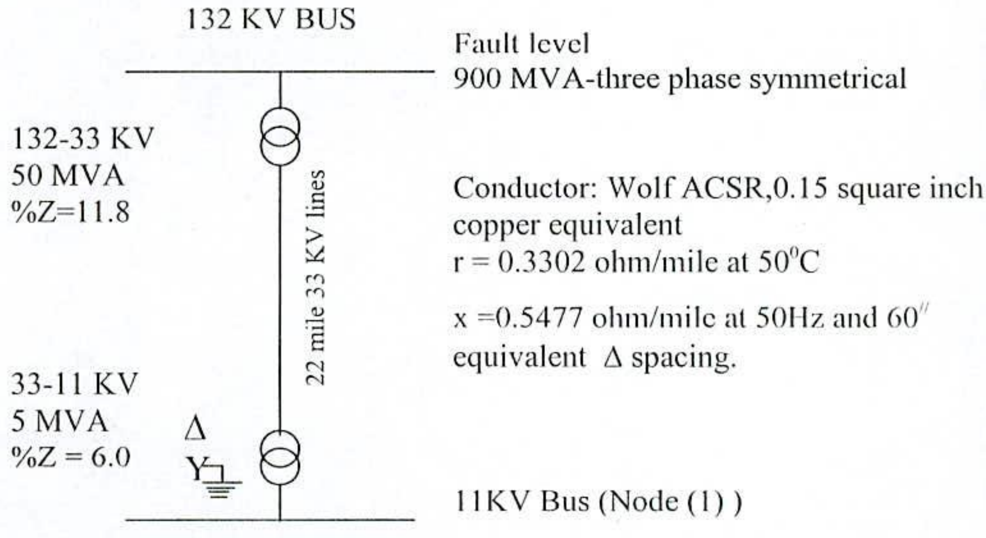


Figure: 4.3 Single line diagram of a power system

Using 100 MVA as the base MVA, the per unit impedance values on the source side of the distribution substation 11KV bus is calculated.

$$z_1(132\ KV\ system\ ) = J\frac{MVA_B}{MVA_{132}} = J\frac{100}{900} = J0.1111\ pu$$

$$z_1(132/33KV\ X-former) = J\frac{\%Z}{100} \times \frac{MVA_B}{MVA_{X-former}} = J\frac{11.8}{100} \times \frac{100}{50} = J0.2360pu$$

Note: The resistance of the 132KV transmission grid and the 132/33KV transformer are so small in comparison with their reactance that they are neglected and the impedance of the system is taken as being equal to reactance.

z_1 (33KV Line) = 22 (0.3302+J 0.5477)=7.2644 + J 12.0494 ohms

$$z_{pu} = \frac{z_1 ohms}{z_B ohms}$$

$$z_B = \frac{KV_B{}^2}{KVA_B} = \frac{33 \times 33}{100} = 10.89\ ohms$$

$$z_1(33KV\ \ Line) = \frac{7.2644 + J12.0494}{10.89} = 0.6671 + J1.1065pu$$

$$z_1(33/11KV\ \ X-former) = J\frac{6.0}{100} \times \frac{100}{5} = J1.2000pu$$

Keeping in mind that the 33/11KV transformer is connected and the zero sequence impedance cannot be reflected through a delta wye (ΔY⏚) connected winding, the source impedances of the system on a per unit basis viewed from Figure 4.2: Coordination Setting Procedure for Relays at Breaker "G" of figure 4.1the distribution substation 11KV bus are summarized as follows:

	$Z_1 = Z_2$	Z_0
132KV system	0+J 0.1111	-
132/33KV transformer	0+J 0.2360	-
33KV line	0.6671+J 1.1065	-
33/11KV transformer	0+J 1.200	0+J 1.2000
	0.6671+ J 2.6536	0+J 1.2000

Since all the following calculations are at the 11KV level, the source impedance per unit values may be changed to ohms on the 11KV base.

$$z_B = \frac{11 \times 11}{100} \qquad = 1.21 \text{ ohms}$$

11KV bus z_1 = z_1 pu x z_B = 1.21 (0.6671+J 2.6536)

z_1 = 0.8072 + J 3.2109 ohms

$z_1 = z_2$ = 3.3108 ohms

z_o = 1.21 (0+J 1.2000) = 0+J 1.4520 ohms

When the impedance values are given in ohms, the three phases and line-to-ground fault currents are calculated by using the following formulas:

$$I_{3\phi-Sym} = \frac{V_F}{z_1}$$

$$I_{(L-G)Max} = \frac{3V_F}{z_1 + z_2 + z_o}$$

$$\& \quad I_{(L-G)Min} = \frac{3V_F}{z_1 + z_2 + z_o + 3z_F}$$

V_F = Line-to-ground volts at fault

z_1, z_2, z_o = Total positive, negative and zero sequence impedances of the system viewed from the fault.

z_F = Fault impedance

All the 11KV bus

$$I_{3\phi-Sym} = \frac{11000}{\sqrt{3}} \times \frac{1}{3.3108} = 1918\,Amps$$

$$I_{(L-G)Max} = \frac{3 \times 11000}{\sqrt{3}} \times \frac{1}{2(0.8072 + J3.2109) + (0 + J1.4520)}$$

$$I_{(L-G)Min} = \frac{\sqrt{3} \times 11000}{2(0.8072 + J3.2109) + (0 + J1.4520) + 3 \times 40}$$

$$= \frac{\sqrt{3} \times 11000}{1.6144 + J7.8738} = \frac{\sqrt{3} \times 11000}{8.0376} = 2370\,Amps$$

$$= \frac{\sqrt{3} \times 11000}{121.6144 + J7.8738} = \frac{\sqrt{3} \times 11000}{121.8690} = 156\,Amps$$

Proceeding as instructed in 3, 4, 5 and 6, the fault currents at the various nodes in the circuit are calculated. The following shows the calculations for determining the fault currents at node (2).

	$z_1 = z_2$ *ohms*	z_o *ohms*
11KV bus (node (1))	$0.8072 + J\,3.2109$	$0 + J\,1.4520$
Section (1) to (2)		
2(0.5670+J 0.6440)		
2(1.1601+J 1.9297)	$1.1340 + J\,1.2880$	$2.3202 + J\,3.8594$
Total Impedance at node (2)	$1.9412 + J\,4.4989$	$2.3202 + J\,5.3114$

At node (2) $I_{3\phi-Sym} = \dfrac{11000}{\sqrt{3}} \times \dfrac{1}{1.9412 + J\,4.4989}$

$$= \frac{11000}{\sqrt{3}} \times \frac{1}{4.8998} = 1296\ Amps$$

$$I_{(L-G)Max} = \frac{3 \times 11000}{\sqrt{3}} \times \frac{1}{2(1.9412 + J4.4989) + (2.3202 + J5.3114)}$$

$$= \frac{3 \times 11000}{\sqrt{3}} \times \frac{1}{6.2026 + J14.3092} = \frac{3 \times 11000}{\sqrt{3} \times 15.5957}$$

$$I_{(L-G)Min} = \frac{3 \times 11000}{\sqrt{3}} \times \frac{1}{2(1.9412 + J4.4989) + (2.3202 + J5.3114) + 3(40 + J0)}$$

Using the work sheet as shown by the attached example to tabulate and record the various impedances and short circuit values at the circuit nodes organize the work and calculations necessary for the fault current study.

The fault currents that are found from this study will later be used to coordinate line over-current protective devices.

b) Determination of the three phase and line-to-ground short circuit currents available on the 11KV bus and different nodes of distribution lines.

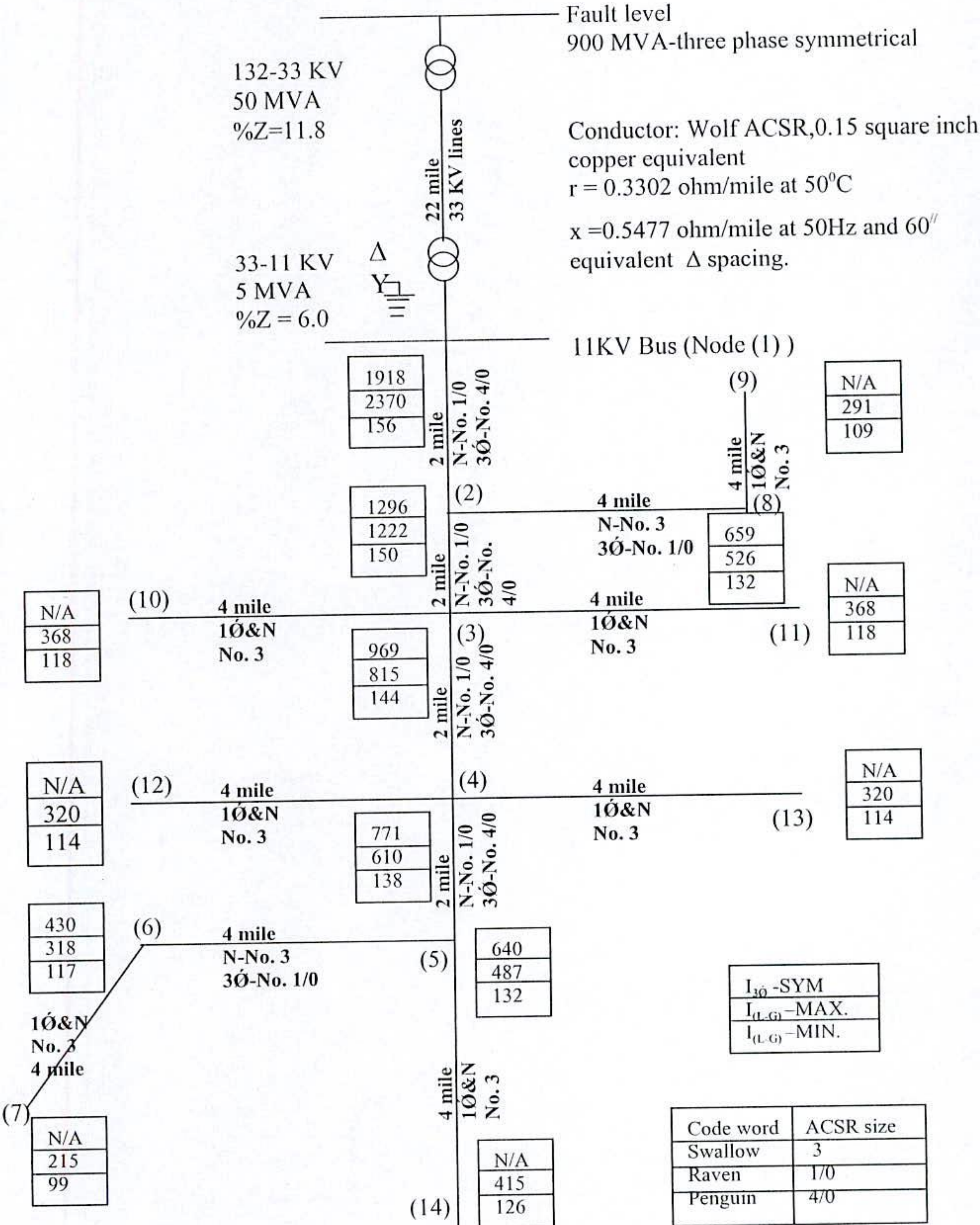


Figure 4.4 Single line diagram of a radial distribution system showing fault currents

TABLE-4.1 FAULT CURRENT CALCULATION WORK SHEET

Section or Node	$R_1=R_2$ ohms	$x_1=x_2$ ohms	$z_1=z_2$ ohms	R_o ohms	x_o ohms	z_1+z_f ($z_f=0$)	$z_1+z_2+z_o$, $z_1+z_2+z_o+3z_f$ ($z_f=40$) ohms	Fault Current $I_{3\phi\text{-sym}}$ Amps	$I_{(L\text{-}G)\text{-Max}}$ Amps	$I_{(L\text{-}G)\text{-Min}}$ Amps
@1 11kv Bus 1 - 2	0.8072 1.1340	3.2109 1.2880	3.3108	0 2.3202	1.4520 3.8594	3.3108	8.0376 121.8690	1918	2370	156
Total @ 2 3 - 4	1.9412 1.1340	4.4989 1.2880	4.8998	2.3202 2.3202	5.3114 3.8594	4.8998	15.5957 127.0112	1296	1222	150
Total @ 3 3 - 4	3.0752 1.1340	5.7869 1.2880	6.5532	4.6404 2.3202	9.1708 3.8594	6.5532	23.3833 132.4257	969	815	144
Total @ 4 4 - 5	4.2092 1.1340	7.0749 1.2880	8.2323	6.9606 2.3202	13.0302 3.8594	8.2323	31.2292 138.0805	771	610	138
Total @ 5 5 - 6	5.3432 4.3200	8.3629 2.8280	9.9241	9.2808 6.7800	16.8896 9.0728	9.9241	39.0984 143.9473	640	487	132
Total @ 6 6 - 7	9.6632 -	11.1909 -	14.785 6	16.0608 -	25.9624 -	14.785 6	59.9117 162.7340	430	318	117
Total @ 7 2 - 8	9.6632 4.3200	11.1909 2.8280		16.0608 6.7800	25.9624 9.0728		88.7062 192.9431	N/A	215	99
Total @ 8 8 - 9	6.2612 -	7.3269 -	9.6377	9.1002 -	14.3842 -	9.6377	36.2042 144.5689	659	526	132
Total @ 9 3 - 10	6.2612 -	7.3269 -		9.1002 -	14.3842 -		65.4060 174.1628	N/A	291	109
Total @ 10 Total @ 11 4 - 12	3.0752 Same	5.7869 as of	Node 10	4.6404	9.1708		51.8198 161.6799	N/A	368	118
Total @ 12 Total @ 13 5 - 14	4.2092 Same -	7.0749 as of -	Node 12	6.9606 -	13.0302 -		59.5917 167.6527	N/A	320	114
Total @ 14	5.3432	8.3629		9.2808	16.8896		45.8803 151.3719	N/A	415	126

TABLE-4.2 Impedance of ACSR conductor in ohms per kilometer

Three-phase Geometric Mean spacing : 58:371 inches

Line-to-neutral spacing : 48 inches

Earth resistively: 100 meter-ohms					conductor temperature :50°C		
Phase Conductor wire size AWG Code Name (British Code Name) (code word)	Neutral wire size (code word)	Positive & Negative sequence Impedance Components			Zero sequence impedance components for four wire multi-grounded neutral circuits		
		$r_1=r_2$	$x_1=x_2$	$z_1=z_2$	R_o	o_x	s_o
# 4/0 AWG (Penguin)	# 1/0 AWG (Raven)	0.3522	0. 4001	0.5330	0.7207	1.1988	1.3987
# 1/0 AWG (Raven)	# 3 AWG (Swallow)	0.6709	0.4392	0.8019	1.0530	1.4090	1.7590
# 3 AWG (Swallow)	# 3 AWG (Swallow)	1.2673	0.4417	1.3421	1.6493	1.4115	2.1709
0.15 CU EQIV(Wolf)*	-	0.2069	0.3353	0.394	0.355	1.5507	1.5909
0.10 CU EQIV. (Dog)	0.05CUEquiv . (Rabbit)	0.3386	0.3875	0.5146	0.7086	1.1456	1.3471
0.05 CU EQIV. (Rabbit)	0.025CUEqiv . (Gopher)	0.6206	0.4102	0.7439	1.0095	1.3671	1.6995
0.025 CU EQIV. (Gopher)	0.025CUEqiv . (Gopher)	0.1342	0.3218	0.3487	0.2906	0.8298	0.8792

*Zero Sequence Impedance components for three wire circuits grounded at the source.

TABLE-4.3 Per Kilometer Resistance and Reactance Of 6.35/11kv Grounded "Y" Distribution Line

Conductor size	OHMS PER CIRCUIT-MILE OF LINE					
	Single phase		'V'-phase		Three phase	
	r	x	r	x	r	x
#4/0 AWG ACSR (PENGUIN)	0.4737	0.6631	0.4737	0.6631	0.3522	0.4001
#1/0 AWG ACSR (RAVEN)	0.7982	0.7625	0.7982	0.7625	0.6709	0.4392
#3 AWG ACSR (SWALLOW)	1.3946	0.7650	1.3946	.7650	1.2673	0.4417
477 MCM (HAWK)					0.1342	0.3218
336.4 MCM (MERLIN)					0.1900	0.3389
0.15 CU EQIV. (WOLF)*					0.2069	0.3353
0.10 CU EQIV. (DOG)					0.3386	0.3875
0.05 CU EQIV. (RABBIT)					0.6206	0.4102
0.025 CU EQIV. (GOPHER)					1.2306	0.4275

Note: I) Resistances are AC values @50 Hz and 50°C

ii)Reactances are @50 Hz and standard REB spacing (1482.6mm)

4.6 Selection of OCR

For proper selection of an OCR the following factors must be taken in consideration :

- Maximum fault current available at the location where recloser is to be installed.
- Maximum load current .
- Coordination with other protective devices on both source and load sides of the recloser.

The maximum fault current will be known or can be calculated.

The maximum calculated fault current, three-phase or single phase-to-ground at the OCR installation point shall not exceed the interrupting capacity of the OCR. It must be less than the interrupting rating of the OCR.

At the farthest point out on the circuit for which the OCR must protect for permanent faults, the maximum calculated fault current should be at least 2 times the minimum tripping current of the OCR.

The maximum continuous current rating of the recloser should be selected to be equal to or greater than the anticipated circuit load.

Coordination with other protective devices (both source-side & load-side) is very important. Proper selection of time delays and operating sequences is vital to insure that any momentary interruption or long time outage due to faults are restricted to the smallest possible section of the system. Generally, the time-current characteristics and operating sequence of a recloser is selected to coordinate with source-side devices. After a specific recloser size and sequence is determined, protective equipment further down the line is then selected to co-ordinate with it.

4.7 Coordination Principle

Proper application of OCR on a distribution system is assured if the following basic co-ordination principles are observed:

(a) The load-side device must clear a permanent or temporary fault before the source-side device interrupts the circuit if it is fuse link or operates to lookout if it is OCR.

(b) Outages caused by permanent faults must be restricted to the smallest section of the system.

These principles primarily influence the selection of operating curves and sequences of the source-side and load-side devices and location of these devices on the distribution system

4.8 Data Required for Relay Setting Study

The following data are required for relay setting study.

a) Type and rating of the protective devices and CTS.
b) The impedances of power transformer, rotating machines and feeder circuits.
c) Maximum and minimum values of fault currents of the system that are expected to flow through each protective device.
d) Starting current of motors and the starting and stalling time of induction motors.
e) Maximum peak load currents through protective devices.
f) Rate of decay of fault current supplied by the generators.
g) Performance curves of the CTS.

4.9 OCR-Fuse Coordination

Coordination between an OCR and fuse can be attained by using methods based on time-current curves adjusted by a multiplying factor.

Coordination of source-side fuses will basically determine what curve or curves can be considered. Load-side fuse links must then be selected to coordinate with these curves. The source- side fuse is selected for protection of the transformer. The OCR must then be sized and curves selected to coordinate with this. Load-side fuses are then selected to coordinate with the OCR.

4.10 Source-side Fuse Links

Fuse links on the source-side (33KV) of a recloser generally protect the system from an internal transformer fault or protect the transformer from a fault at the secondary bus. The OCR at 11 KV incoming bus or the feeder OCR at substation must be selected to co-ordinate with the source-side fuse link so that the fuse does not interrupt the circuit for any fault current on the load-side of the OCR.

Time- current curves can be used to co-ordinate the secondary side OCR with the source-side fuse link if the method is based on this rule:

For maximum calculated fault current at the OCR location, the minimum melting time of the fuse link on the transformer's source side must be greater than the average clearing time of the re-closer's delayed curve, by a specific factor. These multiplying factors for various reclosing intervals and operating sequences are listed in chart - C. The curve must be shifted on the current axis to allow for the transformer ratio. That is, the curves for fuse and OCR are to be plotted or layed for fault current on the same voltage level (33KV) of transformer on the current axis.

4.11 Load-side Fuse Links

Maximum coordination between reclosers and fuse links is generally obtained by setting the recloser for two fast and two delayed operations. The first recloser opening allows about 80% of the temporary fault to clear. The second opening permits approximately another 10% to clear. Before the third opening, the fuse link melts, interrupting persistent or permanent faults.

Coordination is achieved to a lesser degree when one fast operation and three delayed operations are used.

Selective fuse sectionalizing of the faulted section of line beyond a recloser is not possible when the all fast sequence or all delayed sequence is used. All fast sequence does not include time for fuse to clear; all - delayed sequence will result in fuse operation on the first overcurrent.

Two selection rules govern the use of fuse links as protecting devices on the load-side of reclosers:

1. For all values of fault current possible on the section protected by the fuse link, the minimum melting time of the fuse must be greater than the product of the clearing time of the recloser's fast operating curve and the multiplying factor.
2. For all values of fault current possible on the section protected by the fuse link, the maximum clearing time of the fuse should be no greater than the delayed clearing time of the OCR, provided the recloser sequence is set for two or more delayed operations.

Coordination range between the recloser and fuse link is fixed by two selection rules.

1. The maximum coordinating current.
2. The minimum coordinating current.

The maximum coordinating current is the point of intersection of the minimum melting curve of the fuse with the reference curve obtained from the product of the recloser's fast clearing time curve and the multiplying factor.

The minimum coordinating current is the point of intersection of the maximum clearing curve of the fuse link with the delayed curve of the OCR. If the fuse maximum clearing curve does not intersect and lies below the recloser's curve, the minimum coordination point is the minimum trip current of the OCR.

4.12 OCR- OCR Coordination

OCR - OCR coordination is achieved primarily by selection of different series trip coil rating in hydraulic recloser or different minimum trip current values in electronic reclosers. Selection of these are determined after a study of the reclosers time-current characteristics. When coordinating hydraulically controlled reclosers in series, the minimum time required between time-current curves differs depending on which recloser types are involved. On smaller single and three phase reclosers, movement of the series trip coil plunger (when accelerated by over current flowing through the series coil) opens the recloser contact and loads the closing springs. McGraw Edison reclosers of this type of construction are named as H, 3H, 4H, V4H, 6H, V6H, L, E, & 4E.

When two OCRs of this type are in series, time - current curve separation of less than 2 cycles will always result in simultaneous operation. Separation of 2 to 12 cycles may result in simultaneous operation. When curves are more than 12 cycles (about 0.25 second) apart simultaneous operation will not occur. Two OCRs in series should follow the same operating sequence (preferably 2A 2C). So for proper coordination of two OCRs in series the time separation between the lock-out curves should be at least 0.25 sec.

4.13 Selection of Fuses for Lateral Lines

In selecting fuses for lateral, the following points are to be considered:

- The fuse must be large enough to carry the load current. To do this at a value of current 2 to 2.5 times the load current, the minimum melting curve of the fuse should cross the 300 sec. line in the time-current characteristic curves of the fuses.
- The minimum melting curve of the fuse should be above the fast operating curve of the OCR for currents equal to or less than the maximum phase-to-ground fault current at the point of installation of the fuse.

The smallest size fuse which will meet the above two limits should be selected.

4.14 Coordination of Two Fuses in Series

Two fuses in series will be properly coordinated , if the total clearing curve of the smaller size fuse (protecting fuse) lies below a curve which is 75% (on the time axis) of the minimum melting curve of the larger size fuse (protective fuse).

Fuse link coordination can be achieved by the use of time-current curves, coordination tables or by convenient industry established rules of thumb. Use of coordination table is the quick method for proper selection and coordination. Coodination tables 4.1, 4.2 and 4.3 are shown below:

TABLE 4.1 OCR-OCR COORDINATION

OCR TYPE	MAX. FAULT CURRENT (AMPS)	OCR TYPE
100-RX	1350	70-4H
	1550	50-4H
	1400	35-4H
	1000	25-4H
100-OYT	2000	70-4H
	2000	50-4H
	1400	35-4H
	1000	25-4H
70-4H	600	50-4H
	900	35-4H
	1000	25-4H
50-4H	490	35-4H
	680	25-4H
35-4H	300	25-4H

TABLE 4.2 OCR-FUSE (TYPE-T) CO-ORDINATION

OCR TYPE	MAX. FAULT CURRENT (AMPS)	FUSE RATING
100-RX & 100-OYT	3000	80
	2300	65
	1900	50
	1500	40
	1250	30
	900	25
	650	20
70-4H	1500	40
	1200	30
	840	25
	600	20
	420	15
50-4H	1250	30
	900	25
	650	20
	500	15
	350	12
35-4H	740	20
	550	15
	400	12
	275	10
25-4H	600	15
	450	12
	325	10
	225	8

TABLE 4.3 COORDINATION TABLE FOR FUSE

Protecting Fuse Link	Protective Fuse Link									
	10T	12T	15T	20T	25T	30T	40T	50T	65T	80T
	MAXIMUM FAULT CURRENT (AMPS)									
6T	350	680	920	1200	1500	2000	2540	3200	4100	5000
8T		375	800	1200	1500	2000	2540	3200	4100	5000
10T			530	1100	1500	2000	2540	3200	4100	5000
12T				680	1280	2000	2540	3200	4100	5000
15T					730	1700	2500	3200	4100	5000
20T						990	2100	3200	4100	5000
25T							1400	2600	4100	5000
30T								1500	3100	5000
40T									1700	3800
50T										1750
65T										

TABLE 4.4 RECLOSER RATINGS

Recloser Type, Continuous Rating and Interrupting Medium	Trip Coil Ratings Continuous Amps	Minimum Trip Ratings (Amps)	Interrupting Ratings (rms sym. amps) @14.4KV
Type-4H 100 Amps Max. Oil interruption	15 25 35 50 70	30 50 70 100 140	600 1000 1400 2000 2000
Type –RX 400 Amps Max. Oil interruption	100	200	6000

4.15 Factors for Load-side and Source-side Fuse Links

Load-side Fuse Links

For Load-side fuse coordination, the "K" factors are used to multiply the time values of the recloser fast curve. The intersection of this reference curve with the fuse minimum melting curve determines the maximum coordinating current. Figures under the "average" column apply when the fast curves are plotted to average values. Figures under the "Maximum" column apply when the fast curves are plotted to maximum values.

TABLE 4.5

Reclosing Time in cycles	One Fast Operation		Two Fast Operations	
	Average	Maximum	Average	Maximum
25-30	1.3	1.2	2.0	1.8
60	1.3	1.2	1.5	1.35
90	1.3	1.2	1.5	1.35
120	1.3	1.2	1.5	1.35

Source-side Fuse Links

For source -side fuse coordination, the "K" factor listed is used to multiply the time values of the delayed curve. The intersection of this reference curve with the fuse minimum melting time curve determines the maximum coordinating current. Note that either the fuse or recloser curves must be shifted so that both are plotted to the same voltage reference.

TABLE 4.6

Reclosing Time in cycles	Two Fast-Two Delayed sequence	One Fast - Three Delayed sequence	Four-Delayed sequence
25	2.7	3.2	3.7
30	2.6	3.1	3.5
60	2.1	2.5	2.7
90	1.85	2.1	2.2
120	1.7	1.8	1.9
240	1.4	1.4	1.45
600	1.35	1.35	1.35

4.16 Steps in Sectionalizing

a) Complete data is obtained on the power system and on the proposed devices before starting a study.

b) A study of the lines, both on the map and in the field and a tentative decision as to the location of the sectionalizing devices are made.

c) Maximum and minimum fault currents at each tentative sectionalizing point and at the end of the lines, line-to-ground, and three phase faults are Calculated.

d) The devices for the substation to give complete and adequate protection to the substation transformers from fault currents on the distribution lines are selected.

e) The sectionalizing devices from the substation out, or from the ends back to the substation are coordinated. The tentative locations of devices are revised if necessary.

f) The selected devices for current carrying, maximum interrupting and minimum trip ratings are checked.

g) Written instructions and a circuit diagrams for the operating personnel are prepared.

CHAPTER-V

A 33 KV Overcurrent Protection Coordination

5.1 Introduction

Rural electrification system has some 33/11 KV Sub-Station and its 33 KV source line. Power Transformer and 33KV source lines are protected by Power Fuses, OCRs and Oil Circuit Breaker of BPDB. It is essential to maintain coordination among the protective devices. The purpose is to determine what the present coordination is, if it is properly coordinated, and if not, what should be done to improve the coordination.

5.2 Procedure

1. A single-line diagram of the feeder is prepared to the selected PBS substation which shows, the PDB grid-station system that feeds the 33KV to the PBS substation. The single-line diagram shows the transmission 132KV, the PDB Grid-station transformer which feeds the 33KV feeder, the circuit breaker at the Grid-station, the 33KV line, any tee-off, the PBS substation fuse, the line through the PBS substation- including the 11KV OCR in the substation.

2. All points will be numbered at which fault currents will be determined, such as protective devices, branch points, ends of lines, the PBS 33KV fuse and the PBS substation 11KV bus.

3. The conductor size, spacing and distances between all numbered points are to be determined. From the PDB the name, type and setting of all relays controlling the circuit breakers in the 33KV line are to be collected.

4. Using information obtained in step 3, the line impedance will be determined and 3 phase or 2 phase and single phase fault currents at all numbered points are to be calculated. At the 11KV bus of the PDB substation, the current that would appear on the 33KV system from a fault on the 11KV bus, both three phase and single phase are to be determined.

This method of fault current calculation is based on symmetrical components and the impedances are in per unit on a 100 MVA base.

Positive, negative and zero sequence impedance must be determined in per unit on a 100 MA base. For REB's purposes, the positive and negative sequence impedances are assumed to be the same. The positive sequence impedance is the actual line impedance per phase in ohms. This must be converted to per unit on a 100 MVA base.

The line zero-sequence impedance is based on an effectively grounded system with an earth resistivity of 100 meter-ohms. If the PDB transformer is not effectively grounded, then the method of ground must be taken into consideration.

If a transformer bank consists of single-phase transformers and the bank is wye-wye, then the bank's Z_1, Z_2 and Z_0 are all equal to the new impedance and is accumulative. If the bank is delta-wye, then bank's Z_1 and Z_2 are accumulative. Z_0 ceases to exist between the bank and its supply, and it begins to accumulate at the bank and accumulates from there onward. If the bank is delta-delta, Z_1 and Z_2 are equal to the banks new impedance, and Z_0 does not exist for fault current calculations. For 3 phase core-type transformers Z_0 is 85 percent of the Z_1[19].

5. All existing protective devices are to be checked and will be determined if they are operating within their interrupting capacity, within their continuous duty rating, and how far out on the line they will reach. Load current at all protective devices will also be determined. This must not exceed devices rating. Devices maximum interrupting capacity will be found and care should be taken that maximum available fault at the device does not exceed interrupting capacity.

6. The fault current profile are to be drawn using separate profiles for 3 phase and single phase fault currents on log-log paper.

7. On the same log-log paper used in step 6, the substation transformer safe loading curves, the operating curve of the substation protective equipment, i.e. fuse, the ground-instantaneous relay, the ground time delay relay and phase time delay relay are to be drawn. If a recloser is used instead of an OCB, it's fast, slow and lockout curves are to be drawn.

The minimum tripping current is determined by finding the current transformer ratio and transformer tap in use. The curve is drawn from the minimum pick-up current to, but not beyond, the maximum available phase-to-ground fault current. The ground time-delay-relay curve is determined by the particular type of relay and its "time dial" setting. Again, its minimum pick-up current is determined by the CT. ratio and tap setting. This curve is drawn from its minimum pick-up to, but not beyond, the maximum available phase-to-ground fault current. Neither this relay, nor the ground instantaneous-relay will see any fault other than a line-to-ground fault.

The phase-time-delay relay is the same as the ground-time-delay-relay, except that its curve is drawn to, but not beyond, the maximum value of fault current available to it.

8. The minimum-melting-time and maximum-clearing-time curves of the first and second stage fuses as called for in protection scheme are to be drawn. These curves are determined if they do coordinate, and to what extent. If they do not coordinate within the desired limits, it will be determined what relay setting and what fuses will coordinate properly, and then the previously drawn curves will have to replace with these new curves. Fuse curves should be drawn from the template of coordinating-fuse curves.

   In general, the pick-up value of the phase-time-delay relay should be set at twice the normal ampere rating of the circuit. The time of the phase-time-delay relay is selected so as to be above the total clearing curve of the largest lateral fuse by at least 0.25 seconds at all values of current. The pick-up value of the ground-time-delay relay is to be set as low as possible and still be above the total clearing curve of the largest lateral fuse. The time of the ground-time-delay relay is selected so as to be above the total clearing curve of the largest lateral fuse by at least 0.25 seconds at all values of current.

   The pick-up value of the ground-instantaneous relay is generally set at ½ ampere higher than the ground-time-delay setting [19].

   At the farthest point out on the circuit for which the OCB must clear permanent faults, the maximum calculated fault current should be twice the pick-up value of the relay and should trip the relay in less than 5 seconds or before damage to the earthing transformer. At the farthest point out on the circuit for which the OCB must clear temporary faults, the maximum calculated phase-to-ground fault current should be 1 & ½ times the pick-up value of the ground instantaneous relay.

Fuses whose curves extend below the ground-instantaneous relay curve will not coordinate with the relay. These fuses will blow on temporary faults and result in outages, due to the failure of the OCB to operate.

9. All protective installations and changes desired will be drawn on the sketch.

5.3 Sample Problem, Grid sub-station to 33KV sub-station.

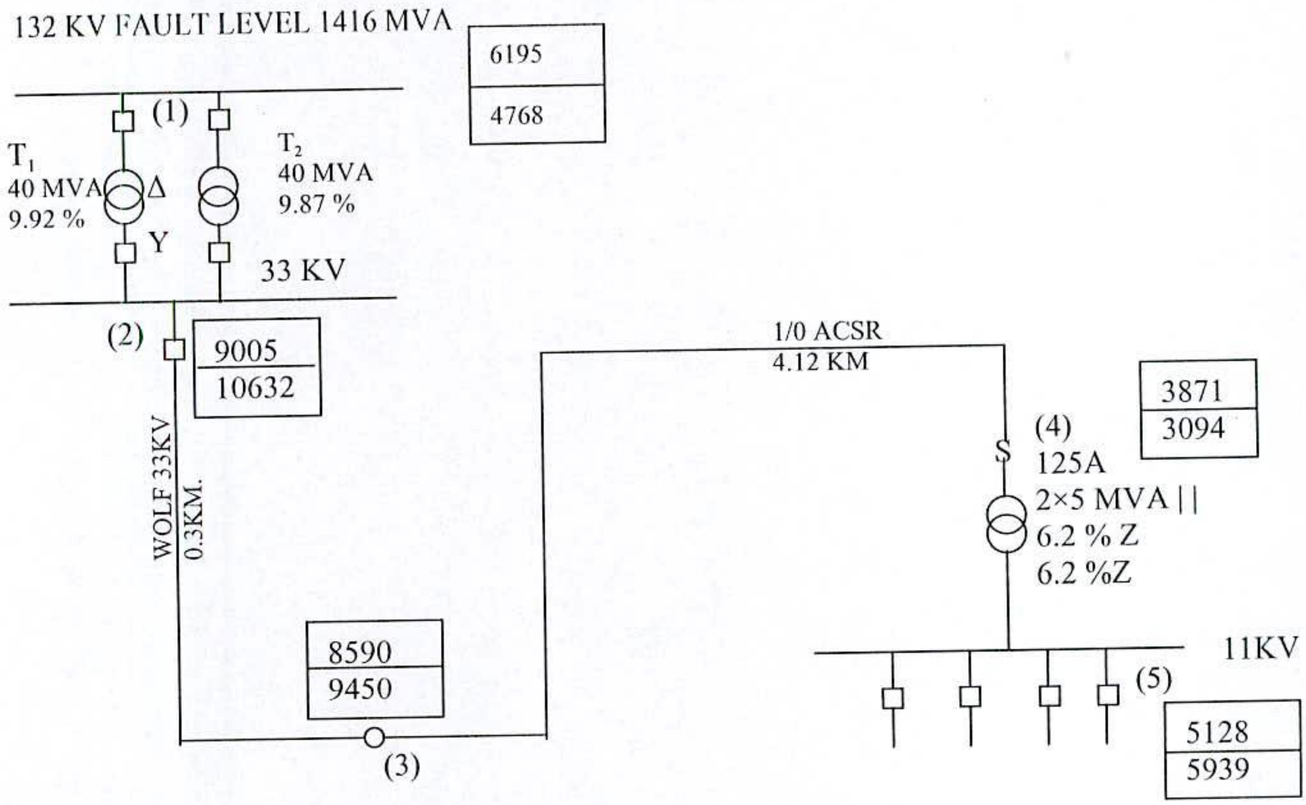


Figure 5.1 Single line diagram of a power system

In the example shown above it is required first to place all components on a 100 MVA base.

1. The 132 KV line fault level is first converted to the transmission line impedance at 100 MVA.

$$Z_1\,(132\,\text{KV System}) = J\frac{MVA_B}{\text{Fault MVA}} = J\frac{100}{1416} = J0.0706pu$$

2. The 2×40 MVA PDB transformer must also have its impedance expressed on a 100 MVA base.

$$Z_1(132\text{-}33\,\text{KV X-former}) = J\frac{\%Z}{100}\times\frac{MVA_B}{MVA_{X\text{-former}}}$$

$$Z_1\,(T_1) = J\frac{9.92}{100}\times\frac{100}{40} = J0.248pu$$

$$Z_1\,(T_2) = J\frac{9.87}{100}\times\frac{100}{40} = J0.2468pu$$

$$Z_1(T_1+T_2) = J\frac{(0.248\times0.2468)}{(0.248+0.2468)} = J0.1237pu$$

It should be kept in mind that the resistance of the 132 KV transmission grid and 132-33 KV transformer are so small in compression with their reactance that they are neglected and the impedance of the system is taken as being equal to reactance.

3. Impedance of 33 KV line will be expressed on a 100 MVA base.

Z_1 (33KV line Wolf) = 0.3(0.2069+J0.3361) = (0.06207+J0.10083) ohms [18]

$$Z_{pu} = \frac{Z_1 ohms}{Z_B ohms}$$

$$Z_B = \frac{KV_B^2}{KVA_B} = \frac{33x33}{100} = 10.89 ohms$$

$$Z_1\,(\text{33KV line wolf}) = \frac{0.06207+J0.10083}{10.89} = 0.0057+J0.0093pu$$

Z_1 (33KV line 1/0) = 4.12(0.6709+J0.44) = (2.7641+J1.8128) ohms

$$Z_1\,(\text{33KV line 1/0}) = \frac{(2.7641+J1.8128)}{10.89} = 0.2538+J0.1664pu$$

4. The 2x5 MVA PBS substation transformers must have their impedance expressed as a 3 phase unit on a 100 MVA base.

Then to a 100 MVA base:

$$z_1(33-11KVX-former) = J\frac{6.2}{5} = J1.24pu$$

The two x-formers are in parallel, so impedance

$$Z_1(33kVX-former.) = \frac{J(1.24x1.24)}{(1.24+1.24)}pu = J0.62pu$$

As 33/11 KV transformer is $\Delta Y_{\perp}$ connected and the zero sequence impedance cannot be reflected through a delta connected winding, total source impedance of the system in per unit basis viewed from the 11 KV bus are summarized as follows

	$Z_1 = Z_2$	Z_0
132 KV system	0+j0.0706	-
132-33 KV Transformer	0+j0.1237	-
33 KV line	0.2595+j0.1757	-
33-11 KV transformer	0+j0.62	0+j0.62
	0.2595+j0.99	0+j0.62

Since all the following calculations are at the 11 KV level, the source impedance per unit values may be changed to ohms on the 11 KV base.

$$Z_B = \frac{11x11}{100} = 1.21ohms$$

11 KV bus $Z_1 = Z_1$ pu x Z_B=1.21(0.2595+J0.99)=0.313995+J1.1979 ohms

$Z_1 = Z_2$ = 1.23837 ohms

Z_0 = 1.21(0+J0.62) = 0+J0.7502 ohms

All the 11 KV bus

$$I_{3\,ph-SYM} = \frac{V_F}{Z_1} = \frac{11000}{\sqrt{3}} x \frac{1}{1.23837} = 5128Amps$$

$$I_{(L-G)-Max} = \frac{3V_F}{Z_1+Z_2+Z_0} = \frac{3x11000}{\sqrt{3}} x \frac{1}{2(0.313995+J1.1979)+(0+J0.7502)}$$

$$= \frac{\sqrt{3}\times 11000}{0.62799+J3.146} = \frac{1.732\times 11000}{3.208} = 5939\,Amps$$

$$I_{(L-G)-Min} = \frac{3V_F}{Z_1 + Z_2 + Z_0 + 3Z_F} = \frac{3x11000}{\sqrt{3}} x \frac{1}{2(0.313995 \ + J1.1979\ ) + (0 + J0.7502\ ) + 3x40}$$

$$= \frac{\sqrt{3} \times 11000}{0.62799 \ + J3.146 + 120} = \frac{1.732 \times 11000}{120.669} = 158\,Amps$$

Fault impedance Z_F is considered as 40 ohm.

The fault current at different nodes are calculated and shown on the attached calculation sheet.

Fault Calculation Worksheet

Sub-Station: Jessore Grid Feeder: Topshidanga Date: 20.01.02 Engineer: S.K.Das

Sec.	Description	Km.	pu Z/km R+jX	Sec.PU Z R+JX	Accum Z R+JX	pu Z_0/Km. R_0+JX_0	Sec Z_0 R_0+JX_0	Accum Z_0 R_0+JX_0	Z_t R_t+JX_t	I_{3p} SYM	I_{LG} MAX
1	PDB132 KV Bass			0+j0.0706	0+j0.0706				0+j. 0706	6195	
1-2	80Mva S/S			0+j0.1237	0+j0.1943		0+j0.1051	0+j0. 1051	0+j0.4937	9005	10632
2-3	Wolf	0. 3	0. 2069+ j0.3361	0.0057+ j0.0093	0. 0057+ j0.2036	0. 355+ 1. 5507	0. 0098+ j0. 0427	0. 0098+ j0. 1478	0. 0212+ j0.555	8590	9450
3-4	1 / 0	4.12	0. 6709+ j0. 44	0. 2538+ j0.1664	0. 2595+ j0.37	1.053+ j1.409	0. 3984+ j0.5531	0. 4082+ j0.6809	0.9272+ j1.4209	3871	3094
4-5	10Mva S/S			0+j0.62	0.2595+ j0.99		0+j0.62	0+j0.62	0.519+ j2.6	5128	5939
11 KV BUS FAULT REFLECTED AT 33 KV										1709	1143

5. After calculating the maximum available fault levels at all important locations, a fault profile is prepared.

   Using log-log paper a fault profile is drawn as shown in figure 5.2 A line is begun at the maximum available single-phase fault current at the first location and extended to the left to the lower maximum available single-phase fault current at the left. A mark is placed at the maximum available single-phase fault current at all points calculated. This is the single- phase fault profile.

The same procedure is followed for the maximum available three-phase fault current. With the exception of faults within the PBS substation at the 11KV level. The three-phase 11KV fault current within the substation is shown as it would appear to the 33 KV system. Also, the line-to-ground fault inversely proportional to the 6,350 : 33,000 volt ratio. Then, the two phase current would be shown on the three-phase profile, but labelled as two phase.

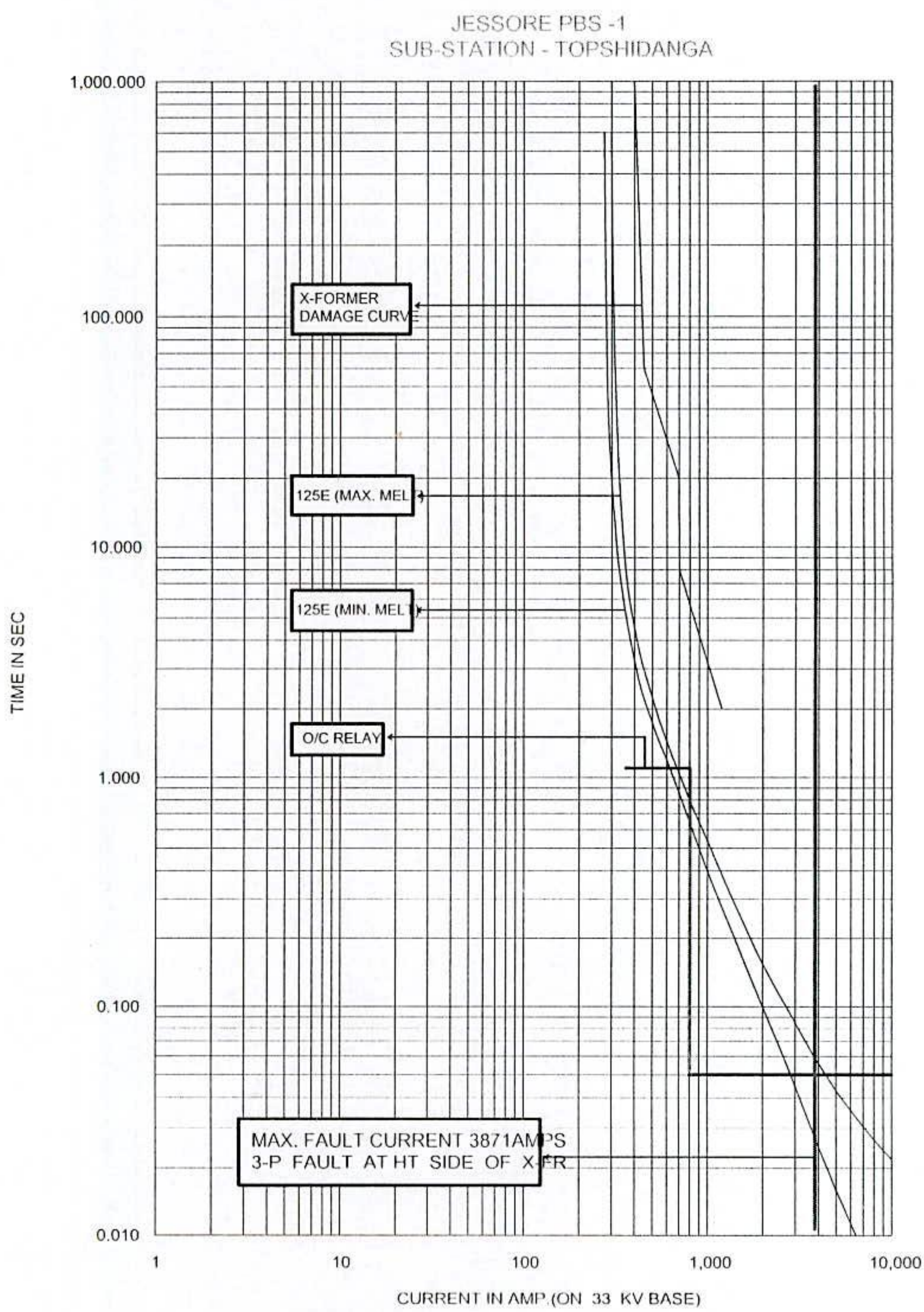


FIGURE 5.2 PHASE FAULT AT HT SIDE OF S/S X-FORMER EXISTING CO-ORDINATION

6. It now becomes necessary to use a light table or light box. If templates are available, the light box is used to draw the short circuit damage curve for the 33KV line conductor on the log-log paper. This should be labelled as curve A. If there are two sizes of conductor, they would be curves A & B respectively. At present the curves are drawn in PC based computer environment.

7. Using the information obtained from the PDB substation relays, the operating curves for the PDB ground relay and also the phase relay are drawn. The minimum pickup of each of these relays will be the current-transformer ratio times the plug setting of each relay. The curve is then determined by the time-dial setting. During drawing these curves, the curve would begin at the lowest ampere pick-up value of the relay and would be drawn to, but not beyond, the maximum available fault current for that device, as shown on the current profile. It must be remembered that the ground relay will only see ground faults; therefore, the point of ending for the ground-relay curve is at its location on the single-phase profile.

8. Now it is drawn in the maximum clearing time and minimum melting curves for the substation transformer fuse. These should begin at their lowest value and extend to, but not beyond, their position on the profiles.

9. The fast and slow curves for the 11KV substation OCR (known as time-current curves) are drawn on the log-log paper as they would appear to the 33KV equipment.

It is now possible to view the plotted curves and determine if, how and where on the current profiles they coordinate.

Now it is required to select relay settings, recloser settings and/or fuses that will coordinate. The installations will be shown on the single line diagram. The selected settings will be drawn on the paper, and will have to write up the instruction for the installation. It must also be explained in writing, why the present settings do not coordinate and how they will coordinate when the recommended installations are made.

5.4 PDB - PBS Over Current Protection Coordination

The objective of PDB-PBS coordination is to prevent the operation, or to limit the operation, of the PDB relays, due to faults other than on the PDB 33KV system.

Two distinct problems exist regarding the coordination of the over current protection devices between the PDB and the PBS protective systems. They are:

1. Operation of the PDB Grid-station relays due to faults on the PBS 11KV system.
2. Operation of the PDB Grid-station relays due to faults in PBS substation transformers.

The solutions to the problems may differ and the solution of one of the problems may help, or hinder, the solution of the other.

The PDB phase relays will see all faults on the 33KV system and all faults on the PBS 11KV system. The PDB phase relay will operate for all faults on the PBS 11KV system where the fault current, for a phase to ground fault, is equal to, or greater, than the PDB phase relay pick-up current is multiplied by 5.2 (33KV/6.35KV=5.2), or where the three-phase 11KV fault current is equal to, or greater, than the PDB phase relay pick-up current is multiplied by 3 (33KV/11KV=3).

Since the PDB ground-relay will see no faults on the PBS 11KV system and since only the PDB phase relays are involved, the 11KV problem should be solved first.

The first step in the solution of these problems is to prepare a fault profile of the 33KV system and Time-Current curves of the existing operation of all devices involved are prepared. On the Time-current curves, the operation, and lock-out curves of the PBS substation 11KV feeder Recloser are to be plotted as they would appear on the 33KV system.Only after the preparation of the Time-current curves and fault profiles, can serious efforts be made to find solutions.

The lock-out curve of the 11KV feeder OCR is compared with the operating curve of the PDB Phase relay and it is determined if the 11KV OCR will lock-out before the PDB phase relay operates to lock-out the PDB circuit breaker. No PDB Grid-station has been found to have an operating reclosing relay, therefore, the 11KV Feeder OCR must lock-out before the PDB phase relay operates to lock-out the PDB circuit Breaker.

For Example, if the PDB phase relay will pick-up on a 33KV phase current of 450 amperes, it will begin to operate on an 11KV phase to ground fault current of, (450x5.2)=2,340 amperes. And on a phase-to-phase or three-phase fault current of, (450x3) = 1,350 amperes. Since faults on the 11KV grounded system almost always begin as a phase-to-ground fault, the phase-to-ground fault should be given first consideration.

The first effort to solve this problem is to determine if the PDB can raise the pick-up value of the phase relay to a value greater than the maximum available phase to ground, or three phase, fault current at the PBS 11KV bus. If they can not raise the pick-up setting the only alternative is to find a means of clearing the 11KV fault fast enough that the PDB phase relay will not operate. It may be necessary to change the operating sequence of the feeder OCR and/or to phase reclosers on all branch circuits where the fault currents can exceed the PDB phase relay pick-up current.

In the example the PDB phase relay is shown to have a minimum pick-up of 200 amperes. Therefore, the relay will begin to operate on any phase-to-ground fault on the PBS 11KV system which exceeds, (200 x 5.2) = 1,040 amperes or, a three phase fault which exceeds, (200 x 3) = 600 amperes. Inspecting the available fault currents at the PBS substation we can see that it will operate on both the bus phase-to-ground and three-phase faults. However, if the PDB can see the pick-up value of the PDB phase relay to 510 amperes it would not operate on 11KV phase-to-ground faults. Since most faults begin as a phase-to-ground fault, this adjustment should eliminate practically all of the operations due to PBS 11KV faults. If they can raise the pick-up of the PDB phase relay to 740 amperes all operations due to 11KV faults should be eliminated. If the PDB cannot adjust the pick-up value of the phase relay then some combination of feeder OCR operations must be found that will place the lockout curve of the OCR below the operating curve of the PDB phase relay.

In the time-current curves shown in figure 5.2 the time of lock-out curve of the OCR, curve must be lowered by approximately, 0.25 seconds. If this is done, all the fuses and OCRs on the 11KV feeders must be re-viewed, in size and sequence, to determine if they coordinate with the new feeder OCR settings, if not, further adjustments should be attempted.

It is possible that if we change the operating sequence of the feeder OCR to two fast "A" curves and one delayed "C" curve the lock-out curve might be satisfactory. The following time-current curve shows how the curves would appear. No reduction in sequence to less than 1, "A" and 1, "C" should be made. A further reduction in sequence will destroy any possibility of coordinating with branch circuit fusing.

This plot shows that it is possible that this operation will work, although the lock-out curve of the OCR and the PDB relay curve are close at some points it is still possible that the scheme will work and the coordination of the rest of the 11KV system may not have to be changed.

It is clear that the solution to the problem is found by trial and error.

The solution to the second problem, PDB relay operation due to PBS substation transformer faults, is much more difficult. But again, trial and error is the process.

The objective is to isolate the transformer when it has a fault without the PDB relay operating.

On the Time-Current paper the Conductor damage curve, the Transformer safe loading curve, the transformer inrush current curve, the Transformer Fuse curve and the PDB Ground-Fault relay operating curve are drawn.

The great majority of faults in the power transformer begin as a phase-to-ground fault. Consequently it is expected that the PDB ground-fault relay will detect the fault first. If the PDB ground-fault relay operates the entire 33KV feeder will be de-energized, which is not desirable. It is desirable that some other device operate first to isolate the transformer fault before the 33KV feeder is de-energized. The device can be a fuse, OCR, circuit breaker or some other type of device. In the PBS systems fuses are used.

In the example it might be best to replace the 125E very slow fuse with a 100E very slow fuse. The 100E very slow fuse would allow a continuous load on the transformer of 114 percent and would allow as much as 228 percent surge for 5 minutes. It might then be found that a 100E very slow fuse is satisfactory. We know from the time-current curves that a 100E standard speed or fast fuse will burn on the 5 Mva transformer inrush current and therefore cannot be used.

The present practice is to use a 125E very slow fuse for transformer protection, but it is found from the time current curves that by replacing the 125E very slow fuse with a 100E very slow fuse it will be able to obtain better coordination with the PDB. The example shows that if the PDB will set the CDG relay on plug 5 and time dial 1 the 33KV system will coordinate better for transformer faults.

This presents another problem. The PDB phase relay will also see the fault and it has been set for plug 2.5 and time dial 0.4, it is now necessary to set the phase relay the same as the ground-relay in order to keep the phase relay from de-energizing the system on a transformer fault.

If the PDB relay has an instantaneous (no intentional delay) trip, with no reclosing, it will operate the PDB circuit breaker on all faults where the current exceeds the pick-up current, even the operation of lightning arresters, and it is probable that there can be no coordination between the PDB and the PBS substations transformers.

As a result of the foregoing it might be advisable to try and see what can be done with an OCR in the 33KV line.

The REB has purchased a number of 33KV 160 ampere OCRs. It might be possible to use these OCRs.

In reviewing the specifications for these OCRs it is found that they have been ordered with 4, "C" curves and 4, "2" ground trip curves. Also that the phase pick-up current is 320 amperes and the ground pick-up current is 87 amperes.

With a phase trip current of 320 amperes it is very doubtful that the phase trip of the 33KV recloser will ever operate.

Plotting the above curves on the 33KV Time-Current graphs it is easily seen that neither of these setting will provided protection.

After trying several operating sequences it is found that if the ground trip is changed to one or even two 1-2 operations and then lock-out, protection may be provided for many of PBS substation transformer faults.

This re-coordination scheme might work for many cases, however, the phase trips of the OCR and the substation fuses would very probably never operate. They would probably never operate because the PDB phase relays would operate first.

The above re-coordination might be the best solution in this example. However, it must be remembered that each and very Grid-station and each PBS substation is a different case and must be solved as a special case. This is true because there are many different types of relays in the PDB Grid-stations as well as differing fault levels at the Grid-stations and PBS substations.

CHAPTER-VI

Study of PBS Radial Distribution Systems

6.1 Introduction

Rural Electrification Board (REB) is an agency working under the ministry of Energy and Mineral Resources, Govt. of the peoples Republic of Bangladesh. The REB plans to supply electricity to each and every village of the country in several phases within shortest possible time. It is working on the Area Coverage Rural Electrification (ACRE) concept which allows construction of 33KV, 11KV, 6.35KV, 0.4KV and 0.23KV electrical distribution lines and 33/11KV S/S. REB purchases electrical energy from Bangladesh Power Development Board (BPDB), an agency of power generation, transmission and distribution under the same ministry. Rural electrification program has been indicated as a prioritized development activity and it has drawn significant attention of the Government. But it has been experienced that there is lack of coordination among the protective devices in REB and PDB systems that occasionally creates unwanted power interruption. Two distinct problems exist regarding the coordination of the over current protective devices between the PDB and the "Pally Bidyut Samity" (PBS).

These are:

1. Operation of the PDB Grid-station relays due to the faults on the PBS 11KV. System.

2. Operation of the PDB Grid-station relays due to faults in the PBS substation transformers.

The solutions to the above mentioned problems may differ and the solution of one of the problems may help, or hinder, the solution of the other. The PDB phase relays will see all faults on the 33KV system and all faults on the PBS 11KV system. The PDB phase relay will operate for all faults on the PBS 11KV system. Where the fault current, for a phase to ground fault, is equal to, or greater than the PDB phase relay pick-up current multiplied by 5.2 (33KV/6.5 KV= 5.2) or where the three phase 11KV fault current is equal to, or greater, than the PDB phase relay pick-up current multiplied by 3 (33KV/11KV = 3). On the other hand excessive voltage drop has become a common curse to the REB, PDB, DESA and DESCO systems. Which creates inconvenience to the consumers as well as the Boards.

6.2 Case Study-1 Topshidanga 33/11 KV Sub-Station

The radial distribution feeders (Circuit-A,B,C&D) of Topshidanga 33/11KV S/S under Jessore PBS-1, a project of Bangladesh Rural Electrification Board are considered for the study of protection scheme and voltage drop calculation. The information of 33KV source feeder for this S/S, and the information of a 11KV radial feeders along with categorywise connected consumers, feeder length with conductor size, relays characteristic curves were collected and stored in data files.

The subststion termed as Topshidanga 33/11 KV has a total capacity of 10 MVA having two three Phase Transformers of Capacity 5 MVA each with average Percentage Impedance 6.20 as shown in figure6.1 under the area coverage of Rural Electrification Program. The sub-station protective devices are two sets of 125E rated standard speed fuses on the 33 kv source side. There are 4 (four) out going 11 KV feeders e.g. circuit-A, Circuit-B, Circuit-C and Circuit-D having Mc.Graw Edison recloser of type RX for protection of fault up to first line ACR. All the ACRs are set for 2A+2C operation to lock- out. Current ratings of reclosers are indicated as follows:

a) For Circuit - A, B & D -100 Amps
b) For Circuit - C - 225 Amps

6.3 Source for the Sub-Station

Topshidanga 33/11 KV Sub-station receives power from Jessore 132 KV Grid Sub-station of Power Development Board. The Grid has 2 X 40 MVA, 132/33 KV transformers. Percentage impedance of each of these transformers is 9.91 % (Avg.) for normal operation. The 33 KV outgoing sides of the transformers are protected with OCBs. The 33 KV outgoing line to the Topshidanga 33/11 KV substation is also protected with OCB operated by JS J72 61-3B/CC, SIEMENS, Static Definite Time Relay. Three phase and single phase fault levels of Jessore Grid Sub-station were 1416 MVA and 1090 MVA respectively as of 2002 year base. Based on this figure and other data the fault currents at different points have been calculated. The calculation sheets have been enclosed in Sec.6.8. A single line diagram showing the source of Grid Sub-station arrangements, REB sub-station arrangements, three phase symmetrical fault level, single phase line to ground fault level etc. at every node is enclosed in section 6.4 of the report. Relevant data for the distribution system are given in the following two Sections.

6.4 Single Line Diagram showing Fault Current From Grid S/S to REB S/S

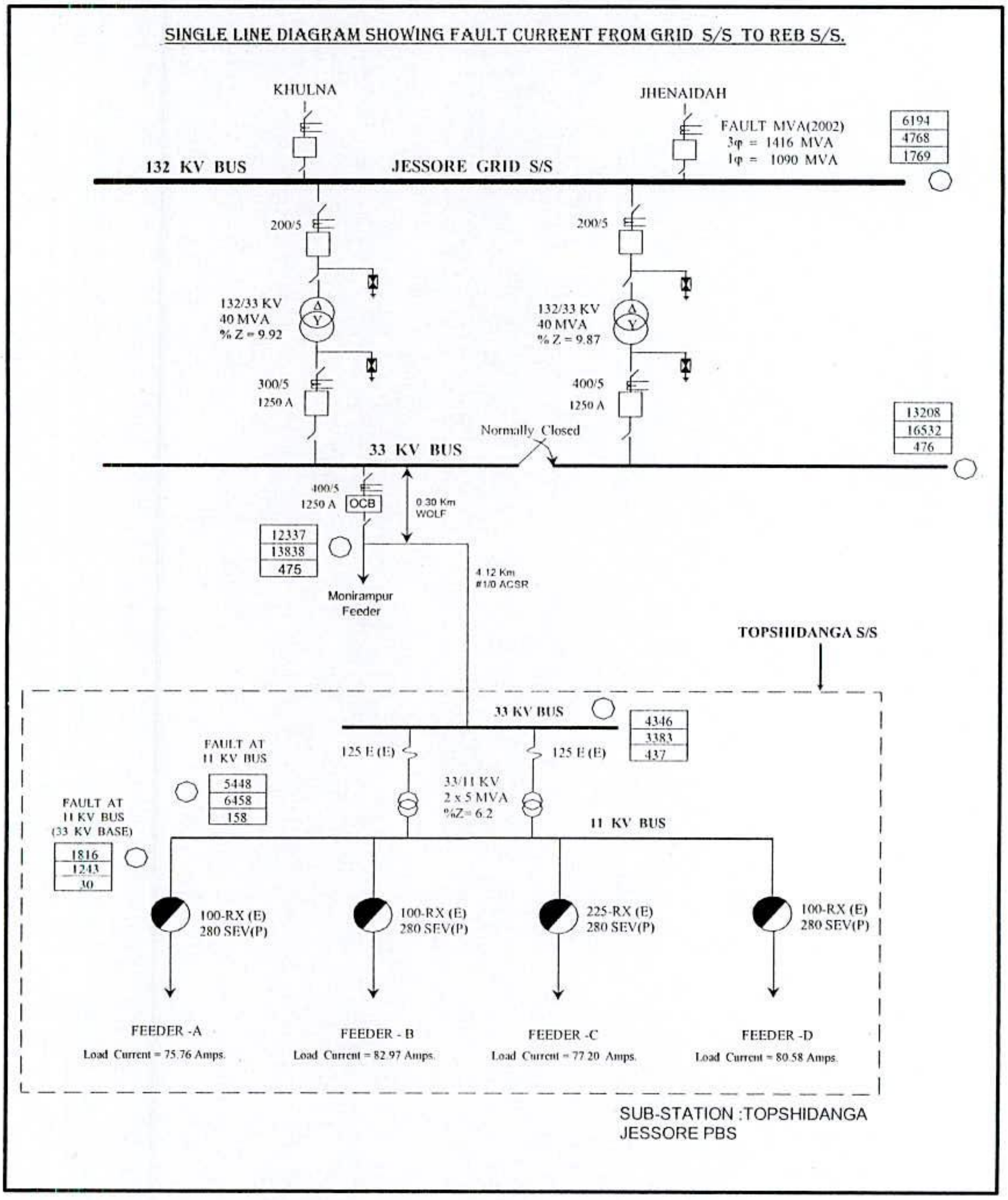


Figure 6.1 Single Line Diagram from Jessore Grid to Topshidanga S/S.

6.5 Information of 33 KV Source Feeder for REB Sub-Station

01. Name of PBS	:	**Jessore PBS -I**
02. Name of REB Sub-Station	:	**Topshidanga**
03. Name of PDB Grid Sub-Station	:	**Jessore (Chanchara)**
04. Capacity of Grid Sub-Station	:	2 x 40 MVA
05 Maximum Demand of Grid Sub-Station	:	70 MVA
06. Connection Type of Transformer	:	△/Y
07. Operational Connection	:	Parallel
08. Percentage Impedence of Grid Transformer	:	
a) T 1	:	Normal-9.92 %
a) T 2	:	Normal-9.87 %
09. Fault Level of Grid Sub-Station (2002 Base)	:	
a) 3-Phase Symmetrical		1496 MVA
b) 1-Phase		1090 MVA
10. Max. Demand of Source Feeder	:	7 MVA
11. Breaker Information for Source Feeder	:	
a)Type		OCB
b)Rating		1250 Amp.
12. Relay Information for Source Feeder	:	
a) Type	:	**JS J72 61-3B/CC**
b) Manufacturer	:	**SIEMENS**
c) Characteristics	:	**Static Definite Time**
13. Relay Settings	:	

O/C Setting		Instantaneous Setting	
TRIP Amps	T.D	Inst. Amps	T.D
$J=J_n$(Basic Setting ....) J=400*(.8+.1+ 0 + . . .)= 360	t_s=.8+.2+.1 t_s=1.1	800	0.20

E/F Setting		Instantaneous Setting	
TRIP Amps	T.D	Inst. Amps	T.D
$J=J_n$(Basic Setting ....) J=400*(.8+0+0+ . . .)= 320	t_s=.8+.2+.1 t_s=1.1	640	0.20

14. C.T Ratio of 33 KV Source Feeder	:	**400/5**

6.6 Information of 33/11 KV REB Sub-Station

01. Name of REB Sub-Station : Topshidanga

02. Capacity of Sub-Station : 2 X 5 MVA

03. Max. Demand of Sub-station (So far) : 6.732 MW

04. Percentage Impedance of Transformer : 6.2% (Avg.)

05. 33 KV Recloser : Not Exists

06. Power Fuse :

	Existing	Proposed
Type	E	E
Characteristics	Standard Speed	Standard Speed
Rating	125 E	125 E

07. Bus Bar ACR : N/A

08. Feeder Outgoing Recloser :

	Feeder-A		Feeder-B		Feeder-C		Feeder-D	
	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed
Feeder Peak Amp	76		82		77		80	
Type	RX	SEV	RX	SEV	RX	SEV	RX	SEV
Manufacturer	Mc.Graw	W.H.	Mc.Graw	W.H.	Mc.Graw	W.H.	Mc.Graw	W.H.
Min Phase Trip	200 Amps	280 Amps	200 Amps	280 Amps	450 Amps	280 Amps	200 Amps	280 Amps
Curve Setting (Phase)	2A+2C	2B+2G	2A+2C	2B+2G	2A+2C	2B+2G	2A+2C	2B+2G
Sensor		X1-X6		X1-X6		X1-X6		X1-X6
Curve Setting (Ground)	2(1-2)+2(2)	2K+2L	2(1-2)+2(2)	2K+2L	2(1-2)+2(2)	2K+2L	2(1-2)+2(2)	2K+2L
Min. Ground Trip amp	110 Amps	140 Amps	110 Amps	140 Amps	110 Amps	140 Amps	110 Amps	140 Amps
Calibration Plug No.		4		4		4		4
Aux. X-former Connection		H1-H2		H1-H2		H1-H2		H1-H2

09. Conductor Size & Length From Grid S/S To REB S/S : Wolf 0.30 Km, 1/0 ACSR 4.12 Km.

6.7 Fault Level Calculation from Grid S/S to 33/11 KV REB Topshidanga S/S

FAULT LEVEL AT SOURCE SIDE

PROJECT : Rural Distribution System
SUBSTATION : Topshidanga
FEEDER : Feeder 1

DATE : 20/01/2002

GRID SUBSTATION : Jessore
BASE MVA : 100 MVA
FAULT LEVEL : 1416

132 KV LEVEL	33 KV LEVEL	11 KV LEVEL	
1 PU = 132 KV	1 PU = 33 KV	1 PU = 11 KV	I3 = Ib/Z1
1 PU = 437.4 AMPS	1 PU = 1749.6 AMPS	1 PU = 5248.6 AMPS	Ig = (3 x Ib)/Zt
1 PU = 174.24 OHMS	1 PU = 10.890 OHMS	1 PU = 1.210 OHMS	Zt = 2Z1 + Zo

SECTION	DESCRIPTION	MVA OR LENGTH	PU Z1/KM R + j X	SECTION PU Z1 R + j X	ACCUMULATED Z1 = R + j X	PU Zo/KM Ro + j Xo	SECTION PU Zo Ro + j Xo	ACCUMULATED Zo = Ro + j Xo	PU Zt Rt + j Xt	I - 3P SYM.	I _ LG MAX
1	132 KV BUS			0 + j0.0706	0+ j 0.0706		0 + j0	0 + j0	0+ j0.1412	6195	-
1 - 2	132/33 KV S/S TRANSFORMER	T-1 40 T-2 40 T-3		0 + j0.1237	0 + j0.1943		0 + j0.1051	0 + j0.1051	0+ j0.4937	9005	10632
2 - 3	33 KV T/L WOLF 33 KV	0.3 KM	0.2069 + j 0.3361	0.0057 + j0.0093	0.0057 + j0.2036	0.355+ j 1.5507	0.0098 + j0.0427	0.0098 + j0.1478	0.0212+ j0.555	8590	9450
3 - 4	33 KV T/L	4.12 KM	0.6709 + j 0.44	0.2538 + j0.1664	0.2595 + j0.37	1.053+ j 1.409	0.3984 + j0.5331	0.4082 + j0.6809	0.9272+ j1.4209	3871	3094
4 - 5	33/11 KV S/S TRANSFORMER	T-1 5 T-2 5 T-3		0 + j0.62	0.2595 + j0.99		0 + j0.62	0 + j0.62	0.519+ j2.6	5128	5939
								11 KV BUS FAULT REFLECTED AT 33 KV		1709	1143

6.8 Voltage Drop, Fault Current and Section Current Calculation Result Sheet

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : TOPSHIDANGA
CIRCUIT : A

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL	DIST.	LINE	RYB
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT I TIME	1-3P	1-LG Max	1-LG Min	VOLT DROP	FROM S/S	AMPS 1.0 TIMES	FOR 1-PH LINE
11 KV-BUS								5128	5938	158	0.000	0.00	-	
BUS	1	4/0	3	0.02	0.00	0.026	0.00	5089	5856	158	0.026	0.02	75.76	-
1	2	3	3	1.36	41.55	0.320	2.42	2328	2129	151	0.346	1.38	6.14	-
2	3	3	3	2.48	13.44	0.049	0.78	1068	926	139	0.395	3.86	0.78	-
2	4	3	3	0.40	4.70	0.054	0.27	1965	1765	149	0.400	1.78	2.94	-
4	5	3	3	0.80	32.99	0.038	1.92	1490	1311	145	0.438	2.58	1.92	-
4	6	3	3	0.48	12.67	0.009	0.74	1650	1462	146	0.409	2.26	0.74	-
1	7	4/0	3	0.72	37.24	0.837	2.17	3967	3871	156	0.863	0.74	69.61	-
7	8	3	3	0.04	75.87	0.004	4.43	3882	3760	156	0.867	0.78	4.43	-
7	9	4/0	3	0.86	5.33	0.914	0.31	3118	2730	155	1.777	1.60	63.02	-
9	10	3	3	1.20	14.51	0.026	0.85	1884	1579	149	1.803	2.80	0.85	-
9	11	4/0	3	1.20	12.74	1.249	0.74	2389	1927	152	3.026	2.80	61.86	-
11	12	3	1	1.20	5.71	0.038	1.00	N.A	1270	146	3.064	4.00	1.00	R
11	13	4/0	3	0.17	0.00	0.175	0.00	2312	1849	152	3.201	2.97	60.99	-
13	14	3	3	0.80	7.06	0.009	0.41	1752	1395	148	3.210	3.77	0.41	-
13	15	4/0	3	0.24	9.62	0.244	0.56	2211	1750	152	3.445	3.21	60.57	-
15	16	3	3	0.60	4.22	0.004	0.25	1803	1423	149	3.449	3.81	0.25	-
15	17	4/0	3	0.21	12.05	0.211	0.70	2130	1671	151	3.656	3.42	59.77	-
17	18	3	1	0.32	2.85	0.006	0.50	N.A	1498	150	3.662	3.74	0.50	B
17	19	3	1	0.06	1.38	0.000	0.24	N.A	1637	151	3.656	3.48	0.24	Y
17	20	4/0	3	0.48	4.12	0.476	0.24	1964	1516	150	4.132	3.90	58.82	-
20	21	3	3	0.64	7.32	0.262	0.43	1613	1249	147	4.394	4.54	9.55	-
21	22	3	3	1.12	6.81	0.012	0.40	1203	943	142	4.406	5.66	0.40	-
21	23	3	3	0.15	9.20	0.056	0.54	1545	1198	146	4.450	4.69	8.73	-
23	24	3	1	0.80	3.35	0.016	0.59	N.A	980	143	4.466	5.49	0.59	Y
23	25	3	3	2.24	8.44	0.759	0.49	923	733	136	5.209	6.93	7.61	-
25	26	3	3	1.36	17.37	0.157	1.01	735	589	130	5.366	8.29	2.95	-
26	27	3	3	1.92	15.04	0.042	0.88	569	461	123	5.408	10.21	0.88	-
26	28	3	3	1.92	18.21	0.053	1.06	569	461	123	5.419	10.21	1.06	-
25	29	3	3	0.22	8.32	0.039	0.49	887	705	135	5.248	7.15	4.16	-
29	30	3	3	1.28	7.41	0.057	0.43	720	578	130	5.305	8.43	1.15	-
30	31	3	3	0.96	8.17	0.012	0.48	630	508	126	5.317	9.39	0.48	-
30	32	3	3	0.12	4.22	0.001	0.25	707	568	129	5.306	8.55	0.25	-
29	33	4/0	3	1.36	0.00	0.058	0.00	807	629	133	5.306	8.51	2.52	-
33	34	3	3	1.04	8.17	0.013	0.48	690	543	129	5.319	9.55	0.48	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : TOPSHIDANGA
CIRCUIT : A

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	I-3P	I-LG Max	I-LG Min				
33	35	3	3	0.09	0.00	0.009	0.00	795	620	133	5.315	8.60	2.05	-
35	36	3	3	1.44	7.49	0.016	0.44	645	510	127	5.331	10.04	0.44	-
35	37	3	3	0.31	11.59	0.019	0.68	757	593	131	5.334	8.91	1.61	-
37	38	3	3	0.80	7.57	0.009	0.44	674	531	128	5.343	9.71	0.44	-
37	39	3	3	0.64	8.44	0.008	0.49	690	543	129	5.342	9.55	0.49	-
20	40	4/0	3	1.04	5.95	0.868	0.35	1680	1261	148	5.000	4.94	49.03	-
40	41	3	1	0.88	5.88	0.029	1.03	N.A	1011	144	5.029	5.82	1.03	B
40	42	4/0	3	0.88	0.00	0.727	0.00	1496	1103	147	5.727	5.82	48.68	-
42	43	3	3	3.00	12.89	0.057	0.75	809	625	133	5.784	8.82	0.75	-
42	44	4/0	3	0.36	0.00	0.293	0.00	1432	1050	146	6.020	6.18	47.93	-
44	45	3	3	1.68	2.57	0.280	0.15	994	750	138	6.300	7.86	4.03	-
45	46	3	3	1.92	27.25	0.203	1.59	722	558	130	6.503	9.78	3.41	-
46	47	3	1	1.36	3.10	0.025	0.54	N.A	471	125	6.528	11.14	0.54	Y
46	48	3	3	2.24	21.88	0.071	1.28	543	428	122	6.574	12.02	1.28	-
45	49	3	3	1.10	8.01	0.013	0.47	819	627	133	6.313	8.96	0.47	-
44	50	4/0	3	1.28	29.29	0.943	1.71	1242	895	144	6.963	7.46	44.40	-
50	51	3	3	0.17	4.22	0.001	0.25	1198	866	143	6.964	7.63	0.25	-
50	52	4/0	3	1.12	10.89	0.798	0.64	1113	793	142	7.761	8.58	42.45	-
52	53	3	1	1.12	8.07	0.049	1.41	N.A	661	137	7.810	9.70	1.41	R
52	54	4/0	3	2.08	36.91	1.416	2.15	932	654	138	9.177	10.66	41.31	-
54	55	3	3	1.60	42.71	0.100	2.49	732	529	131	9.277	12.26	2.49	-
54	56	3	3	0.08	88.89	0.010	5.18	920	647	138	9.187	10.74	5.18	-
54	57	4/0	3	0.12	0.00	0.063	0.00	924	648	138	9.240	10.78	31.49	-
57	58	3	3	0.88	14.54	0.019	0.85	806	574	134	9.259	11.66	0.85	-
57	59	4/0	3	1.12	31.61	0.557	1.84	850	592	136	9.797	11.90	30.64	-
59	60	3	3	0.06	12.18	0.001	0.71	842	588	136	9.798	11.96	0.71	-
59	61	4/0	3	1.28	121.67	0.521	7.10	779	540	134	10.318	13.18	28.08	-
61	62	3	3	0.80	11.04	0.013	0.64	700	492	130	10.331	13.98	0.64	-
61	63	4/0	3	2.80	23.66	0.903	1.38	659	452	129	11.221	15.98	20.34	-
63	64	3	3	0.56	4.47	0.047	0.26	618	428	127	11.268	16.54	1.94	-
64	65	3	3	0.44	0.00	0.019	0.00	588	410	125	11.287	16.98	0.92	-
65	66	3	3	1.04	15.71	0.024	0.92	528	373	121	11.311	18.02	0.92	-
64	67	3	3	0.56	13.14	0.011	0.77	581	406	125	11.279	17.10	0.77	-
63	68	3	3	0.88	5.33	0.659	0.31	596	415	126	11.880	16.86	17.02	-
68	69	3	3	0.40	1.11	0.041	0.06	571	400	124	11.921	17.26	3.88	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : TOPSHIDANGA
CIRCUIT : A

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	1-3P	1-LG Max	1-LG Min				
69	70	3	1	1.36	8.15	0.122	1.43	N.A	355	119	12.043	18.62	2.44	Y
70	71	3	1	0.72	2.85	0.013	0.50	N.A	335	117	12.056	19.34	0.50	Y
70	72	3	1	0.88	2.93	0.015	0.51	N.A	331	116	12.058	19.50	0.51	Y
69	73	3	3	1.60	23.57	0.055	1.37	486	348	118	11.976	18.86	1.37	-
68	74	3	3	0.64	10.15	0.401	0.59	557	391	123	12.281	17.50	14.39	-
74	75	3	1	1.04	4.73	0.028	0.83	N.A	357	119	12.309	18.54	0.83	B
74	76	3	3	0.32	7.75	0.189	0.45	538	380	122	12.470	17.82	13.77	-
76	77	4/0	3	1.76	20.09	0.360	1.17	499	350	119	12.830	19.58	13.31	-
77	78	3	1	0.80	4.15	0.021	0.73	N.A	329	117	12.851	20.38	0.73	B
77	79	4/0	3	0.64	11.20	0.119	0.65	486	340	119	12.949	20.22	12.14	-
79	80	3	3	0.18	22.22	0.006	1.30	478	335	118	12.955	20.40	1.30	-
79	81	4/0	3	0.36	18.45	0.054	1.08	479	335	118	13.003	20.58	10.19	-
81	82	3	3	0.56	6.90	0.145	0.40	456	321	116	13.148	21.14	6.69	-
82	83	3	1	2.32	8.72	0.112	1.53	N.A	273	109	13.260	23.46	1.53	R
82	84	3	3	2.72	81.59	0.319	4.76	367	266	108	13.467	23.86	4.76	-
81	85	4/0	3	0.64	41.65	0.014	2.43	467	326	117	13.017	21.22	2.43	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : TOPSHIDANGA
CIRCUIT : B

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT I TIME	I-3P	I-LG Max	I-LG Min				
11 KV-BUS								5128	5938	158	0.000	0.00	-	
BUS	1	DOG	3	1.20	11.20	1.567	0.65	3512	3226	156	1.567	1.20	82.97	-
1	2	3	1	0.23	11.31	0.014	1.98	N.A	2802	154	1.581	1.43	1.98	R
1	3	DOG	3	0.56	12.72	0.719	0.74	3049	2646	155	2.286	1.76	82.32	-
3	4	3	3	1.36	17.76	0.119	1.04	1757	1463	148	2.405	3.12	4.13	-
4	5	3	3	0.80	8.09	0.010	0.47	1376	1142	144	2.415	3.92	0.47	-
4	6	3	1	0.21	15.00	0.016	2.62	N.A	1364	147	2.421	3.33	2.62	B
3	7	DOG	3	0.48	16.53	0.591	0.96	2736	2291	154	2.877	2.24	80.07	-
7	8	3	1	0.32	9.20	0.016	1.61	N.A	1982	152	2.893	2.56	1.61	Y
7	9	DOG	3	3.60	21.76	4.336	1.27	1536	1136	147	7.213	5.84	77.49	-
9	10	4/0	3	2.00	3.45	2.483	0.20	1223	879	143	9.696	7.84	76.23	-
10	11	3	1	0.13	7.09	0.005	1.24	N.A	858	143	9.701	7.97	1.24	Y
10	12	4/0	3	1.52	1.11	1.873	0.06	1059	750	141	11.569	9.36	74.78	-
12	13	3	3	0.72	9.20	0.010	0.54	932	669	137	11.579	10.08	0.54	-
12	14	3	3	0.48	2.87	0.025	0.17	971	695	138	11.594	9.84	1.20	-
14	15	3	3	0.32	10.40	0.010	0.61	919	661	137	11.604	10.16	0.92	-
15	16	3	3	0.80	5.33	0.006	0.31	808	590	134	11.610	10.96	0.31	-
14	17	3	3	0.24	1.99	0.001	0.12	932	669	137	11.595	10.08	0.12	-
12	18	4/0	3	1.12	12.92	1.342	0.75	963	677	139	12.911	10.48	72.98	-
18	19	3	3	0.80	3.61	0.005	0.21	846	604	135	12.916	11.28	0.21	-
18	20	3	3	0.64	4.22	0.008	0.25	868	617	136	12.919	11.12	0.40	-
20	21	3	3	0.64	2.59	0.003	0.15	787	566	133	12.922	11.76	0.15	-
18	22	4/0	3	0.72	1.11	0.851	0.06	910	637	137	13.762	11.20	71.62	-
22	23	3	3	0.72	5.66	0.006	0.33	815	578	134	13.768	11.92	0.33	-
22	24	4/0	3	0.40	5.74	0.469	0.33	883	617	137	14.231	11.60	71.22	-
24	25	3	3	1.52	3.15	0.585	0.18	709	509	130	14.816	13.12	9.89	-
25	26	3	3	0.16	4.56	0.007	0.27	694	499	130	14.823	13.28	1.12	-
26	27	3	3	0.72	6.98	0.008	0.41	633	461	127	14.831	14.00	0.41	-
26	28	3	3	0.88	7.66	0.010	0.45	621	453	126	14.833	14.16	0.45	-
25	29	3	3	1.28	0.00	0.426	0.00	604	442	125	15.242	14.40	8.58	-
29	30	3	3	1.52	9.70	0.023	0.57	511	381	120	15.265	15.92	0.57	-
29	31	3	3	0.17	3.45	0.052	0.20	592	434	125	15.294	14.57	8.02	-
31	32	3	3	0.56	7.06	0.024	0.41	556	410	123	15.318	15.13	1.47	-
32	33	3	3	0.72	6.95	0.008	0.41	515	383	120	15.326	15.85	0.41	-
32	34	3	3	1.44	4.63	0.017	0.27	479	359	118	15.335	16.57	0.65	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : TOPSHIDANGA
CIRCUIT : B

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	I-3P	I-LG Max	I-LG Min				
34	35	3	1	0.64	2.16	0.009	0.38	N.A	340	115	15.344	17.21	0.38	R
31	36	3	3	0.48	4.56	0.119	0.27	560	413	123	15.413	15.05	6.35	-
36	37	3	3	0.80	5.67	0.044	0.33	515	383	120	15.457	15.85	1.94	-
37	38	3	3	0.50	9.62	0.018	0.56	489	366	118	15.475	16.35	1.61	-
38	39	3	1	0.30	2.93	0.005	0.51	N.A	357	117	15.480	16.65	0.51	R
38	40	3	1	0.32	5.99	0.011	1.05	N.A	356	117	15.486	16.67	1.05	B
36	42	3	3	1.44	4.72	0.253	0.28	483	362	118	15.666	16.49	4.68	-
42	43	3	3	0.96	9.02	0.091	0.53	441	334	115	15.757	17.45	3.01	-
43	44	3	3	0.88	7.49	0.011	0.44	409	312	112	15.768	18.33	0.44	-
43	45	3	3	0.40	5.90	0.023	0.34	426	323	113	15.780	17.85	2.05	-
45	46	3	1	0.80	4.97	0.023	0.87	N.A	304	111	15.803	18.65	0.87	Y
45	47	3	3	0.80	3.81	0.027	0.22	398	304	111	15.807	18.65	1.70	-
47	48	3	1	0.80	7.20	0.031	1.26	N.A	287	109	15.838	19.45	1.26	R
47	49	3	3	0.56	3.79	0.003	0.22	381	292	109	15.810	19.21	0.22	-
42	50	3	3	1.84	14.93	0.084	0.87	409	312	112	15.750	18.33	1.40	-
50	51	3	3	1.20	4.79	0.009	0.28	372	286	108	15.759	19.53	0.28	-
50	52	3	3	0.08	4.22	0.000	0.25	406	310	112	15.750	18.41	0.25	-
24	53	4/0	3	0.40	5.40	0.411	0.31	858	598	136	14.642	12.00	62.28	-
53	54	3	3	0.16	6.56	0.006	0.38	838	585	135	14.648	12.16	1.83	-
54	55	3	1	0.72	3.27	0.014	0.57	N.A	535	132	14.662	12.88	0.57	B
54	56	3	1	1.84	8.29	0.087	1.45	N.A	470	128	14.735	14.00	1.45	Y
53	57	4/0	3	1.04	4.79	1.046	0.28	798	553	134	15.688	13.04	60.13	-
57	58	3	3	3.12	11.75	0.105	0.69	544	396	122	15.793	16.16	1.40	-
58	59	3	1	1.04	3.01	0.019	0.53	N.A	361	118	15.812	17.20	0.53	R
58	60	3	3	0.16	3.18	0.001	0.19	535	390	121	15.794	16.32	0.44	-
60	61	3	1	0.04	1.46	0.000	0.26	N.A	389	121	15.794	16.36	0.26	B
57	62	4/0	3	0.08	10.78	0.079	0.63	794	550	134	15.767	13.12	58.98	-
62	63	3	3	0.64	2.08	0.018	0.12	728	510	131	15.785	13.76	0.69	-
63	64	3	3	1.44	4.79	0.011	0.28	608	436	126	15.796	15.20	0.28	-
63	65	3	3	0.13	4.97	0.001	0.29	715	503	131	15.786	13.89	0.29	-
62	66	4/0	3	1.04	3.10	1.003	0.18	743	513	132	16.770	14.16	57.67	-
66	67	4/0	3	1.84	7.54	0.008	0.44	666	457	129	16.778	16.00	0.44	-
66	68	4/0	3	1.20	14.54	1.139	0.85	691	475	130	17.909	15.36	57.04	-
68	69	3	1	0.80	0.00	0.000	0.00	N.A	438	127	17.909	16.16	0.00	B
68	70	3	3	0.96	7.91	0.253	0.46	617	431	127	18.162	16.32	6.60	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : TOPSHIDANGA
CIRCUIT : B

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	1-3P	1-LG Max	1-LG Min				
70	71	3	3	0.64	4.98	0.005	0.29	575	405	124	18.167	16.96	0.29	-
70	72	3	3	1.20	13.81	0.024	0.81	541	385	122	18.186	17.52	0.81	-
70	73	3	3	0.72	10.78	0.137	0.63	570	402	124	18.299	17.04	5.04	-
73	74	3	3	1.36	13.68	0.190	0.80	496	357	119	18.489	18.40	4.02	-
74	75	3	3	0.48	12.47	0.050	0.73	474	343	117	18.539	18.88	3.22	-
75	76	3	3	0.88	9.20	0.012	0.54	438	320	114	18.551	19.76	0.54	-
75	77	3	3	0.96	6.41	0.054	0.37	435	318	114	18.593	19.84	1.96	-
77	78	3	3	1.12	12.97	0.021	0.76	396	293	111	18.614	20.96	0.76	-
77	79	3	1	0.64	4.72	0.017	0.83	N.A	303	112	18.610	20.48	0.83	B
73	80	3	3	0.88	6.82	0.009	0.40	520	372	121	18.308	17.92	0.40	-
68	81	4/0	3	1.52	10.65	1.271	0.62	635	435	128	19.180	16.88	50.42	-
81	82	3	3	0.96	6.75	0.010	0.39	572	397	124	19.190	17.84	0.39	-
81	83	4/0	3	0.48	1.11	0.396	0.06	619	423	127	19.576	17.36	49.41	-
83	84	3	3	0.80	8.09	0.182	0.47	568	393	124	19.758	18.16	5.90	-
84	85	3	1	0.80	4.80	0.022	0.84	N.A	367	121	19.780	18.96	0.84	R
84	86	3	3	1.04	14.63	0.193	0.85	512	360	120	19.951	19.20	5.43	-
86	87	3	1	1.74	6.08	0.059	1.06	N.A	314	114	20.010	20.94	1.06	Y
86	88	3	1	0.91	11.39	0.055	1.99	N.A	334	117	20.006	20.11	1.99	B
86	89	3	3	1.28	7.68	0.142	0.45	455	325	116	20.093	20.48	2.58	-
89	90	3	3	2.72	14.63	0.059	0.85	365	269	108	20.152	23.20	0.85	-
89	91	3	3	0.80	21.96	0.025	1.28	425	306	113	20.118	21.28	1.28	-
83	92	4/0	3	1.04	6.90	0.763	0.40	588	400	125	20.339	18.40	44.37	-
92	93	3	3	1.84	21.21	0.057	1.24	490	343	119	20.396	20.24	1.24	-
92	94	4/0	3	0.72	13.31	0.506	0.78	568	386	124	20.845	19.12	42.73	-
94	95	3	3	1.52	11.12	0.096	0.65	490	341	119	20.941	20.64	1.65	-
95	96	3	3	1.52	12.92	0.029	0.75	429	304	114	20.970	22.16	0.75	-
95	97	3	3	1.09	4.22	0.006	0.25	445	314	115	20.947	21.73	0.25	-
94	98	4/0	3	0.48	6.92	0.319	0.40	555	377	124	21.164	19.60	40.31	-
98	99	3	3	1.52	34.04	0.198	1.99	481	334	118	21.362	21.12	5.17	-
99	100	3	1	0.80	12.05	0.051	2.11	N.A	314	116	21.413	21.92	2.11	R
99	101	3	3	0.80	12.89	0.015	0.75	448	314	116	21.377	21.92	0.75	-
99	102	3	3	0.64	5.48	0.005	0.32	454	318	116	21.367	21.76	0.32	-
98	103	4/0	3	1.04	18.08	0.613	1.05	529	359	122	21.777	20.64	36.85	-
103	104	3	3	0.96	11.25	0.310	0.66	484	333	119	22.087	21.60	9.19	-
104	105	3	3	0.80	12.63	0.117	0.74	452	314	116	22.204	22.40	3.43	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-1
SUBSTATION : TOPSHIDANGA
CIRCUIT : B

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	1-3P	1-LG Max	1-LG Min				
105	106	3	3	0.56	5.33	0.057	0.31	431	302	114	22.261	22.96	2.25	-
106	107	3	3	1.52	29.04	0.064	1.69	383	273	109	22.325	24.48	1.69	-
106	108	3	3	0.11	4.22	0.001	0.25	427	299	114	22.262	23.07	0.25	-
105	109	3	3	0.72	7.56	0.008	0.44	426	298	114	22.212	23.12	0.44	-
104	110	3	3	0.64	19.65	0.077	1.15	458	318	116	22.164	22.24	5.11	-
110	111	3	1	1.12	17.11	0.101	2.99	N.A	294	113	22.265	23.36	2.99	Y
110	112	3	3	0.09	16.63	0.002	0.97	455	316	116	22.166	22.33	0.97	-
103	113	4/0	3	1.68	38.18	0.736	2.23	493	333	120	22.513	22.32	26.60	-
113	114	3	3	1.20	20.99	0.445	1.22	445	306	115	22.958	23.52	8.57	-
114	115	3	3	1.44	21.84	0.046	1.27	397	277	111	23.004	24.96	1.27	-
114	116	3	3	1.84	22.64	0.378	1.32	385	270	110	23.336	25.36	5.05	-
116	117	3	3	0.32	8.09	0.004	0.47	376	265	109	23.340	25.68	0.47	-
116	118	3	3	2.32	10.13	0.325	0.59	328	236	103	23.661	27.68	3.25	-
118	119	3	3	1.84	19.99	0.053	1.17	293	214	99	23.714	29.52	1.17	-
118	120	3	3	2.08	25.66	0.077	1.50	288	211	98	23.738	29.76	1.50	-
114	121	3	3	0.03	17.54	0.001	1.02	443	305	115	22.959	23.55	1.02	-
113	122	4/0	3	1.68	19.10	0.443	1.11	461	311	117	22.956	24.00	15.80	-
122	123	3	3	0.48	43.81	0.192	2.56	443	301	116	23.148	24.48	9.71	-
123	124	3	3	0.72	13.31	0.014	0.78	418	287	113	23.162	25.20	0.78	-
123	125	3	3	0.12	0.00	0.037	0.00	439	298	115	23.185	24.60	6.38	-
125	126	3	3	3.28	73.84	0.344	4.31	345	243	105	23.529	27.88	4.31	-
125	127	3	3	0.32	4.47	0.030	0.26	428	292	114	23.215	24.92	2.08	-
127	128	3	3	0.40	2.22	0.015	0.13	414	284	113	23.230	25.32	0.82	-
128	129	3	3	0.88	11.78	0.015	0.69	388	269	110	23.245	26.20	0.69	-
127	130	3	3	1.60	17.13	0.040	1.00	379	264	109	23.255	26.52	1.00	-
122	131	4/0	3	0.88	7.60	0.072	0.44	445	300	116	23.028	24.88	4.97	-
131	132	3	3	1.60	14.29	0.035	0.83	394	271	111	23.063	26.48	0.83	-
131	133	4/0	3	0.48	1.11	0.031	0.06	438	295	115	23.059	25.36	3.70	-
133	134	3	3	2.40	37.99	0.181	2.22	366	254	108	23.240	27.76	2.69	-
134	135	3	3	0.80	7.07	0.009	0.41	347	242	106	23.249	28.56	0.41	-
134	136	3	3	0.24	1.11	0.000	0.06	360	250	107	23.240	28.00	0.06	-
133	137	4/0	3	0.96	16.10	0.009	0.94	423	284	114	23.068	26.32	0.94	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : TOPSHIDANGA
CIRCUIT : C

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	1-3P	1-LG Max	1-LG Min				
11 KV-BUS								5128	5938	158	0.000	0.00	-	
BUS	1	4/0	3	0.21	0.00	0.260	0.00	4741	5171	157	0.260	0.21	77.20	-
1	2	3	1	0.07	4.30	0.002	0.75	N.A	4858	157	0.262	0.28	0.75	R
1	3	3	1	0.37	2.57	0.006	0.45	N.A	3764	155	0.266	0.58	0.45	B
1	4	4/0	3	0.52	8.09	0.639	0.47	3980	3889	156	0.899	0.73	76.75	-
4	5	3	1	0.32	4.12	0.007	0.72	N.A	3109	155	0.906	1.05	0.72	Y
4	6	3	1	0.88	8.24	0.040	1.44	N.A	2237	152	0.939	1.61	1.44	B
4	7	4/0	3	0.25	8.51	0.303	0.50	3689	3469	156	1.202	0.98	74.84	-
7	8	DOG	3	0.96	12.82	0.006	0.75	2897	2471	154	1.208	1.94	0.75	-
7	9	DOG	3	0.04	4.98	0.046	0.29	3648	3412	156	1.248	1.02	73.60	-
9	10	3	3	0.36	10.78	0.058	0.63	3032	2723	154	1.306	1.38	5.61	-
10	11	3	1	0.61	3.96	0.112	0.69	N.A	1980	151	1.418	1.99	3.72	Y
11	12	3	1	0.30	10.76	0.017	1.88	N.A	1738	149	1.435	2.29	1.88	Y
11	13	3	1	0.36	6.54	0.013	1.14	N.A	1696	149	1.431	2.35	1.14	Y
10	14	3	3	0.53	9.62	0.042	0.56	2361	2056	151	1.348	1.91	3.44	-
14	15	3	1	1.26	12.46	0.083	2.18	N.A	1270	145	1.431	3.17	2.18	R
14	16	3	3	0.23	12.05	0.004	0.70	2142	1852	150	1.352	2.14	0.70	-
9	17	DOG	3	1.55	9.20	1.669	0.54	2535	2075	153	2.917	2.57	71.41	-
17	18	3	3	0.31	10.70	0.075	0.62	2246	1825	151	2.992	2.88	6.10	-
18	19	3	1	0.88	6.52	0.032	1.14	N.A	1337	147	3.024	3.76	1.14	B
18	20	3	3	0.98	74.36	0.104	4.34	1603	1296	146	3.096	3.86	4.34	-
17	21	DOG	3	2.25	8.26	2.206	0.48	1746	1318	149	5.123	4.82	64.78	-
21	22	3	1	0.13	2.76	0.002	0.48	N.A	1270	148	5.125	4.95	0.48	R
21	23	DOG	3	0.72	3.45	0.701	0.20	1587	1179	148	5.824	5.54	64.29	-
23	24	3	3	0.33	5.95	0.003	0.35	1456	1087	146	5.827	5.87	0.35	-
23	25	DOG	3	0.46	2.57	0.444	0.15	1499	1105	147	6.268	6.00	63.75	-
25	26	3	1	0.53	5.29	0.016	0.93	N.A	978	144	6.284	6.53	0.93	B
25	27	DOG	3	0.25	6.12	0.239	0.36	1456	1069	146	6.507	6.25	62.67	-
27	28	3	3	0.45	5.68	0.004	0.33	1307	966	144	6.511	6.70	0.33	-
27	29	3	3	0.53	7.67	0.006	0.45	1283	950	144	6.513	6.78	0.45	-
27	30	DOG	3	0.61	2.76	0.574	0.16	1359	989	145	7.081	6.86	61.53	-
30	31	3	1	1.84	10.36	0.102	1.81	N.A	699	137	7.183	8.70	1.81	R
30	30A	DOG	3	1.20	3.45	1.115	0.20	1202	862	143	8.196	8.06	61.37	-
30A	32	4/0	3	2.08	48.82	1.958	2.85	994	701	139	10.154	10.14	61.17	-
32	33	3	3	0.74	17.19	0.132	1.00	879	628	136	10.286	10.88	5.22	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : TOPSHIDANGA
CIRCUIT : C

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT I TIME	I-3P	I-LG Max	I-LG Min				
33	34	3	1	0.41	4.55	0.011	0.80	N.A	593	134	10.297	11.29	0.80	B
33	35	3	3	1.44	13.05	0.180	0.76	709	519	130	10.466	12.32	4.22	-
35	36	3	1	0.96	13.23	0.067	2.31	N.A	465	126	10.533	13.28	2.31	Y
35	37	3	3	0.08	8.78	0.005	0.51	701	514	130	10.471	12.40	2.40	-
37	38	3	1	1.28	7.17	0.050	1.25	N.A	445	125	10.521	13.68	1.25	B
37	39	3	3	0.48	10.83	0.008	0.63	658	486	128	10.479	12.88	0.63	-
32	40	4/0	3	0.12	8.78	0.101	0.51	985	693	139	10.255	10.26	53.37	-
40	41	3	3	0.88	8.34	0.011	0.49	852	610	135	10.266	11.14	0.49	-
40	42	4/0	3	0.80	6.44	0.661	0.38	924	647	138	10.916	11.06	52.37	-
42	43	3	3	0.28	8.44	0.016	0.49	883	622	136	10.932	11.34	2.49	-
43	44	3	1	0.96	11.39	0.058	1.99	N.A	548	132	10.990	12.30	1.99	R
43	45	3	1	0.19	5.20	0.006	0.91	N.A	606	136	10.938	11.53	0.91	B
42	46	4/0	3	0.40	0.00	0.295	0.00	896	626	137	11.211	11.46	44.74	-
42	47	3	3	1.12	4.62	0.178	0.27	778	556	133	11.094	12.18	6.62	-
47	48	3	1	0.80	11.11	0.045	1.94	N.A	504	130	11.139	12.98	1.94	Y
47	49	3	3	0.25	0.00	0.031	0.00	751	539	132	11.125	12.43	6.36	-
49	50	3	1	1.28	10.89	0.326	1.91	N.A	464	127	11.451	13.71	5.56	B
50	51	3	1	0.96	8.41	0.044	1.47	N.A	420	123	11.495	14.67	1.47	B
50	52	3	1	0.64	12.46	0.042	2.18	N.A	434	124	11.493	14.35	2.18	B
49	53	3	3	3.20	13.68	0.065	0.80	510	383	120	11.190	15.63	0.80	-
46	54	4/0	3	1.12	16.49	0.818	0.96	827	574	135	12.029	12.58	44.74	-
54	55	3	1	1.12	10.57	0.062	1.85	N.A	502	130	12.091	13.70	1.85	R
54	56	4/0	3	1.72	8.78	1.217	0.51	739	509	132	13.246	14.30	43.00	-
56	57	3	3	0.54	13.35	0.059	0.78	689	480	130	13.305	14.84	3.84	-
57	58	3	1	0.48	13.52	0.034	2.37	N.A	456	128	13.339	15.32	2.37	Y
57	59	3	3	0.16	7.67	0.007	0.45	676	472	129	13.312	15.00	2.12	-
59	60	3	1	0.64	8.17	0.028	1.43	N.A	441	127	13.340	15.64	1.43	R
59	61	3	3	0.10	4.22	0.001	0.25	667	467	129	13.313	15.10	0.25	-
56	62	4/0	3	1.20	5.56	0.787	0.32	688	472	130	14.033	15.50	41.02	-
62	63	3	3	0.64	9.02	0.009	0.53	637	442	128	14.042	16.14	0.53	-
62	64	4/0	3	2.08	39.08	1.300	2.28	614	419	127	15.333	17.58	40.17	-
64	65	3	3	1.08	9.81	0.196	0.57	548	380	123	15.529	18.66	5.62	-
65	66	3	3	0.13	12.47	0.018	0.73	541	376	122	15.547	18.79	4.73	-
66	67	3	3	0.13	7.42	0.010	0.43	534	372	122	15.557	18.92	1.95	-
67	68	3	3	0.88	11.71	0.015	0.68	490	346	119	15.572	19.80	0.68	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : TOPSHIDANGA
CIRCUIT : C

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	1-3P	1-LG Max	1-LG Min				
67	69	3	3	0.07	14.23	0.001	0.83	530	370	122	15.558	18.99	0.83	-
66	70	3	1	0.13	11.77	0.008	2.06	N.A	372	122	15.555	18.92	2.06	R
65	71	3	3	0.48	5.46	0.004	0.32	522	365	121	15.533	19.14	0.32	-
64	72	4/0	3	0.56	8.26	0.297	0.48	597	407	126	15.630	18.14	34.33	-
72	73	3	3	0.80	12.32	0.481	0.72	549	379	123	16.111	18.94	14.00	-
73	74	3	3	1.12	15.49	0.632	0.90	493	346	119	16.743	20.06	13.28	-
74	75	3	3	1.04	6.84	0.556	0.40	449	319	115	17.299	21.10	12.38	-
75	76	3	3	2.24	41.91	0.662	2.44	375	273	109	17.961	23.34	8.88	-
76	77	3	3	1.04	7.49	0.238	0.44	348	256	106	18.199	24.38	6.43	-
77	78	3	1	0.80	5.57	0.025	0.97	N.A	244	104	18.224	25.18	0.97	Y
77	79	3	3	1.36	16.48	0.251	0.96	317	236	102	18.450	25.74	5.30	-
79	80	3	3	1.68	6.33	0.185	0.37	286	215	98	18.635	27.42	3.38	-
80	81	3	1	1.28	10.72	0.073	1.88	N.A	202	95	18.708	28.70	1.88	Y
80	82	3	3	0.24	14.65	0.013	0.85	282	212	97	18.648	27.66	3.01	-
82	83	3	1	1.52	12.32	0.099	2.16	N.A	197	94	18.747	29.18	2.16	B
79	84	3	3	0.18	16.48	0.004	0.96	314	233	102	18.454	25.92	0.96	-
75	86	3	3	2.24	25.24	0.319	1.47	375	273	109	17.618	23.34	5.26	-
86	87	3	1	0.80	3.70	0.017	0.65	N.A	259	106	17.635	24.14	0.65	R
86	88	3	3	0.80	9.36	0.070	0.55	353	259	106	17.688	24.14	3.14	-
88	89	3	1	1.20	8.65	0.057	1.51	N.A	241	103	17.745	25.34	1.51	R
88	90	3	3	2.00	18.60	0.054	1.08	309	231	101	17.742	26.14	1.08	-
72	92	4/0	3	0.72	2.75	0.215	0.16	576	392	125	15.845	18.86	20.54	-
92	93	3	3	0.64	8.51	0.279	0.50	540	371	122	16.124	19.50	13.56	-
93	94	3	1	0.80	4.38	0.020	0.77	N.A	348	120	16.144	20.30	0.77	Y
93	95	3	3	0.80	6.69	0.325	0.39	500	348	120	16.449	20.30	13.06	-
95	96	3	1	0.80	12.66	0.053	2.22	N.A	327	117	16.502	21.10	2.22	B
95	97	3	3	0.32	17.61	0.109	1.03	485	339	118	16.558	20.62	10.46	-
97	98	3	1	2.08	12.53	0.138	2.19	N.A	291	112	16.696	22.70	2.19	Y
97	99	3	3	0.88	20.45	0.224	1.19	449	317	116	16.782	21.50	9.43	-
99	100	3	1	0.80	8.85	0.038	1.55	N.A	299	113	16.820	22.30	1.55	R
99	101	3	3	0.40	14.70	0.074	0.86	434	308	114	16.856	21.90	8.24	-
101	102	3	1	0.80	12.44	0.053	2.18	N.A	291	112	16.909	22.70	2.18	R
101	103	3	3	0.56	10.01	0.066	0.58	414	296	112	16.922	22.46	7.38	-
103	104	3	1	0.24	3.45	0.081	0.60	N.A	291	112	17.003	22.70	6.61	B
104	105	3	1	0.24	4.56	0.069	0.80	N.A	286	111	17.072	22.94	5.70	B

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : TOPSHIDANGA
CIRCUIT : C

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	1-3P	1-LG Max	1-LG Min				
105	106	3	1	0.32	0.00	0.063	0.00	N.A	280	110	17.135	23.26	3.54	B
106	107	3	1	1.60	17.15	0.143	3.00	N.A	253	105	17.278	24.86	3.00	B
106	108	3	1	0.24	3.10	0.004	0.54	N.A	276	109	17.139	23.50	0.54	B
105	109	3	1	1.12	7.74	0.047	1.35	N.A	266	108	17.119	24.06	1.35	B
104	110	3	1	0.08	1.76	0.001	0.31	N.A	290	111	17.004	22.78	0.31	B
103	111	3	3	0.08	3.27	0.000	0.19	412	294	112	16.922	22.54	0.19	-
92	112	4/0	3	1.28	13.10	0.163	0.76	543	368	123	16.008	20.14	9.45	-
112	113	3	3	1.60	11.43	0.107	0.67	468	325	117	16.115	21.74	2.74	-
113	114	3	1	1.04	8.25	0.047	1.44	N.A	301	114	16.162	22.78	1.44	Y
113	115	3	3	0.40	10.78	0.006	0.63	452	316	116	16.121	22.14	0.63	-
112	116	4/0	3	0.72	14.26	0.060	0.83	525	356	122	16.068	20.86	5.95	-
116	117	3	3	0.64	16.12	0.073	0.94	495	339	119	16.141	21.50	3.58	-
117	118	3	1	1.28	6.82	0.048	1.19	N.A	308	115	16.189	22.78	1.19	Y
117	119	3	3	0.11	14.12	0.006	0.82	490	336	119	16.147	21.61	1.97	-
119	120	3	1	1.20	3.01	0.022	0.53	N.A	308	115	16.169	22.81	0.53	R
119	121	3	3	1.04	10.70	0.017	0.62	448	311	116	16.164	22.65	0.62	-
116	122	4/0	3	0.16	0.00	0.004	0.00	522	354	122	16.072	21.02	1.54	-
122	123	3	3	1.20	8.34	0.015	0.49	468	323	117	16.087	22.22	0.49	-
122	124	4/0	3	2.04	18.00	0.019	1.05	479	323	119	16.091	23.06	1.05	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : TOPSHIDANGA
CIRCUIT : D

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	1-3P	1-LG Max	1-LG Min				
11 KV-BUS								5128	5938	158	0.000	0.00	-	
BUS	1	4/0	3	0.32	22.22	0.436	1.30	4559	4838	157	0.436	0.32	80.58	-
1	2	3	3	0.88	5.05	0.034	0.29	2754	2536	153	0.470	1.20	1.69	-
2	3	3	1	0.80	6.15	0.027	1.08	N.A	1709	148	0.497	2.00	1.08	R
2	4	3	3	0.48	5.56	0.004	0.32	2200	1969	150	0.474	1.68	0.32	-
1	5	4/0	3	0.56	7.67	0.745	0.45	3801	3626	156	1.181	0.88	77.88	-
5	6	3	3	0.32	19.96	0.009	1.16	3207	2933	154	1.190	1.20	1.16	-
5	7	4/0	3	0.48	0.00	0.627	0.00	3318	2976	155	1.808	1.36	76.26	-
7	8	3	1	0.16	2.34	0.002	0.41	N.A	2713	154	1.810	1.52	0.41	B
7	9	4/0	3	0.08	0.00	0.104	0.00	3248	2889	155	1.912	1.44	76.26	-
9	10	3	1	0.15	1.11	0.001	0.19	N.A	2655	154	1.913	1.59	0.19	Y
9	11	4/0	3	0.18	4.22	0.234	0.25	3102	2711	155	2.146	1.62	76.07	-
11	12	3	1	1.12	19.28	0.114	3.37	N.A	1620	149	2.260	2.74	3.37	Y
11	13	3	3	1.20	7.75	0.290	0.45	1878	1572	148	2.436	2.82	5.40	-
13	14	3	3	1.12	18.99	0.216	1.11	1328	1106	143	2.652	3.94	4.61	-
14	15	3	3	1.20	17.57	0.031	1.02	1002	834	138	2.683	5.14	1.02	-
14	16	3	3	0.56	4.22	0.063	0.25	1154	960	140	2.715	4.50	2.48	-
16	17	3	3	1.28	28.26	0.052	1.65	885	737	135	2.767	5.78	1.65	-
16	18	3	3	0.96	10.08	0.014	0.59	940	783	136	2.729	5.46	0.59	-
13	19	3	3	0.10	5.77	0.001	0.34	1813	1516	148	2.437	2.92	0.34	-
11	20	4/0	3	0.11	0.00	0.131	0.00	3019	2612	155	2.277	1.73	70.33	-
20	21	3	3	0.23	133.33	0.043	7.78	2722	2322	153	2.320	1.96	7.78	-
20	22	4/0	3	0.75	8.44	0.785	0.49	2549	2091	153	3.062	2.48	62.55	-
22	23	3	1	0.24	3.33	0.004	0.58	N.A	1890	152	3.066	2.72	0.58	B
22	24	4/0	3	0.72	6.44	0.746	0.38	2215	1754	152	3.808	3.20	62.06	-
24	25	3	3	1.52	30.44	0.411	1.78	1377	1094	144	4.219	4.72	6.59	-
25	26	3	3	1.12	4.56	0.008	0.27	1056	846	139	4.227	5.84	0.27	-
25	27	3	3	1.28	32.49	0.060	1.90	1021	819	138	4.279	6.00	1.90	-
25	28	3	3	1.52	45.43	0.100	2.65	973	782	137	4.319	6.24	2.65	-
24	29	4/0	3	0.48	0.00	0.441	0.00	2037	1583	151	4.249	3.68	55.09	-
29	30	3	1	0.05	2.22	0.001	0.39	N.A	1557	151	4.250	3.73	0.39	B
29	31	4/0	3	0.56	14.30	0.510	0.83	1861	1422	150	4.759	4.24	55.09	-
31	32	3	3	0.24	5.33	0.016	0.31	1731	1324	149	4.775	4.48	1.54	-
32	33	3	3	1.28	5.88	0.012	0.34	1230	955	142	4.787	5.76	0.34	-
32	34	3	3	0.72	15.18	0.016	0.89	1414	1090	145	4.791	5.20	0.89	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-1
SUBSTATION : TOPSHIDANGA
CIRCUIT : D

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	1-3P	1-LG Max	1-LG Min				
31	35	4/0	3	1.52	19.86	1.318	1.16	1507	1113	147	6.077	5.76	52.72	-
35	36	3	1	0.32	2.20	0.004	0.38	N.A	1032	145	6.081	6.08	0.38	R
35	37	4/0	3	0.18	0.00	0.154	0.00	1474	1085	147	6.231	5.94	51.18	-
37	38	3	3	0.48	0.00	0.024	0.00	1312	973	144	6.255	6.42	1.02	-
38	39	3	3	0.72	10.67	0.011	0.62	1118	839	141	6.266	7.14	0.62	-
38	40	3	3	0.72	6.90	0.008	0.40	1118	839	141	6.263	7.14	0.40	-
37	41	4/0	3	0.88	0.00	0.738	0.00	1330	966	145	6.969	6.82	50.15	-
41	42	3	1	0.72	8.18	0.032	1.43	N.A	837	142	7.001	7.54	1.43	B
41	43	3	3	0.48	0.00	0.040	0.00	1196	877	143	7.009	7.30	1.71	-
43	44	3	3	1.36	25.09	0.048	1.46	917	688	136	7.057	8.66	1.46	-
43	45	3	3	0.10	4.22	0.001	0.25	1171	860	142	7.010	7.40	0.25	-
41	46	4/0	3	1.04	54.93	0.804	3.20	1192	856	143	7.773	7.86	48.44	-
46	47	3	3	1.12	15.49	0.025	0.90	961	704	138	7.798	8.98	0.90	-
46	48	4/0	3	1.04	6.12	0.755	0.36	1081	768	141	8.528	8.90	44.34	-
48	49	3	3	1.28	1.11	0.565	0.06	864	629	135	9.093	10.18	10.23	-
49	50	3	1	0.64	5.12	0.019	0.90	N.A	575	133	9.112	10.82	0.90	R
49	51	3	3	3.20	9.56	1.325	0.56	560	426	123	10.418	13.38	9.45	-
51	52	3	3	0.80	6.44	0.025	0.38	513	393	120	10.443	14.18	1.75	-
52	53	3	1	1.04	7.84	0.044	1.37	N.A	358	116	10.487	15.22	1.37	R
51	54	3	3	1.84	13.33	0.632	0.78	463	358	116	11.050	15.22	8.52	-
54	55	3	3	0.48	4.44	0.027	0.26	443	343	115	11.077	15.70	2.23	-
55	56	3	1	0.88	7.69	0.037	1.35	N.A	320	112	11.114	16.58	1.35	B
55	57	3	3	0.96	10.77	0.015	0.63	407	318	112	11.092	16.66	0.63	-
54	58	3	3	1.12	10.07	0.071	0.59	418	326	113	11.121	16.34	2.80	-
58	59	3	1	1.52	9.79	0.080	1.71	N.A	290	108	11.201	17.86	1.71	Y
58	60	3	3	0.64	8.55	0.009	0.50	396	310	111	11.130	16.98	0.50	-
54	61	3	3	2.40	20.69	0.391	1.21	377	295	109	11.441	17.62	4.43	-
61	62	3	3	0.40	0.00	0.004	0.00	365	287	108	11.445	18.02	0.65	-
62	63	3	1	0.64	3.69	0.014	0.65	N.A	275	106	11.459	18.66	0.65	R
62	64	3	3	0.08	0.00	0.000	0.00	363	286	108	11.445	18.10	0.00	-
61	65	3	3	0.88	0.00	0.111	0.00	352	278	107	11.552	18.50	3.22	-
65	66	3	3	0.16	20.69	0.012	1.21	348	275	106	11.564	18.66	2.74	-
66	67	3	1	1.60	4.88	0.045	0.85	N.A	248	102	11.609	20.26	0.85	B
66	68	3	3	0.64	11.60	0.011	0.68	333	263	104	11.575	19.30	0.68	-
65	69	3	3	0.08	8.25	0.001	0.48	350	276	106	11.553	18.58	0.48	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : TOPSHIDANGA
CIRCUIT : D

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 20.01.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	I-3P	I-LG Max	I-LG Min				
48	70	4/0	3	0.40	1.11	0.224	0.06	1043	739	140	8.752	9.30	33.75	-
70	71	3	3	4.40	16.19	0.870	0.94	555	420	122	9.622	13.70	4.70	-
71	72	3	3	2.24	15.02	0.049	0.88	443	342	115	9.671	15.94	0.88	-
71	73	3	3	0.56	0.00	0.076	0.00	522	398	120	9.698	14.26	2.88	-
73	74	3	3	2.48	11.26	0.179	0.66	413	321	112	9.877	16.74	1.85	-
74	75	3	3	0.64	20.39	0.020	1.19	391	305	110	9.897	17.38	1.19	-
74	76	3	3	0.06	0.00	0.000	0.00	411	319	112	9.877	16.80	0.00	-
73	77	3	3	2.64	17.79	0.069	1.04	407	317	112	9.767	16.90	1.04	-
70	78	4/0	3	0.08	0.00	0.039	0.00	1036	733	140	8.791	9.38	28.98	-
78	79	3	3	0.64	8.25	0.118	0.48	926	664	137	8.909	10.02	5.31	-
79	80	3	1	0.96	9.68	0.050	1.69	N.A	579	133	8.959	10.98	1.69	R
79	81	3	3	0.88	19.18	0.107	1.12	804	585	134	9.016	10.90	3.14	-
81	82	3	3	0.40	8.37	0.005	0.49	758	555	132	9.021	11.30	0.49	-
81	83	3	3	1.20	26.26	0.045	1.53	678	503	129	9.061	12.10	1.53	-
78	84	4/0	3	1.20	12.13	0.486	0.71	938	659	138	9.277	10.58	23.66	-
84	85	3	3	2.00	11.84	0.037	0.69	697	507	130	9.314	12.58	0.69	-
84	86	3	3	0.64	76.94	0.071	4.49	847	602	135	9.348	11.22	4.49	-
84	87	4/0	3	0.40	1.46	0.124	0.09	910	637	137	9.401	10.98	17.78	-
87	88	DOG	3	0.16	0.00	0.048	0.00	899	629	137	9.449	11.14	17.69	-
88	89	3	3	0.24	0.00	0.062	0.00	866	609	136	9.511	11.38	5.48	-
89	90	3	3	0.24	0.00	0.062	0.00	835	589	135	9.573	11.62	5.48	-
90	91	3	3	1.61	57.92	0.287	3.38	667	484	128	9.860	13.23	5.48	-
91	92	3	3	0.56	4.87	0.004	0.28	622	455	126	9.864	13.79	0.28	-
91	93	3	3	1.84	8.67	0.134	0.51	538	400	122	9.994	15.07	1.81	-
93	94	3	3	0.64	6.21	0.006	0.36	503	377	119	10.000	15.71	0.36	-
93	95	3	3	1.26	16.20	0.030	0.94	473	357	117	10.024	16.33	0.94	-
88	98	DOG	3	0.48	4.22	0.098	0.25	869	606	136	9.547	11.62	12.22	-
98	99	3	3	0.56	101.28	0.081	5.91	799	564	134	9.628	12.18	5.91	-
98	100	3	3	2.56	103.98	0.381	6.06	614	447	126	9.928	14.18	6.06	-

6.9 ACR Scheme of Topshidanga Sub-Station

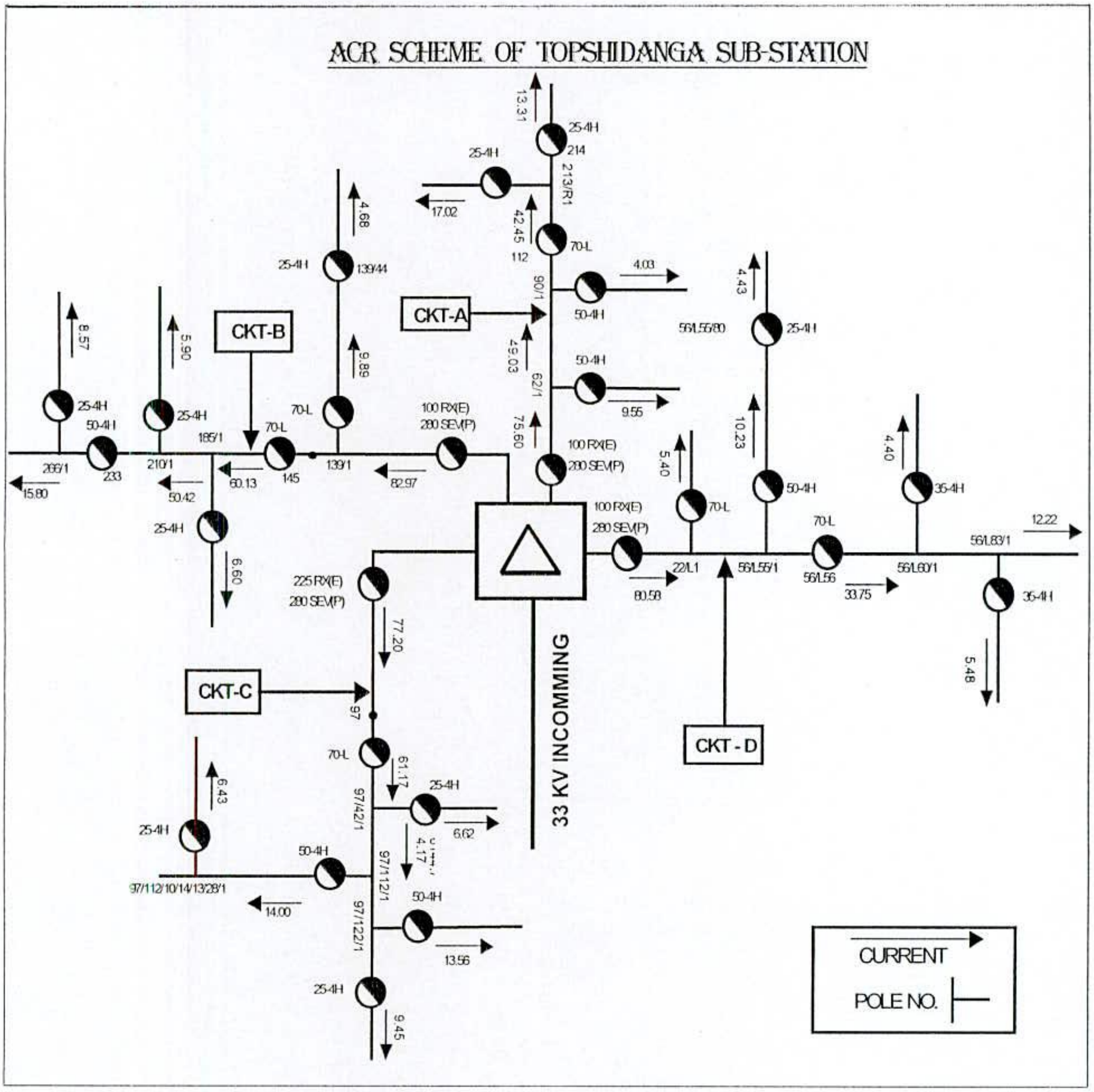


Figure 6.2 ACR scheme of Topshidanga S/S.

6.10 Study of Existing Coordination and Proposed Modification

Feasibility study of the existing protection scheme is conducted first to ensure the effectiveness of the scheme. In the case of the rating of any protective device falling below the ratings and constraining conditions for protection, the scheme is not feasible for coordination. Therefore, new device with proper rating is proposed to ensure the feasibility in phase-I technique.

6.10.1 Coordination of Topshidanga Sub-Station with Jessore Grid.

The PBS sub-station has two sets of 125E fuses at its incoming and the 11 KV outgoing feeders A, B and D are protected with 100-RX ACR and feeder - C is protected with 225-RX ACR. The sub-station has backup protection at PDB Jessore Grid sub-station with OCB operated by JS J72 61-3B/CC , SIEMENS , Static Definite Time Relay .

6.10.2 Phase Fault at H.T Side of the X-former

33 KV source line of the Topshidanga Sub-station is protected with a OCB operated by a JS J7261-3B/CC type definite time relay and the 2×5 MVA Transformer are protected with two sets of 125 E fuse. From the TCC of the existing system Figure 6.3a, it is observed that when a phase fault takes place the 125 E fuse melts before tripping of the PDB O/C relay and Transformer Damage curve remains at the top. Consequently, co-ordination is achieved.

Possibility of using a 160 VWV 33 KV ACR in series with the 125 E fuse was also been studied. From the TCC Figure 6.3b, it is observed that at fault condition the 125 E fuse starts melting before the 160 VWV 33 KV ACR goes in to operation. But for clearing the fault both the ACR and the 125 E fuse hunt together i.e. clear the fault at the same time. For ground trip also even the fast curve 160VWV ACR (curve 1-2) goes in to operation after the 125 E fuse starts melting Figure 6.4(b), so use of 160 VWV 33 KV ACR in series with 125 E fuse do not improve the co-ordination. Therefore, it is recommend not to install 33 KV 160 VWV ACR. However programmable 33 KV ACR may be installed.

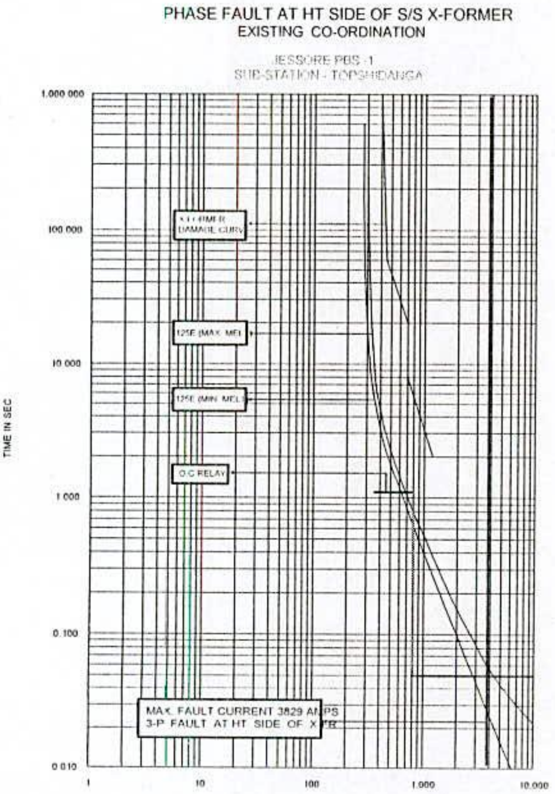


Figure 6.3a Existing Coordination

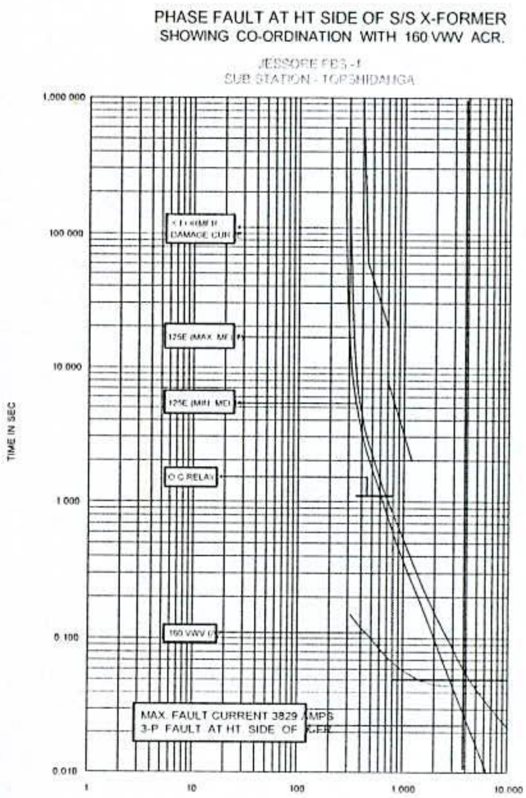


Figure 6.3b Proposed Coordination considering 160VWV ACR

6.10.3 Ground Fault at H.T. Side of the Transformer

From the TCC of the existing system Figure 6.4a it is observed that when a ground fault takes place at the H.T. side of the Transformer the 125 E fuse melts and clears the fault before tripping of the PDB E/F relay. So, co-ordination is achieved. For the minimum ground fault (412 Amp) the fuse also protects the transformer. From Figure 6.4b it is clear that installation of 160 VWV 33 KV ACR do not improves the situation, because, the fast curve of the ACR is slower than the 125 E fuse.

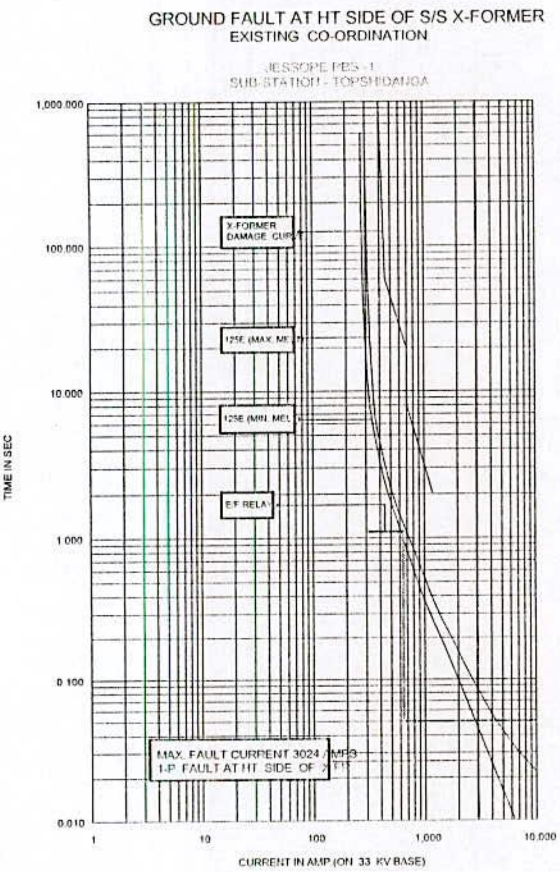


Figure 6.4(a) Existing Coordination

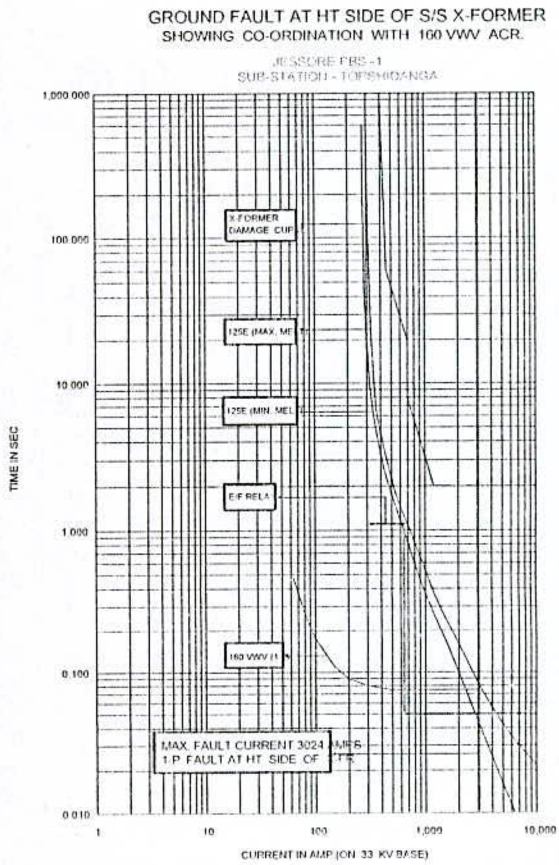


Figure 6.4(b) Proposed Coordination Considering 160 V W V ACR

6.10.4 Phase Fault at L.T Side of 33/11 KV X-Former

a) For Feeder – A, B, D

1) The phase relay maintains co-ordination with 100-RX ACR during its fast & delayed operations for maximum or minimum fault currents at LT side of the transformer (6.5a). But maximum line to ground fault current at LT side of the X-former is very close to the interrupting current of the 100-RX ACR (Figure 6.7 a), so it is recommend to use higher size ACR. Moreover, feeder current for all the feeders are above 70% of the maximum continuous current of the ACR (i.e. 70 amp.).Thus it is recommended to use 280 SEV ACR in all these feeders with 2B+2G curve setting for lockout operation. From fig.6.5 (b), it is observed that at fault condition 280 SEV ACR picks up the fault before PDB O/C relay and the fuse 125 E. Thus, co-ordination is achieved.

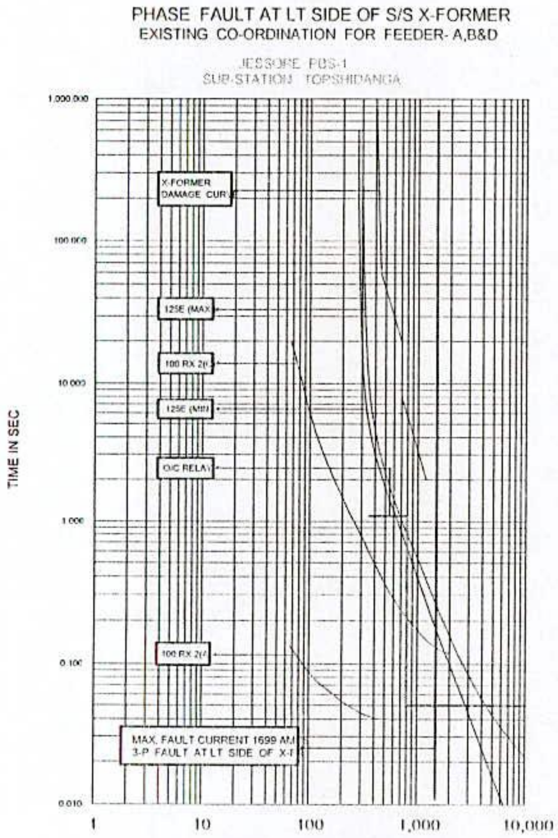


Figure 6.5(a) Existing Coordination

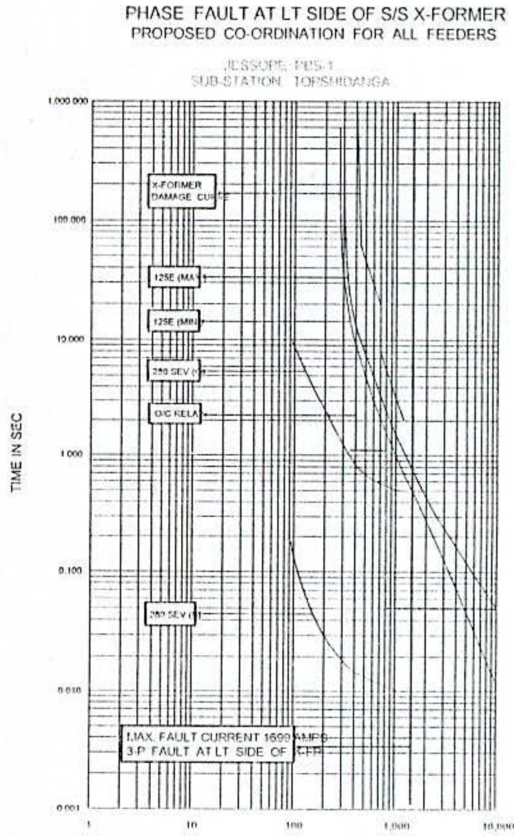


Figure 6.5(b) Proposed Coordination

b) For Feeder–C

1) From Figure 6.6a,it is observed that the phase relay maintains co-ordination with 225-RX ACR during its fast & delayed operations (both for maximum or minimum fault current) for a fault at LT side of the transformer. But for a fault current of the magnitude 1699 Amps the 125E fuse melt before tripping of the 225-RX ACR. So, it is recommended to change the existing 225 RX ACR with 280 SEV ACR for this feeder also. It would be better to use 2B+2G curve setting for lockout operation.

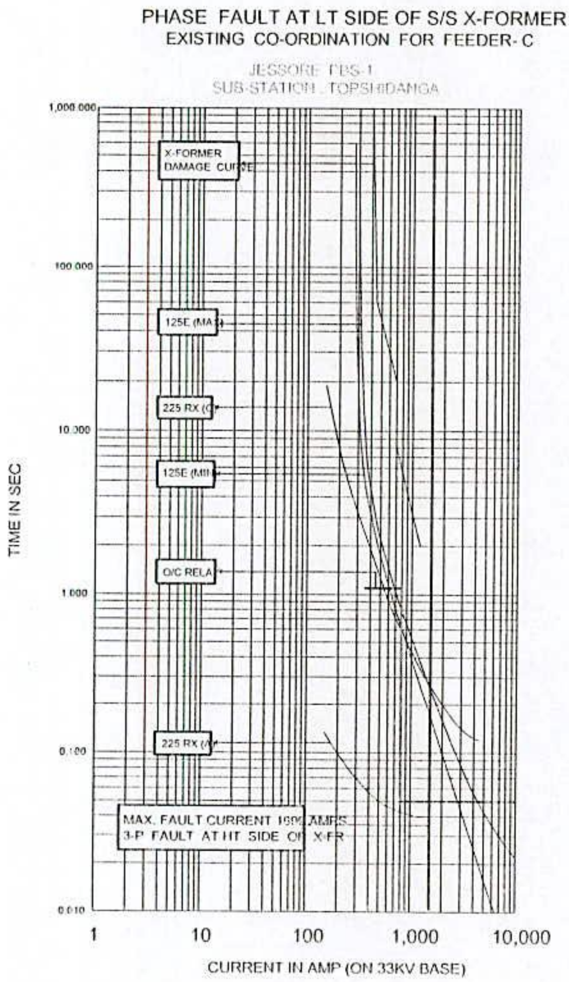


Figure 6.6(a) Existing Coordination

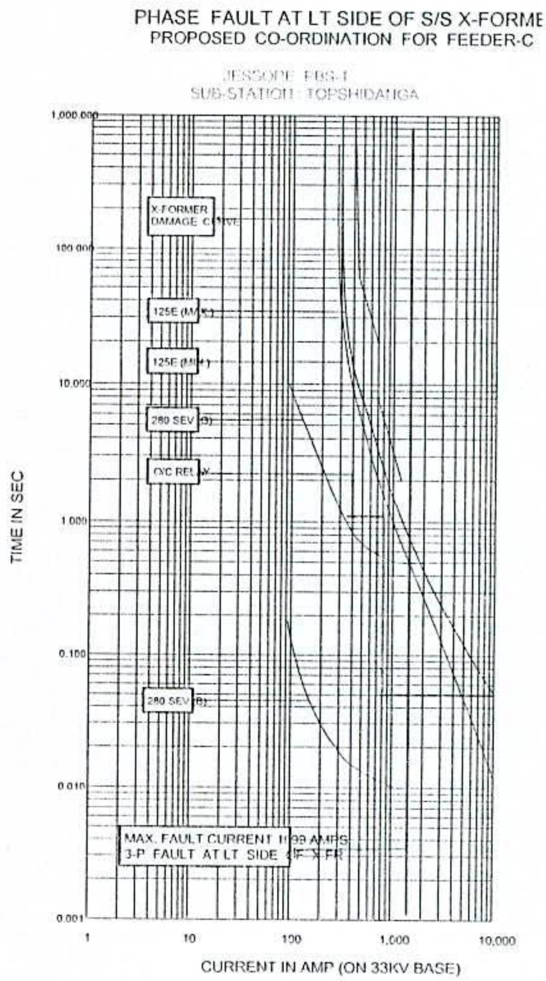


Figure 6.6(b) Proposed Coordination

Phase fault at LT side (11KV lines)

ACR to ACR coordination, ACR to FUSE and FUSE to FUSE coordination are shown in Figure 6.7a, 6.7b, 6.7c, 6.7d, 6.7e & 6.7f.

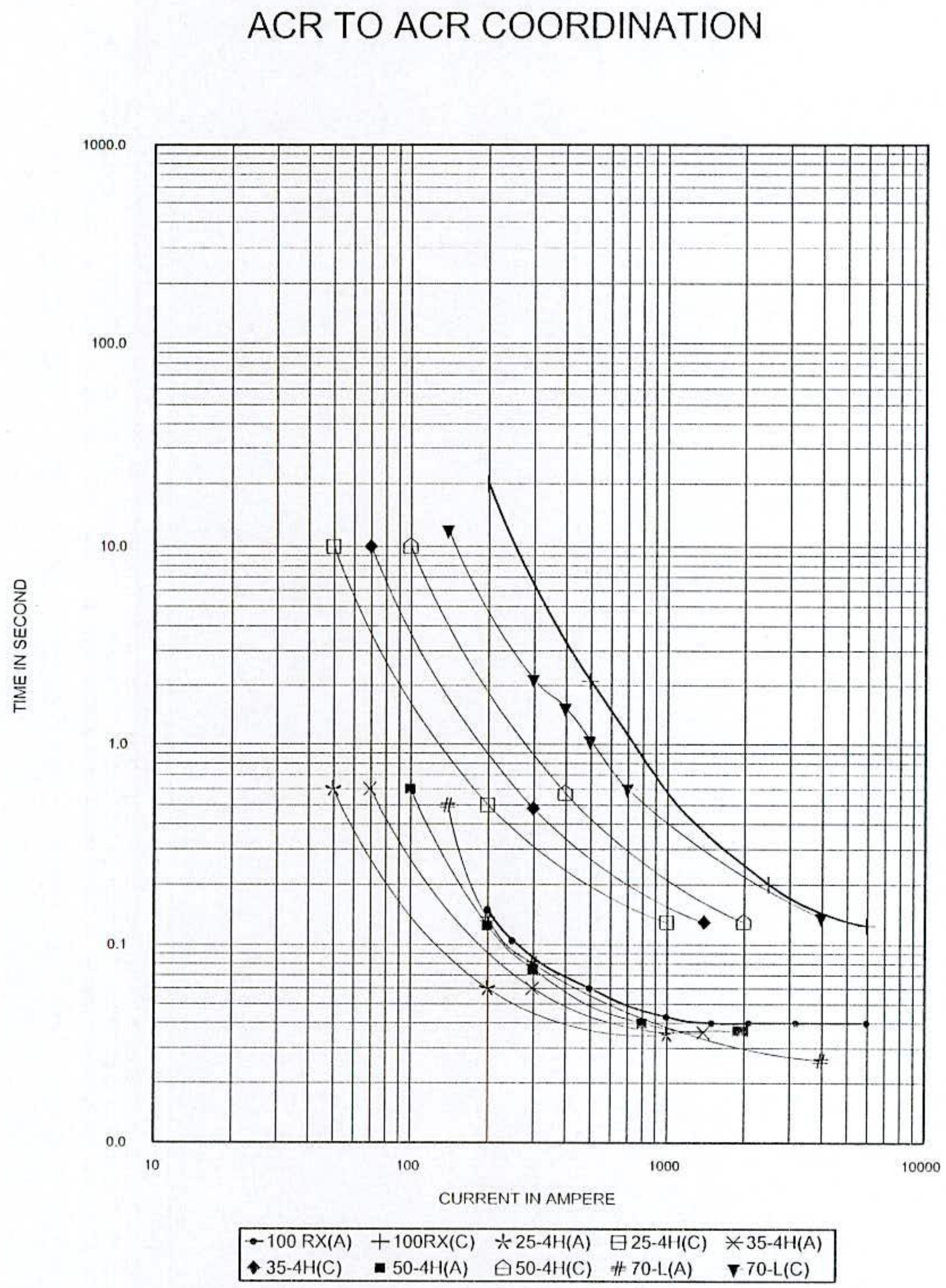


Figure 6.7a ACR to ACR coordination

CO-ORDINATION BETWEEN 100 RX & FUSES

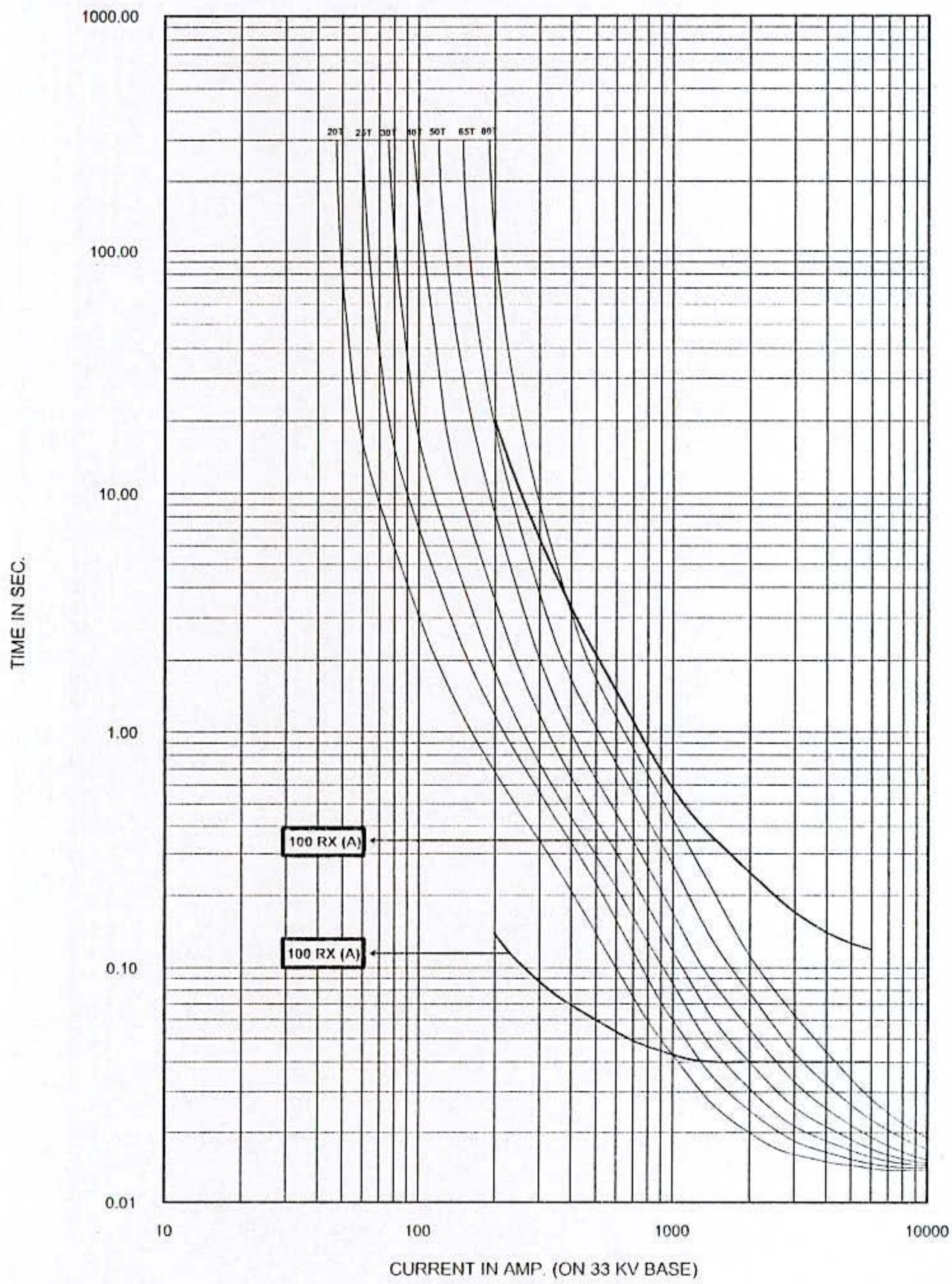


Figure 6.7b 100 RX ACR and Fuse coordination

CO-ORDINATION BETWEEN 70-L & 'T'- TYPE FUSES

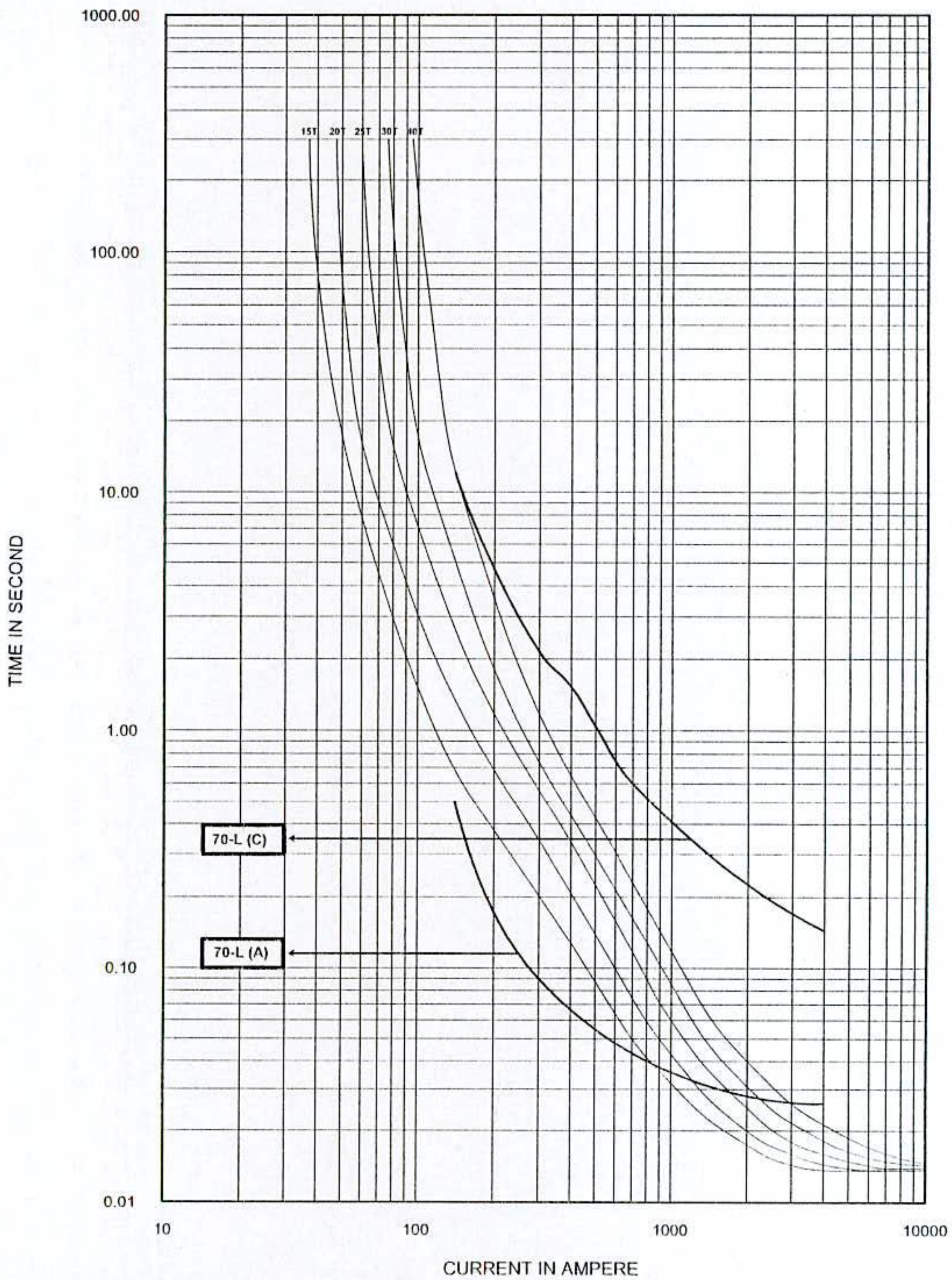


Figure 6.7c 70-L ACR and T Type Fuse coordination

CO-ORDINATION BETWEEN 50-4H & 'T'- TYPE FUSES

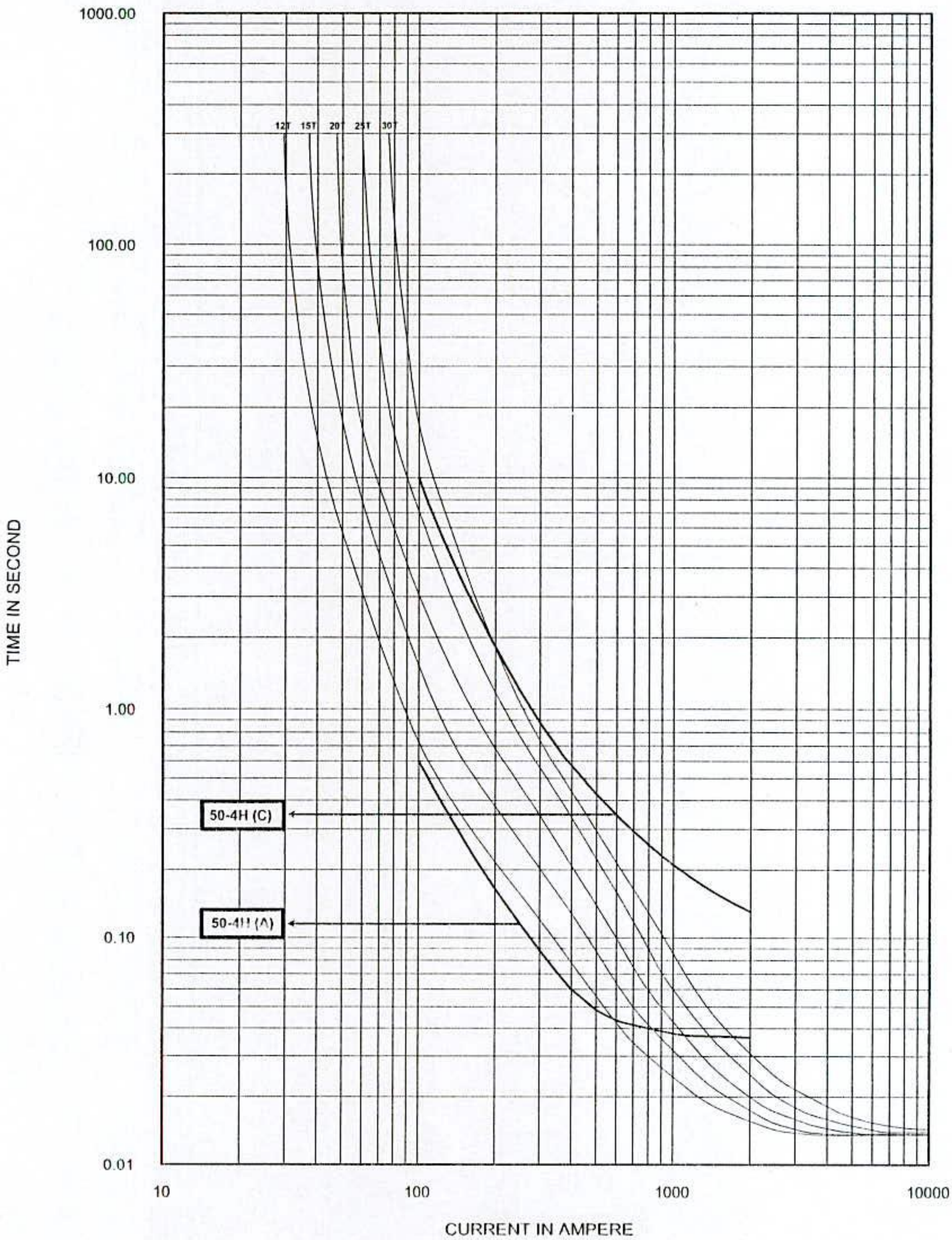


Figure 6.7d 50-4H ACR and T Type Fuse coordination

CO-ORDINATION BETWEEN 35-4H & 'T'- TYPE FUSES

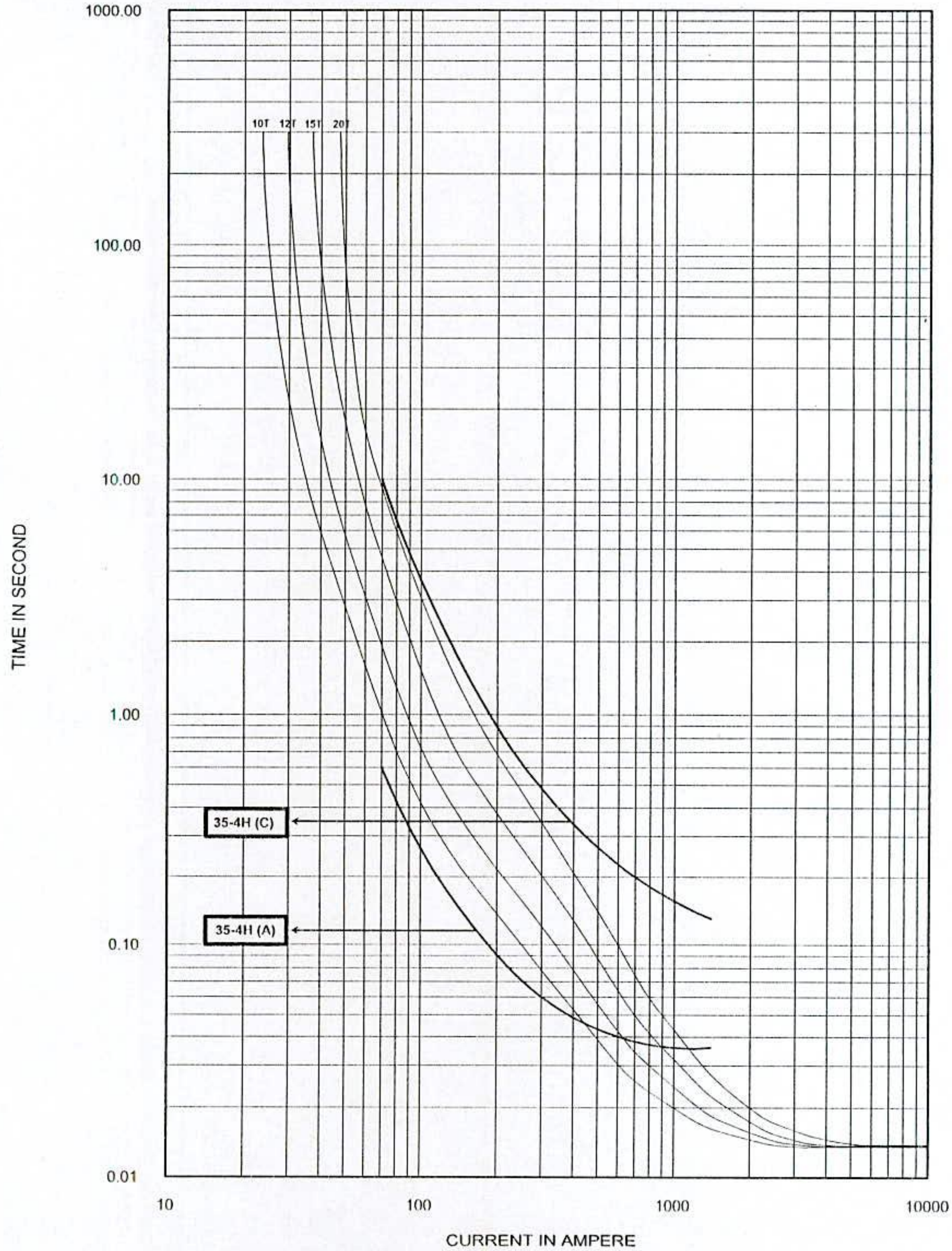


Figure 6.7e 35-4H ACR and T-Type Fuse coordination

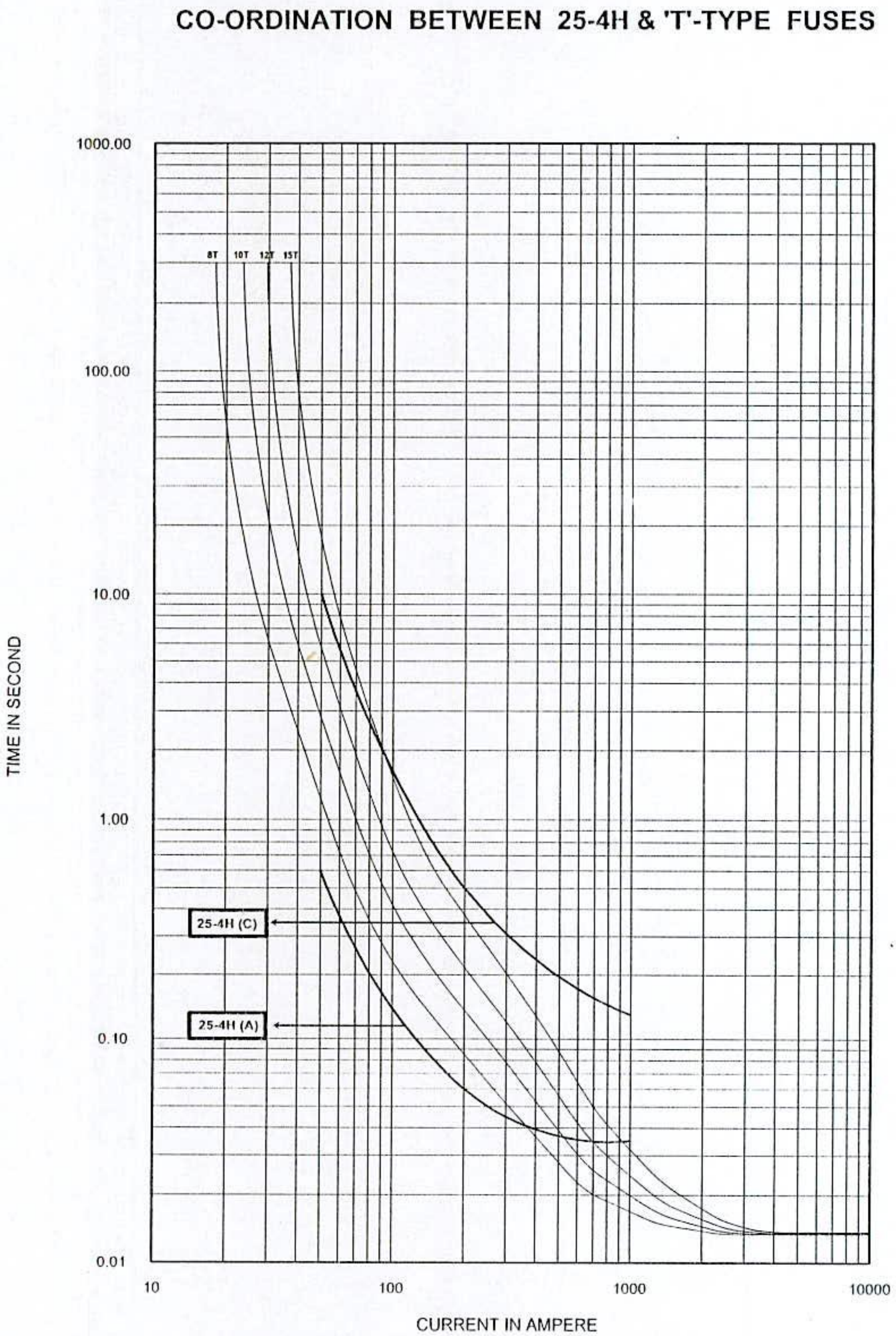


Figure 6.7f 25-4H ACR and T-Type Fuse coordination

6.11 Justification of Proposed ACRs

a) Circuit - A of Topshidanga S/S

ACR at Sub-Station Outgoing

Previously installed 100-RX ACR at the Sub-Station outgoing need to change. Because the maximum interrupting current at the sub-station outgoing point is 5938 amps which is beyond the capacity of the 100-RX type recloser. So it is recommend to install 280 SEV recloser in place of 100-RX type of recloser. The maximum and minimum fault level of the sub-station outgoing is 5938 amps and 158 amps respectively which is within the rated range of 280 SEV. So, replacement of the existing 100-RX ACR at the sub-station outgoing by 280 SEV. ACR is justified.

ACR at Pole No. 62/1

The length of the tap from pole no.62 is about 5.65 Km. There is an ACR of rating 50-4H at the starting of the tap. The maximum fault current is found at this node is about 1964 amps. The ACR is well coordinated with the proposed sub-station ACR and the interrupting current is within the rated range of the ACR. So it is recommend to keep the ACR as it is.

ACR at Pole No. 90/1

The length of the tap is 5.84 Km. At present there is no any ACR for this lengthy tap. The line current of this tap is 4.03 amps and the maximum fault current at this node is 1432 amps. So, it is recommended to install a new ACR of rating 50-4H at this location. At maximum fault level the proposed ACR is well coordinated with the proposed sub-station ACR 280 SEV. The line current is also within the continuous rating of the ACR. The fault current is within the interrupting range of the ACR. So recommendation of installing a new ACR of rating 50-4H at this tap is justified.

ACR at Pole No. 112

At present there exists an ACR of rating 35-4H at pole No.80. The line current at node through the ACR is 48.68 amps which is beyond the continuous current carrying capacity of the existing 35-4H ACR.The location of ACR is at 5.82 Km. away from the sub-station.

So, it is recommended to remove the existing 35-4H ACR and to install a 70-L ACR at pole No. 112 i.e. existing 35-4H ACR of this pole is to be replaced with a 70-L ACR and to be installed on pole no. 112. Both the maximum and minimum fault currents at this point is within the interrupting range of the proposed ACR and it is well coordinated with sub-station ACR 280 SEV. So, installation of a set of 70-L ACR at this node point is well justified.

ACR at Pole No. 213/R1

The length of this tap is approximately 3.52 Km. At present there is no ACR for this lengthy tap. The line current of the tap is only 17.02 amps and the maximum fault current at this node is 659 amps. So, it is recommended to install an ACR of rating 25-4H at this location. At maximum fault level the proposed ACR is well coordinated with the ACR 70-L. The line current is also within the continuous rating of the ACR. The fault current is within the interrupting range of the ACR. So, recommendation of installing a new ACR of rating 25-4H at this tap is justified.

ACR at Pole No. 214

The total length of the backbone is about 21.22 Km. REB recommend to install ACR at a distance 6 to 8 Km. apart from ACR to ACR. So, to protect rest of the backbone it needs to install an ACR bank on pole no. 214 or close to it which is 8.00 Km away from pole no.112 where a bank of 70-L recloser has been recommended to install. The line current at pole no. 214 is only 13.31 amps and the maximum fault current at this node is 659 amps. Therefore it is recommended to install a 25-4H ACR bank, which is well coordinated with its back up ACR 70-L, located at pole No.112. The line current is also within the continuous rating of the ACR. The fault current is within the interrupting range of the ACR. So, recommendation of installing a new ACR of rating 25-4H at this tap is justified.

b) Circuit - B

ACR at Sub-Station Outgoing

Previously installed 100-RX ACR at the Sub-Station outgoing need to be changed. The maximum fault current at the sub-station outgoing point is 5938 amps, which is beyond the maximum interrupting capacity of the 100- RX type recloser. So, it is recommended to install 280 SEV recloser in place of 100-RX type of recloser. The maximum and minimum fault level of the sub-station outgoing are 5938 amps and 158 amps respectively which is within the rated range of 280 SEV. So, replacement of the existing 100-RX ACR at the sub-station outgoing by 280 SEV ACR is justified.

ACR at Pole No. 139/1 and 139/44

The maximum length of this tap line from pole no. 139 (Node no. 24) is 7.87 km having two major sub-tap lines originating from pole no 139-37 and 139-43. But there is no ACR bank for protection of this long tap line. The maximum fault current at this node point is 883 amps and the line current is 9.89 amps only. So, apparently installation of a 35-4H ACR bank for this tap line may be considered well justified. But considering the command area of this tap and its physical condition it is necessary to install another ACR bank on pole no139-44 or close to it depending on the physical site conditions. This is necessary to minimize the number of tripping of the ACR to be installed at the beginning of the tap i.e. on pole no 139-1. ACR bank which is recommended to install at pole no. 139-44 will take care for the faults to be occurred beyond pole no139/44 i.e. it will have a command area for 4.4 Km. of line and for faults of this vast area ACR bank 70-L recommended to install at pole no.139/1 need not to operate. ACR on pole no. 139-1 will take care normally for the faults up to pole no.139-44 along with its two major sub-taps originating from pole no.139-37 and 139-43. For better coordination among these two and with the sub-station ACR (280 SEV), it is recommended to install 70-L ACR bank at pole no.139-1 and a 25-4H ACR bank at pole no.139-44. Both line currents, minimum and maximum fault currents of these two node points are within the rated capacity of the two proposed ACR banks. So, it is justified.

ACR at Pole No. 145

The total length of the backbone (main CKT) is 28.56 Km. So, for protection of the main circuit it is necessary to install a 70-L ACR bank on pole no.145 or close to it depending on site conditions. The line current at this pole is only 60.13 amps and the maximum fault current at this node is 858 amps, which is within the rated capacity of the proposed ACR bank. At maximum fault level the proposed ACR is well coordinated with the proposed sub-station ACR. The line current is also within the continuous rating of the ACR (70-L). So installation of a 70-L ACR bank at this node point is well justified.

ACR at Pole No. 185/1

The length of this tap is 5.60 Km. At present there is no ACR for this lengthy tap. The line current of this tap is 6.60 amps and the maximum and minimum fault currents at this node are 691 amps and 131 amps respectively. So, it is recommended to install a new ACR bank of rating 25-4H at this location. At maximum fault level the proposed ACR is well coordinated with the proposed 70-L ACR at pole no.145. The line current, maximum and minimum fault currents all are within the range of ACR. So recommendation of installing a new ACR of rating 25-4H at this tap is justified.

ACR at Pole No. 210/1

The length of the tap is 5.84 Km. At present there is no ACR for this tap. The line current of this tap is 5.90 amps and the maximum and minimum fault currents at this node are 619 amps and 127 amps respectively. So, it is recommended to install a new ACR bank of rating 25-4H at this location. At maximum fault level the proposed ACR is well coordinated with the proposed back up ACR 70-L recommended to install at pole no. 145. The line current is within the continuous rating of the ACR. Both maximum and minimum fault currents are also within the interruption range of the ACR. So, recommendation of installing a new ACR of rating 25-4H at this tap is justified.

ACR at Pole No. 233

The total length of the main circuit is about 28.56 Km. It is recommended to install a 70-L ACR bank at pole no.145 or nearer to it i.e. about 12 km away from the sub-station ACR (280 SEV). So for the protection of the tail end of the main CKT it is necessary to install another set of ACR. As per REB practice i.e. about 8 km gap is to be maintained between the ACRs .So it is recommend to install a 50-4H ACR bank at pole no. 233 or nearer to it. Both line current and maximum and minimum fault currents at this node are 36.85 amps,555 amps and 124 amps respectively which are within the continuous, interrupting and minimum tripping rating of 50-4H ACR. So, installation of a 50-4H ACR bank at this pole is justified.

ACR at Pole No. 266/1

The length of the tap is approximately 7.44 Km. At present there is no ACR for this lengthy tap. The line current of this tap is 8.57 amps and the maximum fault current at this node is 493 amps. So, it is recommended to install a new ACR bank of rating 25-4H at this location. At maximum fault level the proposed ACR is well coordinated with the proposed back up ACR 50-4H recommended to install at pole no.233.The line current is within the continuous rating of the ACR. The fault current is also within the interrupting rating of the ACR. So, recommendation of installing a new ACR of rating 25-4H at this tap is justified.

c) Circuit –C of Topshidanga S/S

ACR at Sub-Station Outgoing

Previously installed 100-RX ACR at the Sub-Station outgoing need to be changed. Because the maximum fault current at the sub-station outgoing point is 5938 amps, which is beyond the maximum interrupting capacity of the 100-RX type recloser. So, it is recommended to install 280 SEV recloser in place of 225-RX type recloser. The maximum and minimum fault level of the sub-station outgoing is 5938 and 158 amps respectively which is within the rated range of 280 SEV. So, replacement of the existing 100-RX ACR at the sub-station outgoing by 280 SEV ACR is justified.

ACR at Pole No. 97/1

The total length of the main line is about 23.06 Km. REB recommend to install ACR at a distance 6 to 8 Km. in main line. So, it is recommend installing a 70-L ACR bank on pole no.97 i.e. about 8 km apart from the sub-station. The line current at this pole is only 61.17 amps and the maximum and minimum fault currents at this node point are 1202 and 143 amps respectively. So, it is recommended to install an ACR bank of rating 70-L at this location or close to it depending on physical site conditions. At maximum fault level the proposed ACR is well coordinated with the proposed sub-station ACR 280 SEV. The line current as well as both maximum and minimum fault currents is also within the continuous and interrupting rating of the ACR respectively. So, recommendation of installing a new ACR of rating 70-L at the proposed location is justified.

ACR at Pole No. 97/42/1

The length of the tap is approximately 4.17 Km. At present there is no ACR for this tap. The line current of this tap is 6.62 amps and the maximum fault current at this node is 896 amps, which is within the rating of the 25-4H ACR. Although the length of this tap is not so long but due to R.O.W problem, it is recommended to install a 25-4H ACR bank. At maximum fault level the proposed ACR is well coordinated with the proposed back up 70-L ACR recommended to install on pole no. 97. So, installation of a 25-4H ACR bank at this node point is justified. Regular trimming on both sides of the tap lines is essential to reduce the numbers of trips.

ACR at Pole No. 97/112/1 & 97/112/10/14/13/28/1

The length of the tap is approximately 11.08 Km. At present there is no ACR for this lengthy tap. The line current of this tap is 14.00 amps and the maximum and minimum fault currents at this node are 597 amps and 126 amps respectively. So, apparently installation of a 25-4H ACR bank at this node point is well justified. But as the length of this tap is 11.08 km excluding its 5.04 km sub-tap, so it is recommended to install a 50-4H ACR bank at pole no. 97/112/1 to minimize the number of tripping of this ACR.

As per REB standard, it is recommend to install another 25-4H ACR bank on pole no. 97/112/10/14/13/28/1 (in between node nos. 75 and 76). This will have a command on 5.84 km of line. Line current, maximum, and minimum fault currents at this node are 6.43, 375 and 109 amps respectively which is within the rating of the 25-4H ACR. So, proposal for installation of an ACR bank on the above mentioned pole is well justified.

ACR at Pole No. 97/122/1

The length of the tap is 6.00 Km. Further, the tap line have a numbers of branch lines. So, considering the geographical conditions of the location and to minimize line fault due to R.O.W problems, which is mostly of temporary in nature, it is recommend to install a ACR bank of capacity 50-4H at pole no. 97/122/1(in between node nos. 92 & 93). Both lines current, maximum, and minimum fault currents of node no. 92 are13.56, 576 and 125 amps, which is well within the continuous and interrupting rating of the proposed ACR bank. At faulty condition the proposed ACR is well coordinated with the proposed back up 70-L ACR recommended to install at pole no. 97. So, installation of an ACR bank on the above mentioned pole is well justified.

ACR at Pole No. 97/123

The total length of the main line is about 23.06 Km. so, as per REB guideline it is necessary to install another ACR bank down to proposed 70-L ACR bank at pole no. 97. It is recommended to install 25-4H ACR bank preferably on pole no. 97/123 (i.e. in between node nos. 92 and 112). This ACR bank will protect the tail of the line along with its numbers of sub-taps or branch lines and will help to minimize tripping of 70-L ACR bank due to faults of this section of line. Both the line current and fault currents of this node point are 9.45; 576 & 125 amps respectively, which is within the continuous and interrupting capacity of the 25-4H ACR bank. At faulty condition the proposed 25-4H ACR properly coordinates with its back up ACR 70-L and sub-station ACR 280 SEV. So, it is justified to recommend installing a 25-4H ACR bank on pole no.97/123.

d) Circuit - D of Topshidanga S/S

ACR at Sub-Station Outgoing

Previously installed 100-RX ACR at the Sub-Station outgoing need to be changed. The maximum interrupting current at the sub-station outgoing point is 5938 amps, which is beyond the capacity of the 100-RX type recloser. So, it is recommend to install 280 SEV recloser in place of 100-RX type of recloser. The maximum and minimum fault currents of the sub-station outgoing are 5938 and 158 amps respectively, these are within the rated range of 280 SEV. So, replacement of the existing 100-RX ACR at the sub-station outgoing by 280 SEV ACR is justified.

ACR at Pole No. 22/L1

The length of the tap is approximately 4.16 Km. At present there is no ACR for this tap. The line current of this tap is 5.40amps and the maximum fault current at this node is 3102 amps. So, it is recommended to install a new ACR bank of rating 70-L at this location. At maximum fault level the proposed ACR is well coordinated with the proposed sub-station ACR 280 SEV. The line current is also within the continuous rating of the ACR. The fault currents are within the interruption range of the ACR. So, recommendation of installing a new ACR of rating 70-L is justified.

ACR at Pole No. 56/L55/1 & 56/L55/80

Length of this lateral line is 11.36 km. with a good numbers of long sub-lateral lines. As per REB standard is proposed to install a 50-4H ACR bank on pole no. 56/L55/1(in between node no.48 and 49) and another 25-4H ACR bank on pole no. 56/L55/80 (in between node points 54 and 61). ACR bank 50-4H proposed to be installed on pole no. 56/L55/1 will take care for the faults of 8.96 km. long line and the 25-4H ACR bank proposed to install on pole no. 56/L55/80 will take care of the faults of 5.04 km long line in addition to other sub-tap lines. Both line current and maximum fault currents at these two node points (in between 48 and 54) are within the continuous and interrupting ratings of the proposed 50-4H ACR which properly coordinate with each other and with their back up sub-station 280 SEV ACR. So, proposals of these two ACR banks are justified.

ACR at Pole No. 56/L56

The total length of the main line including backbone is about 14.18 Km. As per REB standard, for protection of the main line it is recommend to install a 70-L ACR on backbone pole no.56/L56 i.e. about 8.9 km. apart from the 280 SEV sub-station ACR. At maximum fault level the proposed ACR is well coordinated with the proposed sub-station ACR 280 SEV. Line current, maximum, and minimum fault currents at this node point are 33.75, 1081 and 141 amps respectively, which is within the continuous and interrupting range of the 70-L ACR.

ACR at Pole No. 56/L60/1

The length of the tap is approximately 8.08 Km. At present there is no ACR for this tap. The line current of this tap is 4.70amps and the maximum fault current at this node is 1043 amps. So it is recommend to install a new ACR bank of rating 35-4H at this location. At maximum fault level the proposed ACR is well coordinated with the proposed ACR 70-L. The line current is also within the continuous rating of the ACR. The fault currents are within the interruption range of the ACR. So, recommendation of installing a new ACR of rating 35-4H at this tap is justified.

ACR at Pole No. 56/L83/1

The length of the tap is approximately 5.19 Km. At present there is no ACR for this tap. The line current of this tap is 5.48amps and the maximum fault current at this node is 899 amps. So it is recommended to install a new ACR bank of rating 35-4H at this location. At maximum fault level the proposed ACR is well coordinated with the proposed ACR 70-L. The line current is also within the continuous rating of the ACR. The fault current is within the interruption range of the ACR. So, recommendation of installing a new ACR of rating 35-4H at this tap is justified.

6.12 Recommendations for Feasible (Phase-I) Coordination

The following recommendations are made for the system studied.

1) It is proposed to use 280 - SEV or Microprocessor control ACR instead of 100-RX and 225-RX for Sub-station Outgoing Feeders.

2) X1 – X6 Sensor connection and "2B + 2G" Operation for 280-SEV ACR is recommended. If microprocessor control ACR is installed line ACR should be set at single shot.

3) 125E fuse is to be installed at sub-station incoming.

4) The existing Plug and TD setting of Grid Relay will not to be changed.

6.13 Results for Relay Characteristic Selection

After satisfying the feasibility conditions all the relays in the substation are coordinated graphically with the constraints of minimum coordination interval. The relay characteristic curves for optimal coordination of phase fault and ground fault are shown in Figure 6.3(b), Figure 6.4(b), Figure 6.5(b) & Figure 6.6(b). The Proposed devices and curve settings are given in the following Tables.

The Proposed devices and curve settings

a) Table 6.1 FoCircuit-A of Topshidanga S/S

Pole no.	Existing ACR		Proposed ACR		Remarks
	Size	Curve Setting	Size	Curve Setting	
Sub-Station	100-RX	2A+2C	280-SEV	2B+2G	To be replaced
62/1	3 × 50-4H	2A+2C	3 × 50-4H	2A+2C	Remain unchanged
75-86	3 × 50-4H	2A+2C			To be removed
90/1			3 × 50-4H	2A+2C	To be newly installed
112			3 × 70-L	2A+2C	To be newly installed
213/R1			3 ×25-4H	2A+2C	To be newly installed
214			3 × 25-4H	2A+2C	To be newly installed

b) Table 6.2 For Circuit – B of Topshidanga S/S

Pole no.	Existing ACR		Proposed ACR		Remarks
	Size	Curve Setting	Size	Curve Setting	
Sub-Station	100-RX	2A+2C	280-SEV	2B+2G	To be replaced
139/1			3 × 70-L	2A+2C	To be newly installed
139/44			3 × 25-4H	2A+2C	To be newly installed
145			3 × 70-L	2A+2C	To be newly installed
185/1			3 × 25-4H	2A+2C	To be newly installed
210/1			3 × 25-4H	2A+2C	To be newly installed
233			3 × 50-4H	2A+2C	To be newly installed
266/1			3 × 25-4H	2A+2C	To be newly installed

c) Table 6.3 For Circuit - C of Topshidanga S/S

Pole No.	Existing ACR		Proposed ACR		Remarks
	Size	Curve Setting	Size	Curve Setting	
S/S	225-RX	2A+2C	280-SEV	2B+2G	To be replaced
97/1			3 ×70-L	2A+2C	To be newly installed
97/42/1			3 × 25-4H	2A+2C	To be newly installed
97/112/1			3 × 50-4H	2A+2C	To be newly installed
97/112/10/14 /13/28/1			3 × 25-4H	2A+2C	To be newly installed
97/122/1			3 × 50-4H	2A+2C	To be newly installed
123			3 × 25-4H	2A+2C	To be newly installed

d) Table 6.4 For Circuit –D of Topshidanga S/S

Pole No.	Existing ACR		Proposed ACR		Remarks
	Size	Curve Setting	Size	Curve Setting	
S/S	100-RX	2A+2C	280-SEV	2B+2G	To be replaced
22/L1			3 X 70-L	2A+2C	To be newly installed
	3 X 50-4H	2A+2C			To be removed
56/L55/1			3 X 50-4H	2A+2C	To be newly installed
56/L55/80			3 X 25-4H	2A+2C	To be newly installed
56/L56			3 X 70-L	2A+2C	To be newly installed
56/L60/1			3 X 35-4H	2A+2C	To be newly installed
56/L83/1			3 X 35-4H	2A+2C	To be newly installed

6.14 Requirements of Devices for Proposed Protection Scheme

a)For Circuit - A of Topshidanga S/S

Table 6.5) List of ACR

Existing Device	Proposed ACR	Additional Requirement	Surplus	Remarks
100-RX = 1	280-SEV = 1	280-SEV = 1	100-RX = 1	
	70-L = 1 × 3	70-L = 1 × 3		
50-4H = 2 × 3	50-4H = 2 × 3			
	25-4H = 2 × 3	25-4H = 2 × 3		

Table 6.6 List of Fuse for Circuit-A of Topshidanga S/S

Pole No.	Existing Fuse		Proposed Fuse		Remarks
	Type	Nos	Type	Nos.	
1/1			80T	3	
1/17/1			40T	3	
1/22/1			40T	3	
9/1			80T	3	
32/1			80T	3	
47/1			65T	1	
49/1			65T	3	
62/8/1			30T	3	
62/38/1			25T	3	
62/38/17/1			15T	3	
62/40/1			25T	3	
62/57/1			25T	3	
62/58/1			25T	3	
75/1			50T	1	
86/1			40T	3	
90/21/24/1			25T	3	
90/22			25T	3	
120/1			30T	1	
146/L1			30T	3	
213/L1			20T	3	
213/L7/1			12T	3	
213/R11/1			15T	3	
213/R11/5/1			10T	1	
213/R19/1			15T	1	
247/1			15T	3	
247/7/1			10T	1	

b) For Circuit-B of Topshidanga S/S

Table 6.7 List of ACR

Existing device	Proposed ACR	Additional Requirement	Surplus	Remarks
100-RX = 1	280-SEV = 1	280-SEV = 1	100-RX = 1	
	70-L = 2 × 3	70-L = 2 × 3		
	50-4H=1×3	50-4H=1×3		
	25-4H = 4 × 3	25-4H = 4 × 3		

Table 6.8 List of Fuses

Pole No.	Existing Device		Proposed Fuse		Remarks
	Type	Nos	Type	Nos.	
22/1			80T	3	
111/R1			30T	3	
125/1			30T	3	
139/19/1			20T	3	
139/35/1			20T	3	
139/37/1			20T	3	
139/43/1			20T	3	
139/62			15T	3	
139/84/1			12T	3	
144/1			25T	3	
156/1			25T	3	
156/39/1			15T	1	
157/1			25T	3	
170/1			25T	3	
185/R12/L1			12T	3	
185/R22			15T	3	
204/1			20T	3	
210/23/1			15T	1	
210/39/1			15T	3	

For Circuit- B of Topshidanga S/S

Table 6.8 List of Fuses contd.

Pole No.	Existing Device		Proposed Fuse		Remarks
	Type	Nos	Type	Nos.	
217/1			20T	3	
220/1			20T	3	
220/19/1			12T	3	
232/1			20T	3	
245/1			20T	3	
245/12/1			12T	3	
245/20/1			122T	1	
266/15/1			12T	3	
266/21/1			15T	3	
266/21/28/1			10T	3	
266/32/1			15T	3	
266/38A/1			15T	3	

c) For Circuit –C of Topshidanga S/S

Table 6.9 List of ACR

Existing device	Proposed ACR	Additional Requirement	Surplus	Remarks
225-RX = 1	280-SEV = 1	280-SEV = 1	225-RX = 1	
	70-L = 1 × 3	70-L = 1 × 3		
	50-4H = 2 × 3	50-4H = 2 × 3		
	25-4H = 3× 3	25-4H = 3 × 3		

Table 6.10 List of Fuses

Pole No.	Existing Device		Proposed Fuse		Remarks
	Type	Nos	Type	Nos.	
9/R1			80T	1	
11/1			80T	3	
12/1			80T	3	

For Circuit –C of Topshidanga S/S

Table 6.10 List of Fuses Contd.

Pole No.	Existing Device		Proposed Fuse		Remarks
	Type	Nos	Type	Nos.	
12/5/1			40T	1	
12/10/1			40T	1	
27/1			65T	3	
82/1			40T	1	
97/26/1			25T	3	
97/26/29/1			15T	1	
97/26/29A/1			15T	1	
97/37/1			25T	3	
97/42/16/1			25T	1	
97/56/1			25T	1	
97/64/1			25T	3	
97/105/1			20T	3	
97/105/12A/1			12T	3	
97/112/10/14/14			15T	3	
97/122/22/1			15T	1	
97/122/45/1			10T	1	
97/138/1			15T	3	
97/138/20/1			12T	1	
97/147/1			15T	3	
97/147/8/1			10T	1	
97/147/9/1			10T	1	
97/149/1			15T	3	

d) For Circuit – D of Topshidanga S/S

Table 6.11 List of ACR

Existing device	Proposed ACR	Additional Requirement	Surplus	Remarks
100-RX = 1 50-4H = 1 × 3	280-SEV = 1 70-L = 2 × 3 50-4H = 1 × 3 35-4H = 2 × 3 25-4H = 1 × 3	280-SEV = 1 70-L = 2 × 3 35-4H = 2 × 3 25-4H = 1 × 3	100-4H = 1 × 3	

Circuit – D of Topshidanga S/S

Table 6.12 List of Fuse

Pole No.	Existing Device		Proposed Fuse		Remarks
	Type	Nos	Type	Nos.	
6/1			80T	3	
6/11/1			40T	1	
22/R1			80T	1	
22/L15/14/1			40T	3	
40/1			65T	3	
40/19/L1			40T	3	
40/19/R1			40T	3	
53A/1			50T	3	
53A/2/1			30T	3	
56/L18/1			40T	3	
56/L29/1			40T	3	
56/L42/1			30T	3	
56/L55/56/1			20T	3	
56/L55/79/R1			15T	3	
56/L55/79/R14/1			10T	1	
56/L55/79/L1			15T	3	
56/L55/112/1			12T	3	
56/L55/133/1			12T	3	
56/L55/133/2/1			8T	1	
56/L60/55/1			15T	3	
56/L60/62/1			15T	3	
56/L61/1			30T	3	
56/L61/20			20T	3	
56/L76/R1			25T	3	
56/L89/L1			20T	3	

6.15 Calculated Voltage at the Farthest End

Name of Feeder	Pole Number	Voltage Drop From S/S AT 11 KV	Voltage (1Ø LT)	Distance From S/S
CIRCUIT - A	S/S	0	230	0
	49	3.201	226.799	2.97
	75	5	225	4.94
	90	6.02	223.98	6.18
	120	7.76	222.239	8.58
	148	9.24	220.76	10.78
	178	10.318	219.682	13.18
	213	11.221	218.779	15.98
	235	12.83	217.17	19.58
	247	13.003	216.997	20.58
	247/41	13.467	216.533	23.86

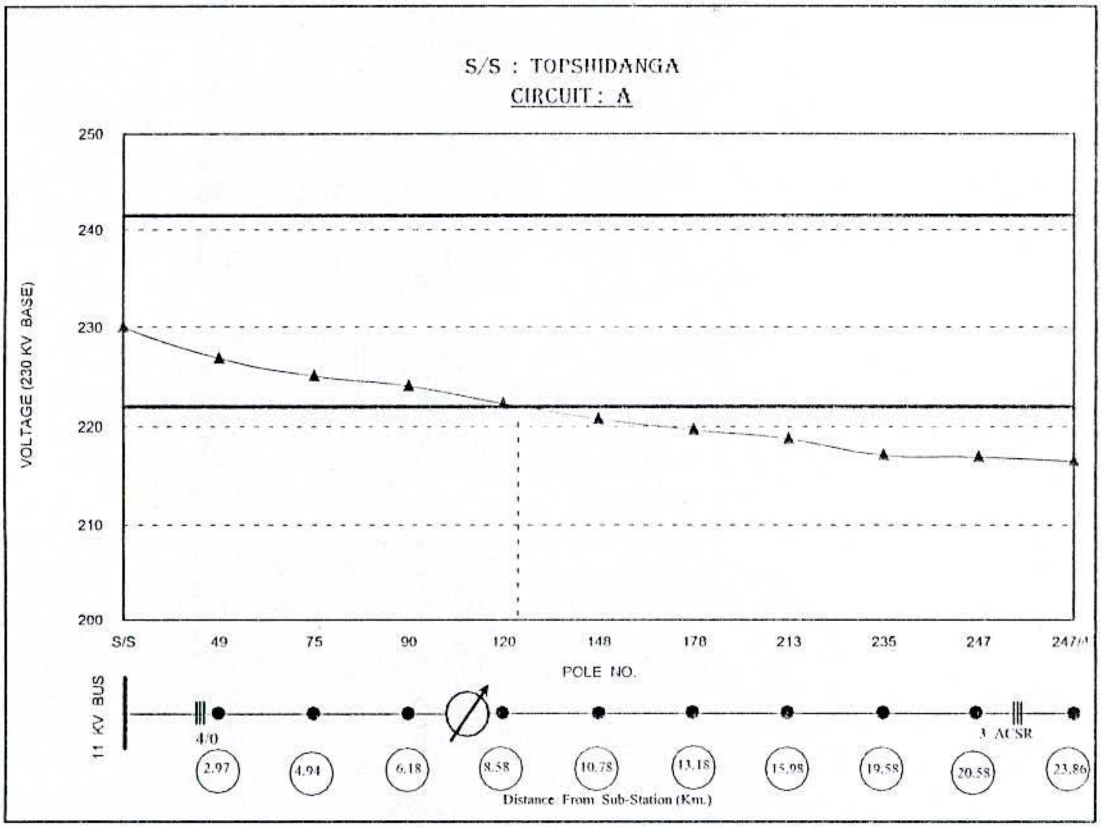
Name of Feeder	Pole Number	Voltage Drop From S/S AT 11 KV	Voltage (1Ø LT)	Distance From S/S
CIRCUIT - B	S/S	0	230	0
	67	7.21	222.79	5.84
	111	11.56	218.44	9.3
	144	14.64	215.36	12
	185	17.9	212.1	15.36
	210	19056	210.44	17.36
	232	21.16	208.84	19.6
	266	22.51	207.49	22.32
	266/21	22.95	207.05	24
	266/21/28	23.18	206.82	24.6
	266/21/28/41	23.52	206.48	27.88

Calculated Voltage at the Farthest End

Name of Feeder	Pole Number	Voltage Drop From S/S AT 11 KV	Voltage (1Ø LT)	Distance From S/S
CIRCUIT - C	S/S	0	230	0
	52	5.12	244.877	4.82
	97	8.196	221.804	8.06
	97/26	10.154	219.846	10.14
	97/42	11.211	218.789	11.46
	97/79	14.033	215.967	15.5
	97/105	15.333	214.667	17.58
	97/122	15.845	214.155	18.86
	97/122/45	16.922	213.078	22.46
	97/122/45/3	17.003	212.997	22.7
	97122/45/3/2	17.072	212.928	22.94
	97/122/45/3/2	17.135	212.865	23.26
	97122/45/3/2/7/11/R9	17.278	212.722	24.86

Name of Feeder	Pole Number	Voltage Drop From S/S AT 11 KV	Voltage (1Ø LT)	Distance From S/S
CIRCUIT - D	S/S	0	230	0
	23	2.23	227.77	1.73
	53A	4.759	225.241	4.24
	56/L16	6.007	223.993	5.76
	56/L42	7.86	222.14	7.86
	56/L60	8.752	221.248	9.3
	56/L83	9.45	220.55	11.14
	56/L83/3	9.51	220.49	11.38
	56/L83/3/L24	9.86	220.14	13.23
	56/L83/L64	10.024	219.976	16.33

6.16 Voltage Drop Profile



Fiqure 6.8(a) Voltage Drop profile of circuit-A

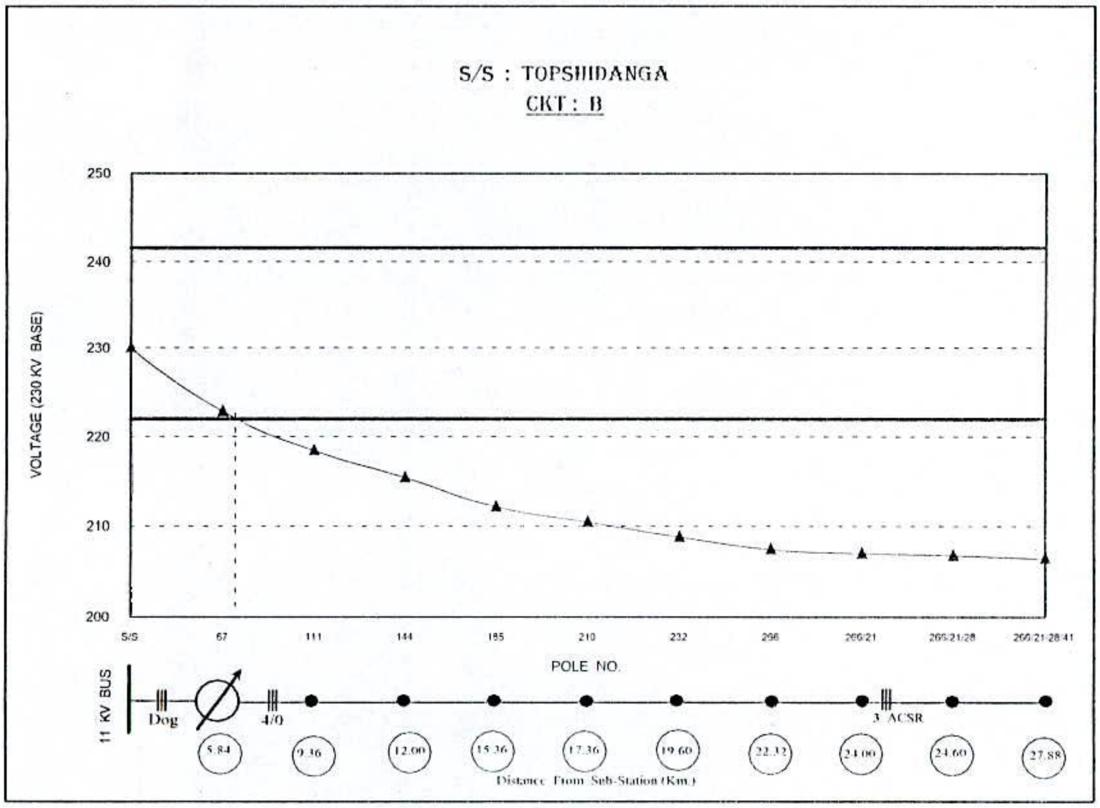


Figure6.8 (b) Voltage Drop profile of circuit-B

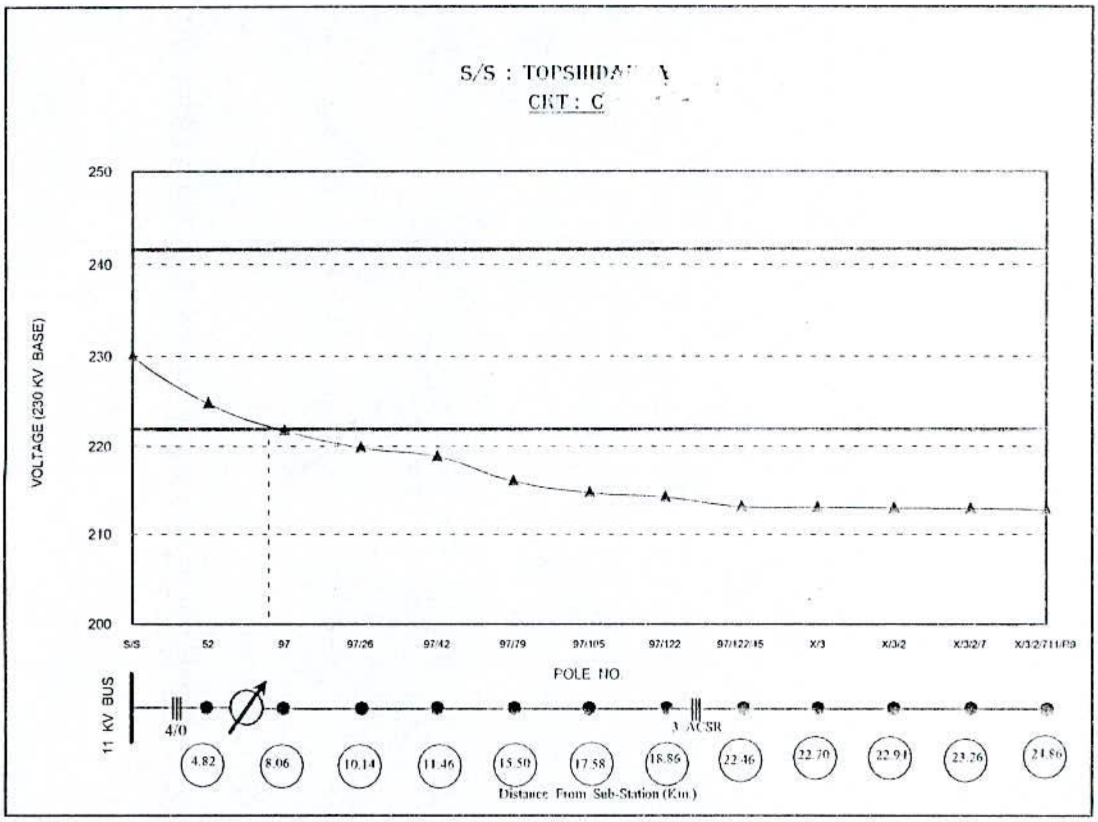


Fig. 6.8 (c) Voltage Drop profile of circuit-C

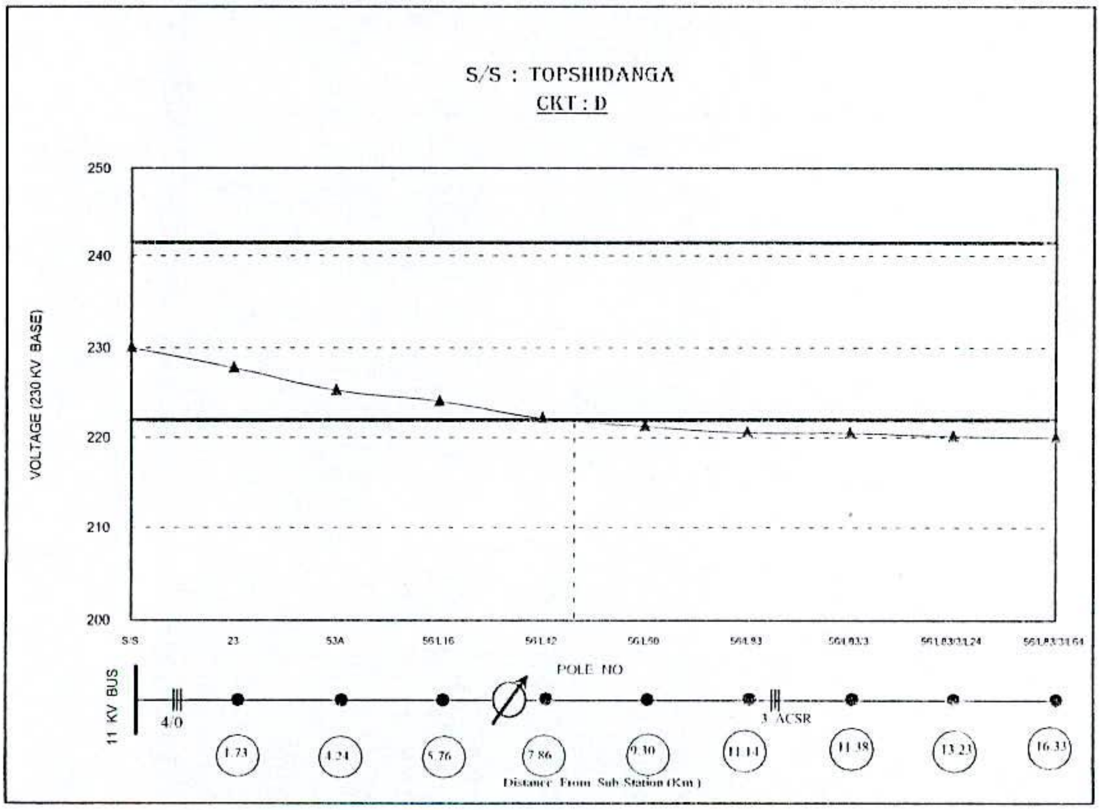


Figure 6.8(d) Voltage Drop profile of circuit-D

6.17 Analysis of Voltage Drop Profile

6.17.1 Basic Considerations

The voltage served to customers of the system is considered to be acceptable when it is adequate for the proper operation of connected lights, appliances, and equipment. Voltage level study is therefore, essential in order to maintain a stable and standard voltage. In order to provide a satisfactory customer service voltage and at the same allow sufficient system voltage drop that will permit economic feeder length and loading. The following service voltage range has been adopted by REB [18].

Allowable variation	Phase to Neutral
Maximum (105 %)	241.5 Volts
Nominal (100 %)	230.0 Volts
Minimum (96.5 %)	221.9 Volts

6.18 Existing Voltage Drop at Different Feeders

Voltage drop at different nodes as well as furthest ends voltages of different lateral lines for Circuit A, B, C and D of Topshidanga S/S are calculated. Results are shown in article no.6.15.

Circuit - A

The maximum voltage drop of Circuit-A of this Sub-Station occurs at pole no.247/41 and the magnitude of the drop is 13.467 volts on 230 volts base. But the allowable drop on primary line at 230-volt base is an only 6.9 volts. So, to improve the line voltage it is essential to install a line voltage regulator.

From the enclosed voltage drop profile of Circuit-A it is observed that the consumers of this circuit, beyond pole no. 120, suffer by under voltage. So, further loading of this circuit is to be restricted. Otherwise it will cause to increase the line current, which will cause more voltage drop in the line. For remedial measure a line voltage regulator is to be installed as we have recommended. This will improve line voltage and will reduce system loss.

Circuit - B

The maximum voltage drop of Circuit-B of this Sub-Station occurs at pole no. 266/21/28/41 and the magnitude of the drop is 23.52 volts on 230 volts base. But the allowable drop on primary line at 230-volt base is an only 6.9 volts. So, to improve the line voltage it is essential to install a line voltage regulator.

From the enclosed voltage drop profile of Circuit-B it is observed that the consumers of this circuit, beyond pole no. 80, suffer by under voltage. So, further loading of this circuit is to be restricted. Otherwise it will cause to increase the line current, which will cause more voltage drop in the line. For remedial measure a line voltage regulator is to be installed as we have recommended. This will improve line voltage and will reduce system loss.

Circuit - C

The maximum voltage drop of Circuit-C of this Sub-Station occurs at pole no. 97/122/45/3/2/7/11/R9 and the magnitude of the drop is 17.278 volts on 230 volts base. But the allowable drop on primary line at 230-volt base is an only 6.9 volts. So, to improve the line voltage it is essential to install a line voltage regulator.

From the enclosed voltage drop profile of Circuit-C it is observed that the consumers of this circuit, beyond pole no. 78, suffers by under voltage. So, further loading of this circuit is to be restricted. Otherwise it will cause to increase the line current, which will cause more voltage drop in the line. For remedial measure a line voltage regulator is to be installed as we have recommended. This will improve line voltage and will reduce system loss.

Circuit - D

The maximum voltage drop of Circuit-D of this Sub-Station occurs at pole no. 56/L83/3/L64 and the magnitude of the drop is 10.024 volts on 230 volts base. But the allowable drop on primary line at 230-volt base is an only 6.9 volts. So, to improve the line voltage it is essential to install a line voltage regulator.

From the enclosed voltage drop profile of Circuit-D it is observed that the consumers of this Circuit, beyond pole no. 56/L29, suffer by under voltage. So, further loading of this circuit is to be restricted. Otherwise it will cause to increase the line current, which will cause more voltage drop in the line. For remedial measure a line voltage regulator is to be installed as we have recommended. This will improve line voltage and will reduce system loss.

6.19 Recommendations for Improvement of Line Voltage

Circuit - A

Maximum voltage drop of this circuit occurs at pole no. 247/41, which is 13.467 volts and it, crosses allowable limit i.e. 6.9 volts at pole no.106. It is therefore, recommend to install a line voltage regulator, preferably on pole no. 106 or at its close proximity depending on physical site conditions, which will raise line voltage to Sub-Station level i.e. 230 volts and will reduce system loss.

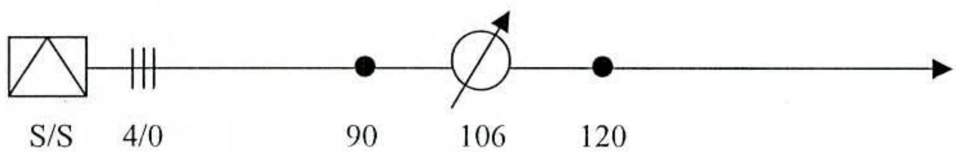


Figure 6.9 (a) Proposal of Voltage Regulator for Circuit-A

Circuit-B

The voltage drop of Circuit-B crosses its allowable limit i.e. 6.9 volts at pole no. 60. So, the consumers beyond this pole suffer from voltage drop problem causing excessive system loss. Maximum voltage drop of this circuit is 23.52volts, which occurs at pole no. 266/28/41. To overcome this voltage drop problem it is recommended to install a line voltage regulator at a close proximity of pole no. 60 depending on it's surrounding conditions. This will raise the line voltage to Sub-Station level i.e. 230volts (Base) and will reduce system loss.

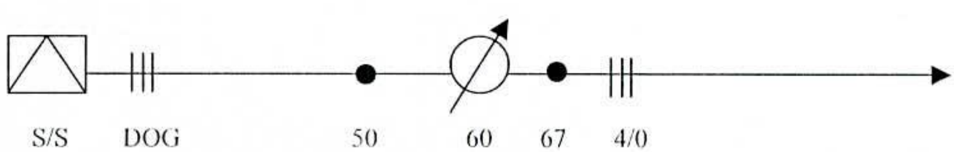


Figure 6.9 (b) Proposal of Voltage Regulator for Circuit-B

Circuit - C

The voltage drop of Circuit-C crosses its allowable limit i.e. 6.9 volts at pole no. 85. So, the consumers beyond this pole suffer from voltage drop problem causing excessive system loss. Maximum voltage drop of this circuit is 17.278volts, which occurs at pole no. 97/122/45/3/2/7/11/R9. To overcome this voltage drop problem it is recommended to install a line voltage regulator at a close proximity of pole no. 85 depending on it's surrounding conditions. This will raise the line voltage to Sub-Station level i.e. 230 volts (Base) and will reduce system loss.

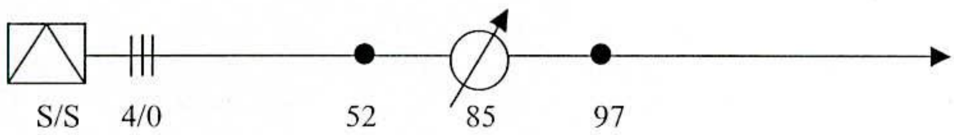


Figure 6.9(c) Proposal of Voltage Regulator for Circuit-C

Circuit-D

The voltage drop of Circuit-D crosses its allowable limit i.e. 6.9 volts at pole no. 56/L25. So, the consumers beyond this pole suffer from voltage drop problem causing excessive system loss. Maximum voltage drop of this circuit is 10.024 volts, which occurs at pole no. 56/L83/L64. To overcome this voltage drop problem it is recommended to install a line voltage regulator at a close proximity of pole no. 56/L25 depending on it's surrounding conditions. This will raise the line voltage to Sub-Station level i.e. 230 volts (Base) and will reduce system loss.

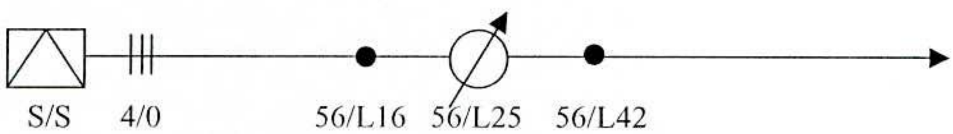


Figure 6.9(d) Proposal of Voltage Regulator for Circuit-D

6.20 Case Study-II Baganchra 33/11 KV Sub-Station

Baganchra 33/11 KV, 5 MVA sub-station of Jessore PBS-1 has been constructed under the area coverage Rural Electrification Program. There are three single phase transformers of Capacity 1.667 MVA each with average 5.81 Percentage Impedance.

The source side protective device of Baganchra 33/11 KV sub-station is a 160 VWV ACR on the incoming 33 KV bus as shown in figure 6.10. There are two out going 11 KV feeders, namely Circuit-A & Circuit-C. McGraw Edison recloser(s) 100-RX (coil rating 100 amps) are used for protection against fault. All the ACRs are set for 2A+2C operation to lockout.

6.21 Source for the Sub-Station

Baganchra 33/11 KV sub-station receives power from Jessore 132/33 KV grid sub-station of Power Development Board. It is connected with Jessore–Satkhira 33 KV feeder. The Grid has 2×40 MVA 132/33 KV transformers. Percentage impedances of these two transformers are 9.87 and 9.92 respectively. The transformers are connected in parallel. The 33 KV outgoing sides of the transformers are protected with OCBs operated by Static Definite Time Relay. The 33 KV incoming feeder of the Baganchra 33/11 KV substation is also protected by100 E fuse when 160 VWV 33 KV ACR is bypassed.

At present 3-Φ and 1-Φ fault level of Jessore Grid Sub-station are 1416 MVA and 1090 MVA respectively as of 2002 base. Based on this figure and other data the fault currents at different points have been calculated. The result sheets have been enclosed in article no. 6.25. A single line diagram showing the source line, Grid Sub-station arrangements, REB sub-station arrangements, three phase symmetrical fault level, single phase line to ground fault level at every node is shown in figure 6.10.

6.22 Single Line Diagram showing Fault Current From Grid S/S to Baganchra S/S

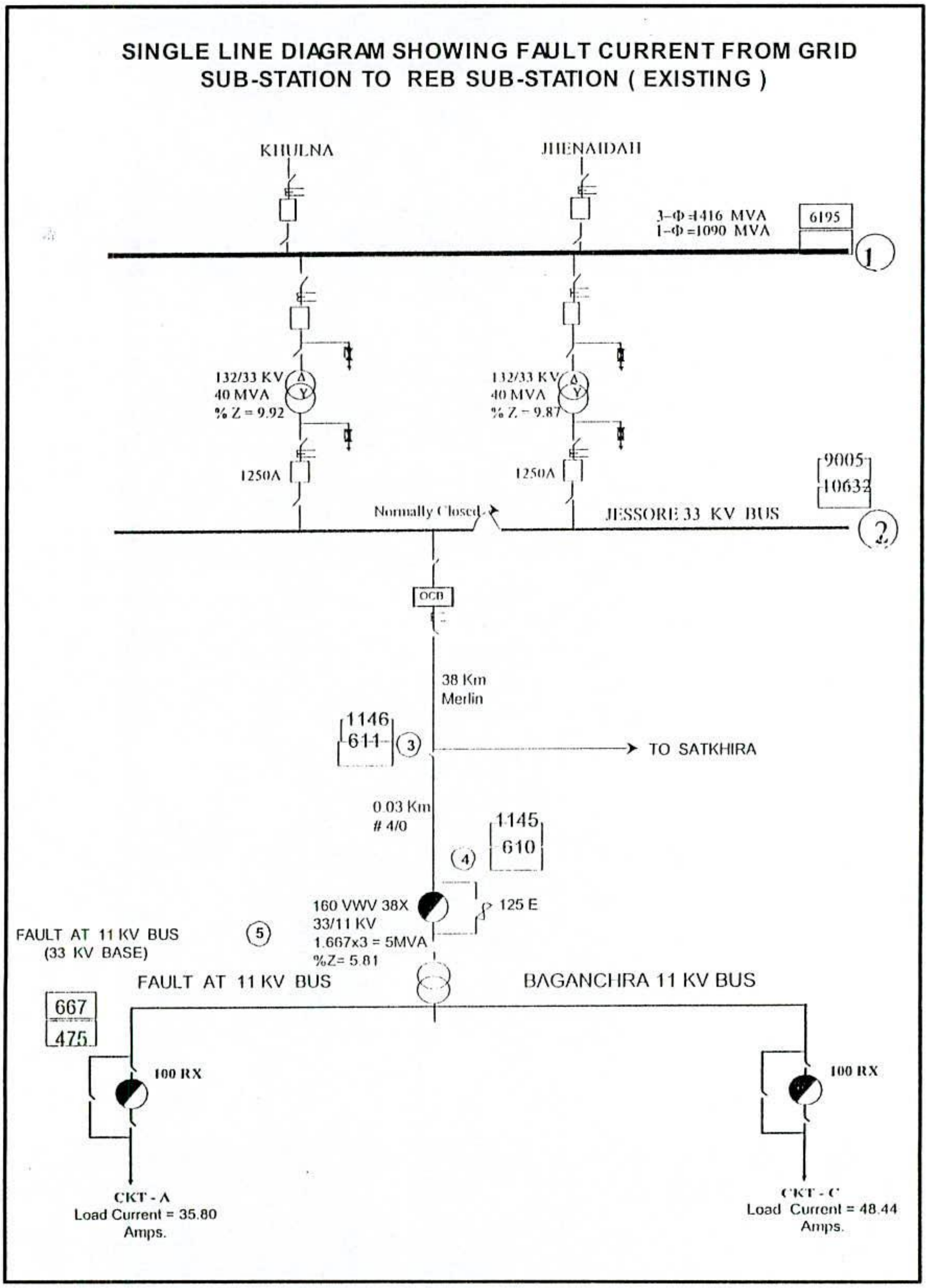


Figure 6.10 Single Line Diagram from Jessore Grid S/S to Baganchra S/S

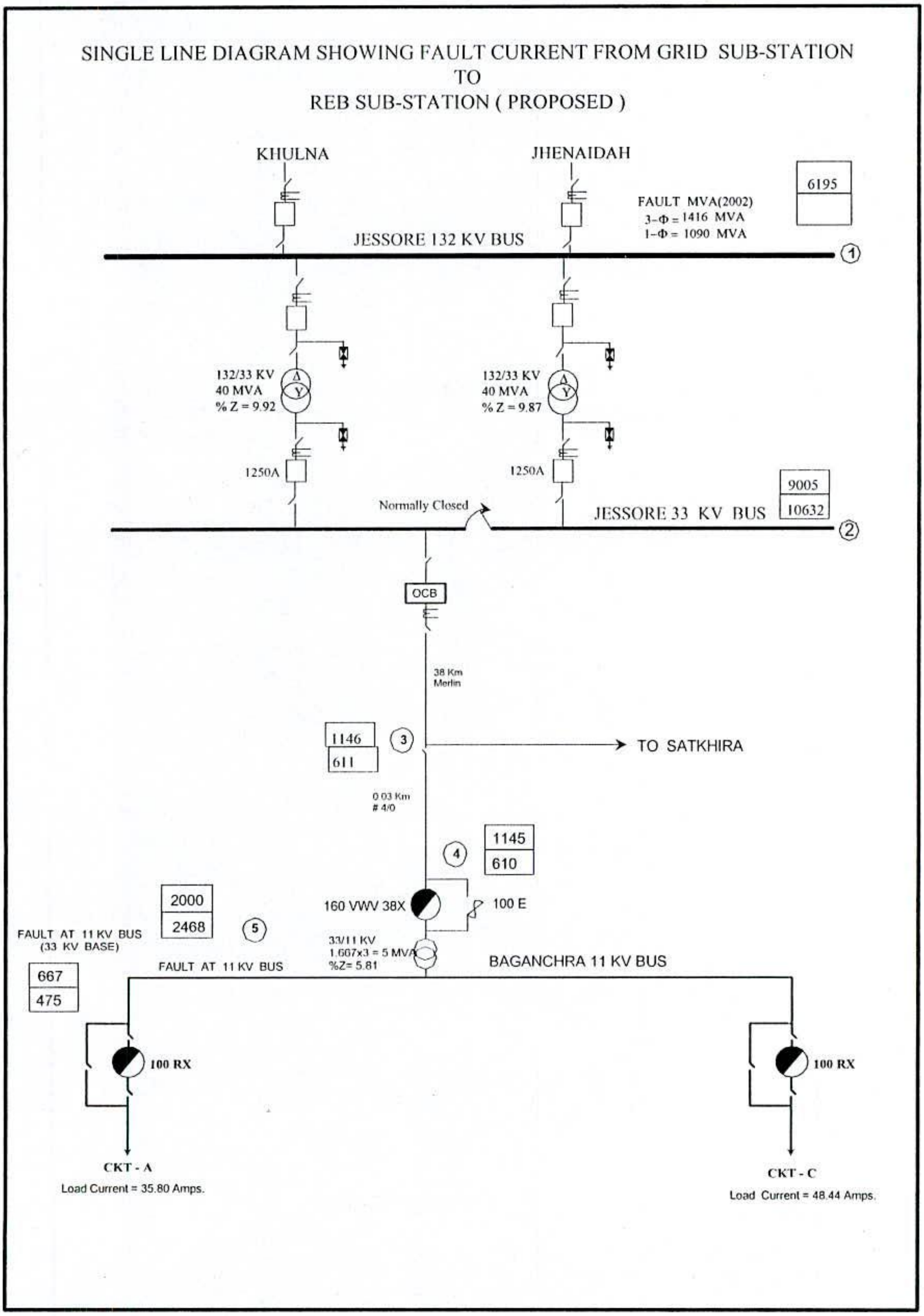


Fig. 6.11 Single Line Diagram from Baganchra S/S for proposed arrangement

6.23 Information of 33 KV Source Feeder For REB Sub-Station

01. Name of PBS : **Jessore PBS -I**

02. Name of REB Sub-Station : **Baganchra**

03. Name of PDB Grid Sub-Station : **Jessore (Chanchara)**

04. Capacity of Grid Sub-Station : 2 x 40 MVA

05. Maximum Demand of Grid S/S : 70 MW

06. Connection Type of Transformer : Delta-Wye

07. Operational Connection : Parallel

08. Percentage Impedance of Grid Transformer :
    a) T 1 : 9.92%
    a) T 2 : 9.87%

09. Fault Level of Grid Sub-Station (2002 Base Case) :
    a) 3-Phase Symmetrical 1416 MVA
    b) 1-Phase 1090 MVA

10. Max. Demand of Source Feeder (So Far) : 9 MW

11. Breaker Information for Source Feeder :
    a) Type : OCB
    b) Rating : 1250 AMP.

12. Relay Information for Source Feeder :
    a) Type : **JS J72 61-3B/CC**
    b) Manufacturer : **SIEMENS**
    c) Characteristics : **Static Definite time**

13. Relay Settings :

O/C Setting		Instantaneous Setting	
TRIP Amps	T.D	Inst. Amps	T.D
$J=J_n$(Basic Setting ....) J=400*(.8+.1+0+.....)= 360	t_s=.8+.2+.1 ts=1.1	800	0.20

E/F Setting		Instantaneous Setting	
TRIP Amps	T.D	Inst. Amps	T.D
$J=J_n$(Basic Setting ....) J=400*(.8+0+0+...)= 320	t_s=.8+.2+.1 t_s=1.1	640	0.20

14. C.T Ratio of 33 KV Source Feeder : 400/5

6.24 Information of 33/11 KV REB (Baganchra) Sub-Station

01. Name of REB Sub-Station : Baganchra

02. Capacity of Sub-Station : 3 X 1.667 MVA

03. Max. Demand of Sub-station (So far) : 2.57 MW

04. Percentage Impedance of Transformer : 5.81% (Average)

05. 33 KV Recloser :

	Existing	Proposed
Type	160 VWV 38X	161 VWV 38X
Manufacturer	Coopers	Coopers
Rating	160 Amps.	160 Amps.
Min. Phase Trip Ampere	320	320
Curve Setting (Phase)	2A+2C	1A
Curve Setting(Ground)	1(1-2)	1(1-2)
Min. Ground Trip	110 Amps.	110 Amps.

06. Power Fuse :

	Existing	Proposed
Type	E	E
Characteristics	Standard Speed	Standard Speed
Rating	125	100

07. Bus Bur ACR : Nil

08. Feeder Outgoing Recloser :

	Feeder- A		Feeder- C	
	Existing	Proposed	Existing	Proposed
Feeder Peak Amp	35.80		48.44	
Type	RX	RX	RX	RX
Manufacturer	McGraw	McGraw	McGraw	McGraw
Rating	100	100	100	100
Phase Trip Ampere	200	200	200	200
Curve Setting (Phase)	2A+2C	2A+2C	2A+2C	2A+2C
Curve Setting(Ground)	2(1-2)+2(2)	2(1-21)+2(2)	2(1-2)+2(2)	2(1-21)+2(2)
Min. Ground Trip amp	63.5	63.5	63.5	63.5

09. Conductor Size & Length From Grid S/S To REB S/S : MERLIN 38.00 Km. & #4/0 ACSR 0.03 Km.

6.25 Fault Level Calculation from Grid s/s to 33/11 KV Baganchra S/S.

FAULT LEVEL AT SOURCE SIDE

PROJECT : Rural Distribution System
SUBSTATION : Baganchra
FEEDER : Feeder 2

DATE : 15/03/2002

GRID SUBSTATION : Jessore
BASE MVA : 100 MVA
FAULT LEVEL : 1416

132 KV LEVEL	33 KV LEVEL	11 KV LEVEL	
1 PU = 132 KV	1 PU = 33 KV	1 PU = 11 KV	I3 = Ib/Z1
1 PU = 437.4 AMPS	1 PU = 1749.6 AMPS	1 PU = 5248.6 AMPS	Ig = (3 x Ib)/Zt
1 PU = 174.24 OHMS	1 PU = 10.890 OHMS	1 PU = 1.210 OHMS	Zt = 2Z1 + Zo

SECTION	DESCRIPTION	MVA OR LENGTH	PU Z1/KM R + j X	SECTION PU Z1 R + j X	ACCUMULATED Z1 = R + j X	PU Zo/KM Ro + j Xo	SECTION PU Zo Ro + j Xo	ACCUMULATED Zo = Ro + j Xo	PU Zt Rt + j Xt	I - 3P SYM.	I_LG MAX
1	132 KV BUS			0 + j 0.0706	0 + j 0.0706		0 + j 0	0 + j 0	0 + j 0.1412	6195	-
1 - 2	132/33 KV S/S TRANSFORMER	T-1 40 T-2 40 T-3		0 + j 0.1237	0 + j 0.1943		0 + j 0.1051	0 + j 0.1051	0 + j 0.4937	9005	10632
2 - 3	33 KV T/L MERLIN 33 KV	38 KM	0.189 + j 0.3389	0.6612 + j 1.1818	0.6612 + j 1.3761	0.45 + j 1.5	1.5694 + j 5.2326	1.5694 + j 5.3377	2.8918 + j 8.0899	1146	611
3 - 4	33 KV T/L	0.03 KM	0.352 + j 0.4009	0.001 + j 0.0011	0.6622 + j 1.3772	0.7207 + j 1.1988	0.002 + j 0.0033	1.5714 + j 5.341	2.8958 + j 8.0954	1145	610
4 - 5	33/11 KV S/S TRANSFORMER	T-1 5 T-2 T-3		0 + j 1.162	0.6622 + j 2.5392		0 + j 1.162	0 + j 1.162	1.3244 + j 6.2404	2000	2468
									11 KV BUS FAULT REFLECTED AT 33 KV	667	475

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : BAGANCHRA
CIRCUIT : A

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 15.03.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT	DIST. FROM	LINE AMPS	RYB FOR
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	I-3P	I-LG Max	I-LG Min	DROP	S/S	1.0 TIMES	1-PH LINE
11 KV-BUS								2000	2468	156	0.000	0.00	-	
BUS	1	4/0	3	1.26	16.10	0.670	0.94	1677	1793	154	0.670	1.26	35.80	-
1	2	4/0	3	0.62	4.22	0.200	0.25	1551	1575	153	0.870	1.88	21.03	-
2	3	3	3	0.91	74.83	0.740	4.36	1277	1217	148	1.610	2.79	20.24	-
3	4	3	3	1.00	46.57	0.065	2.72	1046	956	143	1.675	3.79	2.72	-
3	5	3	3	0.22	0.00	0.131	0.00	1220	1150	147	1.741	3.01	13.16	-
5	6	3	3	3.22	105.41	0.463	6.15	703	615	132	2.204	6.23	6.15	-
5	7	3	3	2.60	41.97	0.679	2.45	769	678	135	2.420	5.61	7.01	-
7	8	3	3	1.72	10.78	0.026	0.63	609	528	128	2.446	7.33	0.63	-
7	9	3	3	0.41	0.00	0.073	0.00	724	635	133	2.493	6.02	3.93	-
9	10	3	3	2.34	17.54	0.057	1.02	540	466	124	2.550	8.36	1.02	-
9	11	3	3	2.98	17.54	0.326	1.02	504	434	122	2.819	9.00	2.91	-
11	12	3	3	1.59	11.20	0.025	0.65	433	371	116	2.844	10.59	0.65	-
11	13	3	3	0.71	4.22	0.036	0.25	470	403	119	2.855	9.71	1.23	-
13	14	3	3	1.75	12.67	0.030	0.74	402	343	114	2.885	11.46	0.74	-
13	15	3	3	1.53	4.22	0.009	0.25	409	350	114	2.864	11.24	0.25	-
2	16	4/0	3	2.70	9.36	0.012	0.55	1162	1025	147	0.882	4.58	0.55	-
1	17	4/0	3	1.12	0.00	0.226	0.00	1461	1434	152	0.896	2.38	13.83	-
17	18	3	3	0.55	3.45	0.003	0.20	1305	1236	149	0.899	2.93	0.20	-
17	19	3	3	0.26	4.22	0.001	0.25	1385	1335	150	0.897	2.64	0.25	-
17	20	4/0	3	0.59	4.22	0.114	0.25	1367	1296	151	1.010	2.97	13.38	-
20	21	3	1	0.37	2.76	0.006	0.48	N.A	1181	149	1.016	3.34	0.48	R
20	22	4/0	3	0.28	5.33	0.052	0.31	1327	1240	150	1.062	3.25	12.99	-
22	23	4/0	3	1.12	8.44	0.113	0.49	1185	1054	148	1.175	4.37	7.22	-
23	24	3	3	1.32	16.76	0.320	0.98	943	811	141	1.495	5.69	6.02	-
24	25	3	3	0.90	13.71	0.018	0.80	818	696	137	1.513	6.59	0.80	-
24	26	3	3	0.96	15.26	0.163	0.89	811	689	137	1.658	6.65	4.24	-
26	27	3	3	0.97	29.23	0.039	1.70	706	596	133	1.697	7.62	1.70	-
26	28	3	3	1.14	28.28	0.046	1.65	690	582	132	1.704	7.79	1.65	-
23	29	4/0	3	0.62	6.44	0.003	0.38	1118	973	147	1.178	4.99	0.71	-
29	30	3	1	0.86	1.90	0.010	0.33	N.A	826	142	1.188	5.85	0.33	B
22	31	4/0	3	0.98	8.44	0.075	0.49	1201	1074	148	1.137	4.23	5.45	-
31	32	3	3	0.84	6.98	0.009	0.41	1035	902	144	1.146	5.07	0.41	-
31	33	4/0	3	0.72	2.34	0.048	0.14	1122	978	147	1.185	4.95	4.55	-
33	34	3	3	0.12	1.90	0.000	0.11	1100	955	146	1.185	5.07	0.11	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : BAGANCHRA
CIRCUIT : A

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 15.03.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	1-3P	1-LG Max	1-LG Min				
33	35	3	3	0.42	5.68	0.003	0.33	1045	901	145	1.188	5.37	0.33	-
33	36	4/0	3	0.81	4.22	0.047	0.25	1045	889	145	1.232	5.76	3.97	-
36	37	3	3	0.32	6.04	0.003	0.35	993	838	144	1.235	6.08	0.35	-
36	38	4/0	3	0.63	0.00	0.032	0.00	992	829	144	1.264	6.39	3.38	-
38	39	3	3	0.32	4.22	0.002	0.25	944	785	142	1.266	6.71	0.25	-
38	40	4/0	3	0.72	0.00	0.034	0.00	937	770	143	1.298	7.11	3.13	-
40	41	3	3	0.68	5.68	0.006	0.33	848	693	139	1.304	7.79	0.33	-
40	42	4/0	3	1.65	0.00	0.070	0.00	831	663	140	1.368	8.76	2.80	-
42	43	3	3	3.09	11.20	0.049	0.65	570	454	127	1.417	11.85	0.65	-
42	44	4/0	3	3.24	1.11	0.104	0.06	680	520	134	1.472	12.00	2.15	-
44	45	3	3	0.75	8.25	0.009	0.48	626	479	131	1.481	12.75	0.48	-
44	46	4/0	3	0.36	0.00	0.009	0.00	666	507	133	1.481	12.36	1.60	-
46	47	3	3	2.28	25.96	0.081	1.51	525	403	124	1.562	14.64	1.51	-
46	48	4/0	3	0.90	1.46	0.001	0.09	635	479	132	1.482	13.26	0.09	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : BAGANCHRA
CIRCUIT : C

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 15.03.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYB FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT 1 TIME	I-3P	I-LG Max	I-LG Min				
11 KV-BUS								2000	2468	156	0.000	0.00	-	
BUS	1	4/0	3	0.59	4.22	0.437	0.25	1836	2101	155	0.437	0.59	48.44	-
1	2	3	3	0.28	5.15	0.002	0.30	1719	1896	154	0.439	0.87	0.30	-
1	3	4/0	3	0.59	1.46	0.433	0.09	1694	1825	154	0.870	1.18	47.89	-
3	4	3	3	1.55	25.20	0.054	1.47	1200	1145	146	0.924	2.73	1.47	-
3	5	4/0	3	0.29	0.00	0.206	0.00	1632	1713	153	1.076	1.47	46.34	-
5	6	3	3	0.54	8.44	0.006	0.49	1449	1448	151	1.082	2.01	0.49	-
5	7	4/0	3	0.36	4.22	0.252	0.25	1560	1591	153	1.328	1.83	45.84	-
7	8	3	1	0.28	2.76	0.004	0.48	N.A	1464	151	1.332	2.11	0.48	R
7	9	4/0	3	0.29	0.00	0.202	0.00	1507	1504	152	1.530	2.12	45.11	-
9	10	3	3	0.27	4.22	0.002	0.25	1424	1393	151	1.532	2.39	0.25	-
9	11	4/0	3	0.31	6.56	0.214	0.38	1453	1421	152	1.744	2.43	44.87	-
11	12	3	3	2.32	42.16	0.133	2.46	928	825	140	1.877	4.75	2.46	-
11	13	4/0	3	0.89	19.46	0.570	1.14	1317	1226	150	2.314	3.32	42.03	-
13	14	3	3	2.15	50.72	0.148	2.96	892	777	139	2.462	5.47	2.96	-
13	15	4/0	3	0.23	0.00	0.135	0.00	1286	1184	149	2.449	3.55	37.93	-
15	16	3	3	0.79	8.44	0.009	0.49	1109	990	145	2.458	4.34	0.49	-
15	17	4/0	3	0.45	0.00	0.260	0.00	1228	1109	149	2.709	4.00	37.44	-
17	18	3	3	2.12	33.98	0.099	1.98	853	732	138	2.808	6.12	1.98	-
17	19	3	3	0.48	4.22	0.003	0.25	1126	999	146	2.712	4.48	0.25	-
17	20	4/0	3	1.06	10.49	0.571	0.61	1111	965	147	3.280	5.06	35.21	-
20	21	3	3	0.71	4.22	0.561	0.25	987	843	143	3.841	5.77	17.55	-
21	22	3	3	1.97	77.71	0.207	4.53	732	612	134	4.048	7.74	4.53	-
21	23	3	3	2.08	81.90	0.974	4.78	721	603	134	4.815	7.85	12.78	-
23	24	3	3	2.80	32.74	0.886	1.91	517	430	123	5.701	10.65	8.00	-
24	25	3	3	2.72	28.38	0.106	1.66	403	334	114	5.807	13.37	1.66	-
24	26	3	3	1.62	6.98	0.016	0.41	442	367	117	5.717	12.27	0.41	-
24	27	3	3	1.60	24.29	0.240	1.42	443	368	117	5.941	12.25	4.03	-
27	28	3	3	1.52	5.98	0.014	0.35	390	324	112	5.955	13.77	0.35	-
27	29	3	3	1.20	38.76	0.063	2.26	400	332	113	6.004	13.45	2.26	-
20	30	4/0	3	0.86	10.69	0.222	0.62	1031	873	145	3.502	5.92	17.05	-
30	31	3	3	0.13	12.49	0.002	0.73	1010	852	144	3.504	6.05	0.73	-
30	32	4/0	3	1.09	10.78	0.259	0.63	944	778	143	3.761	7.01	15.69	-
32	33	3	3	0.37	10.26	0.005	0.60	894	733	141	3.766	7.38	0.60	-
32	34	4/0	3	2.03	43.93	0.415	2.56	816	647	139	4.176	9.04	14.47	-

VOLTAGE DROP, FAULT LEVEL AND SECTION CURRENT

PROJECT : JESSORE PBS-I
SUBSTATION : BAGANCHRA
CIRCUIT : C

SYSTEM DESIGN : 20 KWH/CUST/MONTH
AUTHOR : S K D
DATE : 15.03.02

SECTION		LINE			SECTION			FAULT AMPS			TOTAL VOLT DROP	DIST. FROM S/S	LINE AMPS 1.0 TIMES	RYR FOR 1-PH LINE
S.End	- L.End	WIRE SIZE	PHASE	LENGTH KMs	DEMAND IN KW	VOLT DROP	CURRENT I TIME	I-3P	I-LG Max	I-LG Min				
34	35	3	3	1.92	28.18	0.074	1.64	641	508	131	4.250	10.96	1.64	-
34	36	4/0	3	1.42	61.33	0.187	3.58	744	579	137	4.363	10.46	10.26	-
36	37	3	3	1.12	21.67	0.253	1.26	652	507	132	4.616	11.58	5.59	-
37	38	3	3	1.82	50.79	0.125	2.96	535	419	125	4.741	13.40	2.96	-
37	39	3	3	0.86	23.45	0.028	1.37	592	462	128	4.644	12.44	1.37	-
36	40	4/0	3	3.30	18.70	0.029	1.09	618	465	131	4.392	13.76	1.09	-

6.27 ACR Scheme of Baganchra S/S.

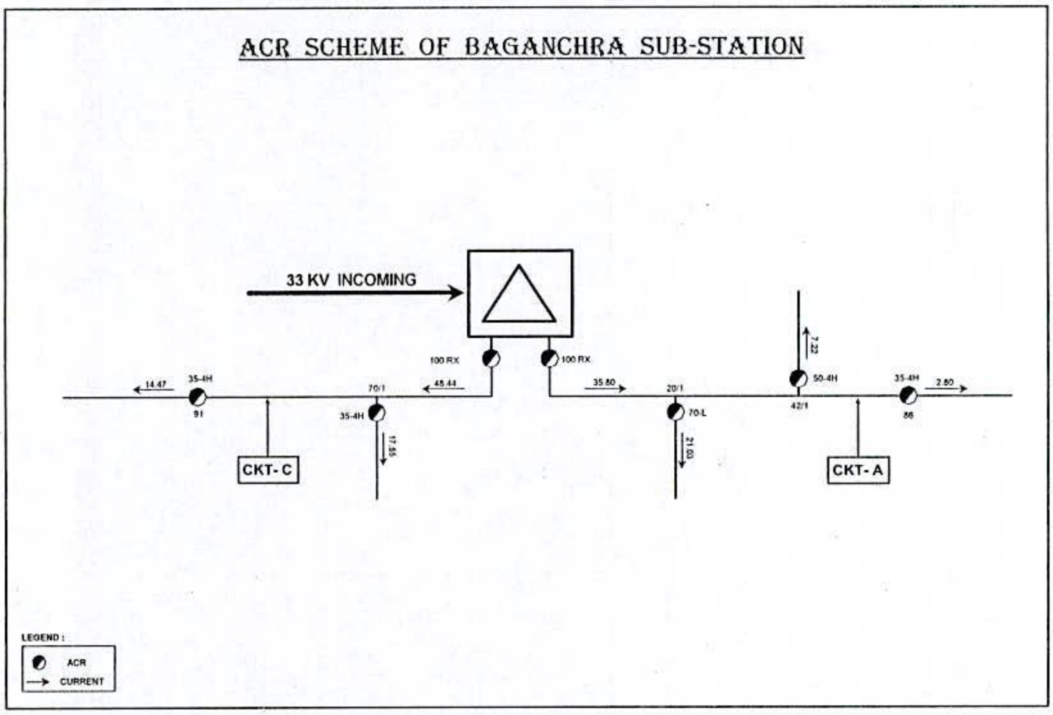


Figure 6.12 ACR Scheme of Baganchra Sub-Station

6.28.1 Study of Existing coordination and proposed modification of Baganchra S/S With Jessore Grid

PBS sub-station has 160 VWV ACR and 125E fuse at its incoming. The fuse is connected in parallel with the ACR but normally opened and comes into operation when ACR is by-passed for maintenance or any other purpose. The 11 KV outgoing feeders A and C are protected with 100-RX ACR. The sub-station has back up protection at PDB Jessore Grid sub-station with OCB operated by JS J172 61-3B/CC. SIEMENS, Static Definite Time Relay.

6.28.2 Phase Fault at H.T Side of the X-Former

From the existing TCC (Figure 6.13a) it is observed that for maximum 3Ø fault at HT side of the transformer, the 160 VWV (setting 2A) goes into operation before tripping Grid over current relay but before going lockout i.e. before operation of 160 VWV (setting 2C) PDB Grid over current relay goes into operation, which is not desired. So, it is proposed to operate 160 VWV ACR by curve 1A (single shot). From the TCC of proposed setting shown in Figure 6.13b it is observed that 160 VWV ACR trips before tripping Grid over current relay. In case of failure of 160 VWV ACR, PDB over current relay will take care and protect power transformer. Transformer damage curve remains at the top. So, coordination is achieved.

From the existing TCC when 160 VWV ACR is by-passed and 125E power fuse is taken into consideration (Figure 6.13c) it is seen that for a maximum 3Ø fault at HT side of the transformer, the 125E fuse melting and the Grid over current relay tripping occur simultaneously, which is not desired. It is also seen from transformer damage curve and TCC curve of 125E fuse that if the fault current is below 300 amps, transformer may damage before melting 125E fuse. From the comparative study of TCC of 125E fuse, 100E fuse and transformer damage curve it is observed that the TCC of 125E fuse is much closer to transformer damage curve than that of 100E fuse. So, it is proposed to replace existing 125E (standard speed) fuse by 100E (standard speed) fuse. From the TCC of proposed setting (Figure 6.13d) it is seen that during fault power transformer will be saved by 100E fuse and also by grid over current relay.

6.28.3 Ground Fault at HT Side of 33/11 KV X-Former

From existing and proposed TCC (Figure 6.14a & Figure 6.14b) it is observed that at the event of a ground fault condition the 160 VWV ACR goes into operation to isolate the fault quickly (the 125 E fuse is by-passed) before grid earth fault relay. In case of failure of 160 VWV ACR the grid earth fault relay will take care by tripping OCB and saves transformer life. Thus the coordination is achieved.

Again from the existing TCC when 160 VWV ACR is by-passed and 125E power fuse is taken into consideration (Figure 6.14c) it is seen that for a ground fault at HT side of the transformer, the 125E fuse melting and the Grid earth fault relay tripping occur simultaneously, which is not desired. It is also seen from transformer damage curve and

TCC curve of 125E fuse that if the fault current is below 300 amps, transformer may damage before melting 125E fuse. From the comparative study of TCC of 125E fuse, 100E fuse and transformer damage curve it is observed that the TCC of 125E fuse is much closer to transformer damage curve than that of 100E fuse. So, it is proposed to replace existing 125E (standard speed) fuse by 100E (standard speed) fuse. From the TCC of proposed setting (Figure 6.14d) it is seen that during fault power transformer will be saved by 100E fuse and also by grid earth fault relay. Transformer damage curve remains at the top. So, the coordination is achieved. For ground fault the proposed 33 KV ACR is to be set for single operation for lock out.

6.28.4 Phase Fault at 11 KV (L.T.) Side of the X-Former

From the TCC of the existing system (Figure 6.15a & 6.15c) it is observed that for any fault on REB 11 KV line i.e. at 11 KV (LT) side of the 33/11 KV transformer the existing 100-RX sub-station outgoing ACR (setting 2A+2C) goes into operation before tripping 160 VWV ACR or before melting of the 125 E fuse and tripping of grid over current relay and if the fault is not cleared during three operations the 11 KV ACR will lockout before tripping 160 VWV ACR or melting of the 125 E fuse and tripping of the grid over current relay. But for a fault below 300 amps, transformer may damage before melting 125E fuse. So, it is proposed to replace existing 125E (standard speed) fuse by 100E (standard speed) fuse. For better coordination it is recommended to operate 160 VWV ACR by curve 1A (single shot). From the TCC of the proposed arrangement (Figure 6.15b & Figure 6.15d) it is observed that for permanent fault condition the 11 KV ACR (100-RX) will first take care of the fault and will lock out before the operation of the 33 KV ACR or 100E fuse and incase of the failure of the 100- RX ACR the 33 KV VWV ACR will operate or 100E fuse will melt before operation of the grid over current relay. So, coordination between the 11KV ACR,33 KV ACR, 100 E fuse and grid over current relay is achieved. Coordination between sub-station 100RX ACR and down stream ACRs is shown in Figure 6.15e where as ACRs-Fuse coordination are shown in Figures 6.15f to Figure 6.15i.

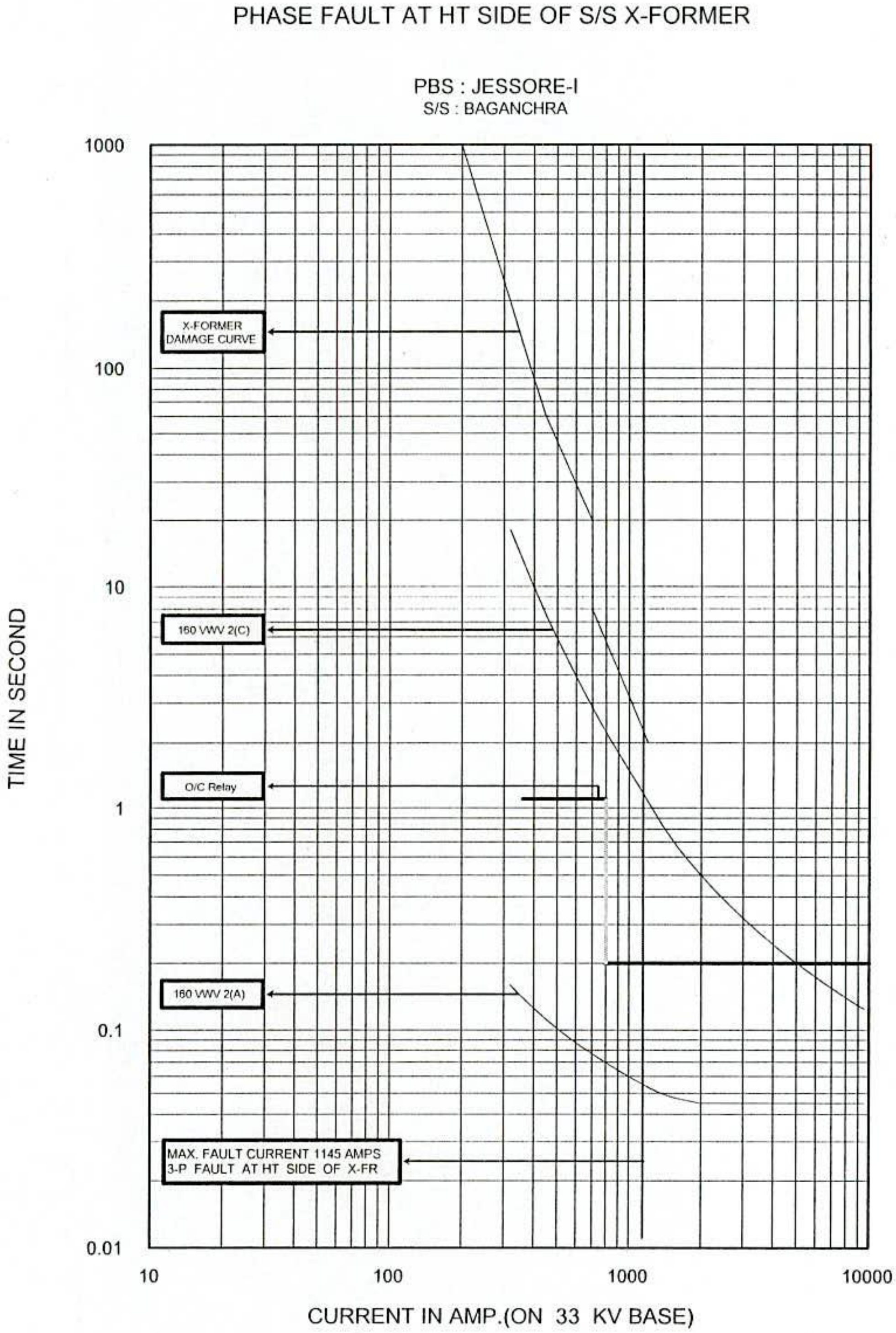


Figure 6.13a Existing Coordination (125 E fuses bypassed)

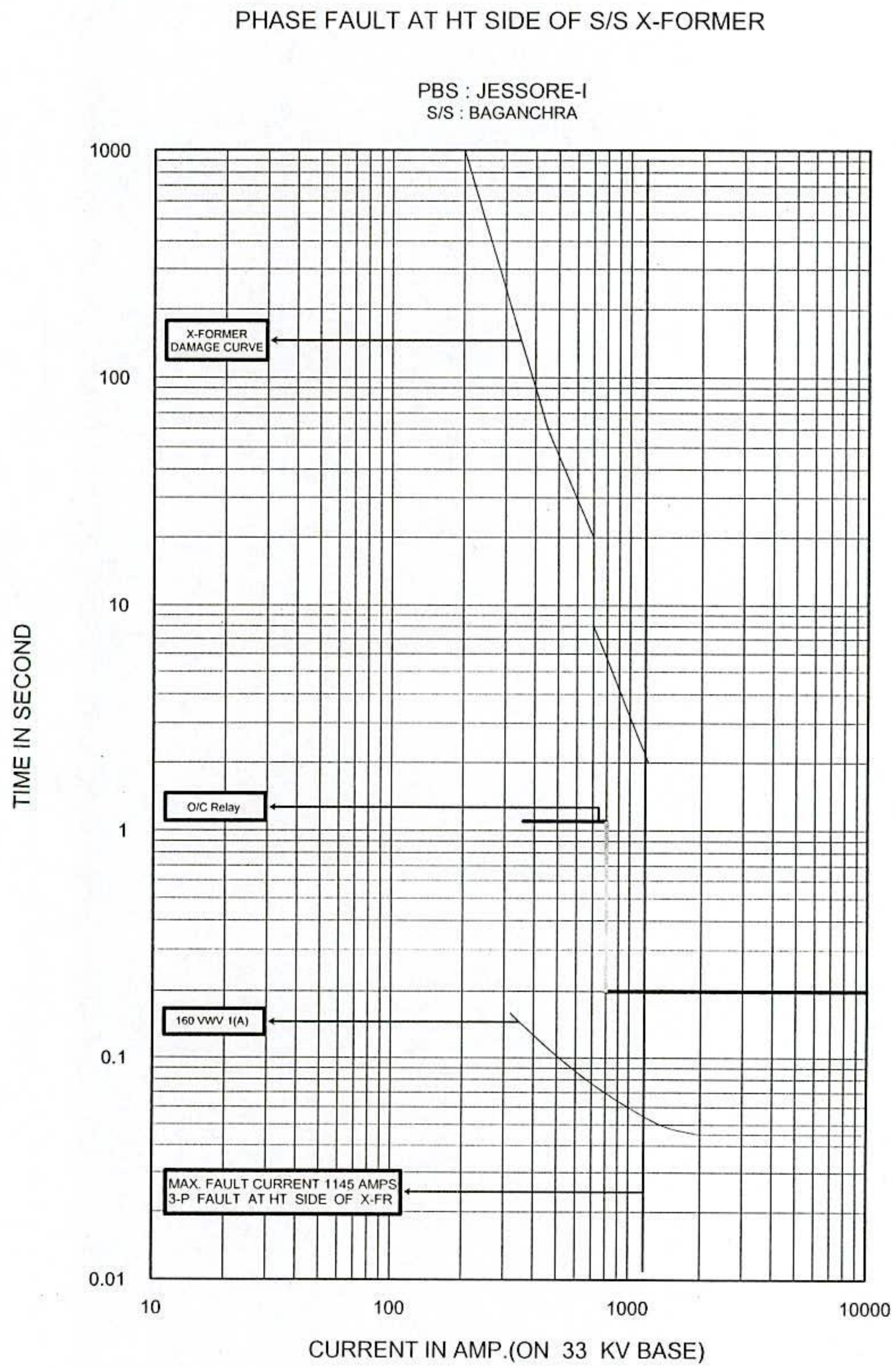


Figure 6.13b Proposed Coordination (100E fuses bypassed)

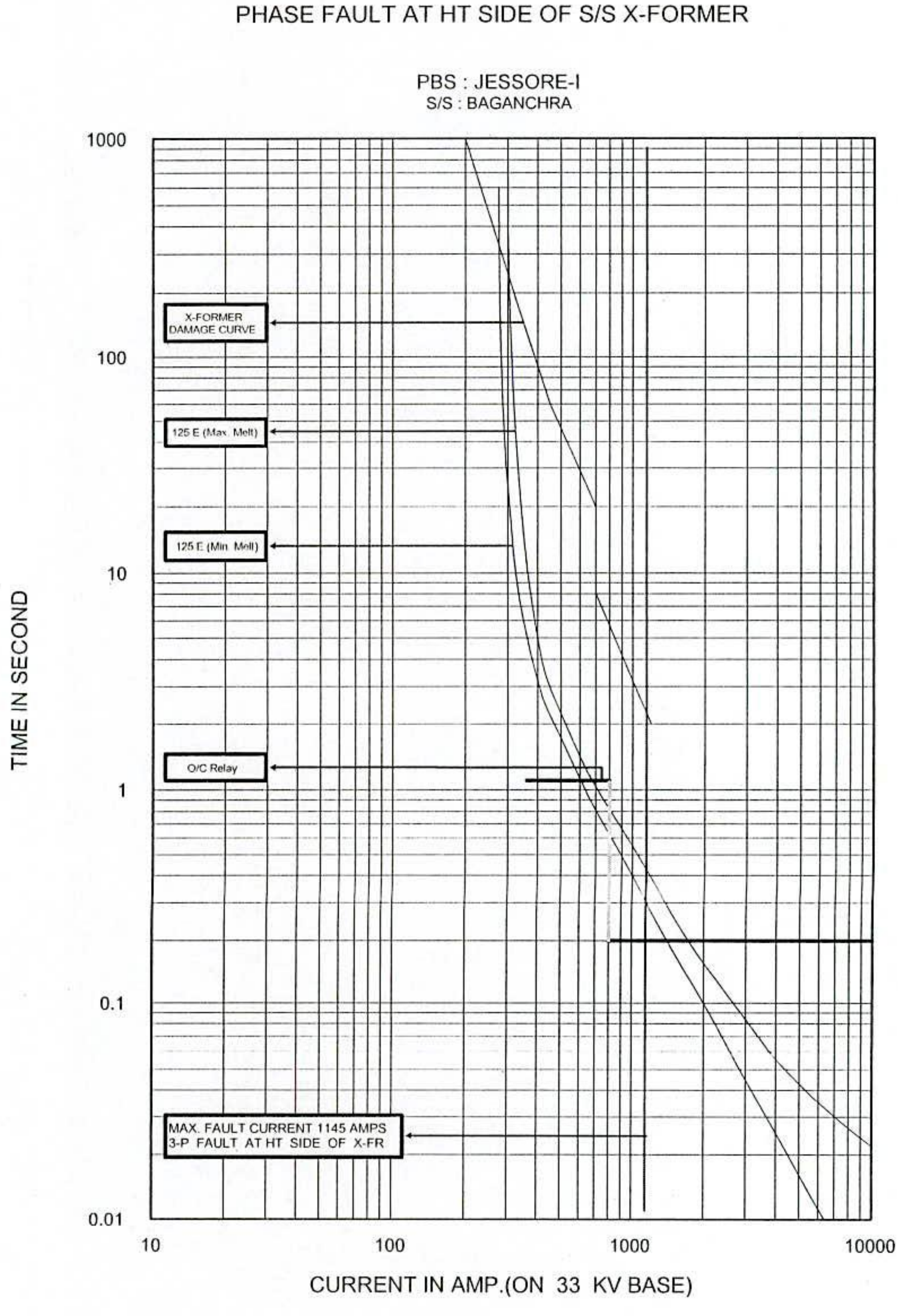


Figure 6.13c Existing Coordination (160 VWV ACR Bypassed)

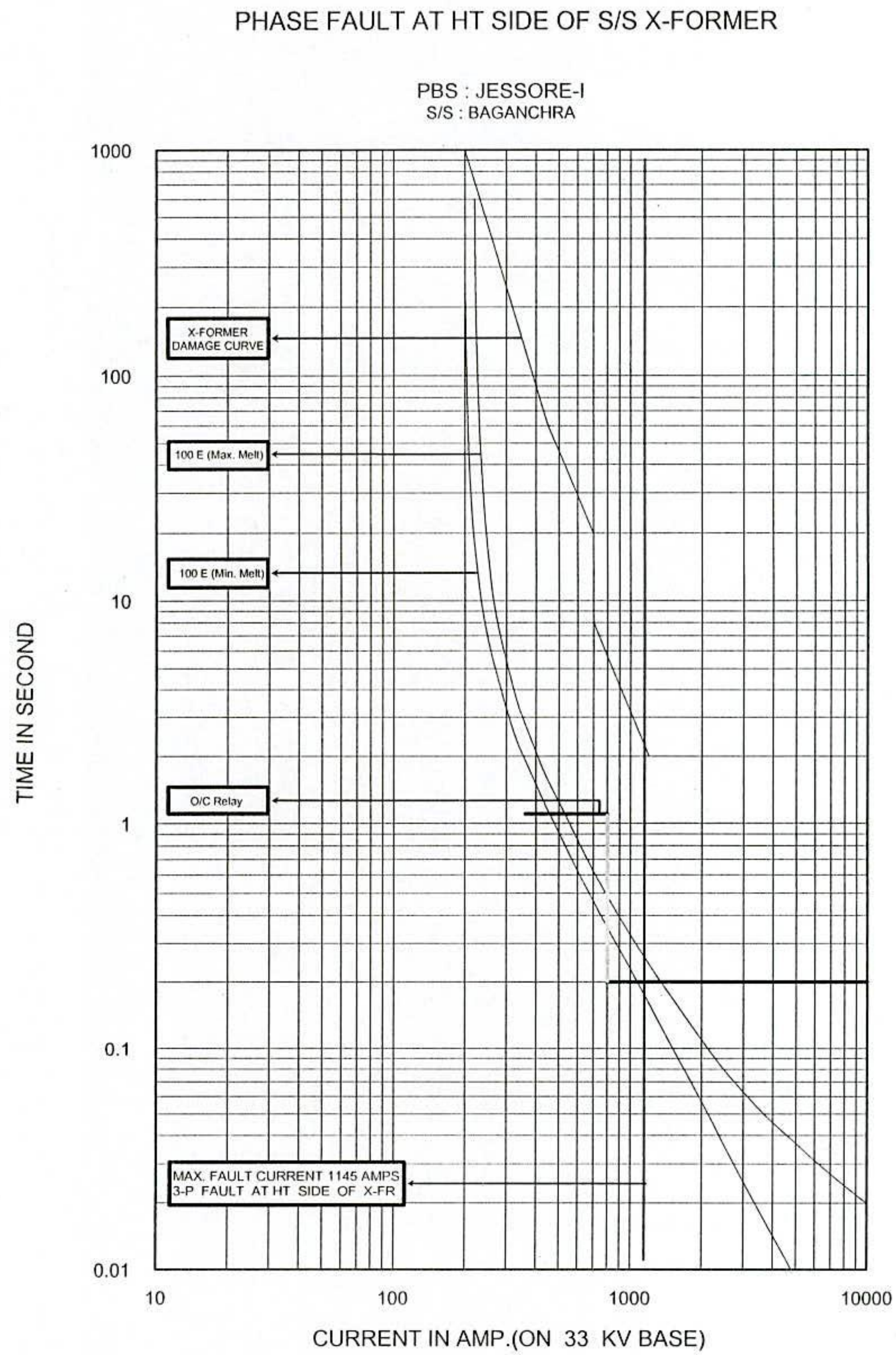


Figure 6.13d Proposed Coordination (160 VWV ACR bypassed)

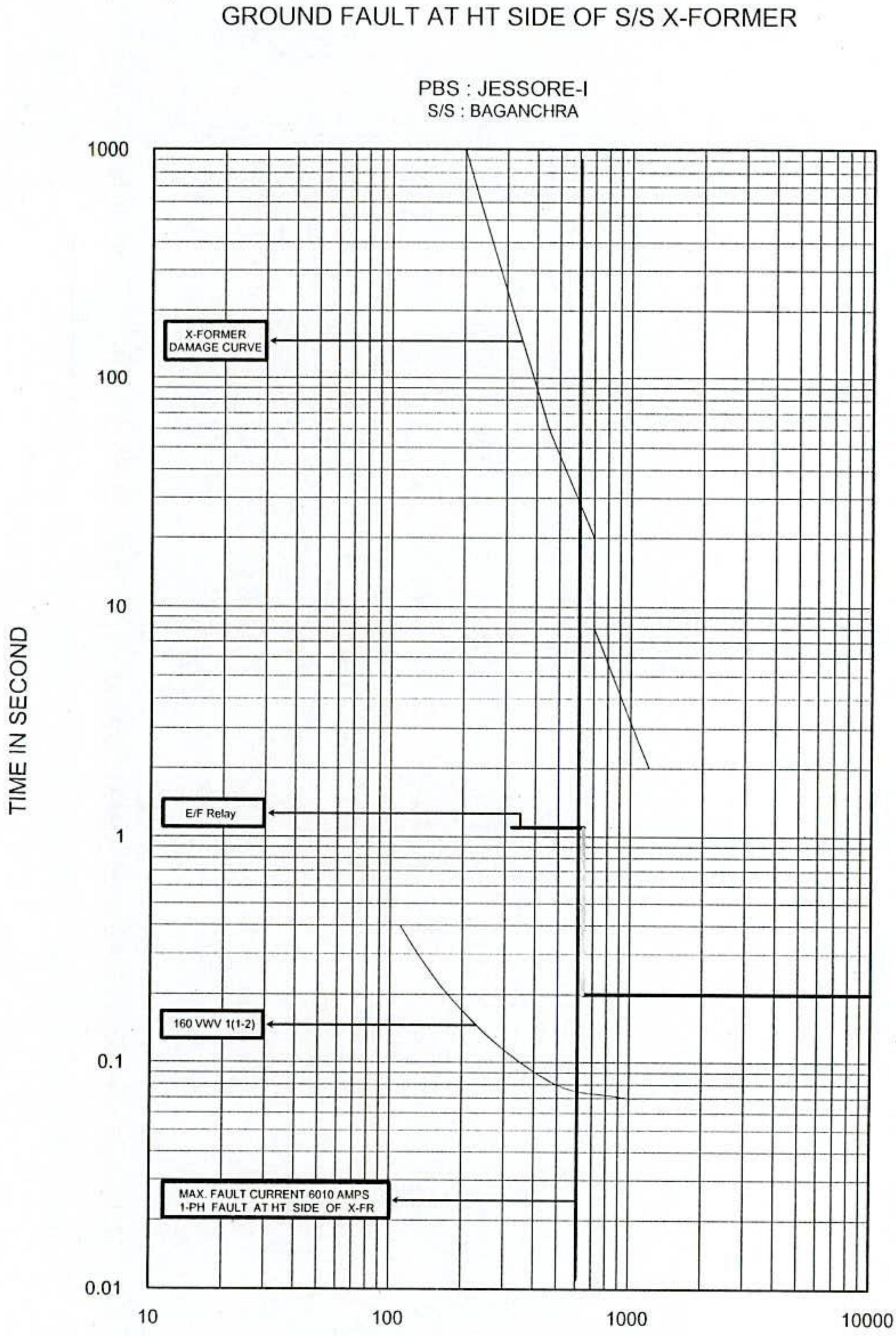


Figure 6.14a Existing Coordination (125E fuse bypassed)

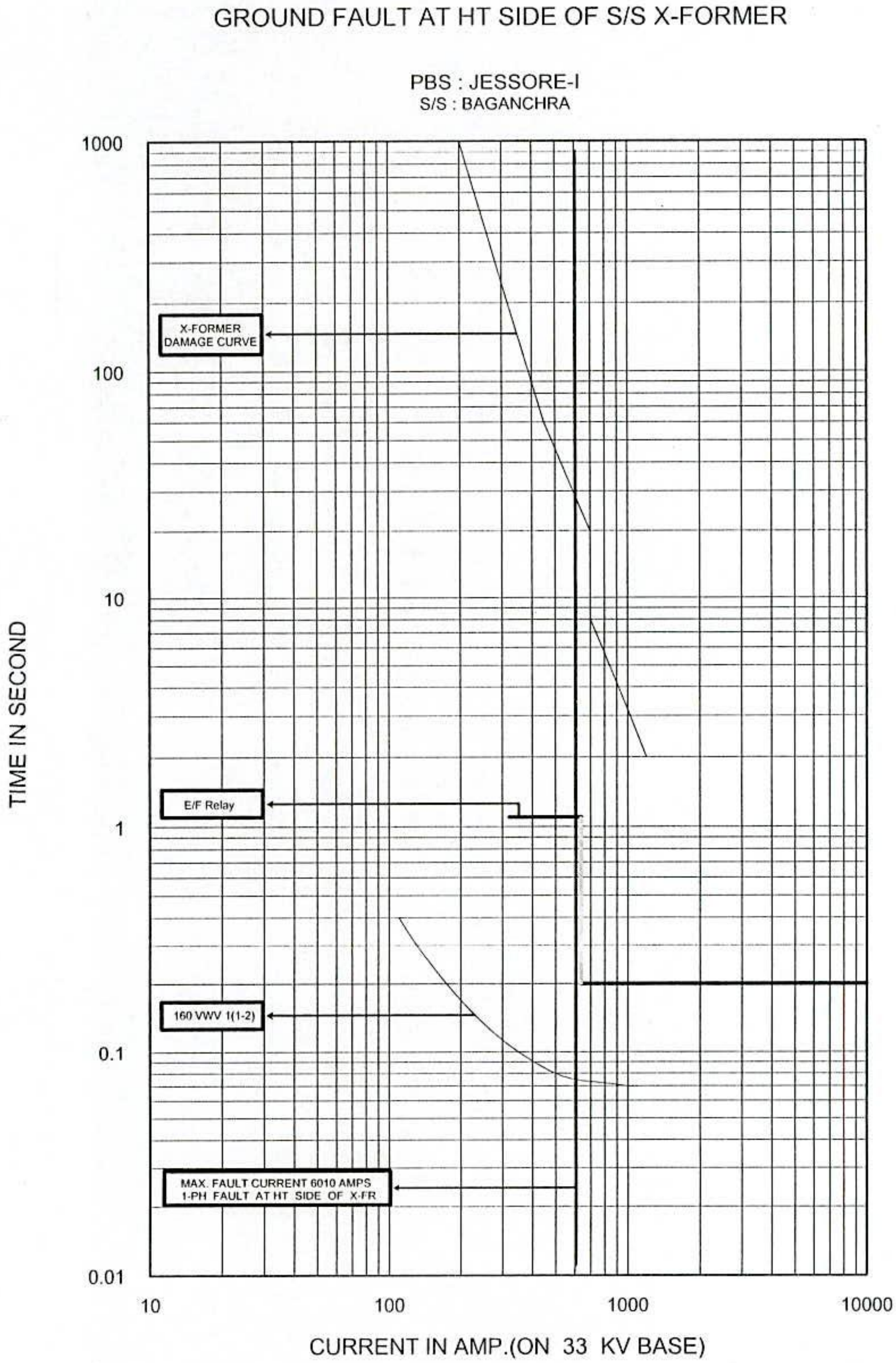


Figure 6.14b Proposed Coordination (100E fuse bypassed)

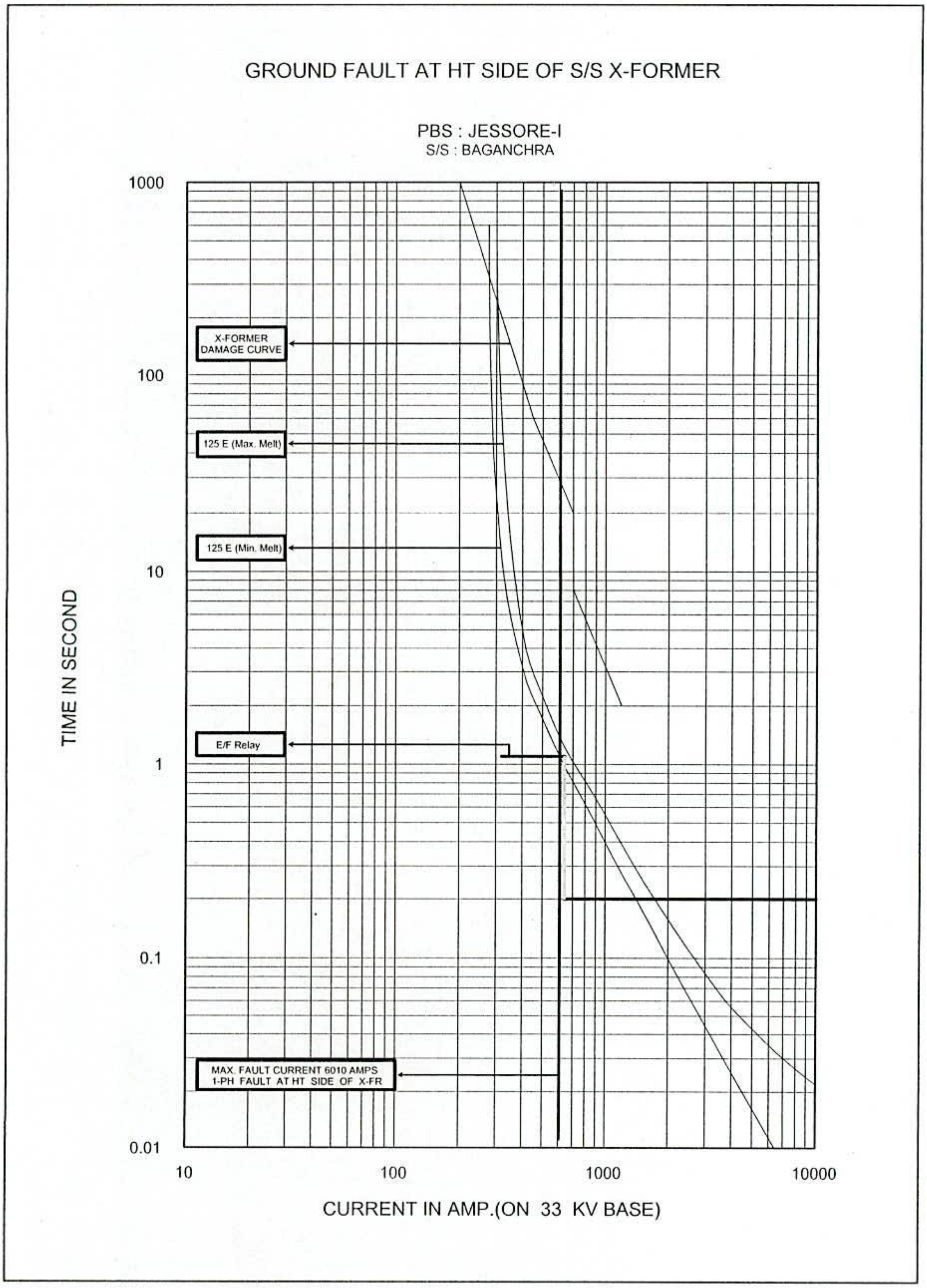


Figure 6.14c Existing Coordination (160 VWV ACR bypassed)

GROUND FAULT AT HT SIDE OF S/S X-FORMER

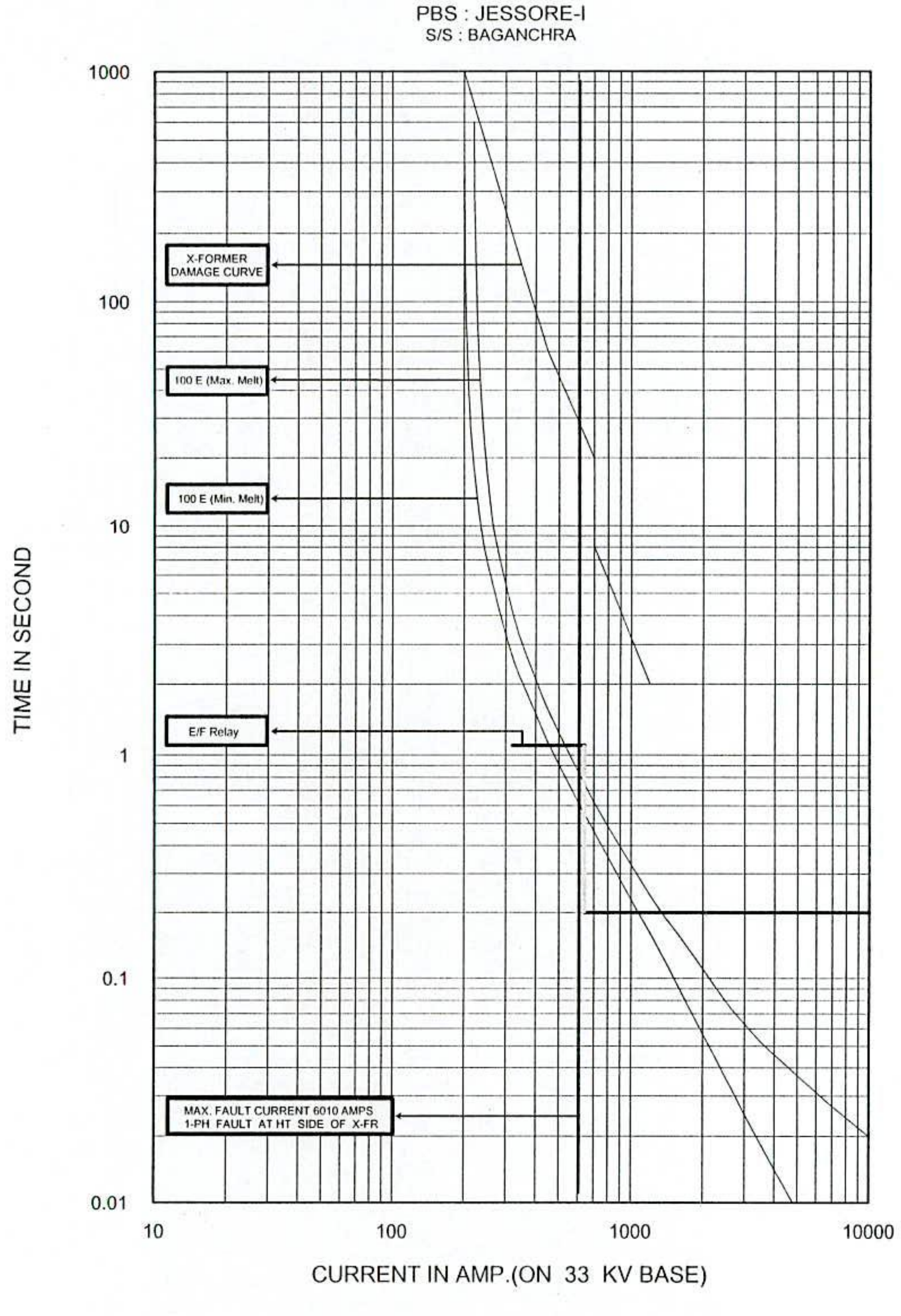


Figure 6.14d Proposed Coordination (160 VWV ACR bypassed)

PHASE FAULT AT LT SIDE OF S/S X-FORMER

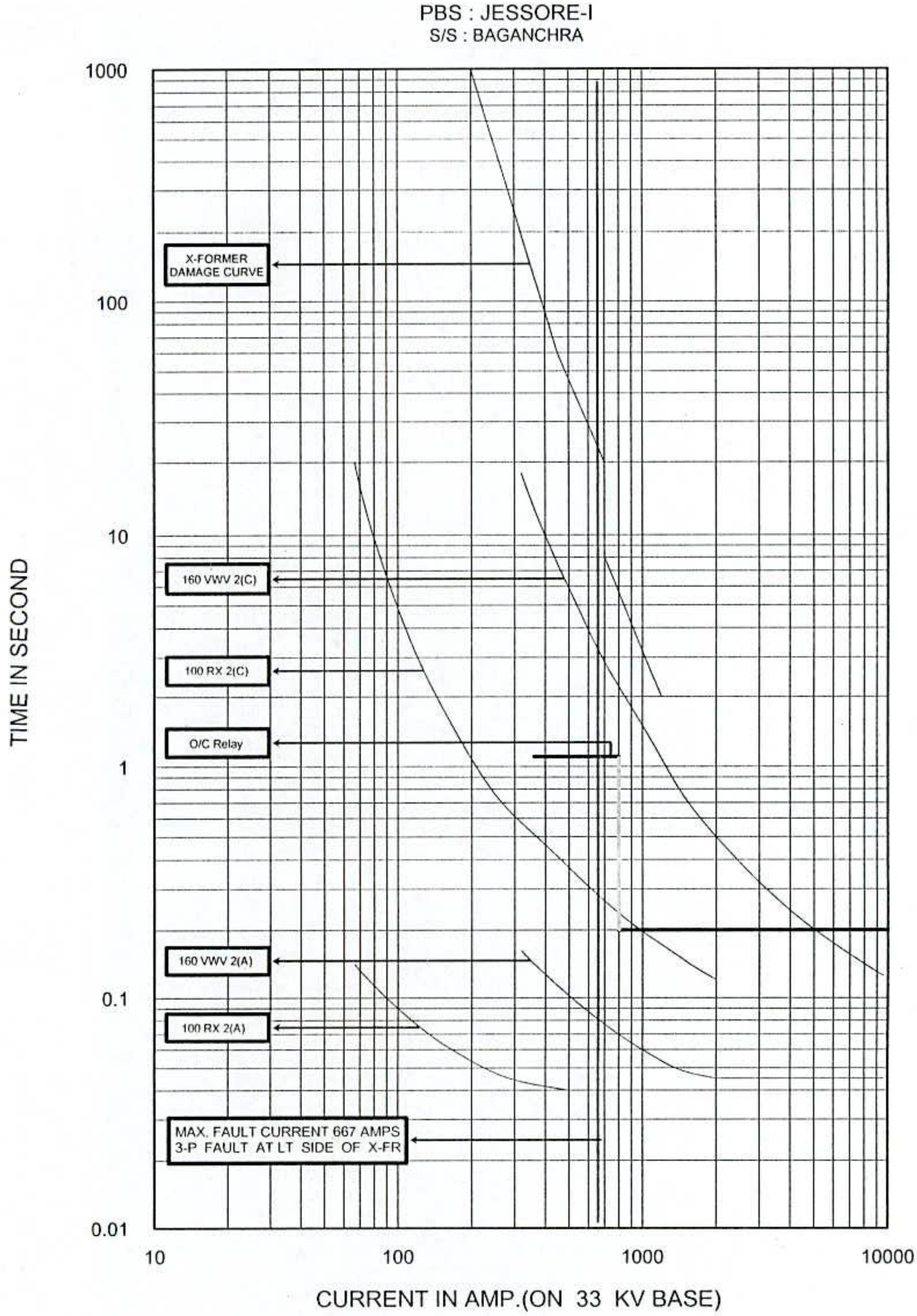


Figure 6.15a Existing Coordination for all Feeders
(125E fuses bypassed)

PHASE FAULT AT LT SIDE OF S/S X-FORMER

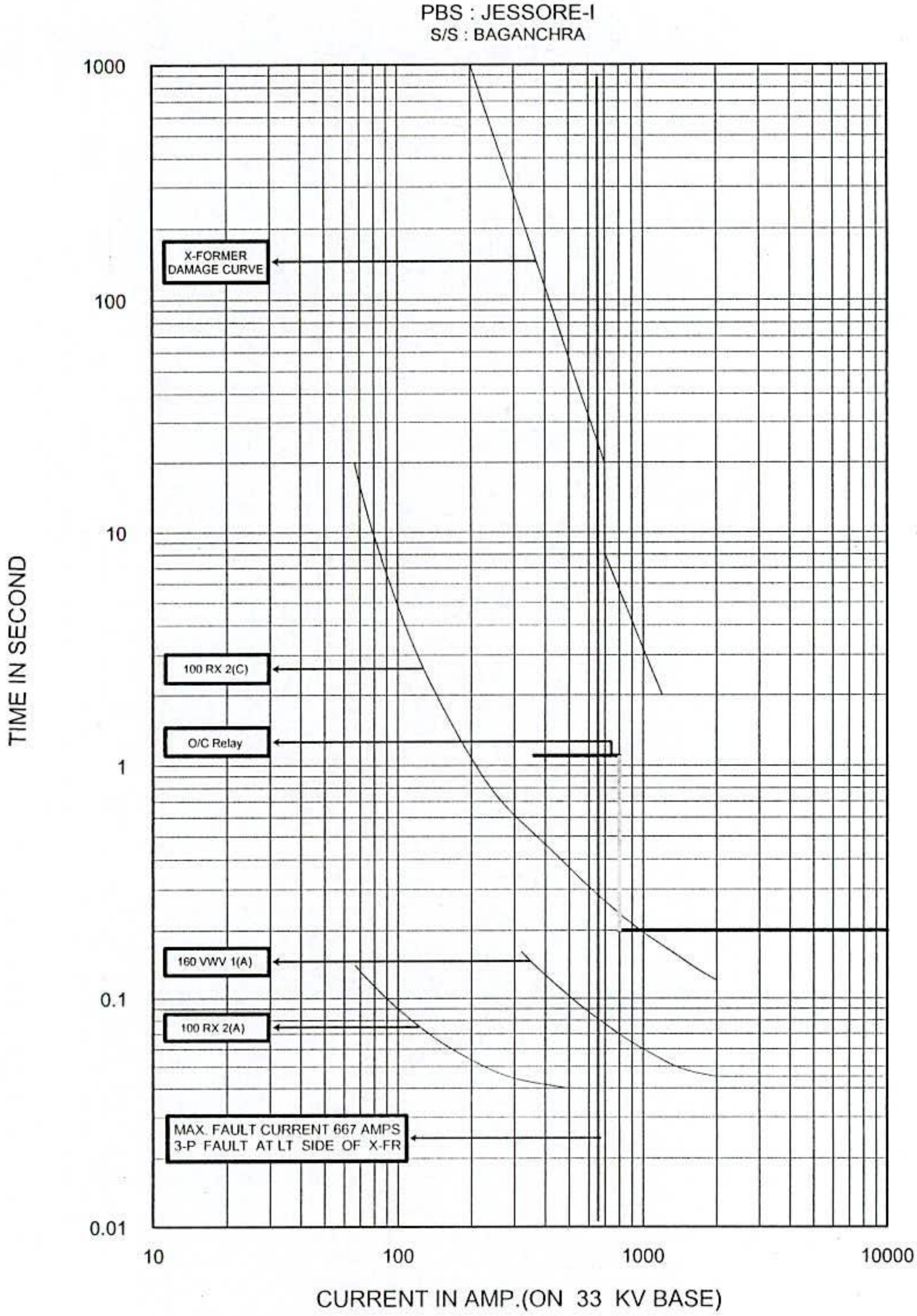


Figure 6.15b Proposed Coordination for all Feeders (100E fuse bypassed)

PHASE FAULT AT LT SIDE OF S/S X-FORMER

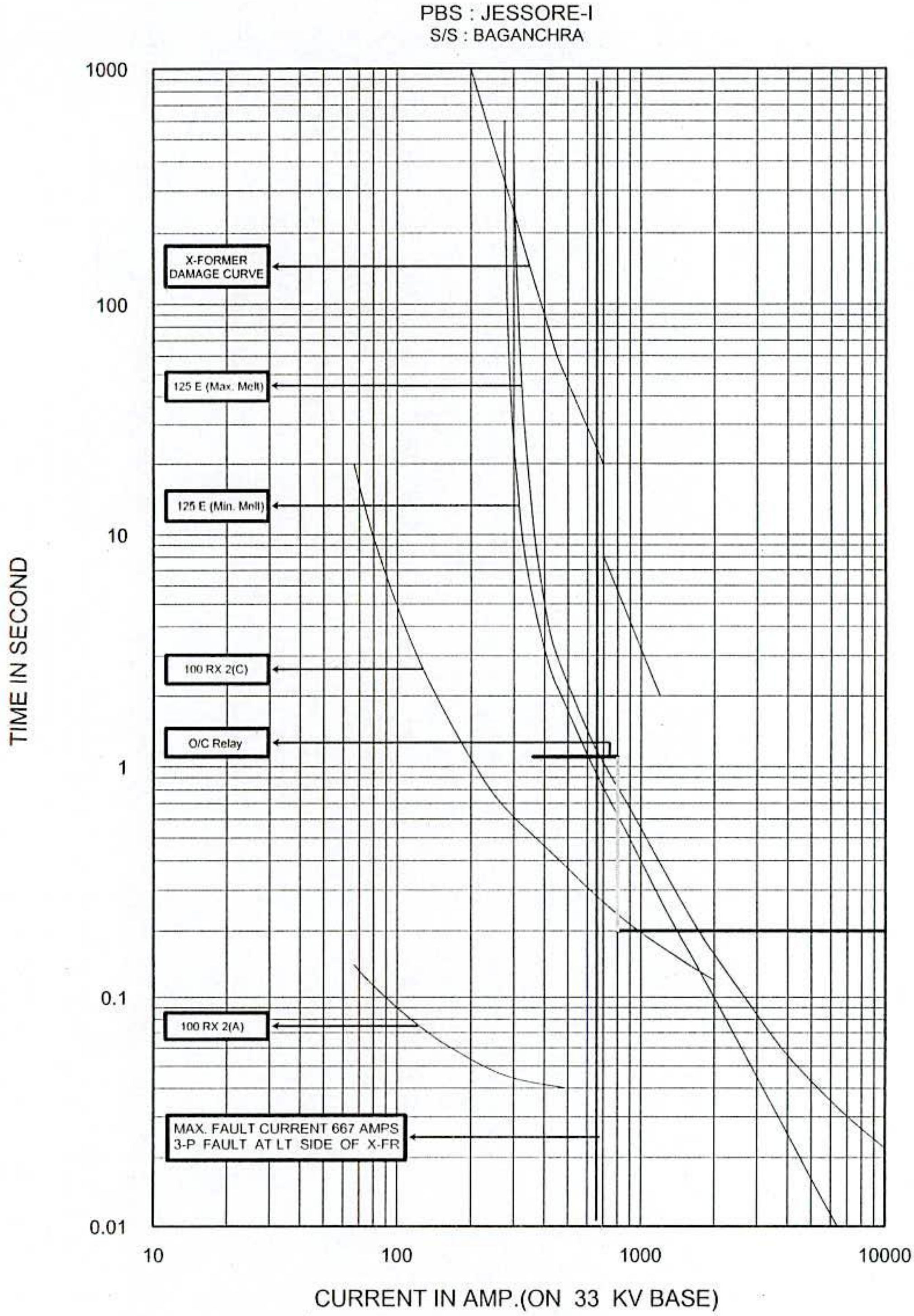


Figure 6.15c Existing Coordination for all Feeders (160 VWV ACR bypassed)

PHASE FAULT AT LT SIDE OF S/S X-FORMER

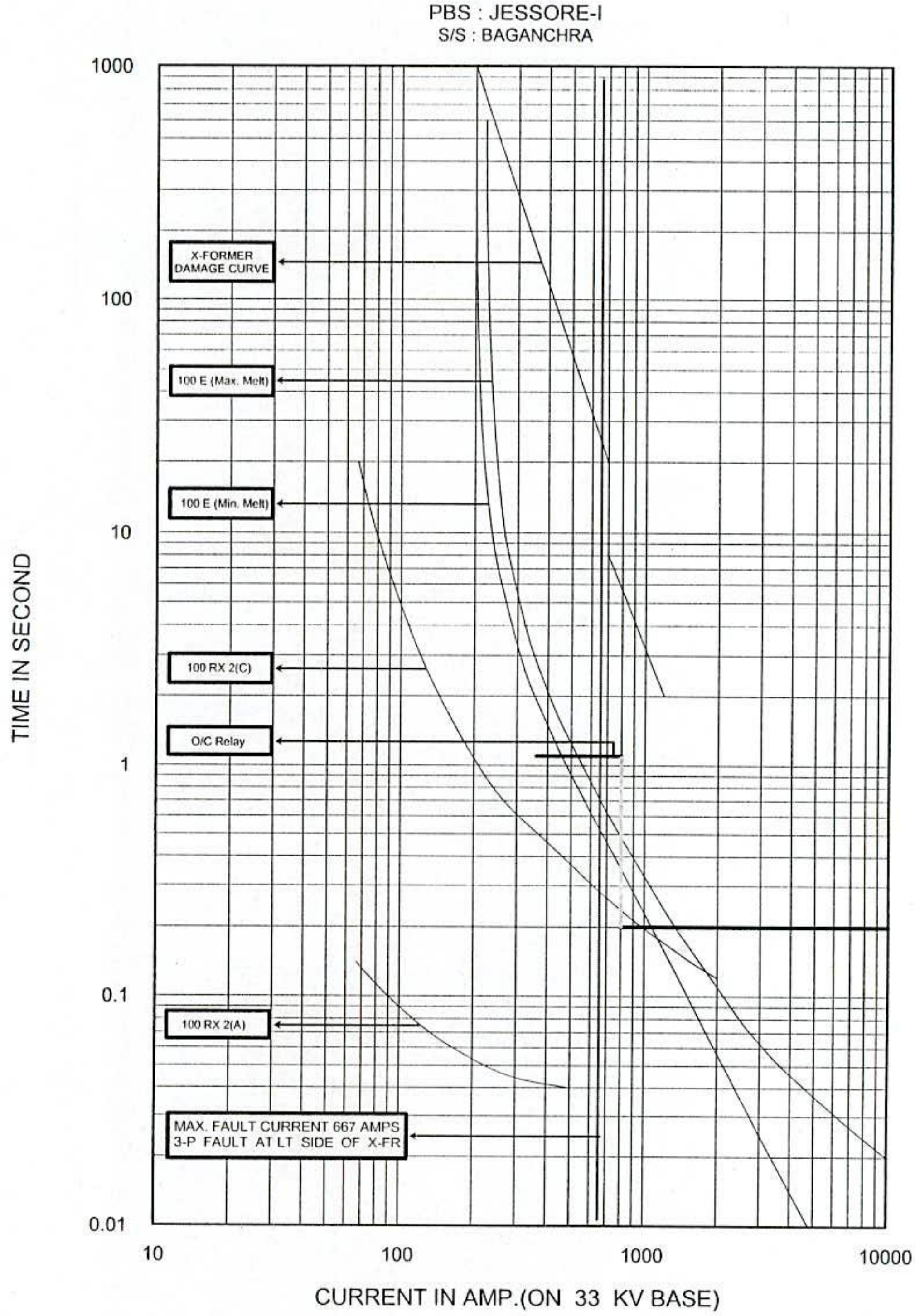


Figure 6.15d Proposed Coordination for all Feeders
(160 VWV ACR bypassed)

ACR TO ACR CO-ORDINATION

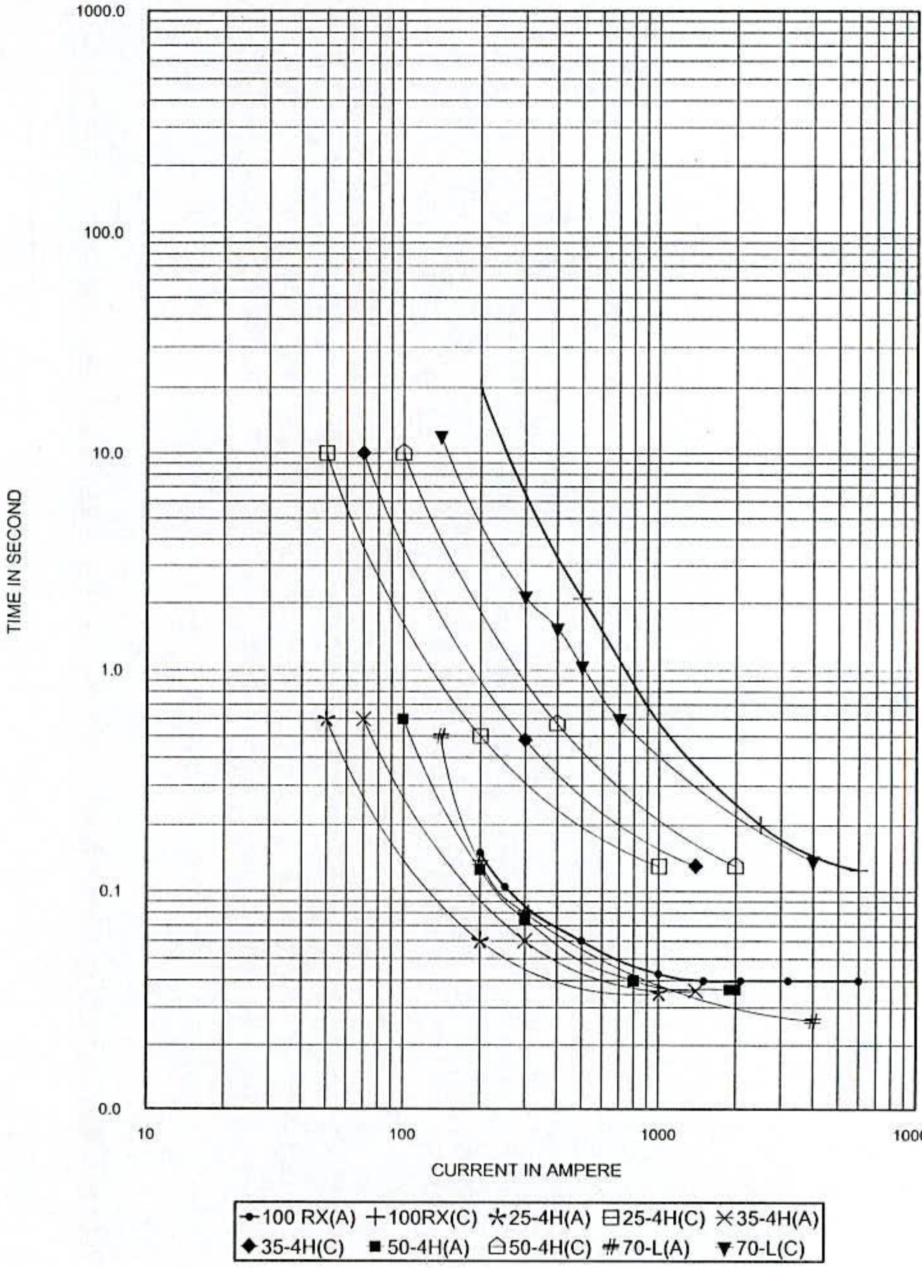


Figure 6.15e ACR-ACR Coordination

COORDINATION BETWEEN 100 RX & FUSES

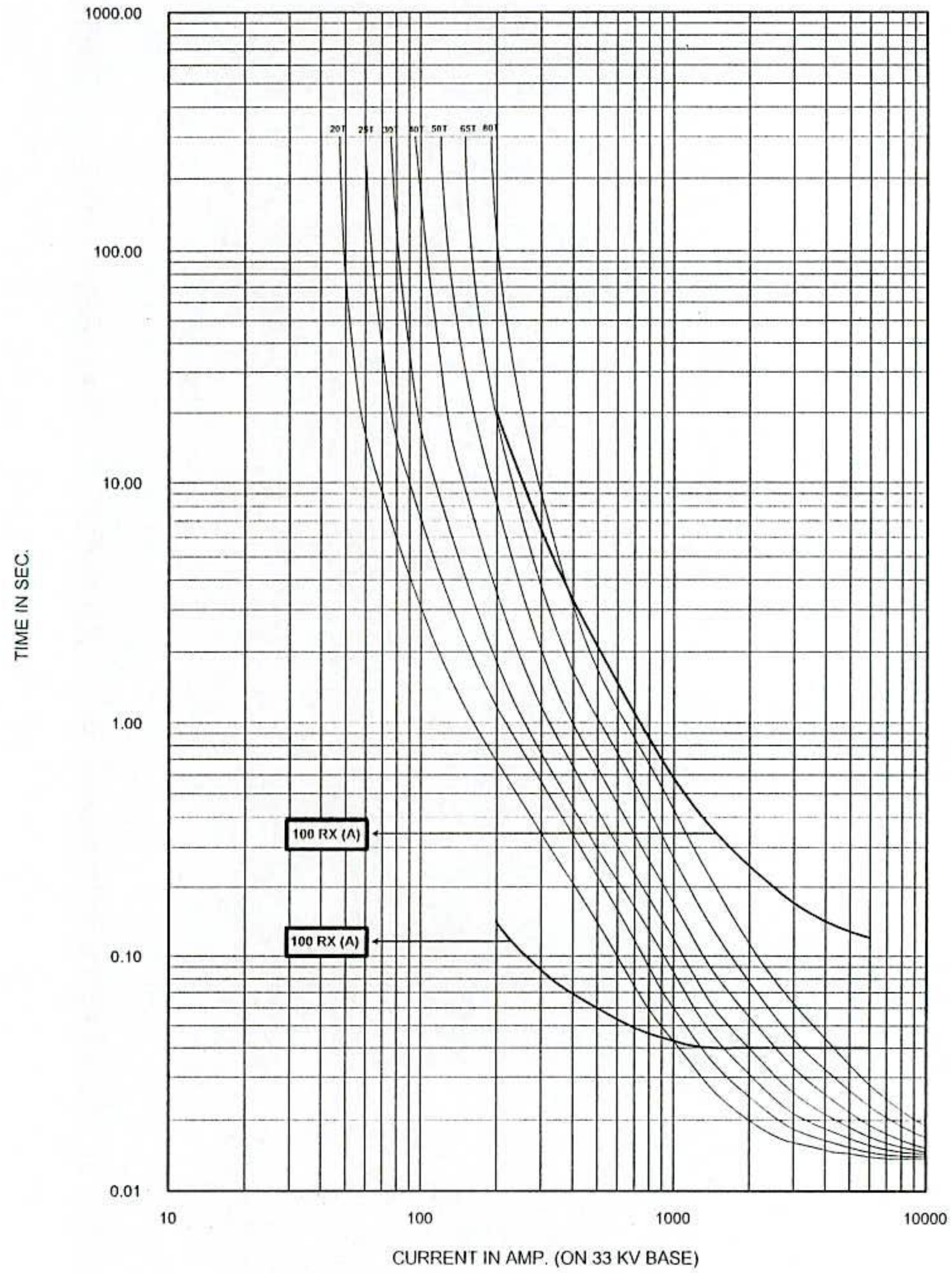


Figure 6.15f 100RX ACR and fuses coordination

CO-ORDINATION BETWEEN 70-L & 'T'- TYPE FUSES

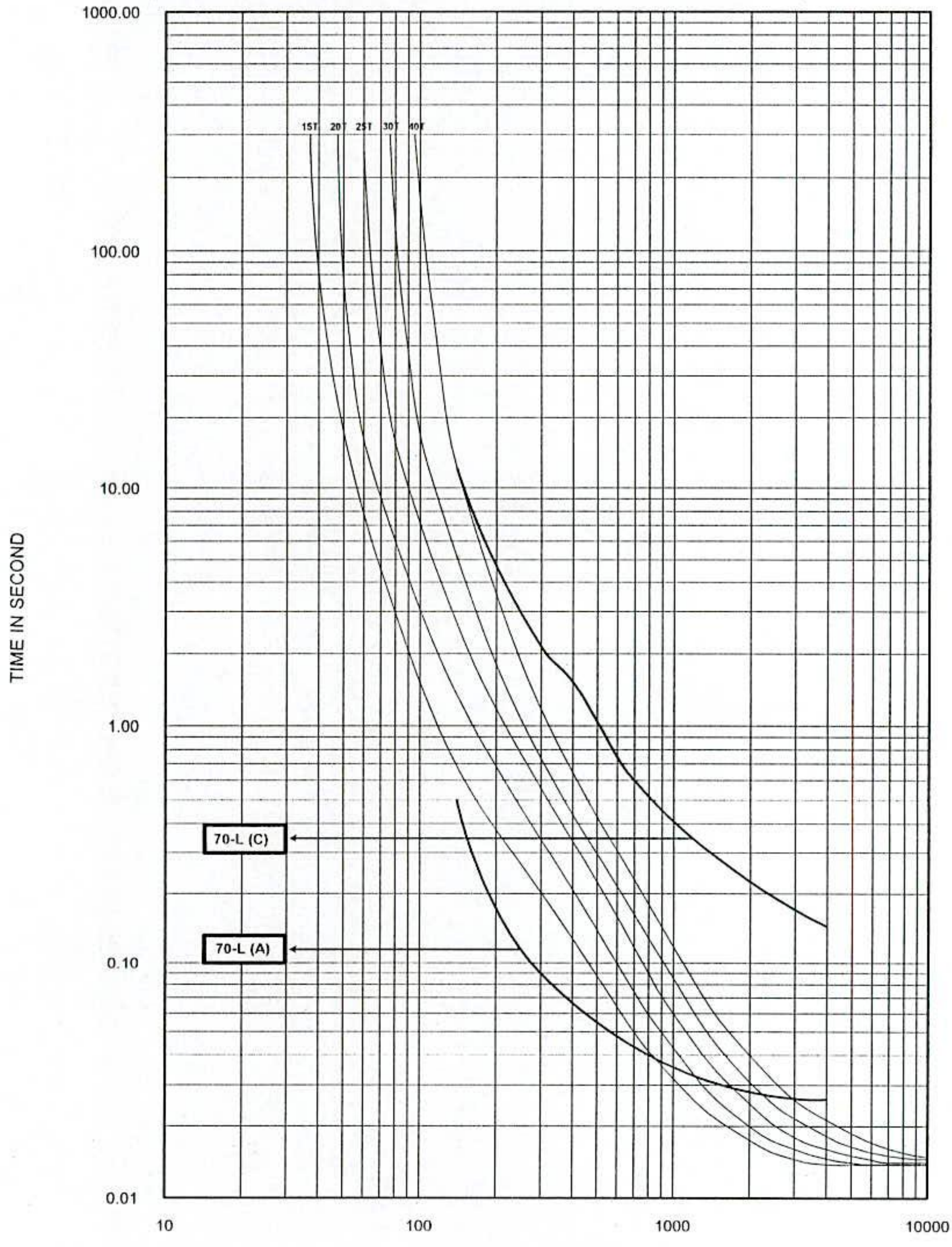


Figure 6.15g 70L ACR and fuses coordination

CO-ORDINATION BETWEEN 50-4H & 'T'- TYPE FUSES

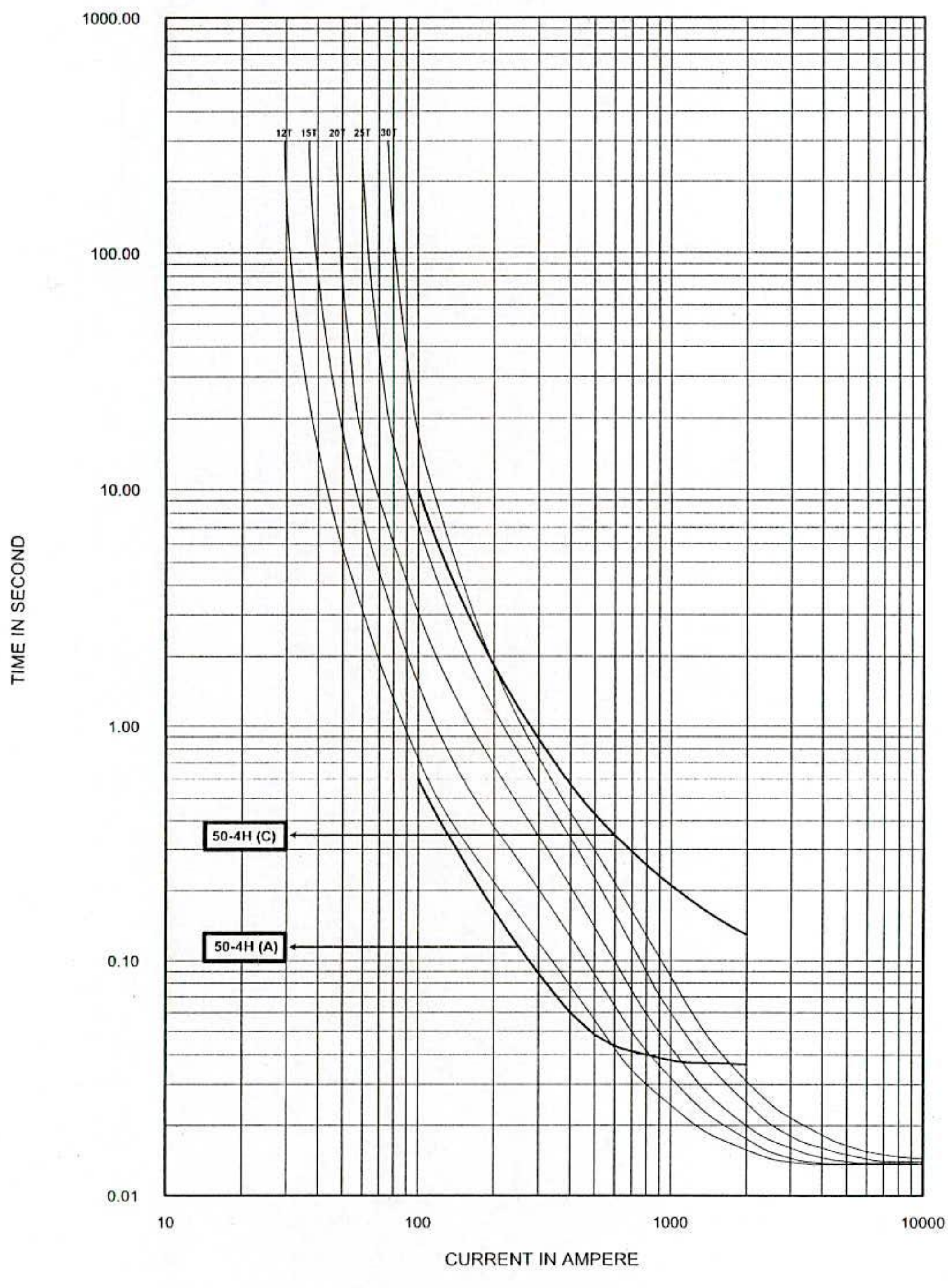


Figure 6.15h 50-4H ACR and fuses

CO-ORDINATION BETWEEN 35-4H & 'T'- TYPE FUSES

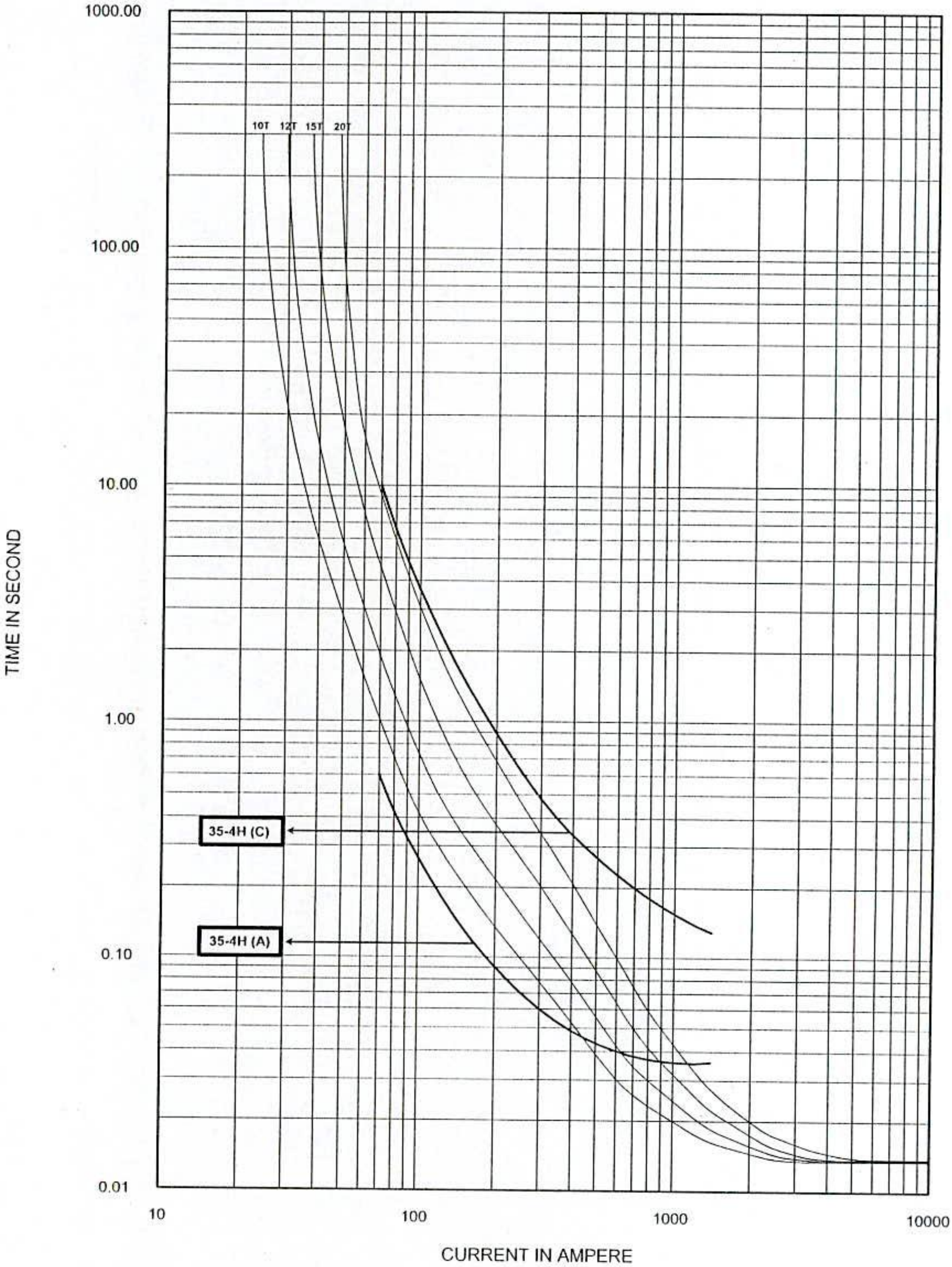


Figure 6.15i 35-4H ACR and Fuses Coordination

6.29 Justification of Proposed ACR

Circuit - A

ACR at Sub-Station Outgoing

Previously installed 100 RX ACR at the Sub-Station outgoing need no changing. Because the maximum and minimum fault currents of the sub-station out going are 2468 amps and 156 amps respectively and feeder current is 35.80 amps which are within the rated range of the 100 RX ACR. It is therefore, recommended to keep the existing 100 RX ACR at the sub-station out going.

ACR at Pole No. 20/1

The length of the tap is 9.98 km. At present there is no ACR for this tap. The line current of this tap is 21.03amps and the maximum and minimum fault currents at this node are 1793 amps and 154 amps respectively. So, it is recommended to install a new ACR of rating 70-L at pole no.20/1. At maximum fault current this ACR maintains good coordination with the sub-station ACR (100 RX). So the proposed 70-L ACR is suitable for continuous line current as well as maximum and minimum fault currents.

ACR at pole No. 42/1

The length of the tap is 4.54 km. At present there is no ACR for this tap. The line current of this tap is 7.22amps and the maximum and minimum fault currents at this node are 1327 amps and 150 amps respectively. So, it is recommended to install a new ACR of rating 50-4H at pole no. 42/1.At maximum fault current this ACR maintains good coordination with the sub-station ACR (100 RX). So the proposed 50-4H ACR is suitable for continuous line current as well as maximum and minimum fault currents.

ACR at Pole No. 86

The total length of the main line is about 13.26 Km. As per REB standard ACRs are to be installed at a distance of 6 to 8 Km. apart in main line. So, it is recommended to install a 35-4H ACR on pole no.86 i.e. about 7.11 km. apart from the sub-station. The line current at this node is only 2.80 amps and the maximum and minimum fault currents at this node are 937amps and 143amps respectively. At maximum fault current this ACR maintains good coordination with the sub-station ACR (100 RX). So the proposed 35-4H ACR is suitable for continuous line current as well as maximum and minimum fault currents.

Circuit - C

ACR at Sub-Station Outgoing

Previously installed 100 RX ACR at the Sub-Station outgoing need no changing. Because the maximum and minimum fault levels of the sub-station out going are 2468 amps and 156 amps respectively and feeder current is 48.44 amps, which are within the rated range of the 100 RX ACR. It is therefore, recommended to keep the existing 100 RX ACR at the sub-station out going.

ACR at Pole No. 70/1

The length of the tap is 8.39 km. At present there is no ACR for this tap. The line current of this tap is 17.55 amps and the maximum and minimum fault currents at this node are1111amps and 147 amps respectively. So, it is recommend installing a new ACR of rating 35-4H at pole no. 70/1. At maximum fault current this ACR maintains good coordination with the sub-station ACR (100 RX). So the proposed 35-4H ACR is suitable for continuous line current as well as maximum and minimum fault currents.

ACR at Pole No. 91

The total length of the main line is about 13.76 Km. As per REB standard ACRs are to be installed at a distance of 6 to 8 Km. apart in main line. So, it is recommended to install 35-4H ACR on pole no. 91 i.e. about 7.01 km. apart from the sub-station. The line current at this node is only 14.47 amps and the maximum and minimum fault currents at this node are 944amps and 143amps respectively. At maximum fault current this ACR maintains good coordination with the sub-station ACR (100 RX). So the proposed 35-4H ACR is suitable for continuous line current as well as maximum and minimum fault currents.

6.30 Recommendations for Feasible (Phase-I) Coordination

The following recommendations are made for the system studied.

1) 33 KV ACR (160 VWV 38X) is to be set for 1(A) curve for phase fault at H.T. side of the transformer and for ground fault 1(1-2) curve is to be used.

2) For phase fault at the L.T. side of the transformer 11 KV (100 RX) is to be set for 2A+2C curve for lock out and for ground fault to be set for 2(1-2) +2(2) curve for lock out.

3) Existing 125 E (standard speed) fuses are to be replaced by100 E (standard speed) fuses.

6.31 Results for Relay Curve Setting

After satisfying the feasibility conditions all the relays in the substation are coordinated graphically with the constraints of minimum coordination interval. The relay characteristic curves for optimal coordination of phase fault and ground fault are shown in Figure 6.13(b), 6.13(d), 6.14(b), 6.14(d),6.15(b) & 6.15(d).

The Proposed devices and curve settings are given in the following Table

For Circuit. – A

Table 6.13 List of ACR

Pole no.	Existing ACR		Proposed ACR		Remarks
	Size	Curve Setting	Size	Curve Setting	
Sub-Station	100-RX	2A+2C	100-RX	2A+2C	**Remain unchanged**
20/1			3 X 70-L	2A+2C	**To be newly installed**
42/1			3 X 50-4H	2A+2C	**To be newly installed**
86			3 X 35-4H	2A+2C	**To be newly installed**

b) For Circuit-C

Table 6.14 List of ACR

Pole no.	Existing ACR		Proposed ACR		Remarks
	Size	Curve Setting	Size	Curve Setting	
Sub-Station	100-RX		100-RX		**Remain unchanged**
70/1			3 X 35-4H		**To be newly installed**
91			3 X 35-4H		**To be newly installed**

6.32 Requirement of Devices for Proposed Coordination Scheme

List of ACR & Protective Devices

a) For Circuit. - A

Table 6.15 List of ACR

Existing device	Proposed ACR	Additional Requirement	Surplus	Remarks
100-RX = 1	100-RX = 1			
	70-L = 1 X 3	70-L = 1 X 3		
	50-4H = 1 X 3	50-4H = 1 X 3		
	35-4H = 1 X 3	35-4H = 1 X 3		

Circuit. -A

Table 6.16 List of Fuse

Pole No.	Existing Device		Proposed Fuse		Remarks
	Type	Nos.	Type	Nos.	
20/7/10A/L1			30T	3	**To be newly installed**
20/7/12A/1			30T	3	**To be newly installed**
20/7/42/R1			20T	3	**To be newly installed**
20/7/46/1			20T	3	**To be newly installed**
20/7/85/1			15T	3	**To be newly installed**
20/7/93/1			15T	3	**To be newly installed**
20/8			40T	3	**To be newly installed**
34/R1			40T	3	**To be newly installed**

Circuit. -A

Table 6.16 Contd. List of Fuse

Pole No.	Existing Device		Proposed Fuse		Remarks
	Type	Nos.	Type	Nos.	
34/L1			40T	3	To be newly installed
40/1			40T	1	To be newly installed
42/8/18/L1			25T	3	To be newly installed
42/8/33/L1			25T	3	To be newly installed
42/13/1			30T	3	To be newly installed
53/1			30T	3	To be newly installed
61/R1			30T	3	To be newly installed
61/L1			30T	3	To be newly installed
70/1			25T	3	To be newly installed
77/1			25T	3	To be newly installed
85/1			25T	3	To be newly installed
105/1			20T	3	To be newly installed
146/1			15T	3	To be newly installed
150/1			15T 3	3	To be newly installed

b) For Circuit - C

Table 6.17 List of ACR

Existing device	Proposed ACR	Additional Requirement	Surplus	Remarks
100-RX	100-RX 3 X 35-4H 3 X 35-4H	35-4H = 2 X 3		

Circuit – C of Baganchra S/S

Table 6.18 List of Fuse

Pole No.	Existing Device		Proposed Fuse		Remarks
	Type	Nos.	Type	Nos.	
22/1			65T	3	To be newly installed
29/1			50T	3	To be newly installed
32/1			50T	3	To be newly installed
36/1			50T	1	To be newly installed
38/1			40T	3	To be newly installed
43/1			40T	3	To be newly installed
55/1			30T	3	To be newly installed
57/1			30T	3	To be newly installed
61/R1			30T	3	To be newly installed
61/L1			30T	3	To be newly installed
70/6/R26/38/R1			15T	3	To be newly installed
70/6/R26/38/L1			15T	3	To be newly installed
70/6/R26/59/1			12T	3	To be newly installed
70/7			20T	3	To be newly installed
79/1			25T	3	To be newly installed
90/1			25T	3	To be newly installed
111/L1			20T	3	To be newly installed
128/1			20T	3	To be newly installed
128/12/1			12T	3	To be newly installed

6.33 Voltages at the Farthest End

a) For Circuit - A

Name of Feeder	Pole Number	Voltage Drop From S/S. at 230 base	Voltage (1 ØLT)	Distance From S/S
Circuit - A	S/S	0.000	241.500	0.00
	20	0.670	240.83	1.26
	42	1.062	240.438	3.25
	61	1.185	240.315	4.95
	77	1.264	240.236	6.39
	105	1.268	240.232	8.76
	146	1.472	240.028	12.00
	160	1.482	240.018	13.26

b) For Circuit - C

Name of Feeder	Pole Number	Voltage Drop From S/S 230 base	Voltage (1ØLT)	Distance From S/S
Circuit- C	S/S	0.000	241.500	0.00
	22	0.437	241.063	0.59
	38	1.530	239.97	2.12
	55	2.314	239.186	3.32
	70	3.280	238.22	5.06
	90	3.761	237.739	7.01
	128	4.363	237.137	10.46
	160	4.392	237.108	13.76

6.34 Voltage Drop Profile

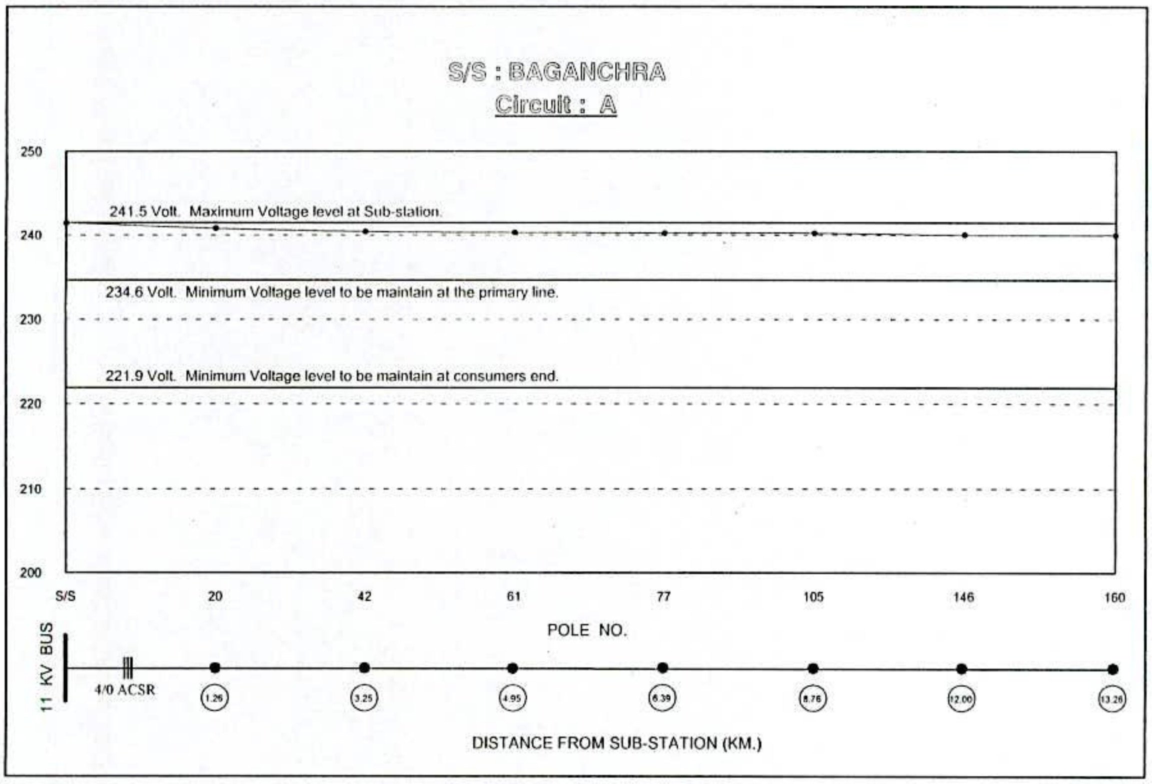


Figure 6.16a Voltage Drop Profile

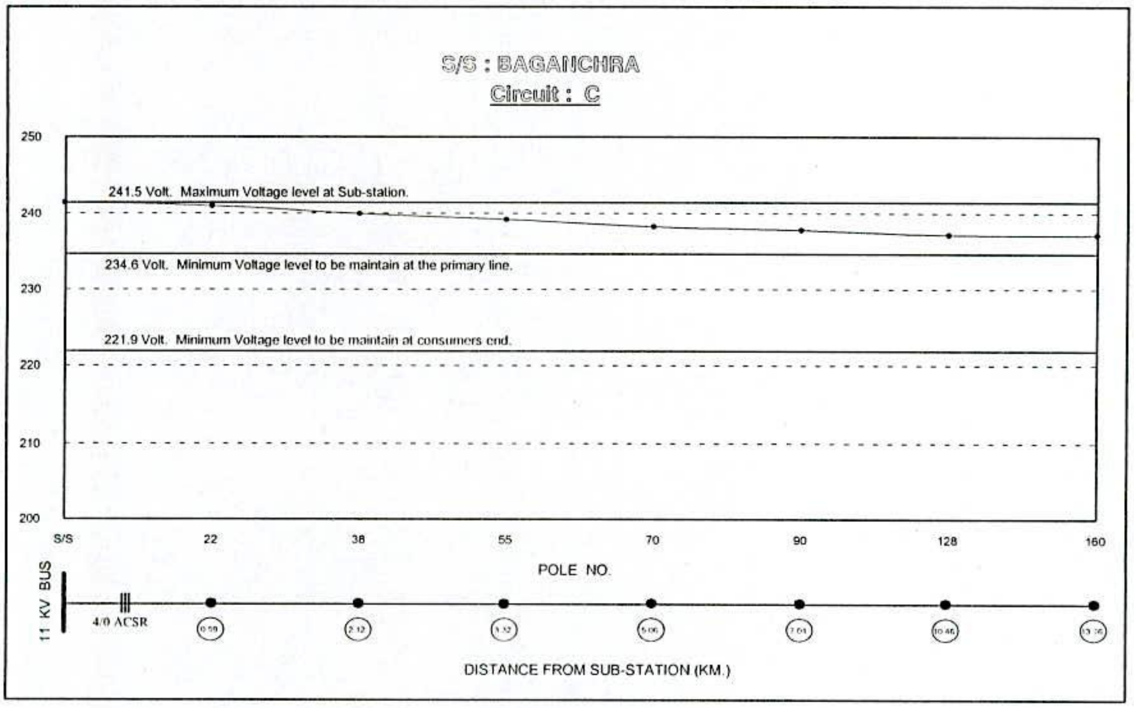


Figure 6.16 b Voltage Drop Profile

6.35 Analysis of Voltage Drop Profile

Circuit-A

The maximum voltage drop of Circuit-A of this Sub-Station occurs at pole no. 160 and the magnitude of the drop is 1.482 volts on 230 volts base. But the allowable drop on primary line at 230-volt base is only 6.9 volts [18]. So, further loading in this feeder is allowable.

Circuit-C

The maximum voltage drop of Circuit-C of this Sub-Station occurs at pole no. 160 and the magnitude of the drop is 4.392 volts on 230 volts base. But the allowable drop on primary line at 230volt base is only 6.9 volts [18]. So, further loading in this feeder is allowable.

6.36 Conclusion

Since the Voltage Drop of different feeders are within the permissible limit and there is adequate scope for further loading of the feeders, so installation of line voltage regulator for any feeder is not required at this stage.

CHAPTER-VII

Conclusion

7.1 Discussion

Methodologies have been described in this study for sectionalizing and coordination of protective devices in two radial distribution systems of Jessore PBS-1. Firstly feasibility of existing coordination schemes has been carried out by verifying the constraining conditions. In this case a number of proposals have been given to replace fuses, OCRs, ACRs, etc. by devices with proper ratings in articles 6.13, 6.14, 6.31 & 6.32. Change of devices has also been proposed.

a) After ensuring feasibility of existing devices the protection schemes coordination of the devices is done considering optimal performance. In the cases of miscoordination curve settings are changed as shown in article 6.13 & article 6.31 to ensure possible optimum operation.

Voltage drop calculation at far end points of different feeders has been carried out and recommendations are provided in article 6.19 and article 6.35. It has been observed that the far end voltage drop of feeders A, B, C & D under Topshidanga sub-station has exceeded permissible limit. Proposal for improving voltage level to an adequate limit has also been given in article 6.19

The study conducted in this thesis is based on sectionalizing the distribution schemes. The sectionalizer protects the feeder from branch faults to reduce outages and loss of revenue. Sectionalizers contribute the advantage of ease of returning to service.

7.2 Conclusion

The main objectives of this study were to propose a methodology for protection schemes and voltage drop compensation of radial distribution systems. Two case studies have been considered for the purpose. Based on impedance model of the distribution systems and connected loads the values of fault currents as faults occur at different sections of the system, maximum load currents and voltage drop were calculated. Nonlinear time current characteristic curves for the relays and fuses were used for coordination study. The main features of this study concerns the followings:

b) The protective devices in existing rural distribution system are not properly coordinated.

c) A simple methodology to coordinate the protective devices of radial distribution system is presented.

d) The modification of system protection scheme is done through proper fuses and ACRs.

e) Non feasible protective devices are detected and replacements are proposed.

f) Changes in curve settings are done to ensure possible optimum operation.

f) The relay setting and coordination technique described in this thesis can be used to obtain proper coordination between the protective devices provided in a distribution system

g) The voltage drop study technique described in this thesis can be used to improve the voltage level of the distribution system.

h) The technique described in this thesis reduces unwanted interruption, decreases system loss, increases consumer's satisfaction, saves equipment and conductors life and over all increases the system reliability.

7.3 Recommendation for Further Research

It has been observed that studies on radial distribution schemes are minimal. However, this system covers major distribution sector in Bangladesh. Therefore, extended research in this field is suggested. The major areas that may be covered by further research are listed below:

a) Relay TCC curves may be modeled by non-linear power series
b) Linear Programming software may be used for the whole system for optimization
c) The line and transformers may be modeled more accurately considering resistance, inductance and capacitance effects.
d) Tie lines for distribution schemes may be used and reliability may be assured.
e) Loss model of radial systems may be considered to evaluate the system loss of distribution systems.

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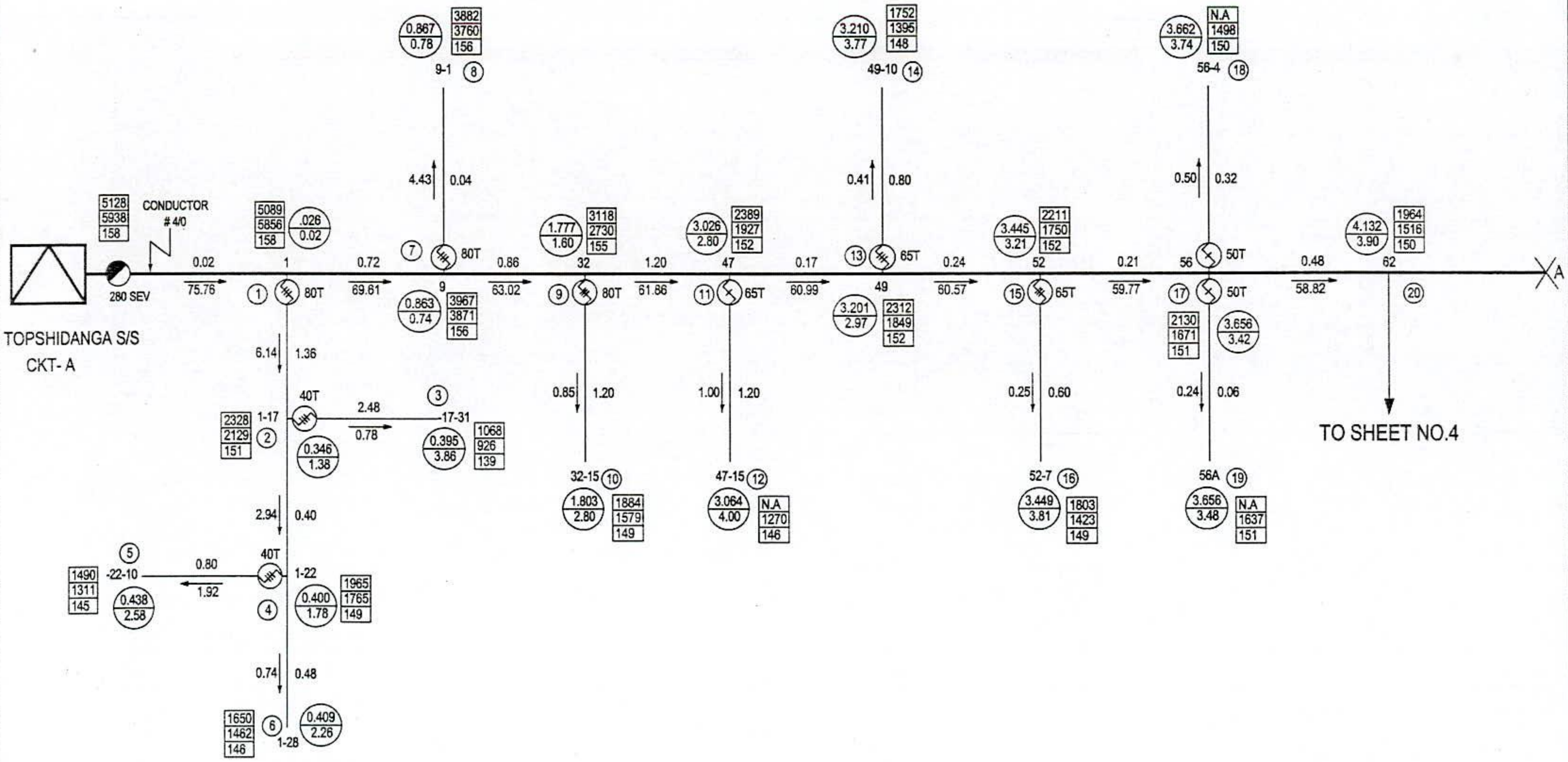

TOPSHIDANGA SUB-STATION

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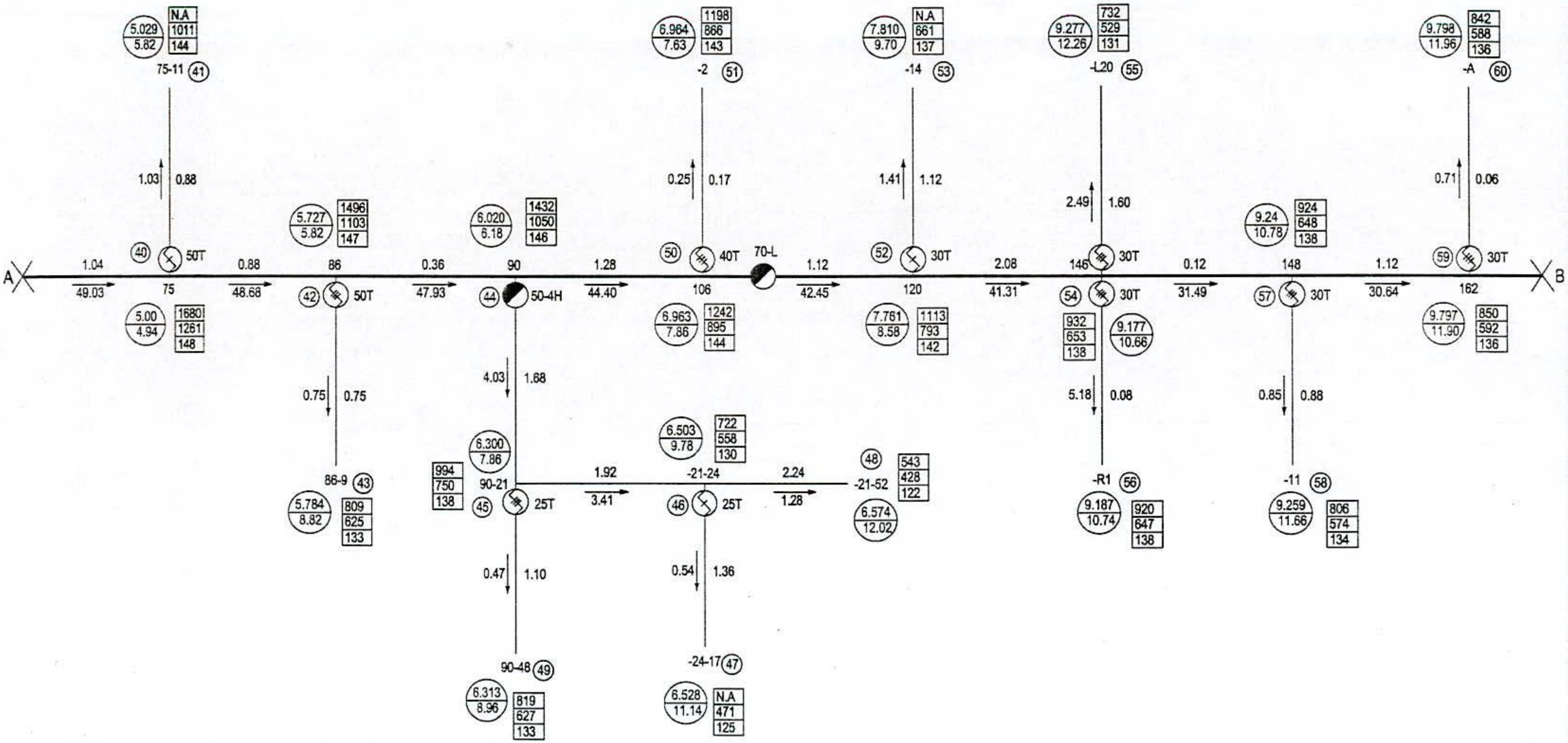

TOPSHIDANGA SUB-STATION

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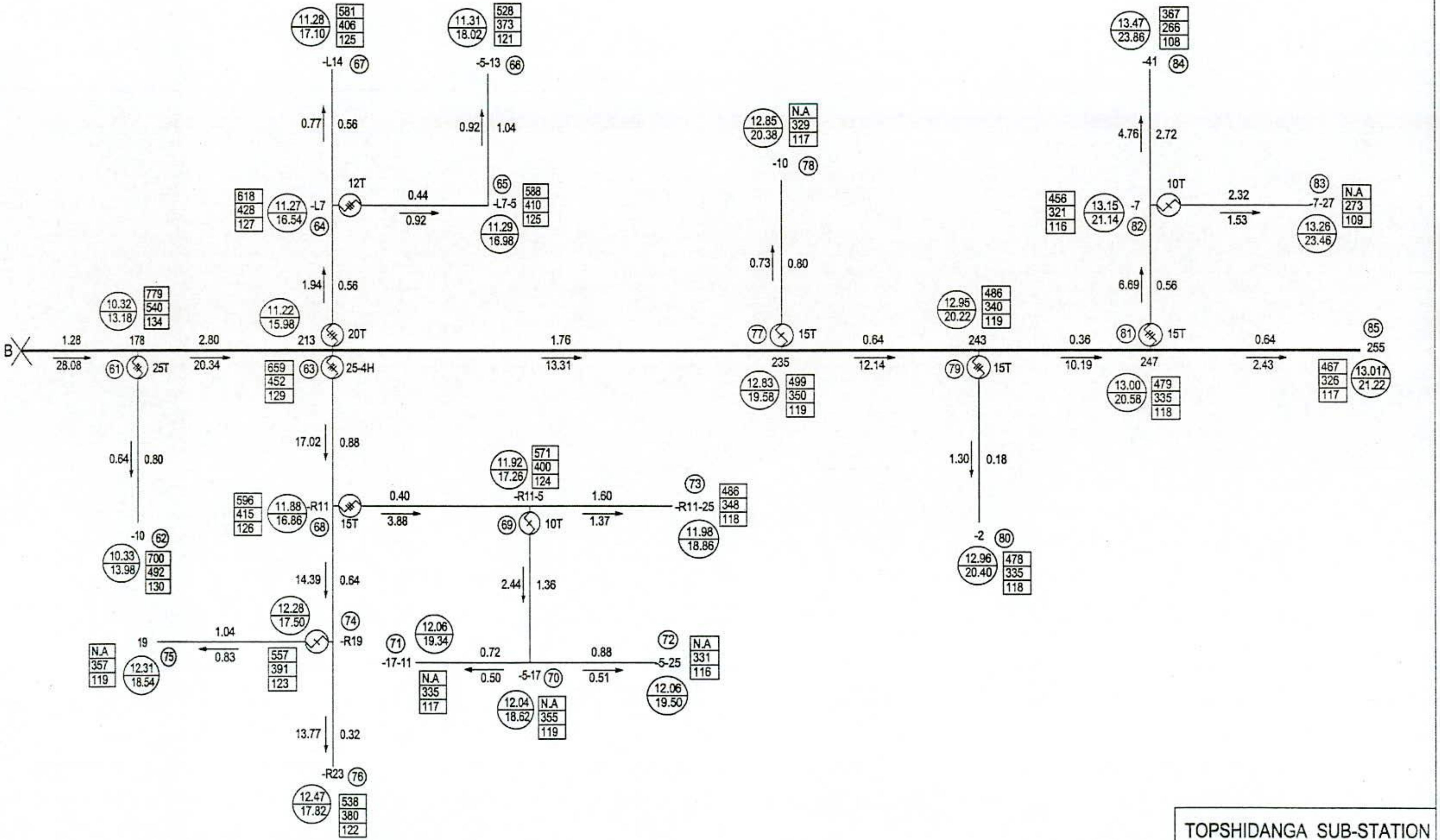

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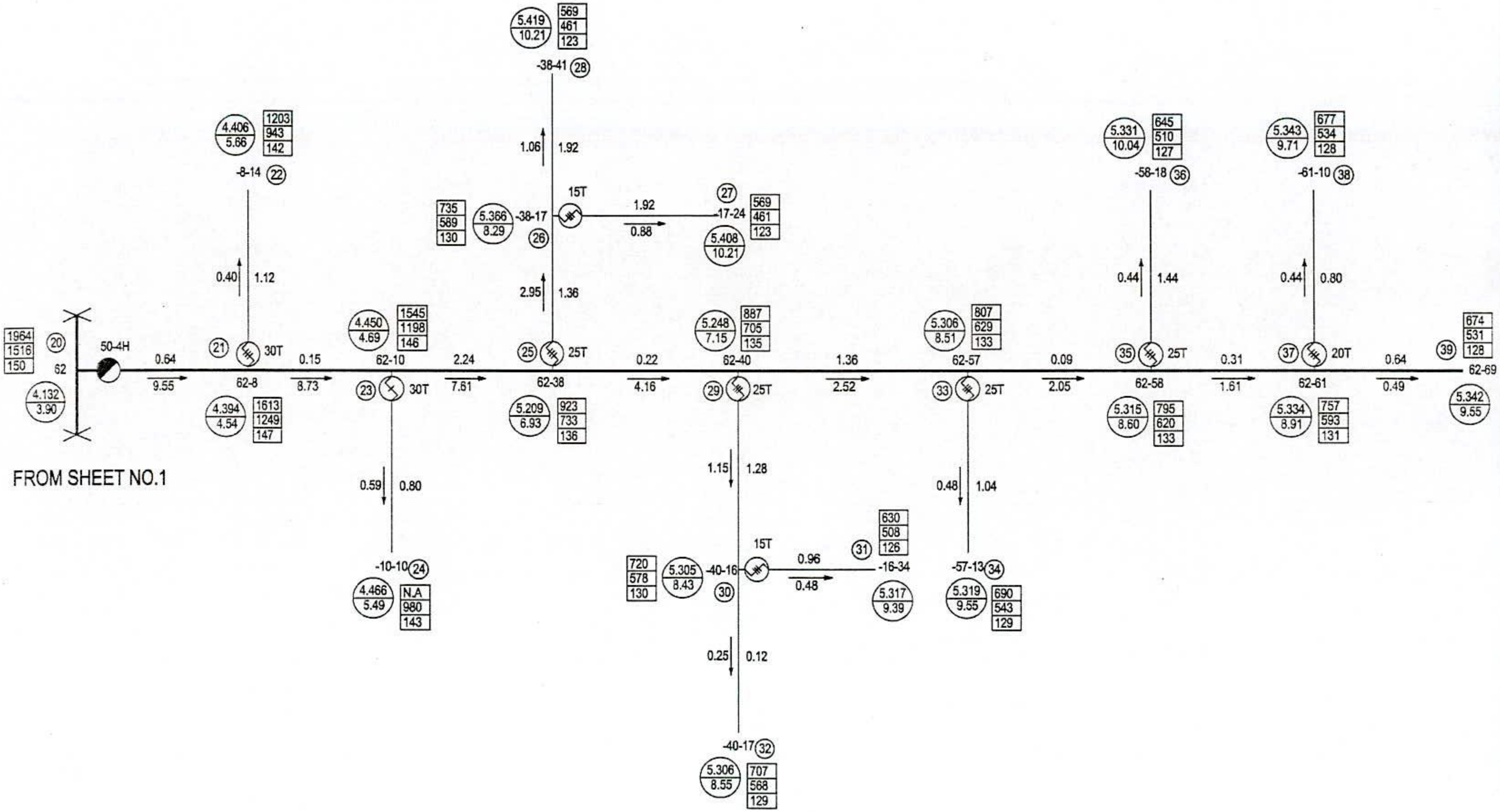

TOPSHIDANGA SUB-STATION

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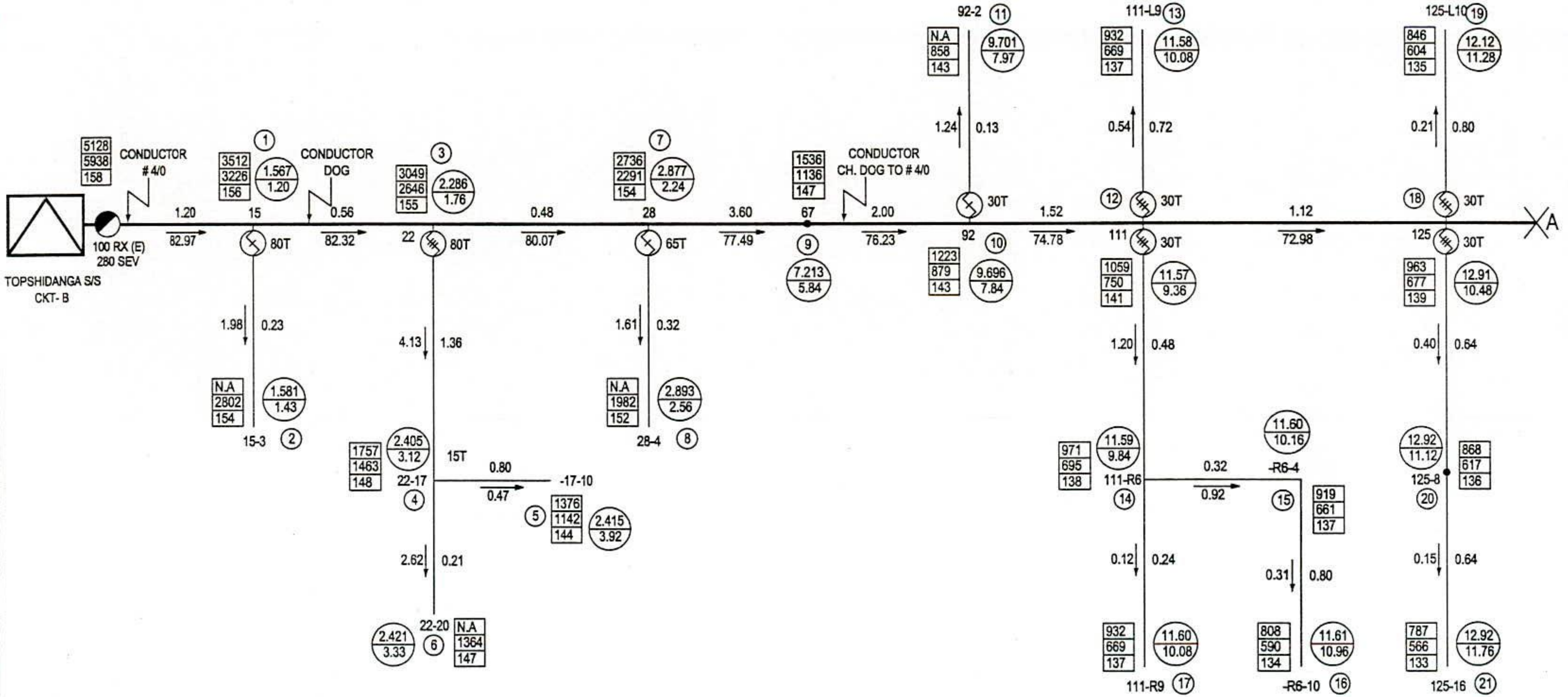

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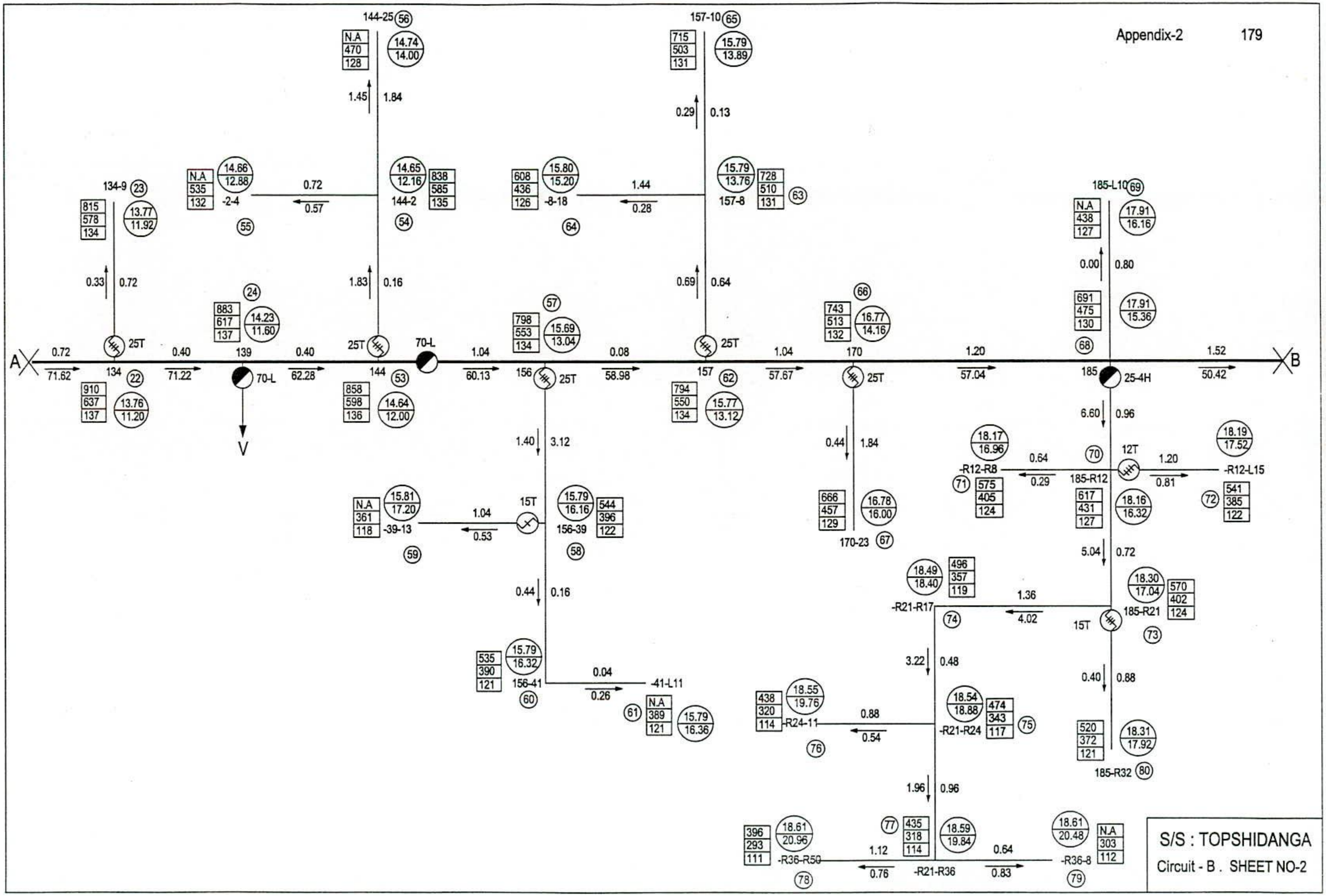
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V
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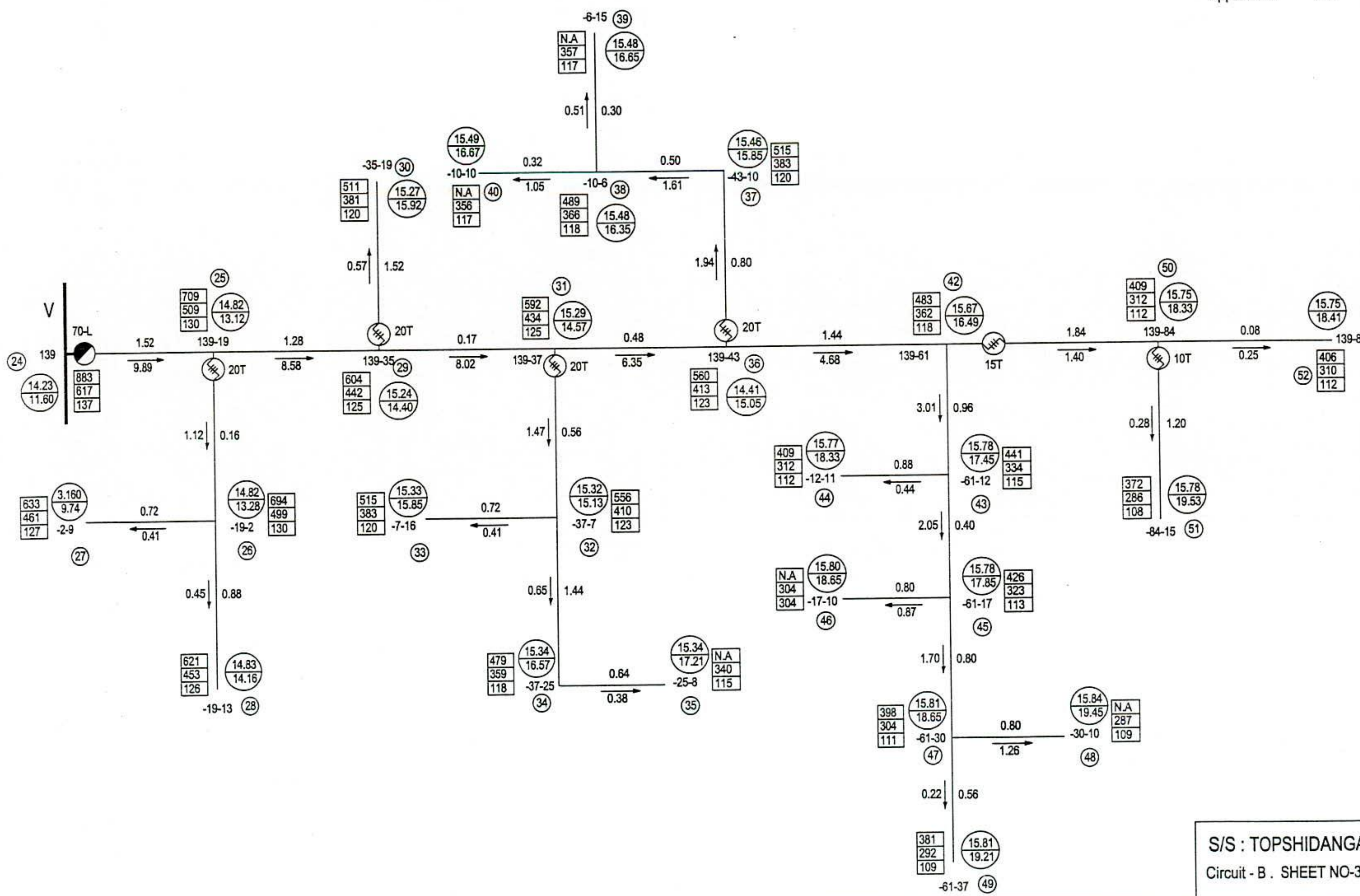

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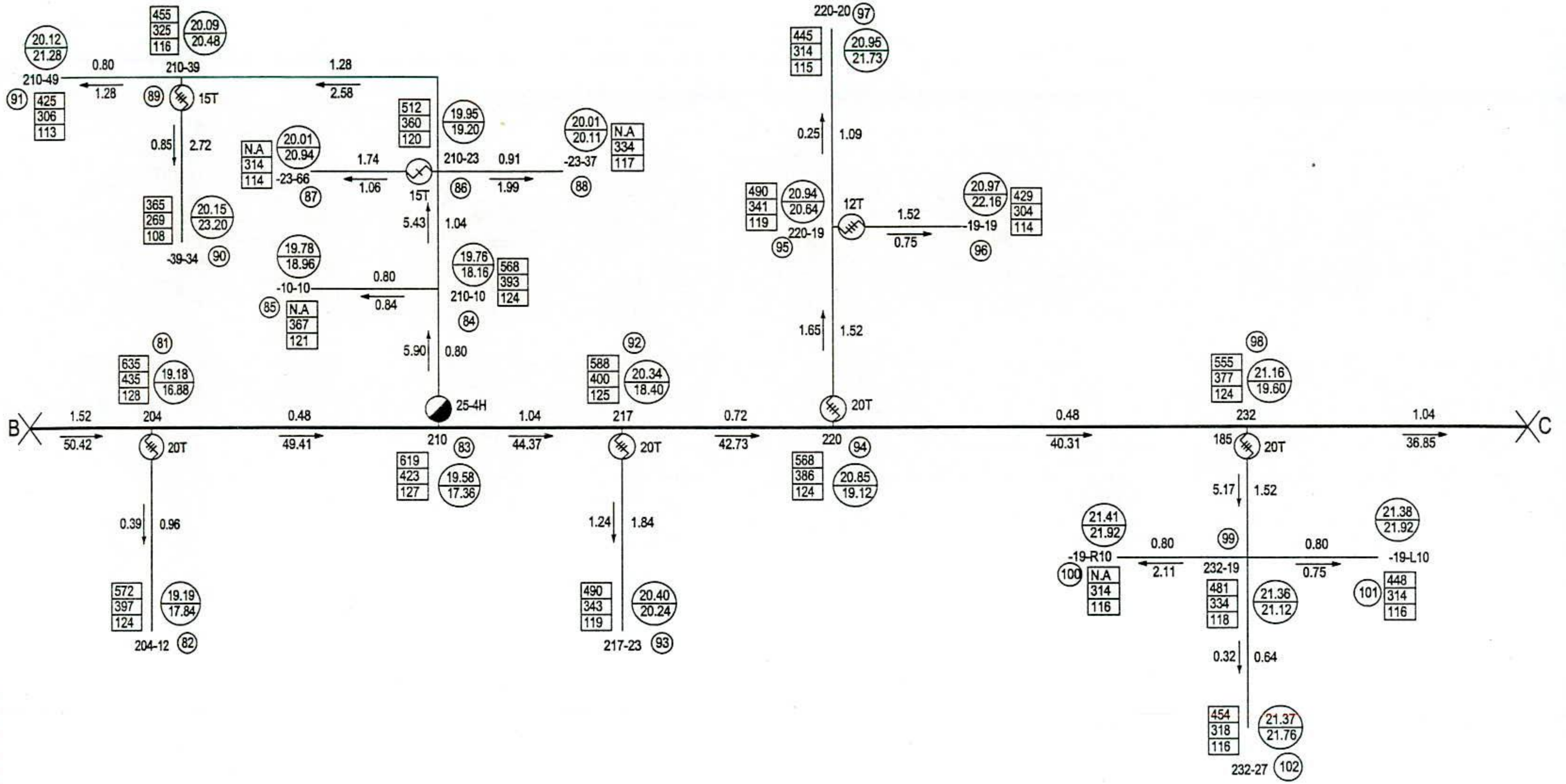

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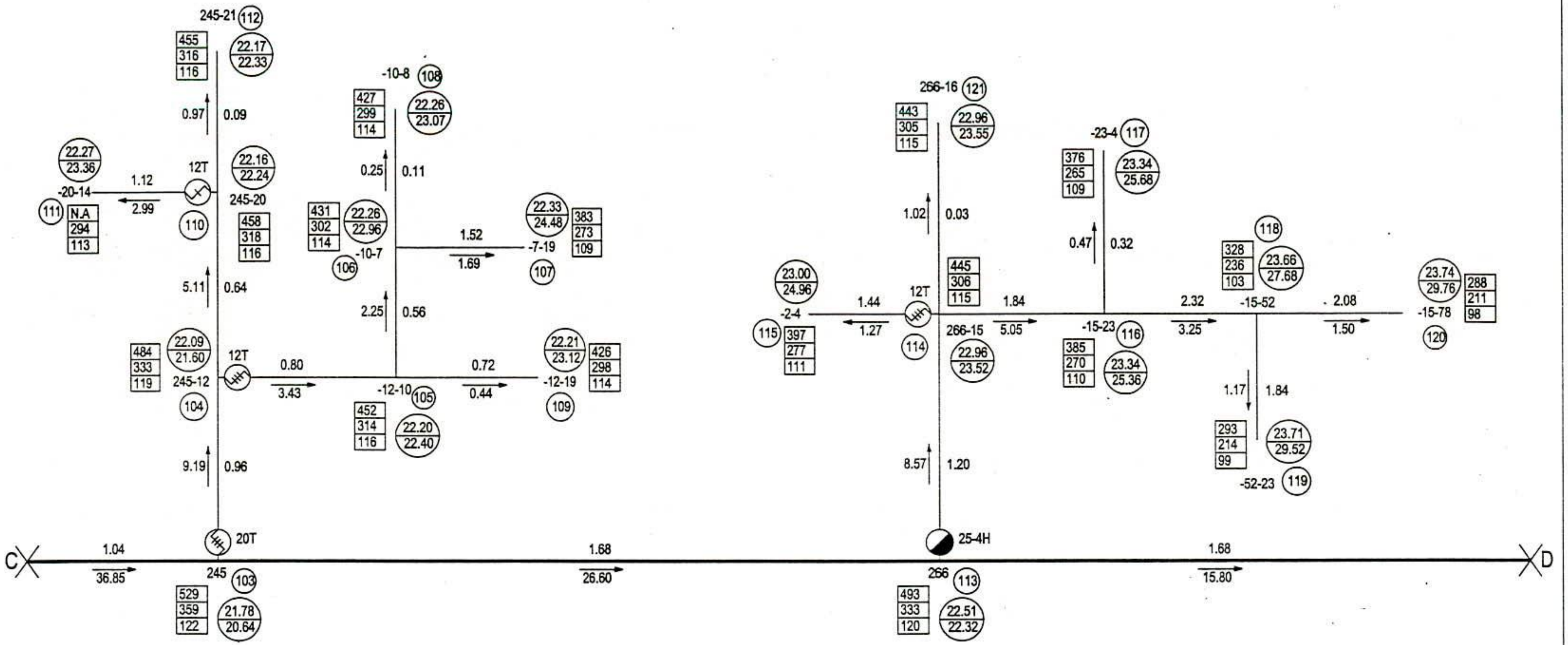

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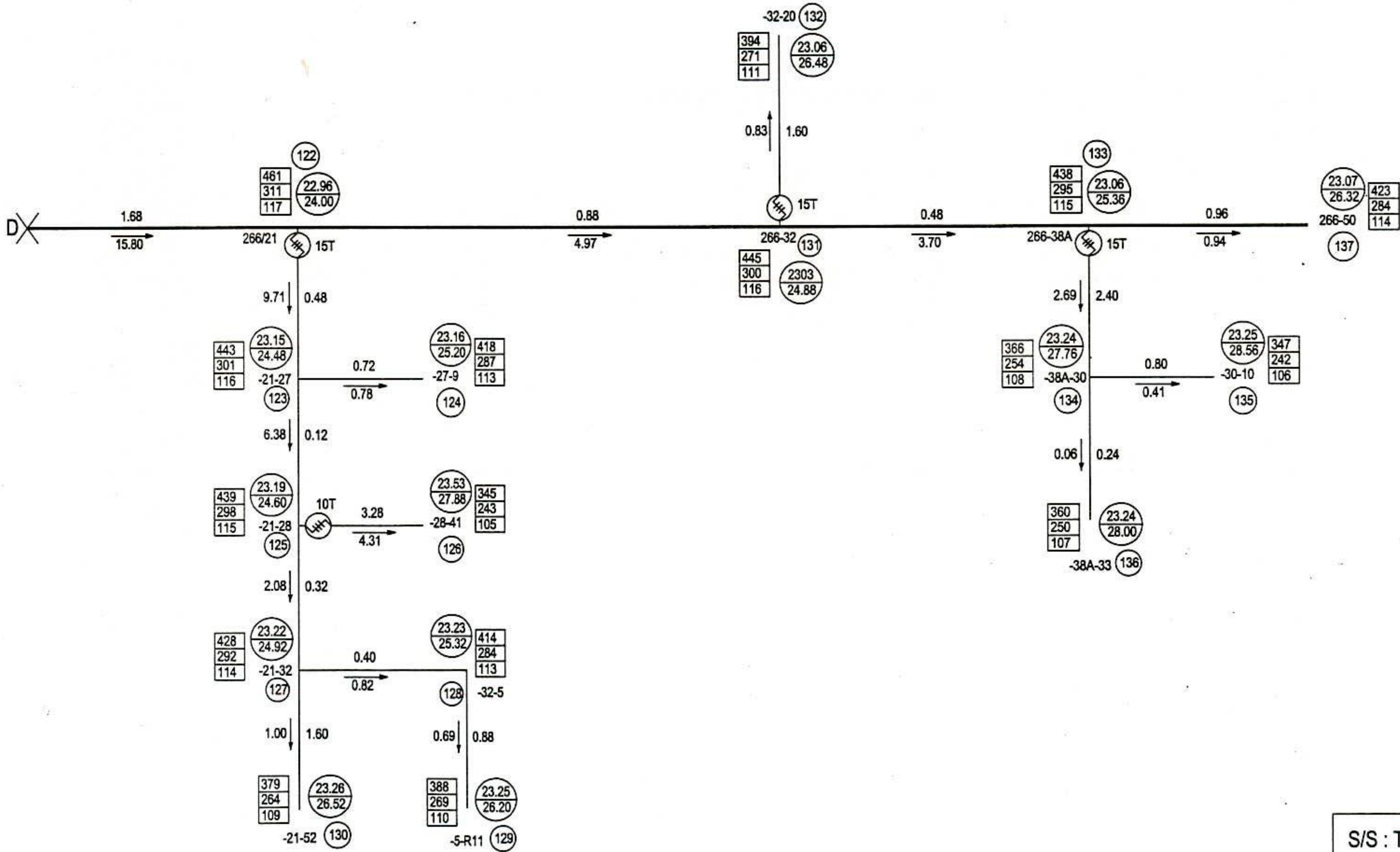

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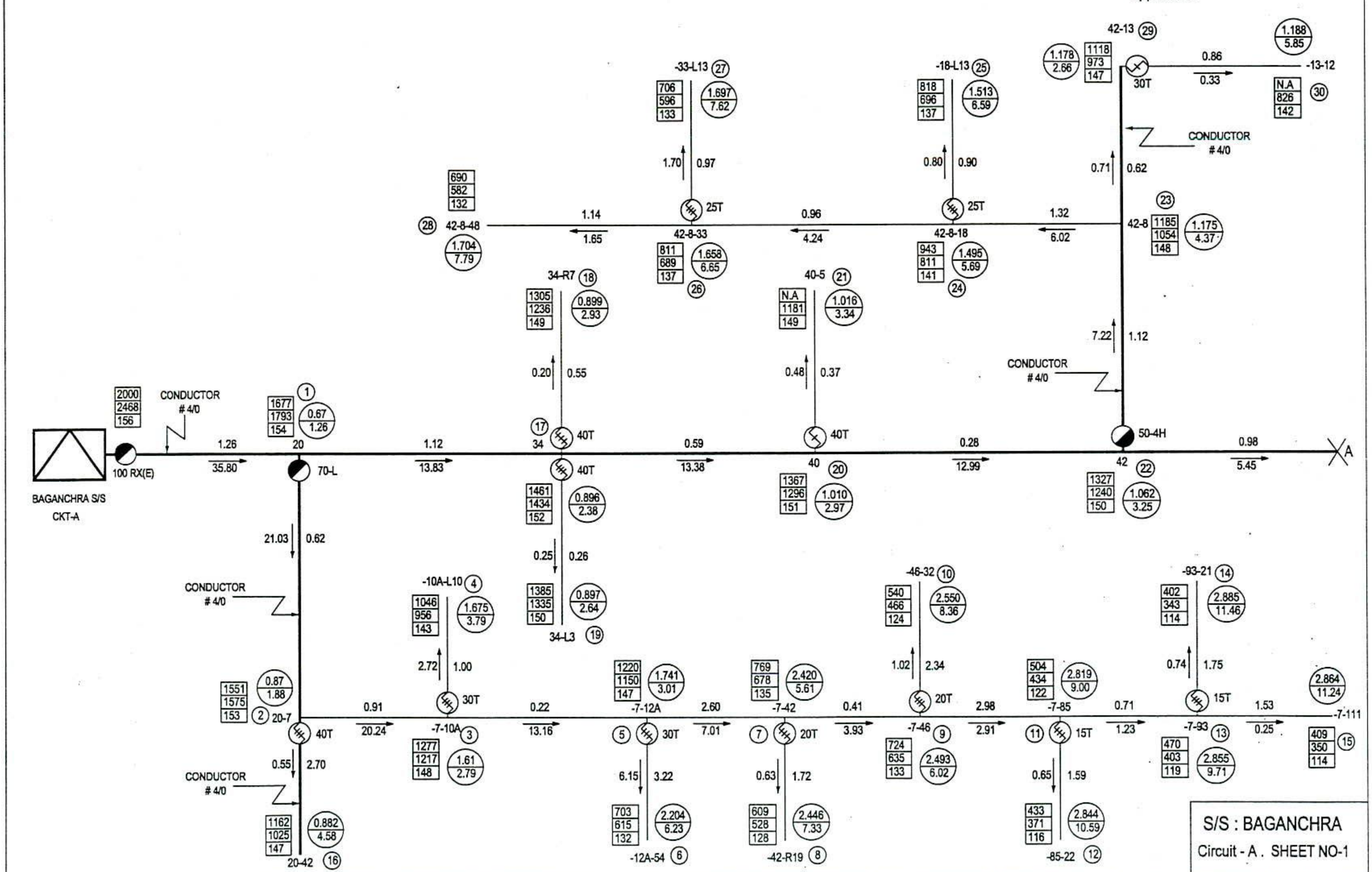
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CKT-A
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100 RX(E)
CONDUCTOR # 4/0
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(1) 1677 1793 154 0.67 1.26
20 70-L
1.12 13.83
(17) 34 40T
34-R7 (18) 1305 1236 149 0.899 2.93
0.20 0.55
40T 1461 1434 152 0.896 2.38
0.25 0.26
1385 1335 150 0.897 2.64
34-L3 (19)
0.59 13.38
40 (20) 1367 1296 151 1.010 2.97
40T
40-5 (21) N.A 1181 149 1.016 3.34
0.48 0.37
0.28 12.99
50-4H 42 (22) 1327 1240 150 1.062 3.25
0.98 5.45 A
CONDUCTOR # 4/0
7.22 1.12
42-8 (23) 1185 1054 148 1.175 4.37
1.32 6.02
42-8-18 943 811 141 1.495 5.69 (24)
25T
0.80 0.90
-18-L13 (25) 818 696 137 1.513 6.59
0.96 4.24
42-8-33 811 689 137 1.658 6.65 (26)
25T
1.70 0.97
-33-L13 (27) 706 596 133 1.697 7.62
1.14 1.65
(28) 42-8-48 690 582 132 1.704 7.79
0.71 0.62
CONDUCTOR # 4/0
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30T
0.86 0.33
-13-12 1.188 5.85 N.A 826 142 (30)
21.03 0.62
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1551 1575 153 (2) 20-7 0.87 1.88
40T
0.55 2.70
CONDUCTOR # 4/0
1162 1025 147 0.882 4.58
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0.91 20.24
-7-10A (3) 30T 1277 1217 148 1.61 2.79
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-10A-L10 (4) 1046 956 143 1.675 3.79
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(7) -7-42 20T 769 678 135 2.420 5.61
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0.41 3.93
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-46-32 (10) 540 466 124 2.550 8.36
2.98 2.91
(11) -7-85 15T 504 434 122 2.819 9.00
0.65 1.59
433 371 116 2.844 10.59
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0.74 1.75
-93-21 (14) 402 343 114 2.885 11.46
1.53 0.25
-7-111 409 350 114 (15) 2.864 11.24
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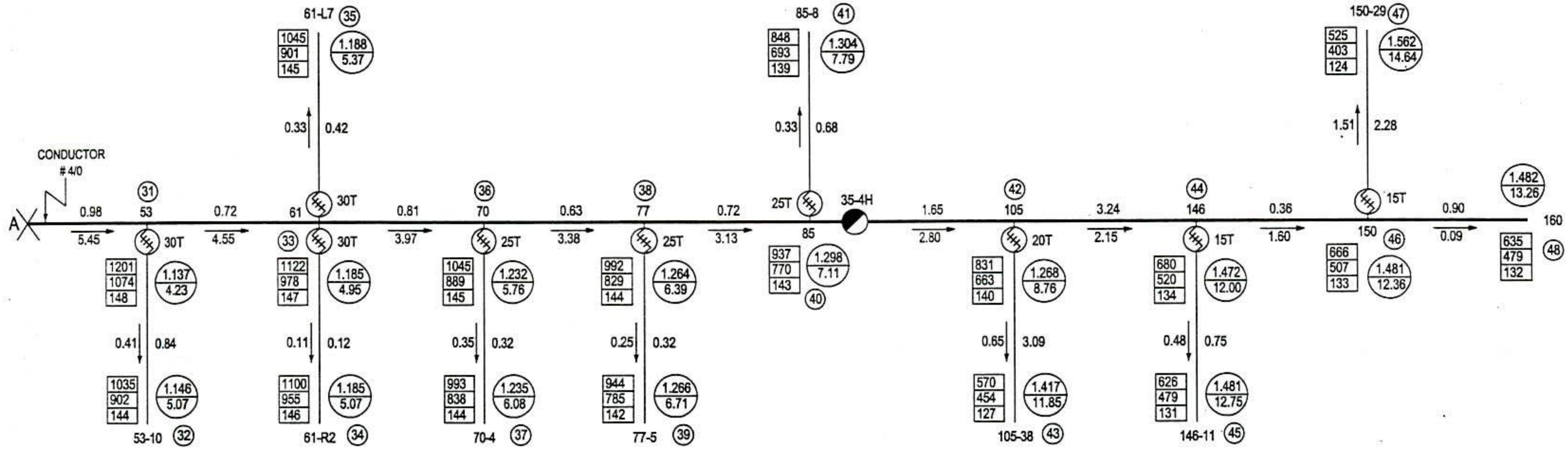

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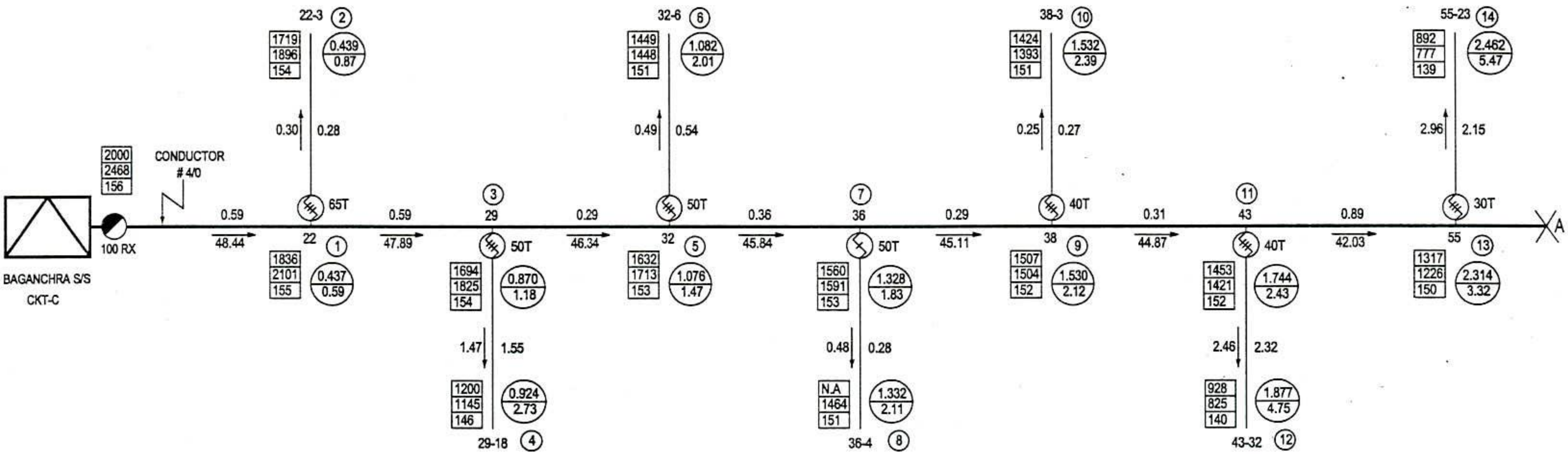

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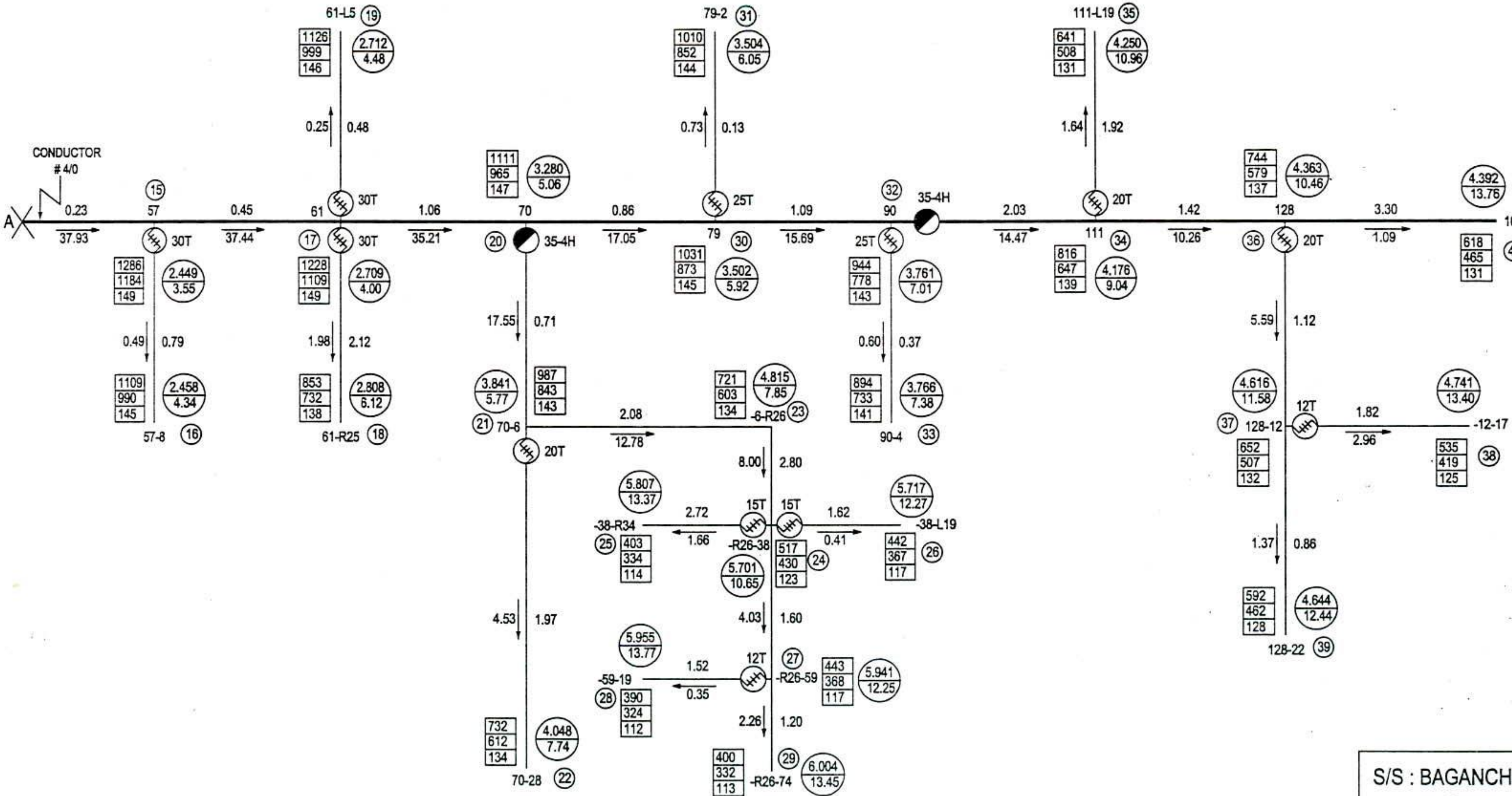

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Department of Electrical & Electronic Engineering.

We hereby recommended that the thesis report prepared by
Santosh Kumar Das.
Entitled, "A Study on Sectionalizing and Coordination of Protective Devices and Voltage Drop Compensation of Rural Distribution System".

9.5.02

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