

DISTRIBUTION DEVICE COORDINATION

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SYSTEM OVERVIEW

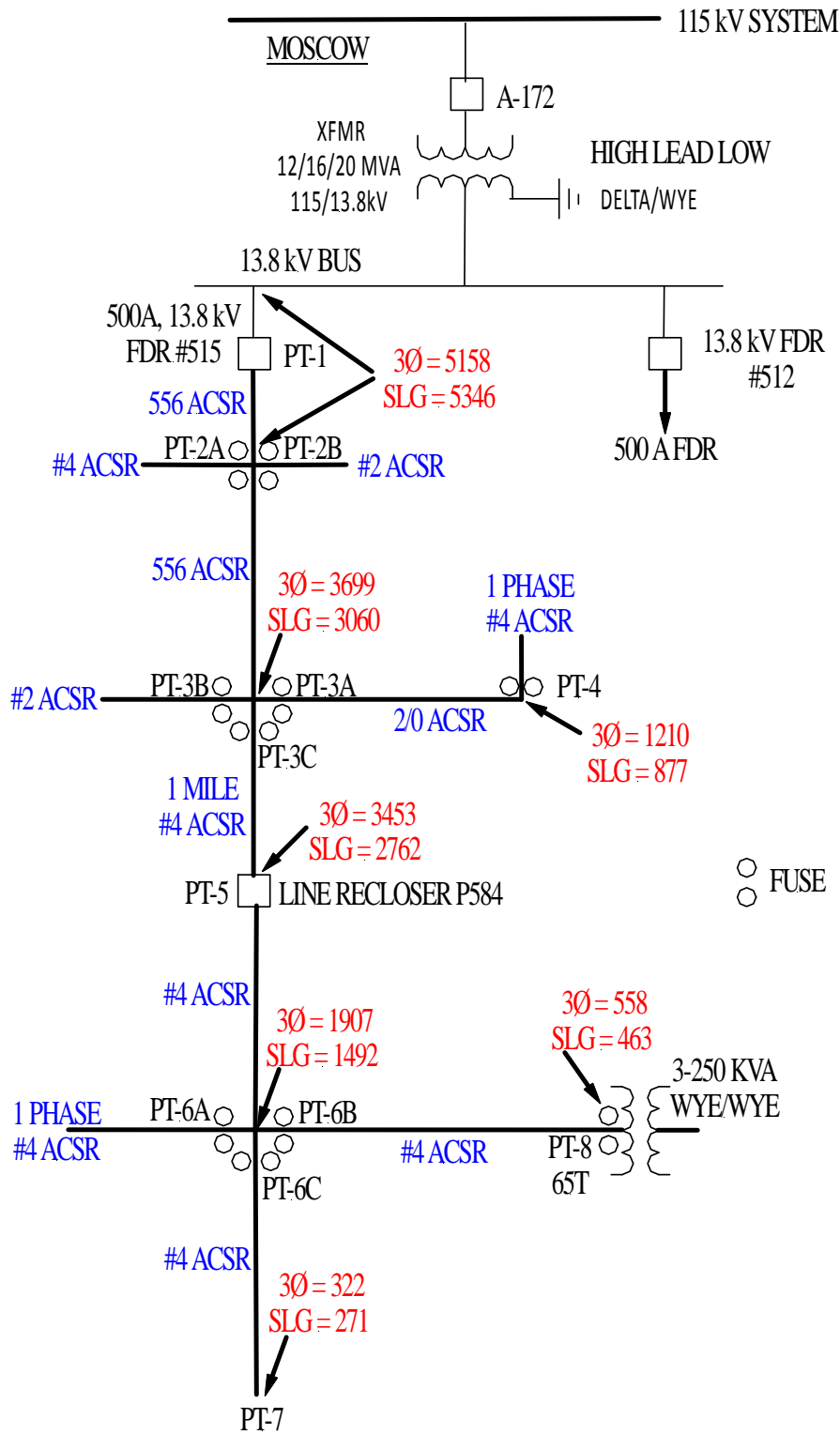


Figure 1. System Overview of a Typical 115/13.8 kV Substation and a 13.8 kV Distribution Feeder. – Used to work problem at end of paper.

SYMMETRICAL COMPONENTS

Three Phase 13.8 kV Fault

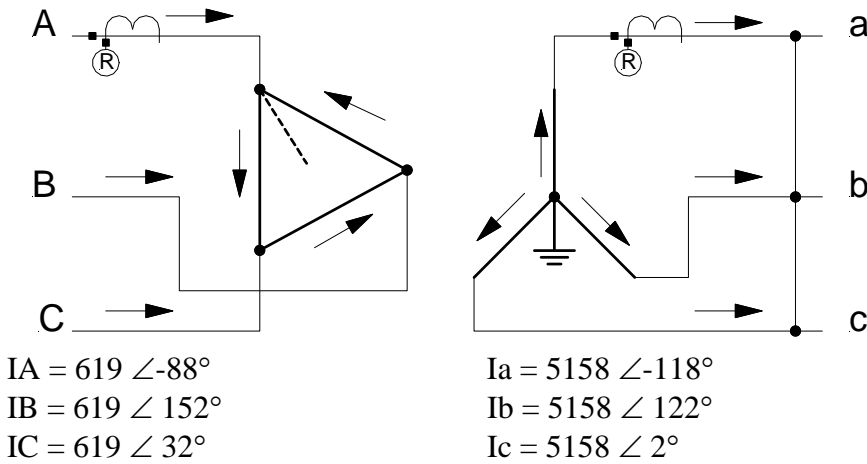


Figure 2. Current distribution through a Delta-Wye high lead low transformer bank for a three phase 13.8 kV fault.

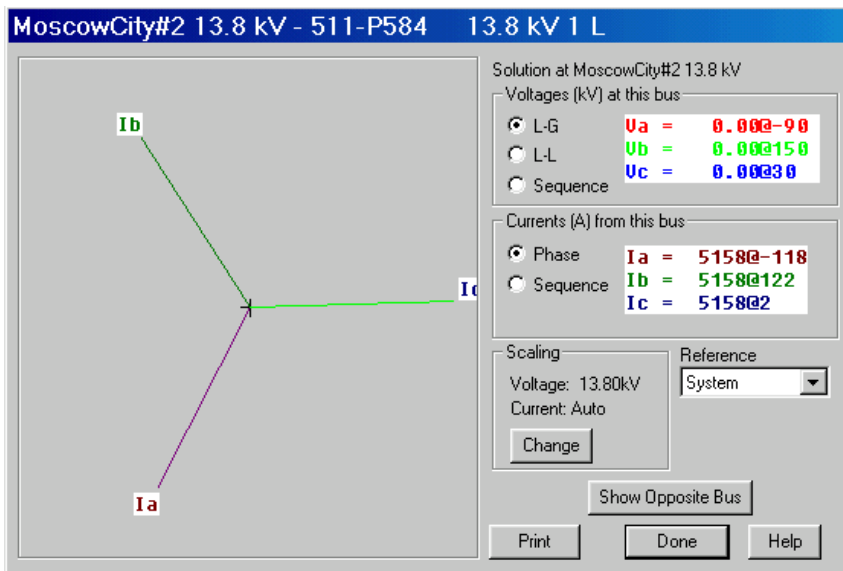


Figure 3. 13.8 kV **phase** currents for a 13.8 kV **three-phase** bus fault at Moscow.

The formula for calculating a three phase fault magnitude is: $I_a = I_b = I_c = V_n \div Z_{1n}$ (Z_1 or Z^+) in Ω where:

- V_n (V_a , V_b or V_c) is the line to neutral voltage at the fault. You only have **positive sequence** voltage and current since the system is balanced. That is; $I_a = I^+$. The current angles are referenced to the system, which in this case is the 115 kV (see Figure 4).

SYMMETRICAL COMPONENTS

- Z_1 is the line to neutral positive (balanced) sequence impedance (series resistance and reactance) of the system (all generators, transformers and lines) to the point of fault. Here it is made up of the entire Avista system Z_1 + the Z_1 of the Moscow xfmr.
- The current will lag (with an ABC CCW rotation) the voltage by the Z_1 system inductive impedance angle of the system (here, that's 88°). NOTE: Since the voltage is zero at the fault, the angle as given by ASPEN does not represent the normal voltage angle.
- A three phase fault is similar to balanced load where the three currents are equal and 120° apart. Of course for a load, typically the current angle would be very close to the voltage angle.

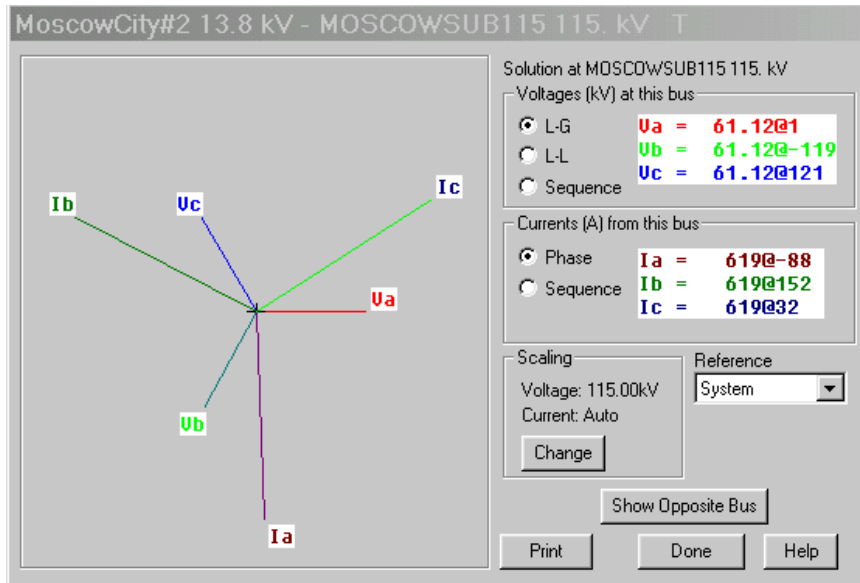


Figure 4. 115 kV **phase** currents and voltages for the 13.8 kV bus **three-phase** fault at Moscow.

- The current magnitudes are equal to the 13.8 kV currents divided by the transformer ratio of $115/13.8 = 8.33$ or $5158/8.33 = 619$ amps. This is the **line** current flowing in the line connected to the transformer and not what is flowing in the transformer windings. This is the current that a relay would see from a CT on the transformer high side bushing or a fuse would see.
- Note the current angles lead the 13.8 kV current angles by 30° . That's because this transformer is connected high lead low (where the high side voltages lead the low side voltages for an ABC CCW rotation).
- Also note that V_a is at 0° because ASPEN made the 115 kV system the reference for the system and the voltage magnitudes are about 92% of normal. Normal is $115 \text{ kV} \div \sqrt{3} = 66.4 \text{ kV}$ and $61.1 \div 66.4 = 0.92$.

Single Line to Ground 13.8 kV Fault

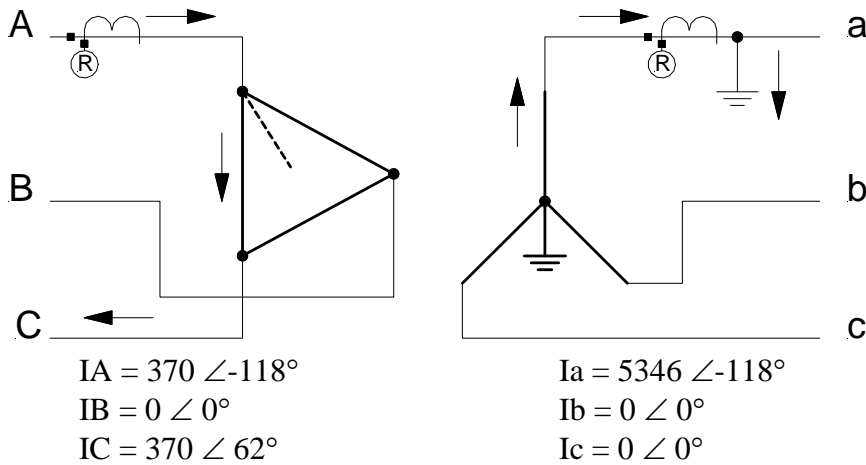


Figure 5. Current distribution through a Delta-Wye high lead low transformer bank for a phase A single line to ground 13.8 kV fault.

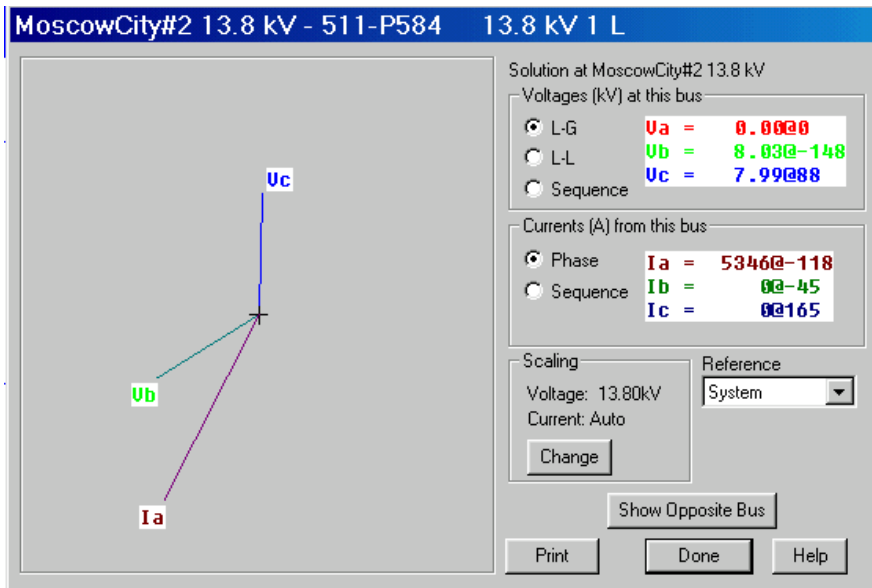


Figure 6. 13.8 kV **phase** voltages and currents for a 13.8 kV **single line to ground (SLG)** bus fault on phase A at Moscow.

The formula for calculating a SLG fault magnitude on Phase A is: $I_a = 3V_a / (Z_1 + Z_2 + Z_0)$ where:

- V_a is again the line to neutral voltage at the fault.
- Z_1 is the line to neutral positive sequence impedance of the system.
- Z_2 is the line to neutral negative sequence impedance of the system (which is normally = to Z_1).
- Z_0 is the line to neutral zero sequence impedance of the system. This is generally a different value from Z_1 or Z_2 because it includes the impedance of any neutral wires and the

SYMMETRICAL COMPONENTS

ground plane. Here, since the transformer is connected delta on the 115 kV, we can only use the transformer Z0 (and not the Avista system Z0) because there is no ground connection from the transformer to the 115 kV system.

- Because the Z0 of the transformer is less than the total Z1 (system + transformer), the SLG fault is slightly higher than the three-phase fault (5346 A vs. 5158 A).
- The current will lag the voltage by the Z1, Z2 & Z0 system inductive impedance angle of the system (again 88°). NOTE: Since the phase B & C voltages are not zero, their angles are correct.
- 3I0 is the sum of the 3 phase currents and since $I_b \text{ \& } I_c = 0$, then $3I_0 = I_a$. This means the phase and ground overcurrent relays on the feeder breaker see the same amount of current.

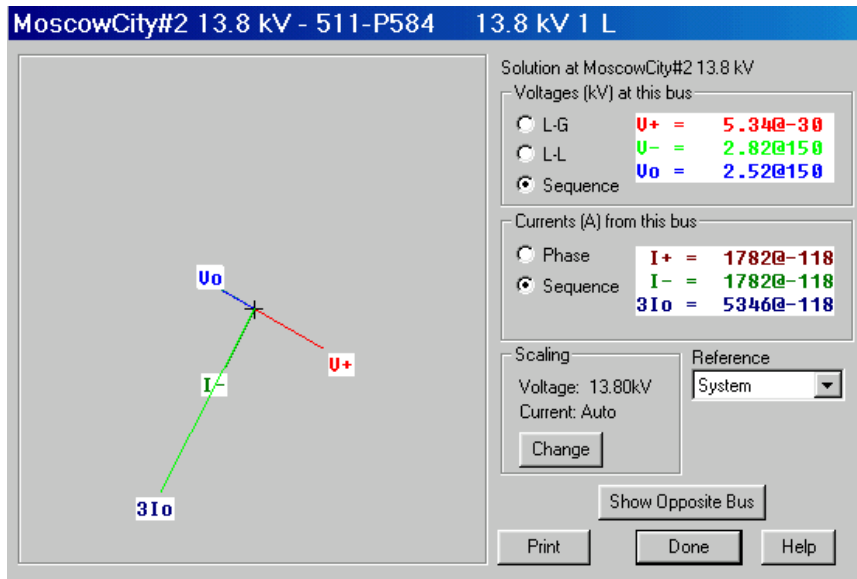


Figure 7. 13.8 kV **sequence** voltages and currents (positive, negative and zero) for a 13.8 kV **SLG** bus fault on phase A at Moscow.

- Note that V^- & V_0 are $= \frac{1}{2}$ of V^+ and in the opposite direction so that $V_a = 0$ at the point of fault.
- Note that I^+ (I_1) & I^- (I_2) are at the same angle as $3I_0$ (which is the same as I_a) and $I_a = 3I_0 = I^+ + I^- + I_0$ and $I^+ = I^- = I_0$.

SYMMETRICAL COMPONENTS

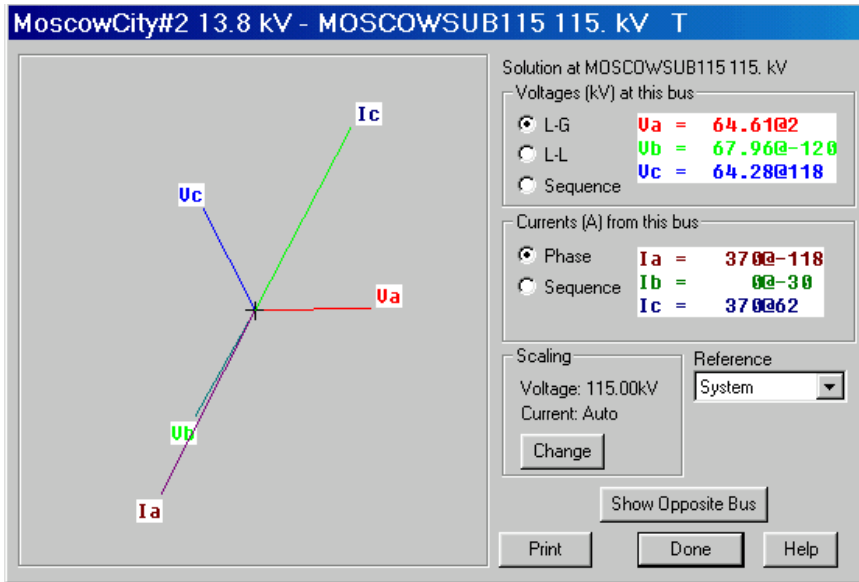


Figure 8. 115 kV **phase** voltages and currents for a 13.8 kV **SLG** fault on phase A at Moscow.

Note I_a still leads the 13.8 kV I_a by 30° (-118°) the same as the three phase fault. Also note that I_a is much less than the I_a for a three-phase fault. That's because I_0 can't flow on the 115 kV system for a SLG on the 13.8 kV (I_0 circulates in the delta). The calculation is: $5346 / (8.33 * \sqrt{3}) = 370$ amps. In other words the high side phase current is the $\sqrt{3}$ less than it was for the 3ϕ fault. $5346 =$ the 13.8 kV A phase current. 8.33 is the transformer ratio.

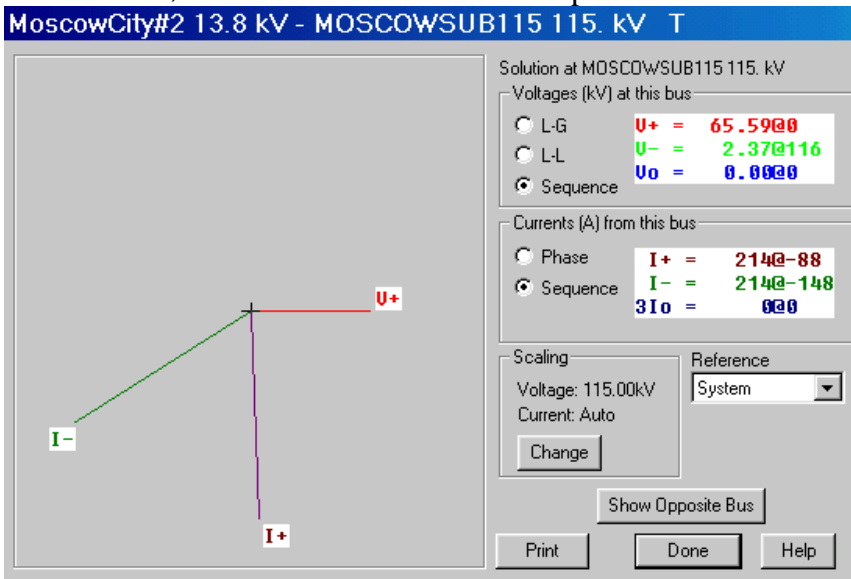


Figure 9. 115 kV **sequence** voltages and currents for a 13.8 kV **SLG** fault on phase A at Moscow.

Note that the I^+ & I^- are 60° apart. That's because I^+ rotates a positive 30° and I^- rotates a minus 30° for a HLL connection. Add them together and they equal I_a (this is where you get the $\sqrt{3}$ reduced magnitude from a 3ϕ fault). Note that $3I_0 = 0$ since the transformer connection is delta – wye.

Phase-to-Phase 13.8 kV Fault

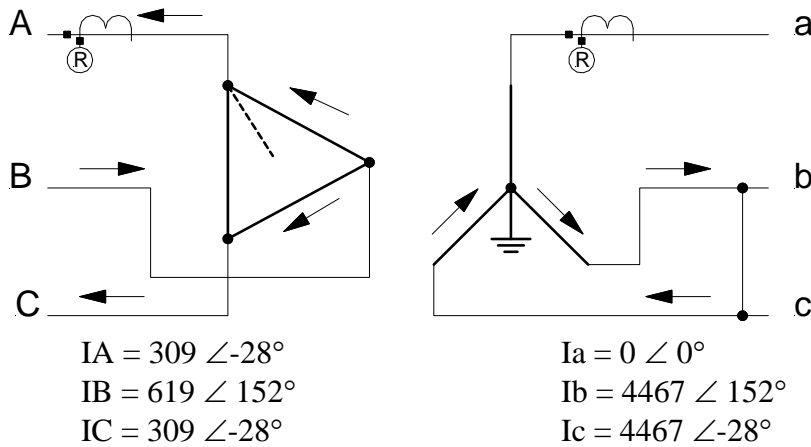


Figure 10. Current distribution through a Delta-Wye high lead low transformer bank for a phase-to-phase 13.8 kV fault.

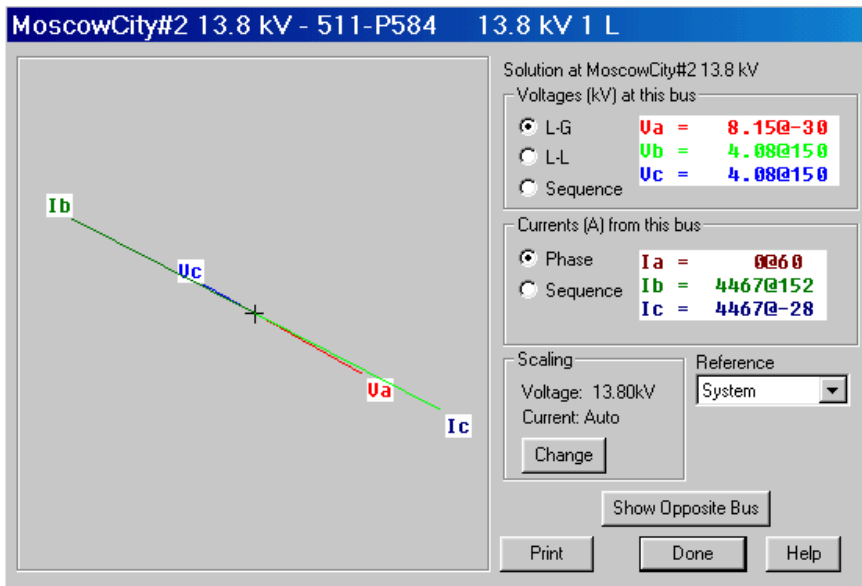


Figure 11. 13.8 kV **phase** voltages and currents for a 13.8 kV **line-to-line** bus fault on phases B & C at Moscow.

- Note that I_b & $I_c = 4467$ A which is $4467/5158 = 86.6\%$ of the current for a three phase fault. That's because the voltage used is $V_{\phi-\phi}$ which is $\sqrt{3}$ times V_n but the impedance used is $Z_1 + Z_2$ or 2 times Z_1 so the value is $1.732/2 = 86.6\%$. The formula for the B to C phase fault is: $I = (V_b - V_c)/(Z_1 + Z_2)$.
- Note that I_b & I_c are in the opposite direction. That is; the current flows out on B phase and in on C phase while V_b & V_c are in the same direction as I_b .
- Note that V_b & V_c are $\frac{1}{2} V_A$ and in the opposite direction.

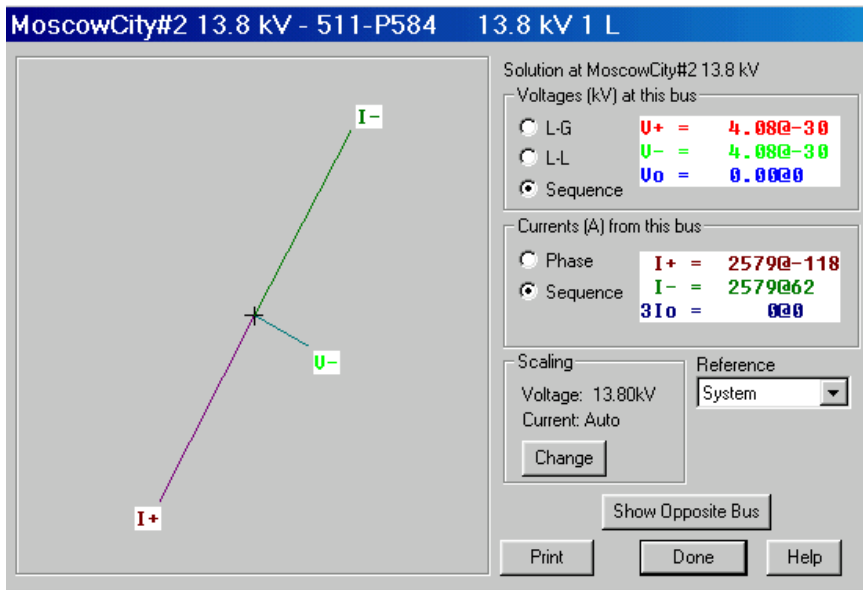


Figure 12. 13.8 kV **sequence** voltages and currents for a 13.8 kV **line-to-line** bus fault on phases B & C at Moscow.

- Note that I^+ & I^- are equal and in opposite directions so they will sum to 0. That's because this is given in terms of I_a , which is 0. In order to obtain the I_b & I_c currents you have to rotate I_a^+ & I_a^- by: ($I_b = I_a^+$ rotated by 240° plus I_a^- rotated by $120^\circ = 2579\angle122^\circ + 2579\angle182^\circ = 4467\angle152^\circ$) and ($I_c = I_a^+$ rotated by 120° plus I_a^- rotated by $240^\circ = 2579\angle2^\circ + 2579\angle302^\circ = 4467\angle-28^\circ$).
- The above shows that $I_2 = \text{the phase current}/\sqrt{3}$ ($4467/\sqrt{3} = 2579$).
- Note that V^+ & V^- are in phase so when they are added together to get V_a , the V_a magnitude is normal. To get V_b & V_c again you rotate the sequence voltages similar to the current above.

SYMMETRICAL COMPONENTS

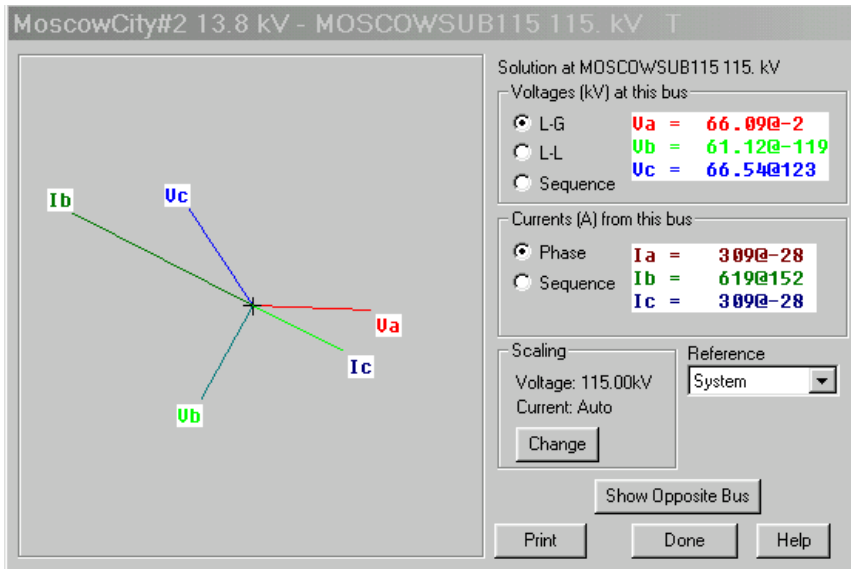


Figure 13. 115 kV **phase** voltages and currents for a 13.8 kV **line-to-line** bus fault on phases B & C at Moscow.

- Note that $I_b = 619$ amps which is the same value as it saw for a 3ϕ fault. That's because of the way the positive and negative sequence currents added after the 30° phase shift.
- Also note that I_a & I_c added together = I_b and in the opposite direction to get the current in and out of the delta winding.

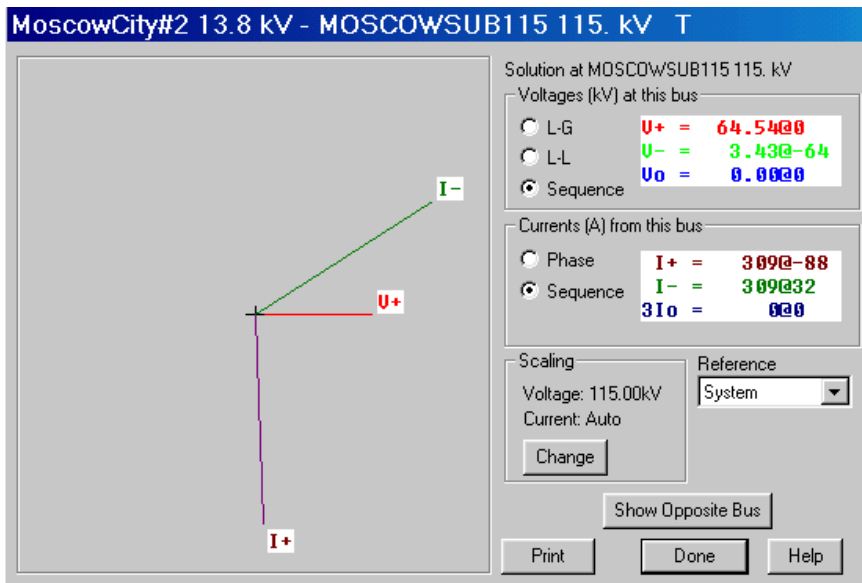


Figure 14. 115 kV **sequence** voltages and currents for a 13.8 kV **line-to-line** bus fault on phases B & C at Moscow.

- Again the sequence values are given for phase A and you have to rotate them to get phases B & C.
- Note that the I^+ & I^- are 120° apart (were 180° apart at 13.8 kV). That's because I^+ rotates a positive 30° and I^- rotates a minus 30° for a HLL connection. Add them together and they equal I_a .

Symmetrical Components - Summary of 13.8 kV Faults

If you have a Delta-Wye transformer bank, and you know the voltage ratio and secondary phase current values for 13.8kV 3LG (5158) and SLG (5346) faults, you can find the rest:

3LG

$$I_A = 619 \quad \underline{I_a} = 5158 \quad 5158 / 8.33 = 619 \quad \underline{I_a} = 5158 = I_1$$

$$I_B = 619 \quad \underline{I_b} = 5158$$

$$I_C = 619 \quad \underline{I_c} = 5158$$

SLG

$$I_A = 370 \quad \underline{I_a} = 5346 \quad 5346 / (8.33 \times \sqrt{3}) = 370 \quad \underline{I_a} = 5346 = 3I_0$$

$$I_B = 0 \quad \underline{I_b} = 0$$

$$I_C = 370 \quad \underline{I_c} = 0$$

L-L

$$I_A = 309 \quad \underline{I_a} = 0 \quad 5158 \times \sqrt{3} / 2 = 4467 \quad \underline{I_b} \times \sqrt{3} = 7737 = 3I_2$$

$$I_B = 619 \quad \underline{I_b} = 4467 \quad 4467 / (8.33 \times \sqrt{3}) = 309$$

$$I_C = 309 \quad \underline{I_c} = 4467 \quad 309 \times 2 = 619$$

TRANSFORMER PROTECTION DEVICES

TRANSFORMER PROTECTION USING 115 KV FUSES

For the smaller 115/13 kV substation transformers up through 7.5 MVA, we generally use 115 kV fuses for protection simply because of the cost. Some advantages to this are:

- Low cost.
- Low maintenance.
- Does not require a panel house or substation battery.
- Some fuses that Avista has used are GE, Southern States and S&C.

There are also several disadvantages to using fuses however, which are:

- The interrupting rating can be as low as 1,200 amps (for some older models) and only go up to 10,000 amps at 115 kV. By contrast a modern circuit switcher can have an interrupting rating of 25,000 amps and a breaker can have even higher (we typically use 40,000 amps interrupting).
- The fuses we generally use are rated to blow within 5 minutes at twice their nameplate rating. Thus, a 65-amp fuse will blow at 130 amps. This compromises the amount of overload we can carry in an emergency and still provide good sensitivity for faults.
- The fuse time current characteristic (TCC) is fixed (although you can buy a standard, slow or very slow speed ratio which are different inverse curves).
- The sensitivity to detect faults (especially low side Single Line to Ground faults) is not very good as compared to using a circuit switcher or breaker and low side neutral overcurrent relaying. This is because we use DELTA/WYE connected transformers so the phase current on the 115 kV is reduced by the $\sqrt{3}$ as opposed to a three-phase fault. For example a typical 13.8 kV SLG fault through a 7.5 MVA transformer is 4,000 amps at 13.8 kV and $4000/(8.3*\sqrt{3}) = 277$ amps at 115 kV. Since we use 65 amp fuses for this size transformer, our margin to detect this fault is only $277/(2*65) = 2.13:1$. By contrast a low set feeder ground relay could probably be set between 480 to 720 amps so our margin to detect this fault would be around 8.3 to 5.5:1 (4000/480 or 720).
- Some fuses can be damaged and then blow later at some high load point.
- When only one 115 kV fuse blows, it subjects the customer to low distribution voltages. For example the phase to neutral distribution voltages on two phases on the 13.8 kV become 50% of normal.
- No indication of faulted zone (transformer, bus or feeder).

TRANSFORMER PROTECTION USING A CIRCUIT SWITCHER

Some advantages to this over fuses are:

- Higher interrupting.
- Relays can be set to operate faster and with better sensitivity than fuses.
- Three phase operation.
- Provide better coordination with downstream devices.

TRANSFORMER PROTECTION DEVICES

Some disadvantages would be:

- Higher cost.
- Higher maintenance.
- Requires a substation battery, panel house and relaying.
- Transformer requires CT's.

TRANSFORMER PROTECTION USING A BREAKER

This is very similar to using a circuit switcher with a couple of advantages such as:

- Higher interrupting.
- Somewhat faster tripping than a circuit switcher (3 cycles vs. 6 – 8 cycles).
- Possibly less maintenance than a circuit switcher.
- The CT's would be located on the breaker so it would interrupt faults on the bus section up to the transformer plus the transformer high side bushings.

RELAY SETTING CRITERIA

The distribution feeder relay settings have to meet the following criteria (as basically does any other protective device):

- Protect the feeder conductor from thermal damage due to faults (not overloads).
- Detect as low a fault current as possible (our general rule is 0.5 times the calculated fault at the next device or end of feeder).
- For all relays other than the phase overcurrent, this means to set the **pickup as sensitive** as we can and the **time lever as low** as we can and still coordinate with the highest set downstream device.
- Coordinate with all downstream devices whether fuses or reclosers by the desired Coordinating Time Interval (CTI) – see Table 6. This is the minimum amount of time we want between the operation of the devices.
- Carry normal maximum load (phase overcurrent only).
- Pickup the feeder in a cold load condition ($\cong 2$ times maximum normal load) or pickup $\frac{1}{2}$ of the next feeder load ($\cong 1.0 + 2 * \frac{1}{2} = 2$ times normal load, phase overcurrent only).
- Most overhead feeders also use reclosing capability to automatically re-energize the feeder for temporary faults. Most distribution reclosing relays have the capability of providing up to three or four recloses (Avista generally uses either one or two). The reclosing relay also provides a reset time generally adjustable from about 10 seconds to three minutes. This means if we run through the reclosing sequence and trip again within the reset time, the reclosing relay will lockout and the breaker will have to be closed by manual means.
- Lockout only for faults within the protected zone. That is; won't lockout for faults beyond fuses, line reclosers etc.

Distribution Fuse Protection/Saving Scheme:

A lot of overhead residential or rural feeders will also use a '**fuse protection scheme**'. This is done by using both an instantaneous/fast OC trip and an inverse time delayed OC curve similar to a fuse curve (See Figures 18 & 19). The time delayed OC is set to coordinate with the maximum device out on the feeder. This means that if a fault occurs on a fused lateral, you want the following to happen:

- Trip and clear the fault at the station (or line recloser) by the instantaneous trip before the fuse is damaged for a lateral fault.
- Reclose the breaker. That way if the fault were temporary the feeder is completely re-energized and back to normal.
- During the reclose the reclosing relay has to block the instantaneous trip from tripping again. That way, if the fault still exists you force the time delay trip and the fuse will blow before you trip the feeder again thus isolating the fault and re-energizing most of the customers.
- Of course if the fault were on the main trunk the breaker will trip to lockout.
- There are variations on this such as using more than one instantaneous trip or more than one time delay trip, varying the different reclose times etc. For example Avista often uses one instantaneous trip and two time delayed trips with a fast (1/2 second) and a 15 second reclose.

Industrial, URD or Network Feeders

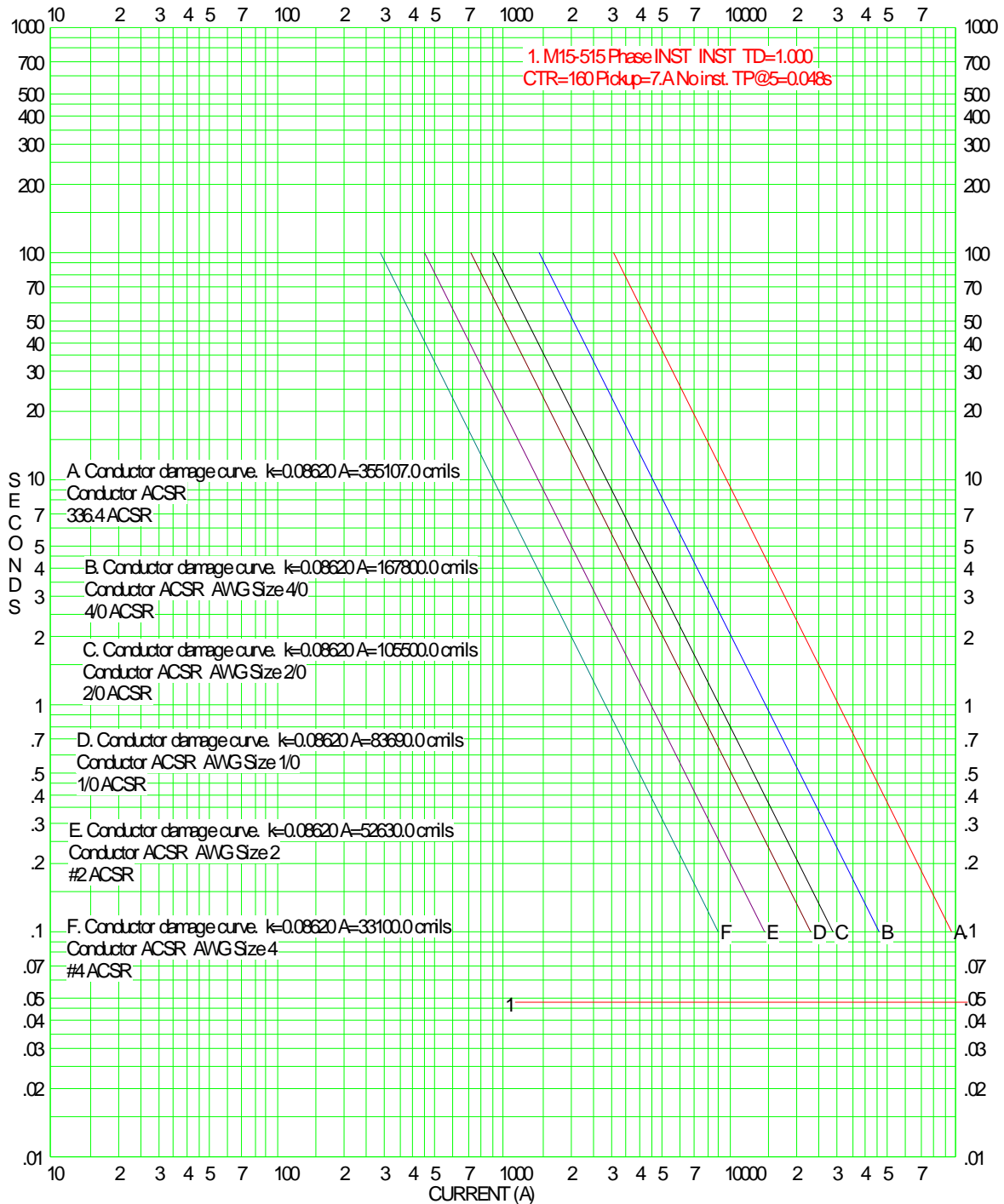
- Generally these would not use fused laterals so would not use a fuse protection scheme. Depending on several factors they also may not use reclosing.

Distribution Transformers:

The distribution transformer relay settings have to (should) meet the following criteria (there will be several compromises here): NOTE: These are for an outdoor bus arrangement and not switchgear which also uses a bus breaker between the transformer relaying and the feeder relaying. This also doesn't include the transformer sudden pressure relay.

- Protect the feeder conductor from thermal damage in case the feeder breaker can't trip. This normally can't be done completely since the transformer relaying has to be set higher than the feeder relaying.
- Protect the transformer from thermal damage.
- Detect as low a fault current as possible. It would be desirable to be just as sensitive as the feeder relaying in case the feeder breaker can't trip but this can't always be done.
- For all relays other than the phase overcurrent, this means to set the **pickup as sensitive** as we can and the **time lever as low** as we can and still coordinate with the highest downstream device by the desired CTI (Table 6).
- Coordinate with all downstream devices, which is the feeder breaker relaying.
- Carry normal maximum load (phase overcurrent only).
- After an outage, pickup the station cold load ($\cong 2$ times maximum normal, phase overcurrent only).
- Differential relay operate for internal transformer faults only and account for CT and transformer ratio mismatch.

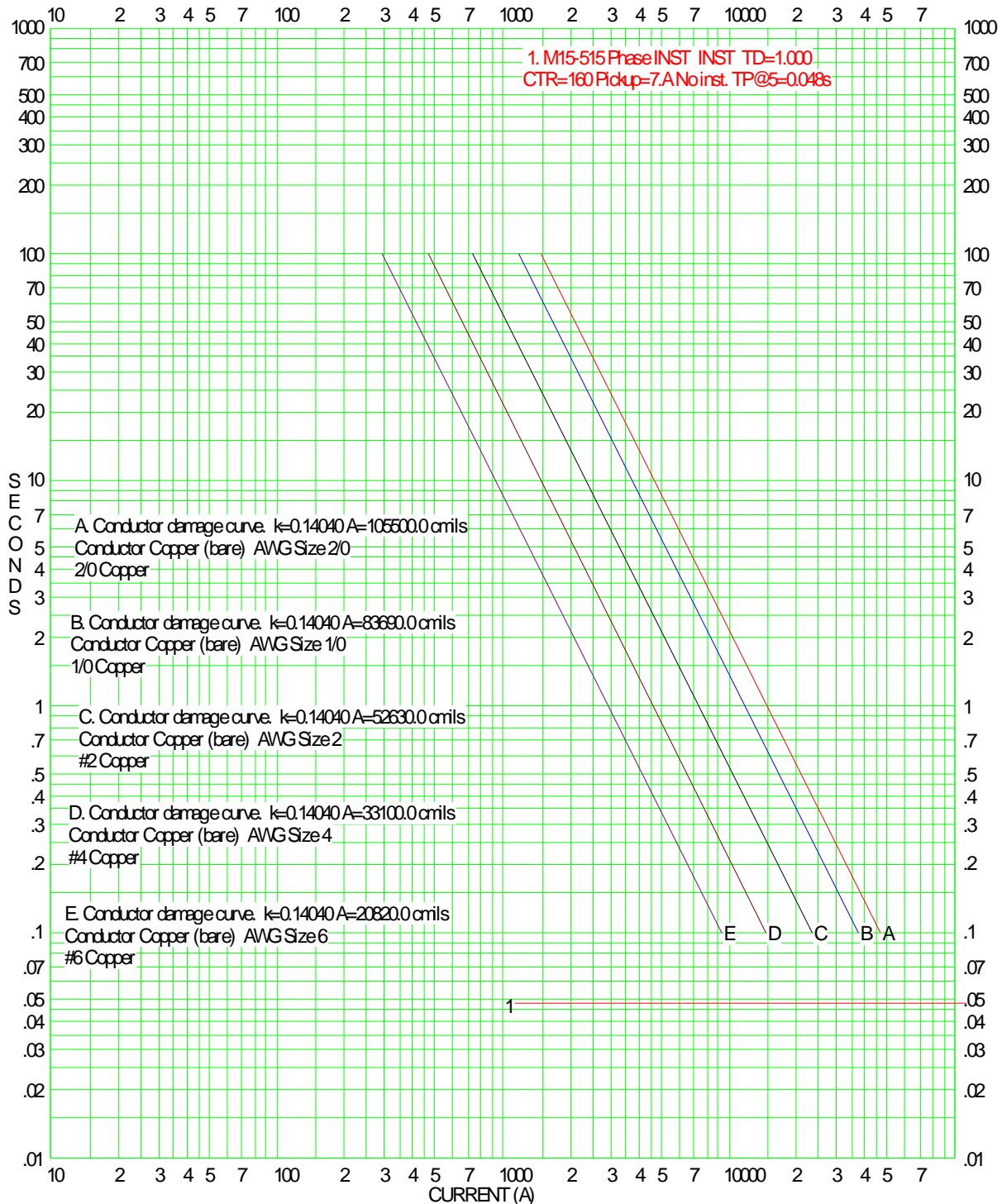
FIGURES AND TABLES



TIME-CURRENT CURVES @ Vdltage 13.8kV		By DLH
For ACSR Conductor Damage Curves		No.
Comment		Date 12/13/05

Figure 15. ACSR Conductor damage curves from ASPEN.

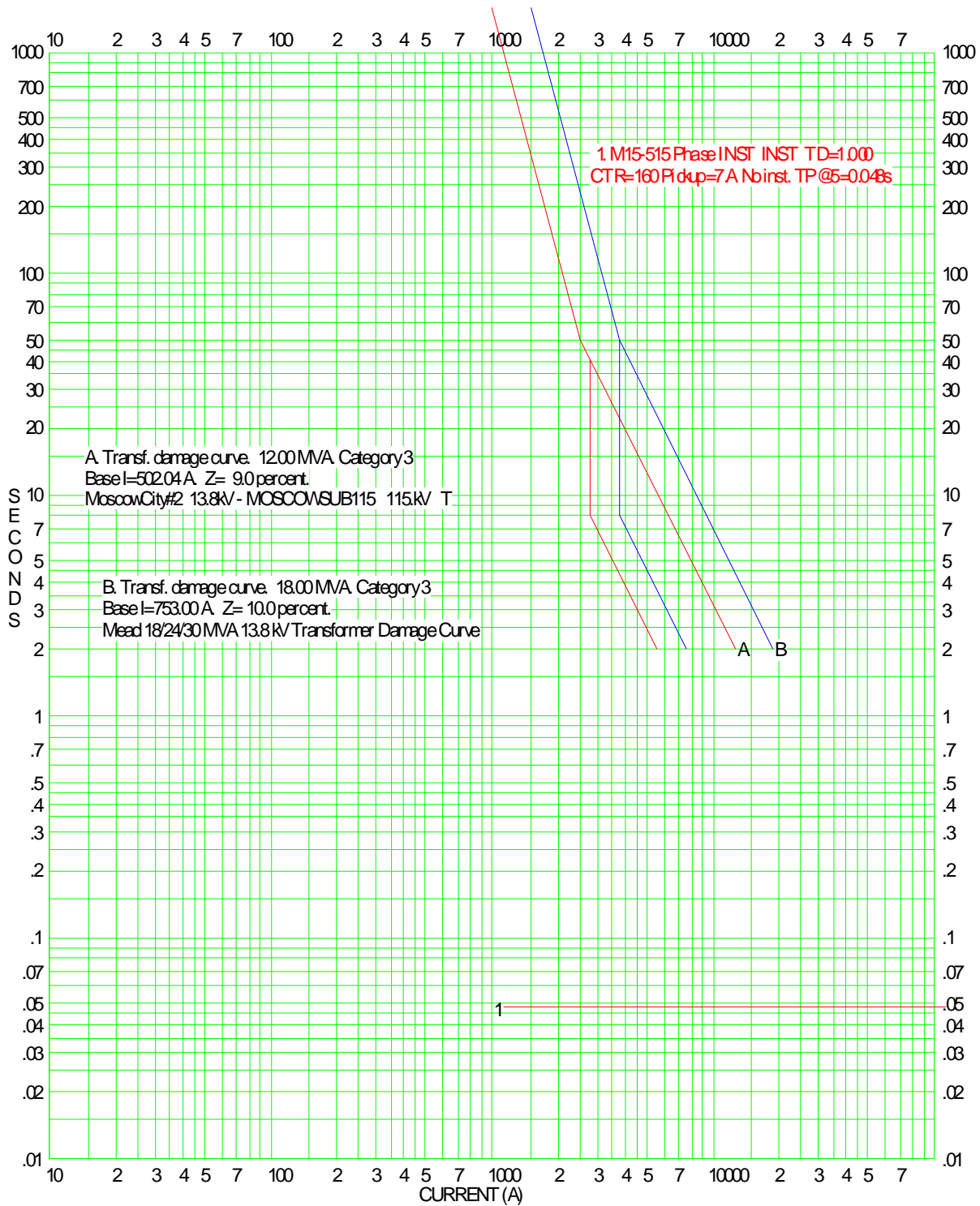
FIGURES & TABLES



TIME-CURRENT CURVES @ Voltage 13.8 kV		By DLH
For	Copper Conductor Damage Curves	No.
Comment		Date 12/13/05

Figure 16. Copper Conductor damage curves from ASPEN.

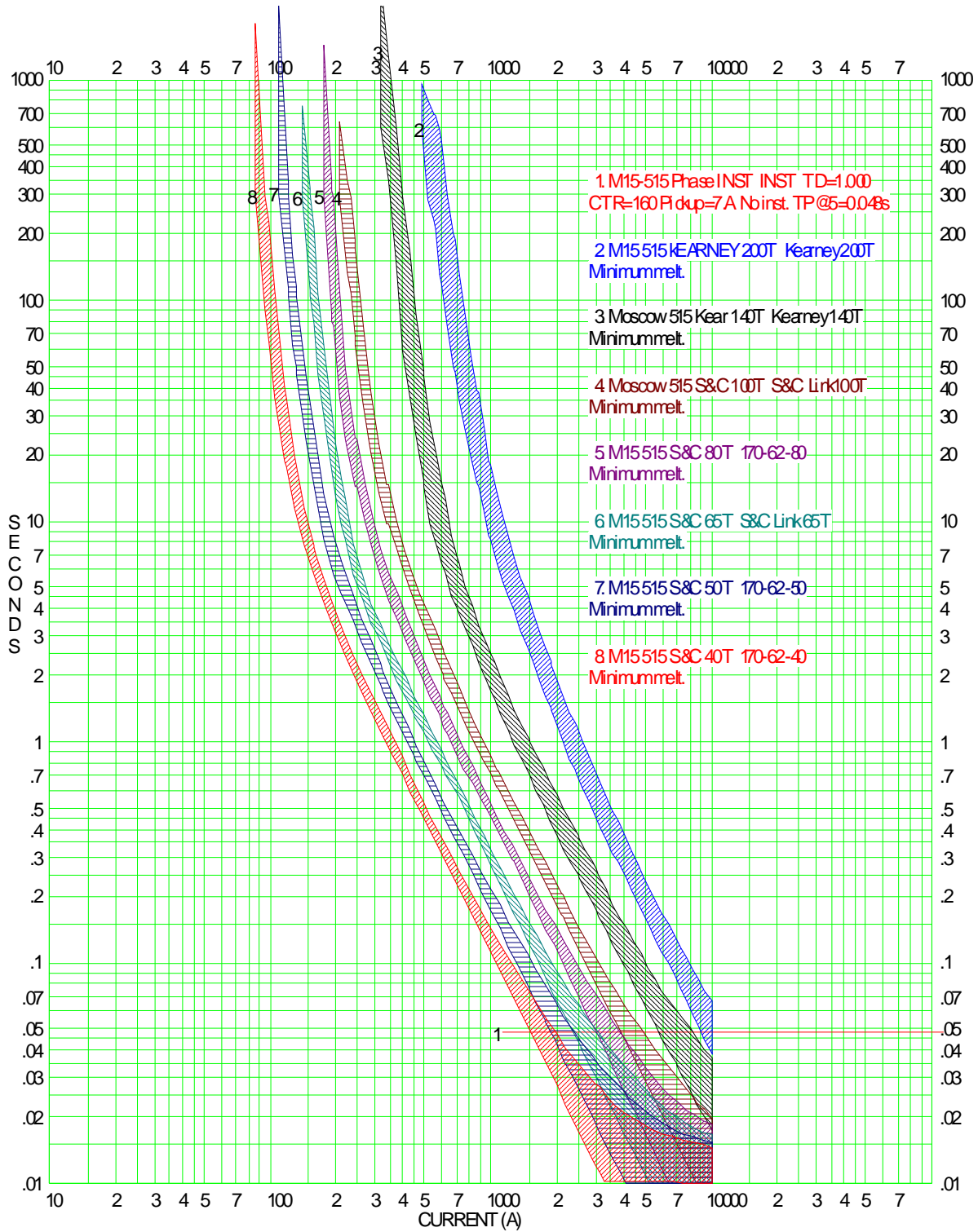
FIGURES & TABLES



TIME-CURRENT CURVES @ Voltage 13.8kV		By DLH
For Transformer Damage Curves		No.
Comment		Date 12/13/05

Figure 17. 12/16/20 and 18/24/30 Transformer Damage Curves.

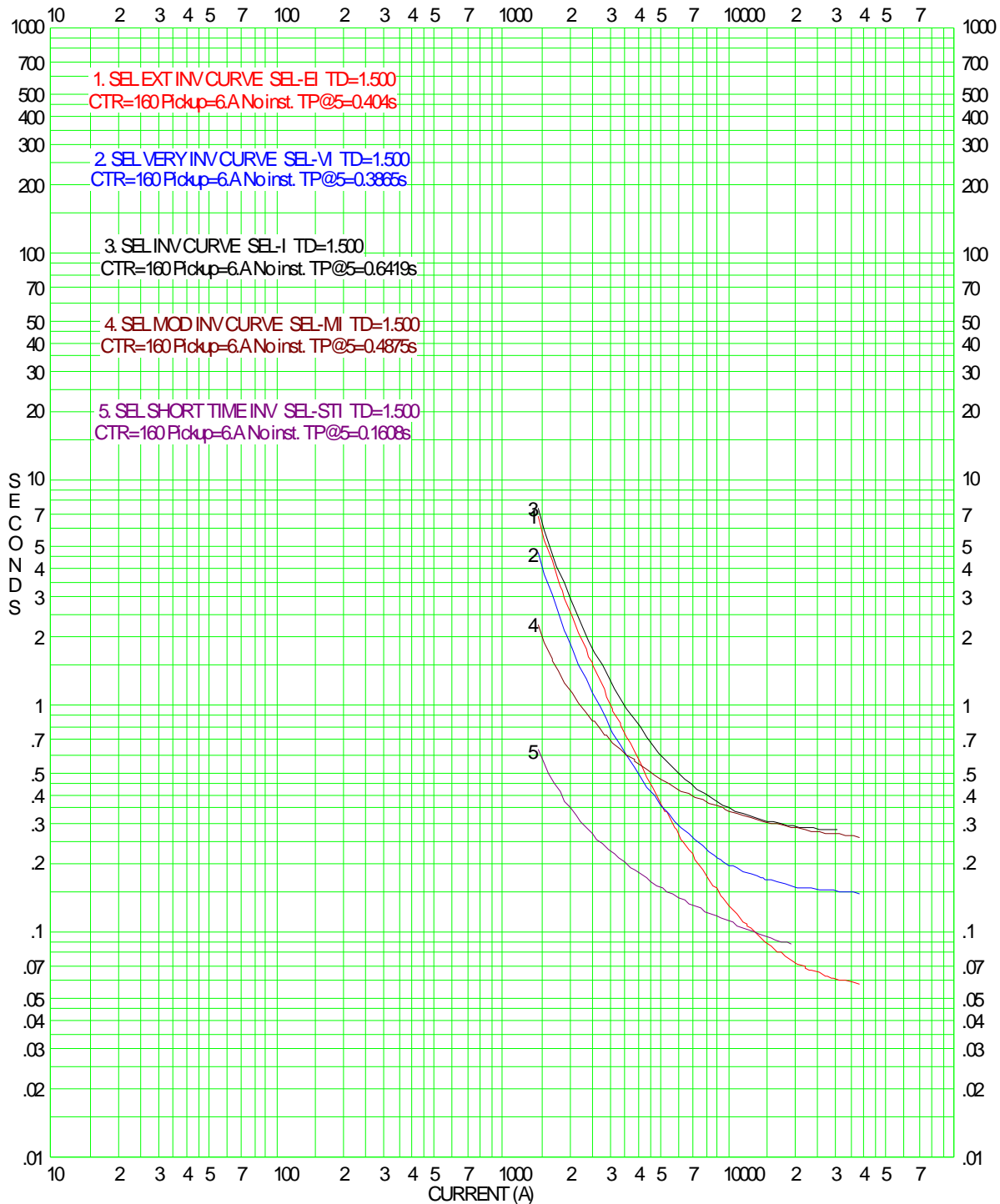
FIGURES & TABLES



TIME-CURRENT CURVES @ Voltage 13.8kV		By DLH
For	Commonly Used Fuse Curves	No.
Comment		Date 12/13/05

Figure 18. Commonly Used Distribution Fuses.

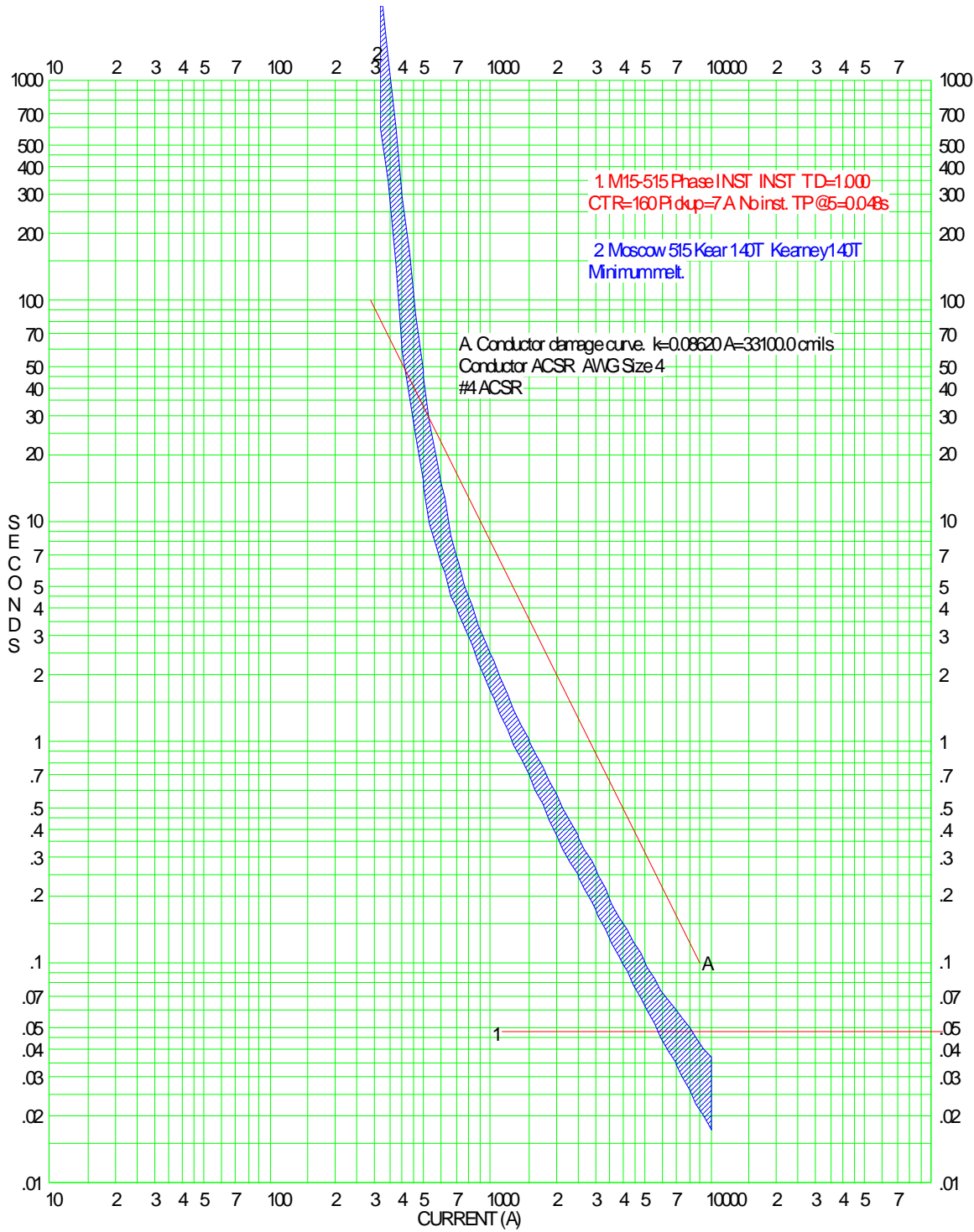
FIGURES & TABLES



TIME-CURRENT CURVES @ Voltage 13.8kV		By DLH
For	VARIOUS SEL OVERCURRENT RELAY CURVES	No.
Comment		Date 12/21/05

Figure 19. SEL Various Overcurrent Relay Curves. These are basically the same as various E-M relays.

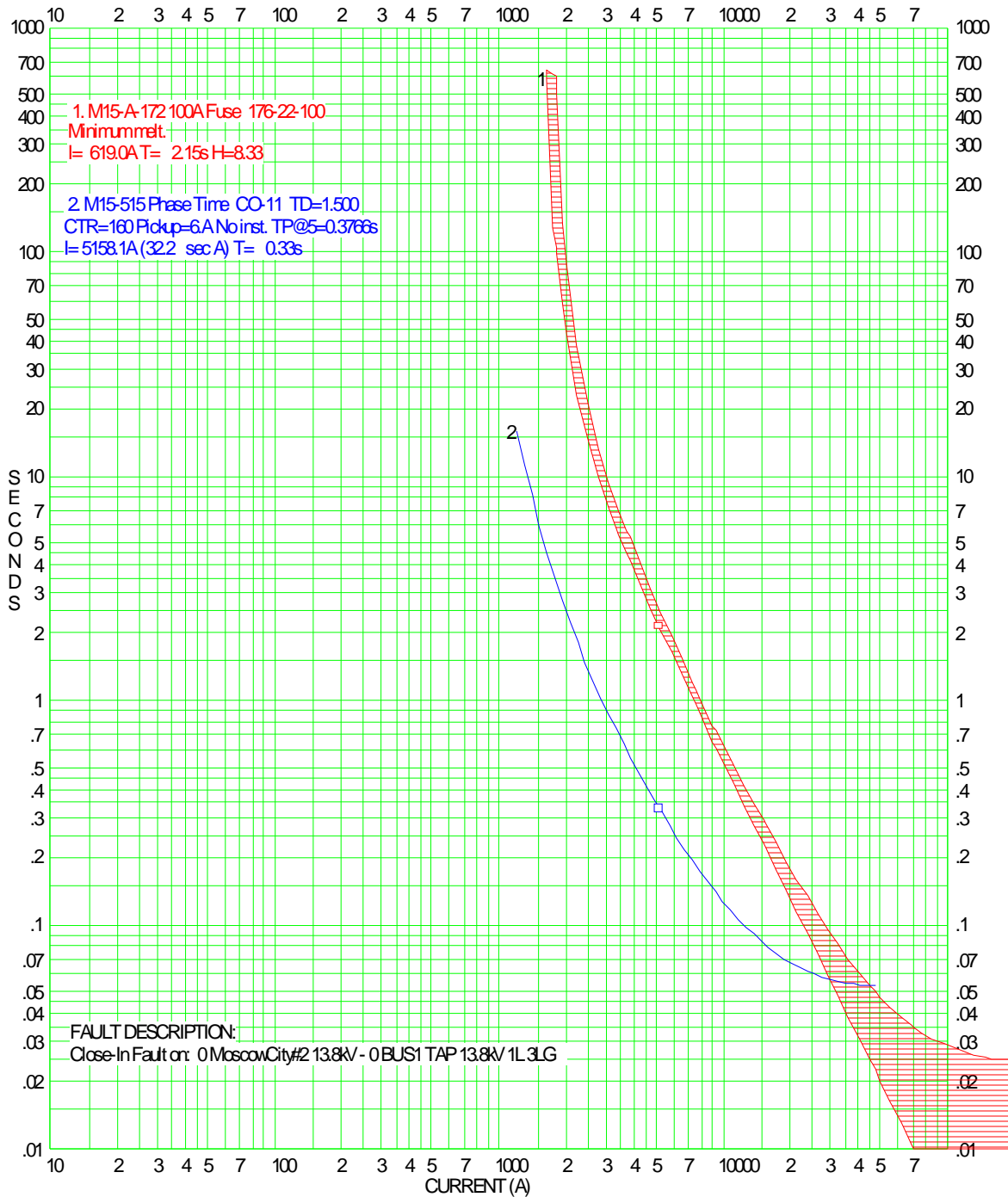
FIGURES & TABLES



TIME-CURRENT CURVES @ Voltage 13.8 kV		By DLH
For	Comparing 140T VS #4 ACSR Damage	No.
Comment	140T won't Protect #4 ACSR Below About 550 Amps	Date 12/13/05

Figure 20. Comparing a 140T fuse Vs. #4 ACSR Damage curve. The 140T won't protect the conductor below about 550 amps where the curves cross.

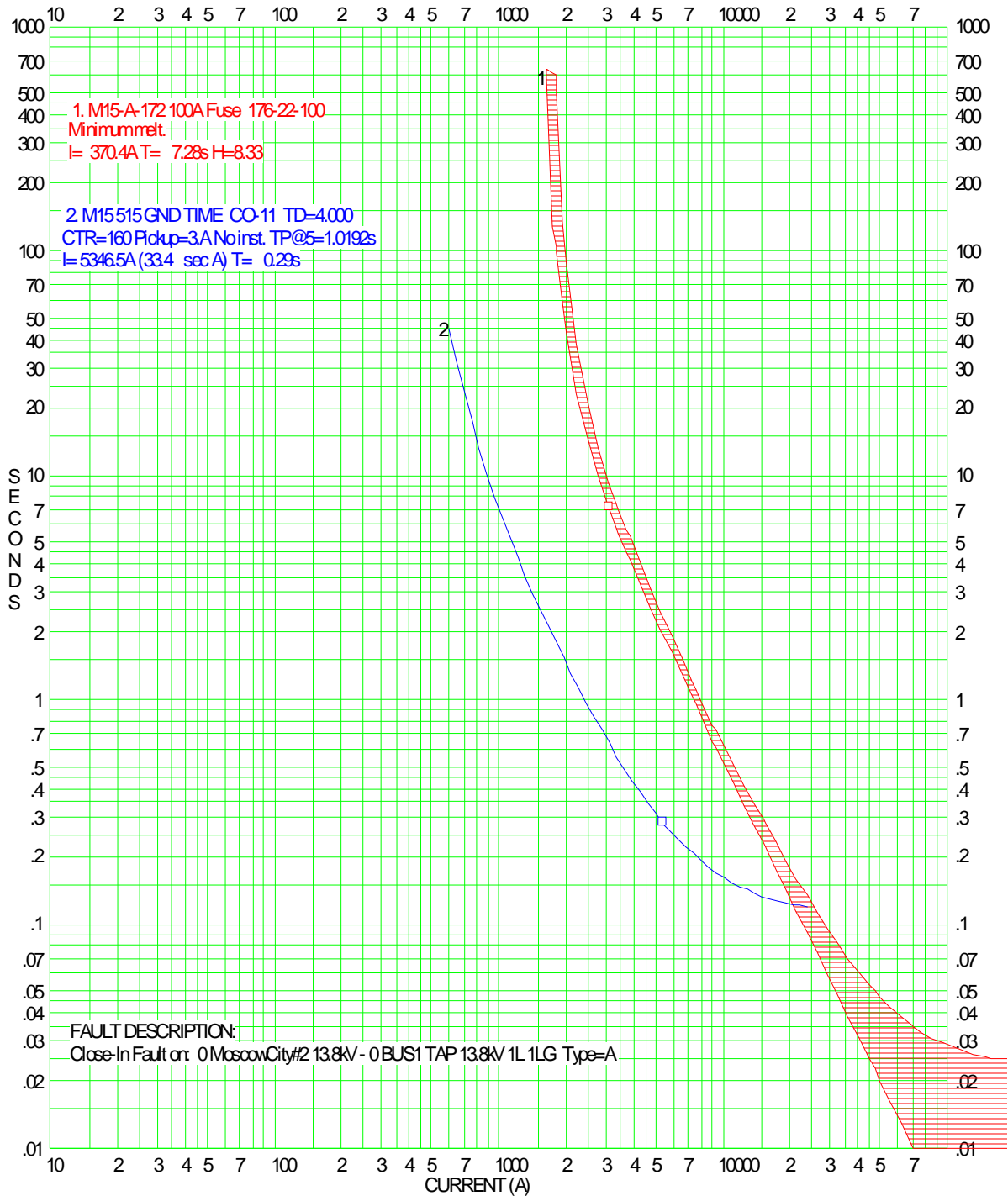
FIGURES & TABLES



TIME-CURRENT CURVES @ Voltage 13.8kV		By DLH
For	Comparing a 115kV Fuse with Feeder Relays	No.
Comment	Coordinating for a 3 Phase Fault. 100A Fuse sees 619 amps	Date 1/11/06

Figure 21. Comparing a 100 Amp S&C 115 kV fuse with the Moscow feeder phase relay. The 100-amp fuse blows at 200 amps and sees 619. Margin = 619/200 = 3.1:1.

FIGURES & TABLES



TIME-CURRENT CURVES @ Voltage 13.8 kV		By DLH
For	Comparing a 115 kV Fuse with Feeder Relays	No.
Comment	Coordinating for a SLG Fault. 100A Fuse sees 370 amps	Date 1/11/06

Figure 22. Comparing a 100 Amp S&C 115 kV fuse with the Moscow feeder ground relay. The 100-amp fuse blows at 200 amps and sees 370. Margin = $370/200 = 1.85:1$.

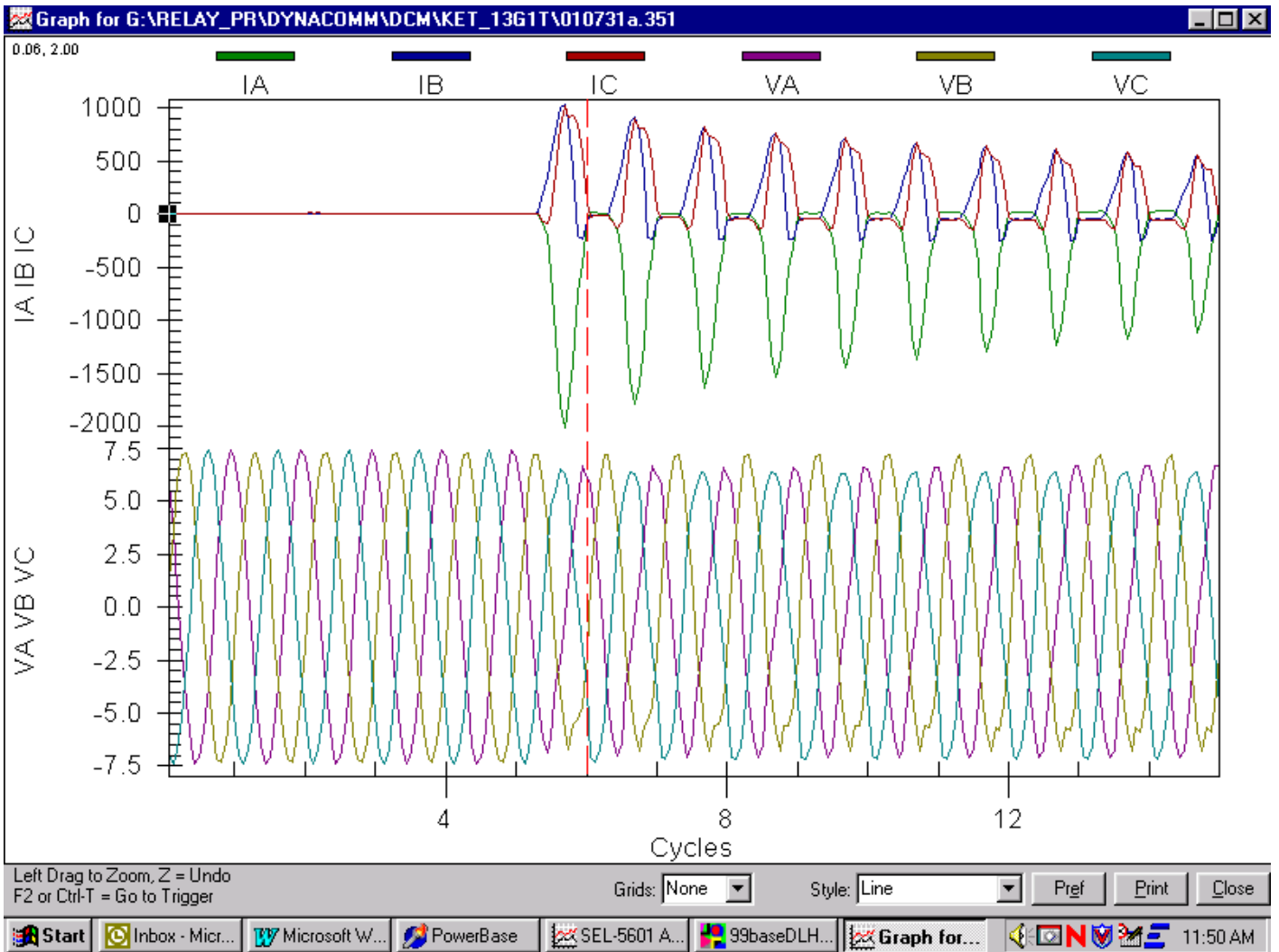


Figure 23. Transformer inrush **UNFILTERED** current. Inrush is the current seen when energizing a transformer. The maximum peak current is about 1800 amps. Note Ia is the sum of Ib + Ic.

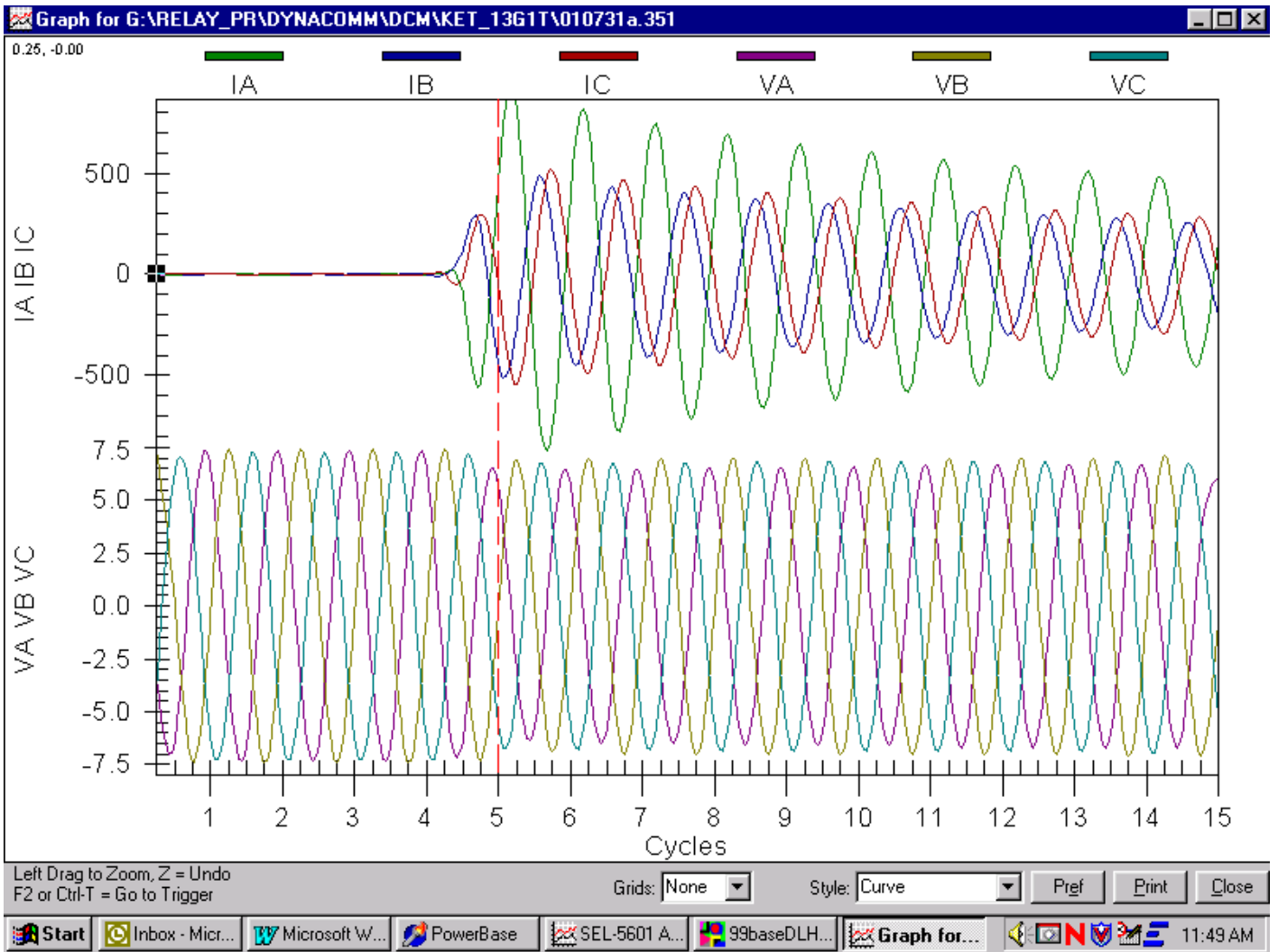


Figure 24. Transformer inrush **FILTERED** current (filtered by SEL digital filters to show basically only 60 HZ). Maximum peak is about 700 amps.

Universal Distribution Fuse Links

Avista generally uses S&C type T universal fuse links used with open type cutouts for most of its applications. That's because the S&C fuse link uses silver in the fuse link instead of a tin alloy. A silver link has both a total clear and a minimum melt curve associated with its melting characteristic and is not damageable. That basically means if the fuse hasn't blown, it's still all right. However, a tin alloy link is damageable with a damage curve that is about 75% of its minimum melt curve. This means it's much harder to coordinate two sets of fuses with one another and it's also harder to protect the fuse by tripping the breaker or recloser on an instantaneous trip than the S&C. By using the silver fuse link, we can also use every size made below. That is; fuses in series can be one size apart and still coordinate. With the tin alloy we could only use about 1/2 the ratings because the fuses one size apart wouldn't coordinate. We said that the S&C fuse could be protected from a temporary fault by a fast clearing time of 3.5 cycles if the minimum melt curve was at 0.1 seconds. NOTE: The S&C silver link is only made up through 100 amps while the 140 and 200 amp fuses are a tin alloy. There are other types of fuses made but these are not shown.

Table 1. Shows the maximum fault current for which S&C type T fuses can still be protected by a recloser/breaker instantaneous trip for temporary faults (minimum melt curve at 0.1 seconds):

- 6T – 120 amps
- 8T – 160 amps
- 10T – 225 amps
- 12T – 300 amps
- 15T – 390 amps
- 20T – 500 amps
- 25T – 640 amps
- 30T – 800 amps
- 40T – 1040 amps
- 50T – 1300 amps
- 65T – 1650 amps
- 80T – 2050 amps
- 100T – 2650 amps
- 140T – 3500 amps
- 200T – 5500 amps

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Table 2. Shows the maximum fault current for which S&C type T fuses can coordinate with one another.

NOTE: These values were taken from the S&C data bulletin 350-170 of March 28, 1988 based on **no preloading and then preloading** of the source side fuse link. Preloading is defined as the source side fuse carrying load amps equal to it's rating prior to the fault. This means there was prior heating of that fuse so it doesn't take as long to blow for a given fault.

Source Side Fuse	Load Side Fuse	Maximum Coordinating Current No preload	Maximum Coordinating Current With preload
200T	140T	8,300	4,650
140T	100T	5,800	3,800
100T	80T	3,600	1,900
80T	65T	2,700	1,400
65T	50T	2,200	Too close
50T	40T	1,550	640
40T	30T	1,400	820
30T	25T	1,100	570
25T	20T	840	360
20T	15T	630	315
15T	12T	540	295
12T	10T	410	210
10T	8T	320	175
8T	6T	235	145

Table 3. Typical continuous and 8 hour emergency rating of the S&C T rated silver fuse links plus the 140T and 200T.

Fuse Rating	Continuous	8 Hour emergency
6T	7.8	8.8
8T	10	12
10T	13	15
12T	16	18
15T	22	25
20T	27	31
25T	36	41
30T	42	49
40T	52	59
50T	63	72
65T	88	100
80T	105	115
100T	120	135
140T	210	225
200T	295	320

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Table 4. Conductor current ratings for various sizes of ACSR conductor at 25°C ambient taken from the Westinghouse Transmission & Distribution book.

Conductor	Rating
556	730
336.4	530
4/0	340
2/0	270
1/0	230
#2	180
#4	140

Table 5. Conductor current ratings for various sizes of copper conductor at 25°C ambient taken from the Westinghouse Transmission & Distribution book.

Conductor	Rating
2/0	360
1/0	310
#2	230
#4	170
#6	120

Table 6. Typical Coordinating Time Intervals (CTI) that Avista generally uses between protective devices. Other utilities may use different times.

DEVICES:	CTI (Seconds)
Relay – Fuse Total Clear	0.2
Relay – Series Trip Recloser	0.4
Relay – Relayed line Recloser	0.3
Low Side Xfmr Relay – Feeder Relay	0.4
High Side Xfmr Relay – Feeder Relay	0.4
Xfmr Fuse Min Melt – Feeder Relay	0.4

Table 7. Typical minimum conductor that can be protected by the Avista feeder settings and S&C type T fuses. These are what Avista uses. Other companies may use different values. The relay phase pickup for a given feeder rating is typically about twice the feeder rating and we use Extremely Inverse curves.

Feeder Setting or Fuse	MIN Conductor Size
500 AMP fdr Setting	#2CU or 1/0 ACSR
300 AMP fdr setting	#4CU or #2ACSR
200T	#2CU
140T	#4CU or #2ACSR
100T	#6CU or #4ACSR
65T	#8CU

Table 8. IEEE numbers for various relays, breakers etc, that could be used in a distribution substation. Avista sometimes adds letters to these such as F for feeders, T for transformers, B for bus and BF for breaker failure.

- 2 – Time delay relay.
- 27 – Undervoltage relay.
- 43 – Manual transfer or selective device. We use these for cutting in and out instantaneous overcurrent relays, reclosing relays etc.
- 50 (or 50P) – Instantaneous overcurrent phase relay.
- 50N (or 50G) – Instantaneous overcurrent ground (or neutral) relay.
- 50Q – Instantaneous Negative Sequence overcurrent relay.
- 51 (or 51P) – Time delay overcurrent phase relay.
- 51N (or 51G) – Time delay overcurrent ground (or neutral) relay.
- 51Q – Time delay Negative Sequence overcurrent relay.
- 52 – AC circuit breaker.
- 52/a – Circuit breaker auxiliary switch closed when the breaker is closed.
- 52/b – Circuit breaker auxiliary switch closed when the breaker is open.
- 59 – Overvoltage relay.
- 62 – Time Delay relay
- 63 – Sudden pressure relay.
- 79 – AC Reclosing relay.
- 81 – Frequency relay.
- 86 – Lock out relay which has several contacts. Avista uses 86T for a transformer lockout, 86B for a bus lockout etc.
- 87 – Differential relay.
- 94 – Auxiliary tripping relay.

Table 9. Definitions and glossary of terms used in this paper.

- 5 amps per MVA = amps per phase at 1 MVA 3Ø power at 115 kV = $1000000 / (3 * [115000 \div \sqrt{3}]) = 5.02$ amps.
- 41.8 amps per MVA = amps per phase at 1 MVA 3Ø power at 13.8 kV = $1000000 / [3 * (13800 \div \sqrt{3})] = 41.84$ amps.
- Z1 is the line to neutral positive (balanced) sequence impedance (resistance and reactance) of the system (all generators, transformers and lines) to the point of interest.
- Z2 is the line to neutral negative sequence impedance of the system (which is normally = to Z1).
- Z0 is the line to neutral zero sequence impedance of the system. This is generally a different value from Z1 or Z2 because it includes the impedance of any neutral wires and the ground plane. At the 13.8 kV bus, since the transformer is connected delta on the 115 kV, we can only use the transformer Z0 (and not the Avista system Z0) because there is no ground connection from the transformer to the 115 kV system.
- Va (or Van) is the line to neutral voltage for Phase A. Vb & Vc are the line to neutral voltages for those phases. The Ø-Ø voltage = $\sqrt{3} * V_n$.
- V₁ (or V⁺) is the positive sequence voltage for whichever phase you are referring to.
- V₂ (or V⁻) is the negative sequence voltage for whichever phase you are referring to.
- V₀ (or V0) is the zero sequence voltage for whichever phase you are referring to.
- Ia is the single phase current for Phase A, Ib for phase B and Ic for phase C.
- I₁ (or I⁺) is the positive sequence current for whichever phase you are referring to.

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- I_2 (or I) is the negative sequence current for whichever phase you are referring to.
- I_0 (or $I0$) is the zero sequence current for whichever phase you are referring to.
- P is for phase, N is for neutral & Q is for negative sequence.
- $3I0$ is the total ground or neutral current for ground faults. This is the current that flows up the transformer neutral.
- CCW is counterclockwise rotation of the system. That is; phase A leads phase B by 120° and leads phase C by 240° .
- HLL is a high lead low transformer connection. That is; the phase A voltage to the high side windings leads the low side voltage by 30° (other angles are possible).
- LLH is a low lead high transformer connection. That is; the phase A voltage to the high side windings lags the low side voltage by 30° (other angles are possible).
- SLG is single line to ground fault.
- The letter 'a' is an operator that when applied to voltages or currents rotates them by plus (or CCW) 120° . The letter 'a²' shifts them by 240° . EXP: using phase A as a reference we would have $V_b = a^2V_{a1} + aV_{a2} + V_0$ or said another way $V_b = V_{a1} \angle 240^\circ + V_{a2} \angle 120^\circ + V_0$. $V_c = aV_{a1} + a^2V_{a2} + V_0$.
- TCC is Time Current Characteristic. This is generally done on a log-log graph like is shown in this paper. The vertical axis is the time and the horizontal is the current magnitude.
- EI = EXT INV = Extremely Inverse Time Current Curve.
- VI = VERY INV = Very Inverse Time Current Curve.
- INV = Inverse Time Current Curve.
- MI = MOD INV = Moderately Inverse Time Current Curve.
- STI = Short Time Inverse Time Current Curve.
- TL = TD = time lever (or dial) used with inverse time overcurrent curves. This shifts the curve up and down on the TCC graph. However, it does not change the shape of the curve.
- PU = Pickup value of the unit. This moves the curve right and left on the TCC graph.
- CT = Current Transformer.
- BCT = Bushing Current Transformer.
- PT = VT = Potential (or voltage) transformer.
- E-M = Electromechanical relay.
- MP = Microprocessor relay.
- TC = Torque Control. This controls whether or not an element will be able to operate. We used this to control certain instantaneous elements in a transformer MP relay from a feeder MP relay. The term torque control is from the E-M relaying.
- DC Offset – When a fault occurs at the voltage peak, the current can be offset from the zero axis by as much as 1.6 times because of the ratio of reactance to resistance of the system (the higher the ratio the greater the offset). This is called Asymmetrical current. The offset then decays over a few cycles so that the positive and negative current magnitudes are basically equal. This is called Symmetrical current.
- CTI – Coordinating Time Interval. This is the minimum operating time desired between two protective devices.

FEEDER AND TRANSFORMER PROTECTION USING ELECTROMECHANICAL RELAYING

Feeder - The normal electromechanical feeder relaying consists of 3 phase and 1 ground overcurrent relay. Each relay has both an instantaneous and time delay unit. Typical settings for a normal 500 amp feeder having to coordinate with 140T line fuses would be as follows:

1. Phase overcurrent:
 - Set 51P pickup $\cong 2*500 = 1000$ amps to pickup cold load or $\frac{1}{2}$ of the next feeder cold load. Since we use 800/5 CT ratios, the setting would be tap 6 = 960 amps primary.
 - 51P Time Lever(TL) – This would be set to provide $\cong 0.2$ seconds coordination (see Table 6) between the relay and the maximum fuse size which is usually a 140T. This is the coordination time that Avista feels comfortable with basically because the fuse total clear curve is a maximum value and all deviations should be negative. However, other utilities may use a different number. This would be done assuming a fused lateral across the street from the sub and would be for either a 3 \emptyset or SLG fault (I.E. maximum feeder fault). A typical curve would be \cong TL 1.75 - 2.5. This would vary depending on the 13.8 kV fault duty.
 - 50P - The instantaneous unit would be set similar to the 51P. However, since it will pickup whenever the feeder is closed in due to inrush and cold load (which can be as high as 5 times the normal load), it has to be set higher than the 51P so it can drop back out before the block of the instantaneous unit by the reclosing relay can reset which may be as low as 3 seconds from the lockout position. A typical setting would be 7.0 amps = 1120 amps primary (116.7% of the 51P).
2. Ground overcurrent:
 - 51N pickup – Since this doesn't operate on load, it can be set down to merely coordinate with the 140T across the street with 0.2 seconds coordination time. A typical minimum setting would be tap 3 = 480 amps PU. See Figure 28.
 - 51N TL – This would be set for the same criteria as the phase TL. A typical setting would be 4.0 – 5.0.
 - 50N – This is set the same PU as the time or 3.0 amps sec = 480 amps primary.
3. Reclosing (79) – We will use either one fast or one fast and one time delay reclose to lockout. We will normally block the instantaneous unit from tripping after the first trip to provide for a fuse protecting scheme. The reset time Avista normally uses is from 90 to 180 seconds. The time to reset from the lockout position is 3 to 6 seconds for an E-M reclosing relay.

Transformer - The normal transformer relaying will consist of 3 high side phase and 1 low side ground overcurrent relays plus a sudden pressure. We could also use a high side ground but generally haven't because it won't detect ground faults through the transformer.

At switching stations we also used a low side BØ OC relay for breaker failure purposes and we fused the DC control circuit of the high side phase overcurrent relays separately from the other relaying. This BØ relay has to be set similar to the high side except it's worst coordination case is a 3Ø fault. We would then use a breaker failure overcurrent relay to operate a bus lockout relay to clear the fault. Typical settings for both a 12/16/20 MVA and an 18/24/30 MVA transformer coordinating with a 500 amp feeder would be:

1. Phase overcurrent (on 115 kV transformer BCT's):

- 51P pickup – This has to be able to pick up the entire transformer load cold load or $\cong 2 \times$ normal. Our typical rule of thumb for this is $2.4 \times$ highest MVA rating. For a 12/16/20 (5 amps per MVA) this is $2.4 \times 20 \times 5 = 240$ amps (1920 amps at 13.8 kV). For an 18/24/30 this is $2.4 \times 30 \times 5 = 360$ amps (2880 amps at 13.8 kV). The pickup is so high that we can't be as sensitive as the feeder phase relay so can't reach to the same fault points on the feeder. Thus the ability to detect multi phase faults and protect the feeder conductor are compromised.
- 51P time lever – This relay has to coordinate with the feeder phase relays for a maximum feeder fault with 0.4 sec coordination time (Table 6). Avista uses 0.4 sec coordination time because there is more uncertainty about the actual ratio of amps seen on the high side vs. the low side. The worst case for this is a Ø-Ø fault since the feeder phase relays see 86.6% of what they saw for a 3Ø fault but yet one of the high side relays see the same as for a 3Ø fault because of the delta/wye connection (see figure 13). A typical TL would be $\cong 1.2 - 2.0$.
- 50P – This is a direct trip element and is set to not detect a maximum fault on the 13.8 kV bus. Since the inst unit is a hinged armature device, it responds to current 'DC Offset' so the setting we have used is $\sqrt{3} \times$ MAX 13.8 kV fault. A typical setting is 900 to 1500 amps primary.

2. Ground overcurrent (on 13.8 kV transformer BCT's):

- 51N pickup – This relay will be set to coordinate with the feeder phase relays in case the feeder ground relay is out of service. The minimum pickup to coordinate with a 500 amp feeder phase relay is 960 amps. We again compromise our ability to detect feeder faults since the feeder ground is twice as sensitive as the transformer ground.
- 51N time lever – This would normally be $\cong 4.0 - 6.0$. This could be set to coordinate with 0.3 seconds margin since we are on the same voltage. However, a little more conservative setting would still use the 0.4 seconds because the transformer unbalance can be greater than any one feeder so it might see slightly more current for a fault. However, the phase OC relay also sees at least some load that the ground relay doesn't see so the 0.3 seconds may be acceptable. Avista prefers the 0.4 seconds for all elements.
- 50N – We can't use this element because we can't coordinate it with the feeder relays.

FEEDER AND TRANSFORMER PROTECTION WITH E-M RELAYS

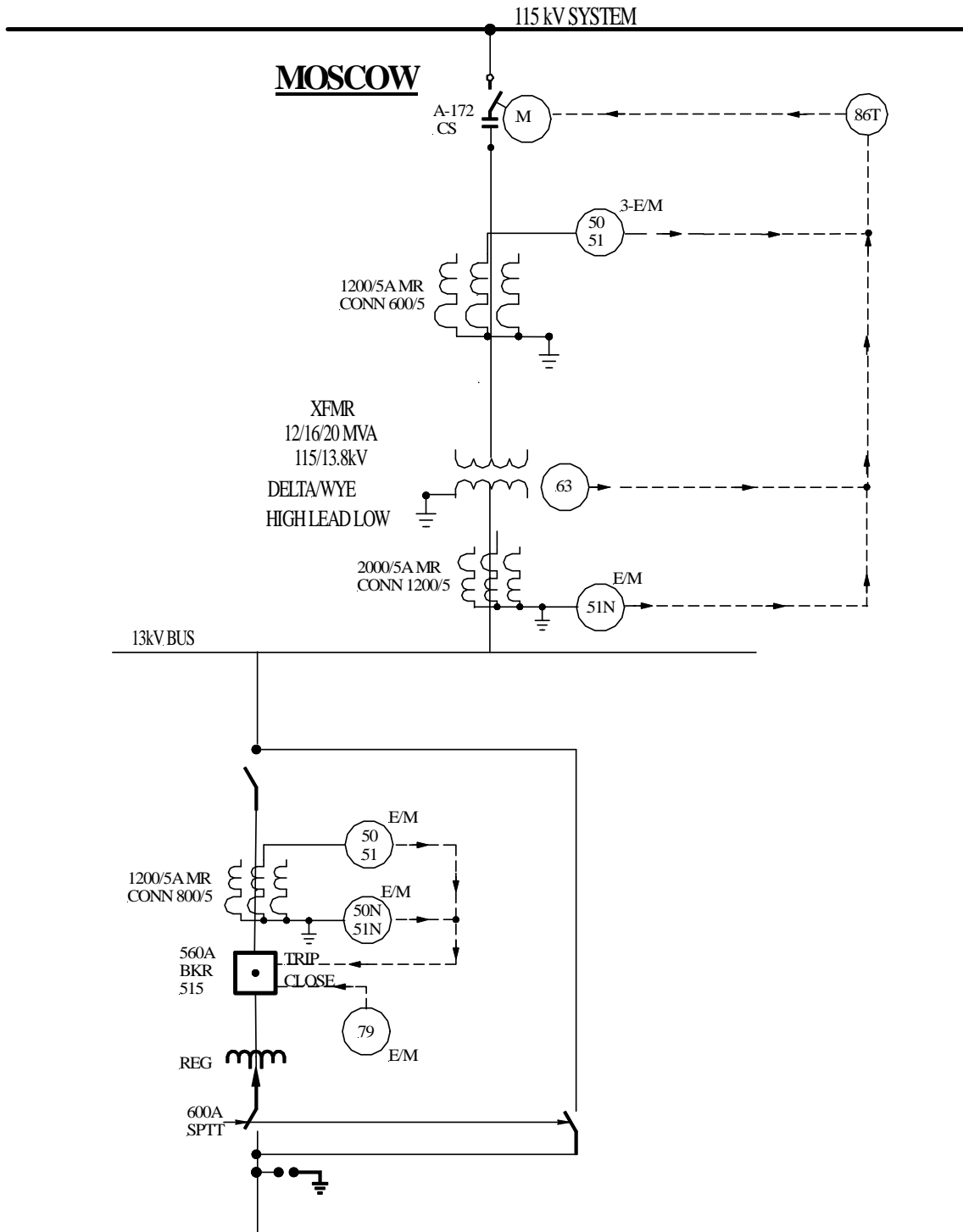


Figure 25. Moscow 115/13.8 kV Partial One Line.

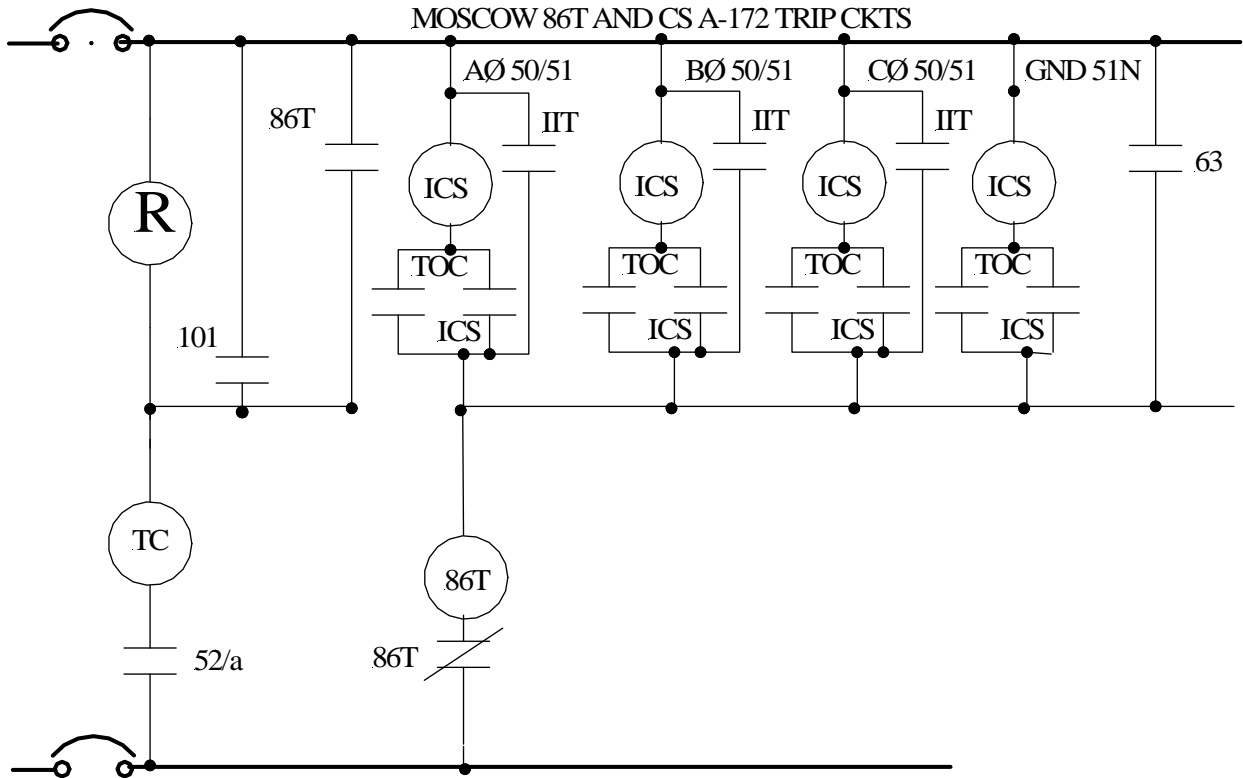
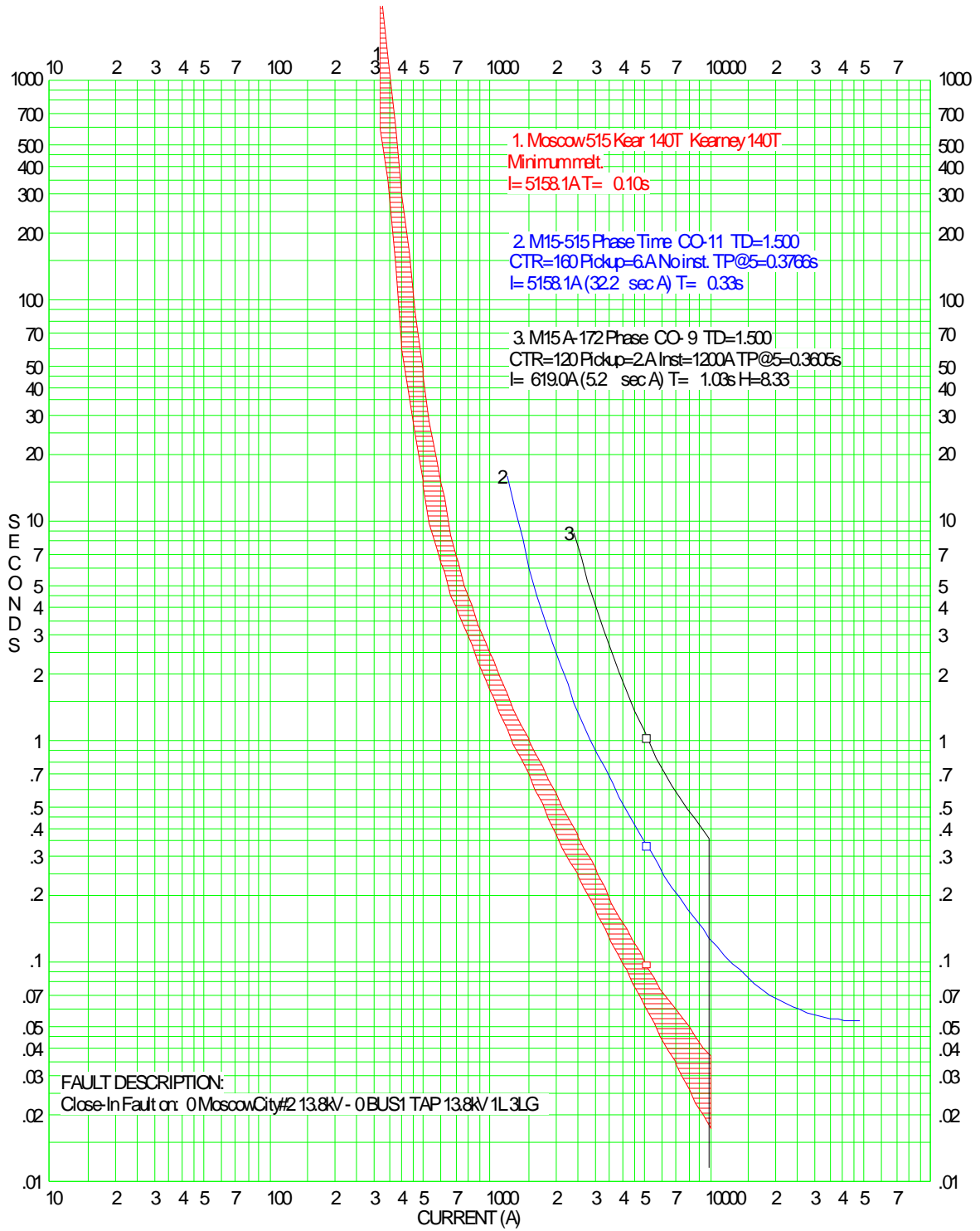


Figure 26. Moscow 86T and Circuit Switcher Partial Schematic.

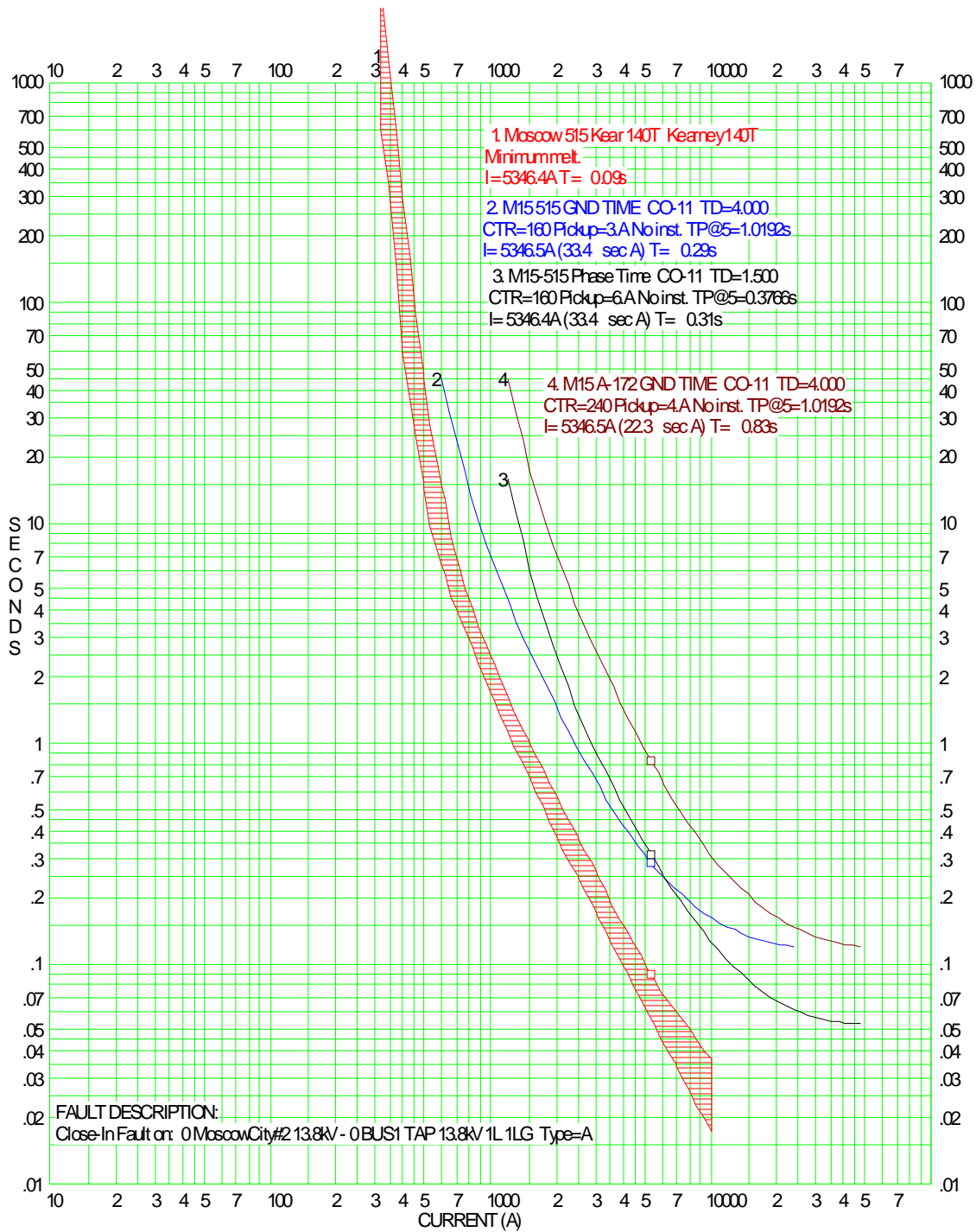
FEEDER AND TRANSFORMER PROTECTION WITH E-M RELAYS



TIME-CURRENT CURVES @ Voltage 13.8kV		By DLH
For	M15 A-172 CS with fdr 515 with Kearney 140T Fuse	No.
Comment	Three Phase Fault	Date 12/12/05

Figure 27. Coordinating E-M Relays for a 500 Amp Feeder Using a 140T fuse and Coordinating a CS Using E-M Relays with the 500 Amp Feeder for a Three Phase Fault.

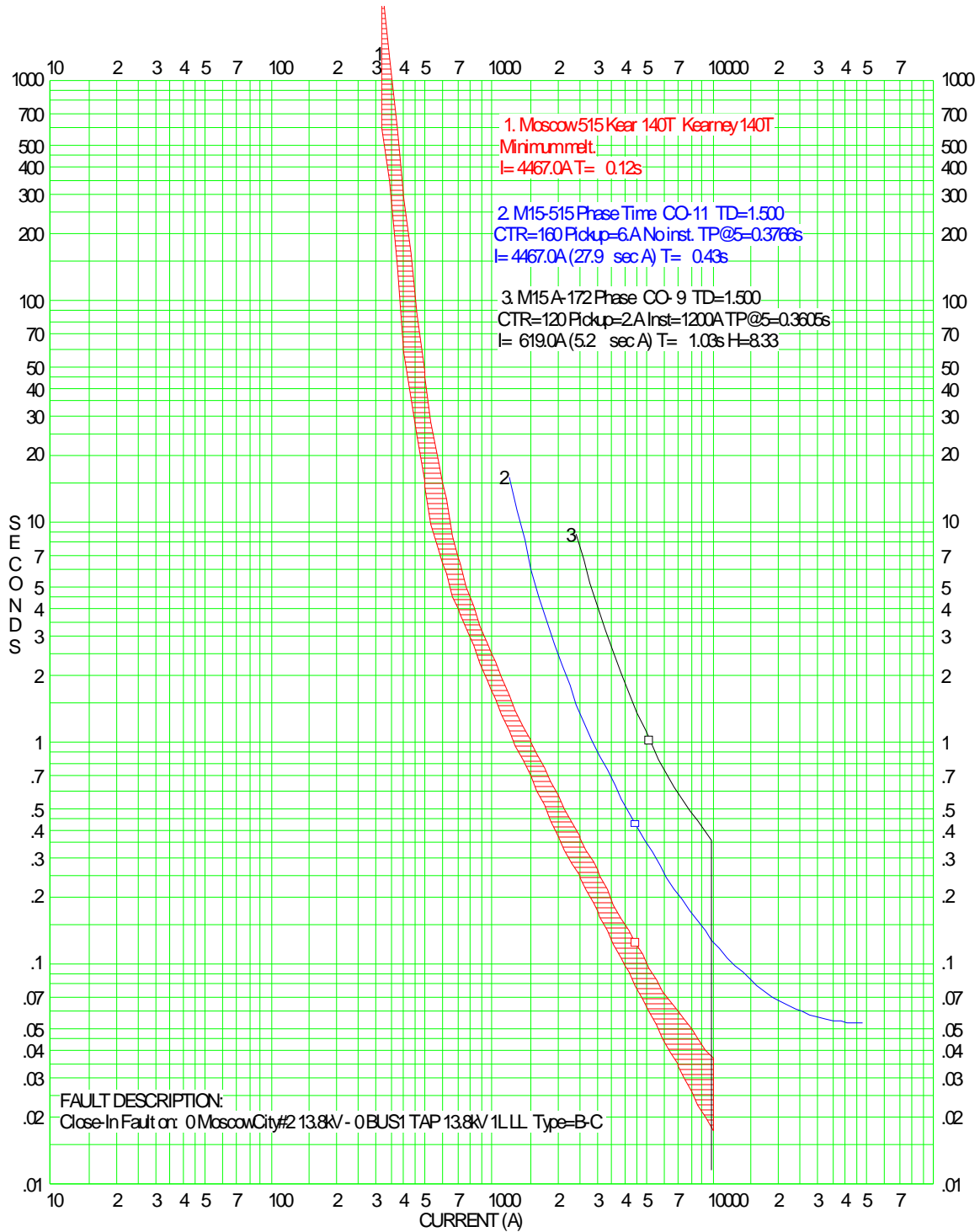
FEEDER AND TRANSFORMER PROTECTION WITH E-M RELAYS



TIME-CURRENT CURVES @ Voltage 13.8 kV		By DLH
For	Moscow CS with fdr 515 with 140T fuses	No.
Comment	Single Line to Ground Fault	Date 12/12/05

Figure 28. Coordinating E-M Relays for a 500 Amp Feeder Using a 140T fuse and Coordinating a CS Using E-M Relays with the 500 Amp Feeder for a Single Line to Ground Fault.

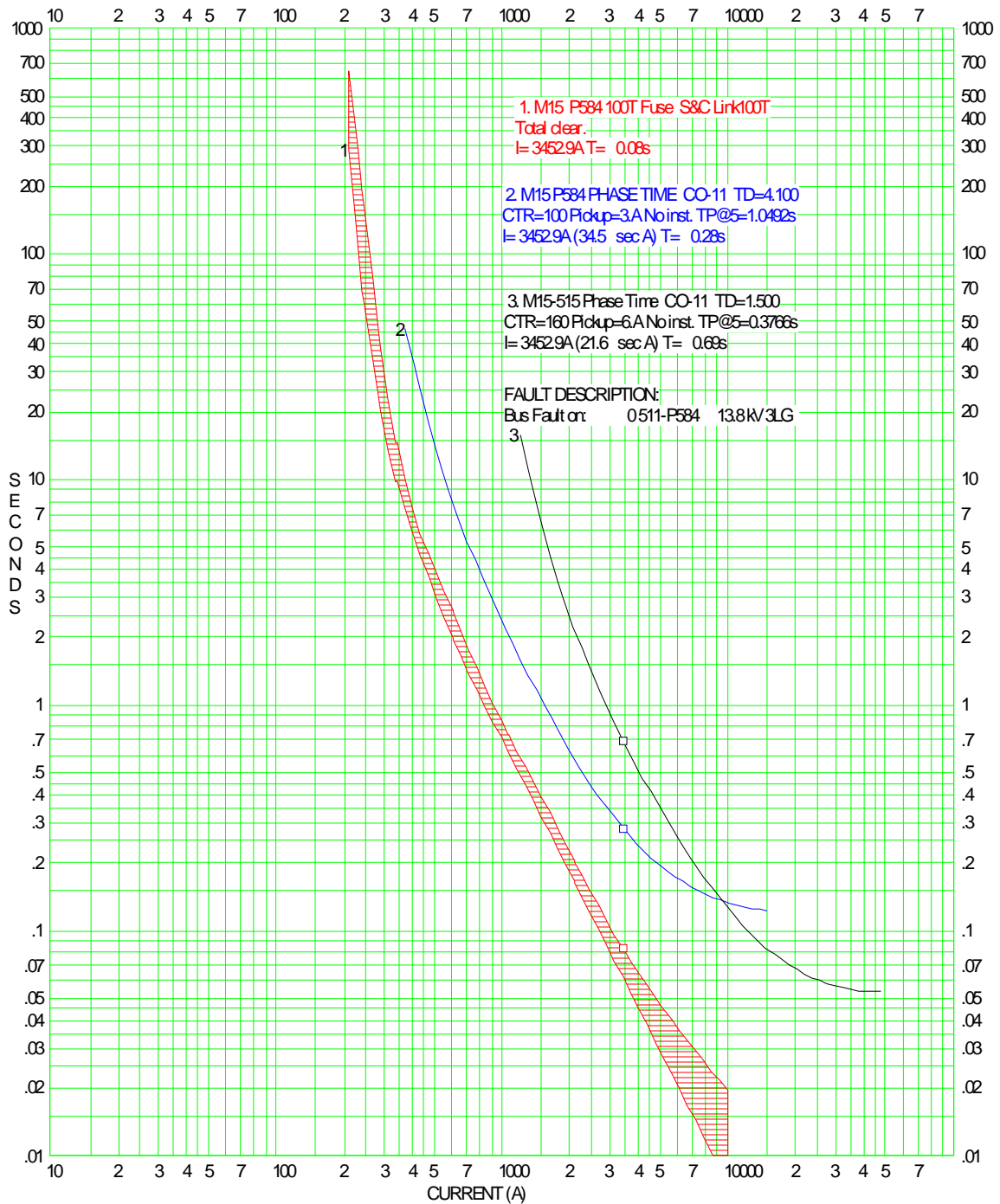
FEEDER AND TRANSFORMER PROTECTION WITH E-M RELAYS



TIME-CURRENT CURVES @ Voltage 13.8 kV		By DLH
For	Moscow CSA-172 with fdr 515 with 140T Fuse	No.
Comment	Line to Line Fault	Date

Figure 29. Coordinating E-M Relays for a 500 Amp Feeder Using a 140T fuse and Coordinating a CS Using E-M Relays with the 500 Amp Feeder for a Line to Line Fault.

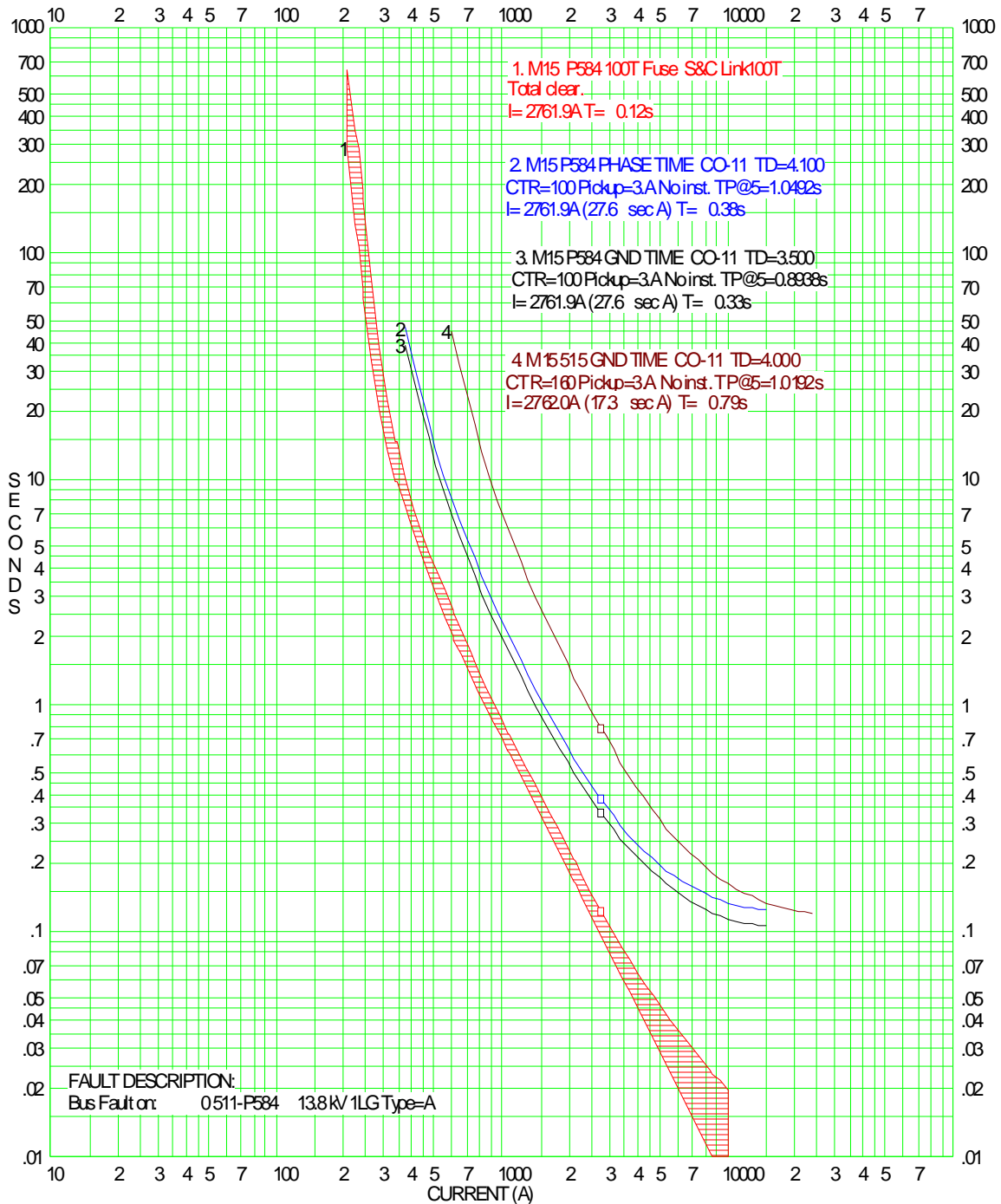
FEEDER AND TRANSFORMER PROTECTION WITH E-M RELAYS



TIME-CURRENT CURVES @ Voltage 13.8kV		By DLH
For M15515 with P584 with 100T		No.
Comment Three Phase Fault Example		Date 12/5/05

Figure 30. Coordinating E-M Relays for a Line Recloser Using a 100T fuse and Coordinating a 500 Amp Feeder Using E-M Relays with the Line Recloser for a Three Phase Fault.

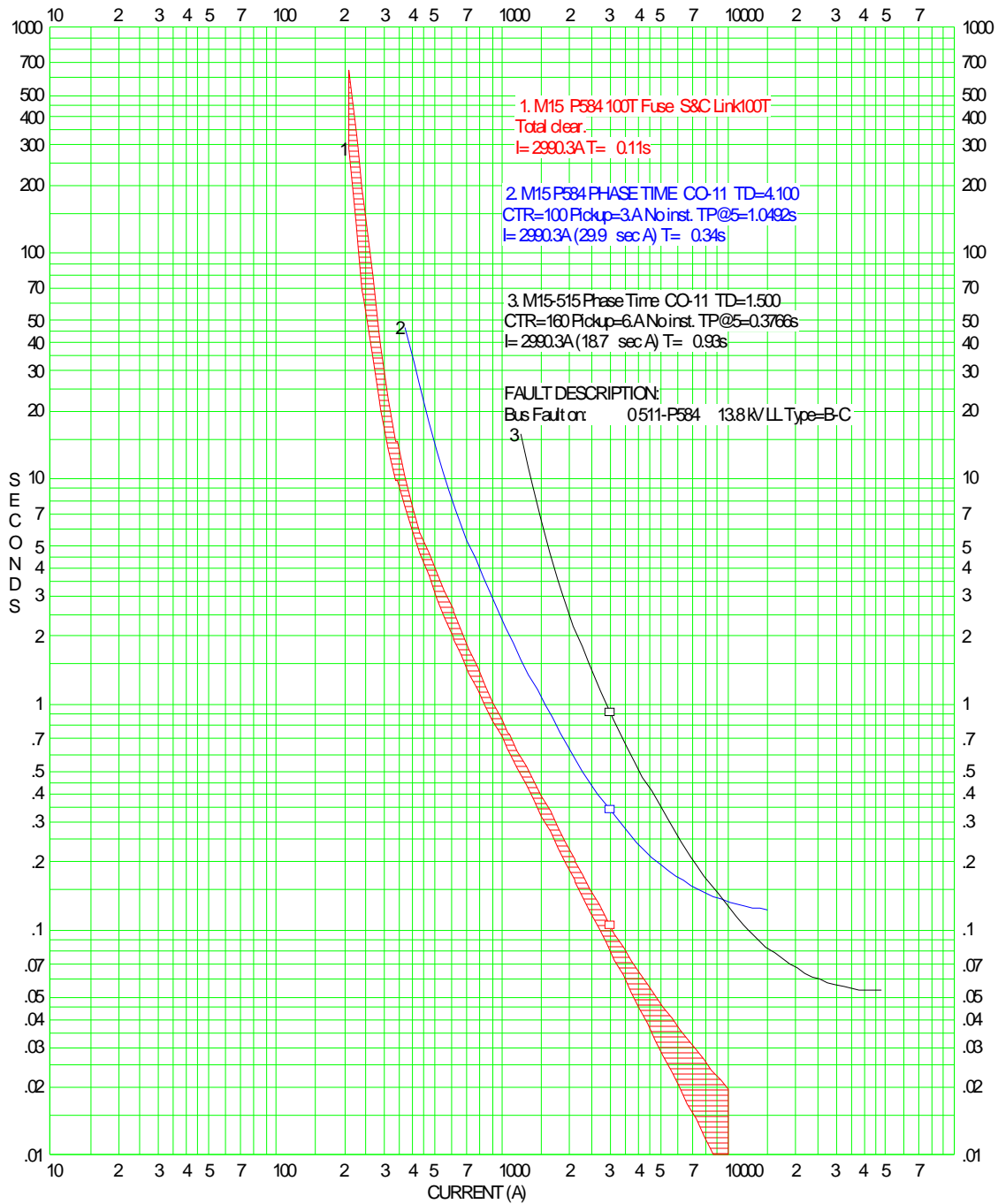
FEEDER AND TRANSFORMER PROTECTION WITH E-M RELAYS



TIME-CURRENT CURVES @ Voltage 138 kV		By DLH
For M15 515 with P584 with 100T fuse		No.
Comment Single Line to Ground Fault		Date 1/11/06

Figure 31. Coordinating E-M Relays for a Line Recloser Using a 100T fuse and Coordinating a 500 Amp Feeder Using E-M Relays with the Line Recloser for a Single Line to Ground Fault.

FEEDER AND TRANSFORMER PROTECTION WITH E-M RELAYS



TIME-CURRENT CURVES @ Voltage 13.8kV		By DLH
For M15 515 with P584 with 100T		No.
Comment Line to Line Fault Example		Date 12/5/05

Figure 32. Coordinating E-M Relays for a Line Recloser Using a 100T fuse and Coordinating a 500 Amp Feeder Using E-M Relays with the Line Recloser for a Line to Line Fault.

FEEDER AND TRANSFORMER PROTECTION USING MICROPROCESSOR RELAYS

The following is at a new station where we can use microprocessor relaying on all of the feeders plus the transformer. We will use SEL 351 and 587 relays for our example since that is Avista's present standard. Of course there are some general advantages to using MP relaying over E-M. Some of these are:

1. The taps are selectable in very small increments.
2. There are several independent units contained in the relay (up to 6 instantaneous and 2 time delay).
3. Internal logic programming capability.
4. Less CT burden (CT's can saturate with high burdens and high fault values and won't produce a good secondary current to the relay).
5. Event reporting.
6. Remote Communication capability.

Feeder – The normal relaying will use the SEL 351 phase, negative sequence and ground elements. We use one phase and ground instantaneous element. NOTE: We don't use the instantaneous negative sequence because of the possibility of false trips due to motor contributions for external faults. The time delay pickup units for phase, negative sequence and ground are used to operate an output contact to torque control some low set fast elements on the 50/51 transformer relay. The relay is also programmed to provide a breaker failure output in case the breaker fails to open. Again, for a 500 amp feeder we have:

1. Phase overcurrent:
 - 51P pickup - Set the pickup at 960 amps for the same reasons as the E-M relays.
 - 51P TL – Set the same as the E-M relays for the same reasons.
 - 50P pickup – Set similar to the E-M 50PF pickup. NOTE: This unit has a higher dropout characteristic than the E-M relays so it could probably be set closer to the 51P pickup.
2. Ground overcurrent:
 - 51G pickup – This is actually the residual element in the 351 which is obtained by adding the 3 phase currents. There is also a neutral element (single coil) that is not used. The pickup is the same as the E-M relay or 480 amps.
 - 51G TL – This is the same as the E-M relay.
 - 50G – This is the same as the E-M relay = 480 amps.
3. Negative Sequence:
 - 51Q pickup – This element can be set for similar criteria to the ground element since it doesn't respond to load. Similar to the ground which responds to $3I_0$, this unit responds to $3I_2$. That is; it should be set **as sensitive as possible with the lowest time lever** and still coordinate with the 140T with 0.2 seconds margin. The worst coordination case for this element is for a $\emptyset-\emptyset$ fault (see figures 8 & 11 for a comparison). For this fault if the fuse sees 6000 amps \emptyset flow, the negative sequence current is 3464 ($6000 \div \sqrt{3}$) and $3I_2 = 10,392$ amps. The similarity to the ground pickup is $480 * \sqrt{3} = 831$. Thus we wind up with $\cong 830$ amps minimum pickup to coordinate with the 140T. The advantage to this element is that it is

more sensitive than the phase element for the \emptyset - \emptyset fault. The difference in sensitivity is: $960 \cdot \sqrt{3} \div 830 = 2.0$.

- 51Q TL – The criteria is the same as for the ground unit.
 - 50Q pickup – We don't use this element because of the possibility of false trips.
4. Reclosing – This is the same as the E-M reclosing. The major difference is that we can choose the time from lockout to reset to allow more time for the cold load to subside and drop out the inst unit. We have been choosing 30 seconds.

Transformer - The normal transformer relaying will consist of a SEL 351 connected to the 115 kV BCT's and the neutral element (single coil) connected to the 13.8 kV BCT's (or possibly a neutral CT). In addition to the normal tripping elements, the SEL 351 will also use 'fast' ($\cong 4$ cycles) elements that are torque controlled by the feeder time pickup elements. That is; if an overcurrent element picks up on a feeder, it will block the 351 torque controlled element. Of course this can't be used at a station that has any feeders that use E-M relays.

NOTE: One of the major differences between using all microprocessor relays and E-M relays is that with the microprocessor relays, you can coordinate like elements with like elements only. For example, with the E-M we coordinate the transformer ground with the feeder phase because the feeder ground could be out of service. With microprocessors, the entire relay would be out of service and not just one element. Therefore, we can coordinate the transformer ground with just the feeder ground and obtain a more sensitive setting.

Typical settings for both a 12/16/20 MVA and an 18/24/30 MVA transformer coordinating with the 500-amp feeder above would be:

1. SEL 351 Phase overcurrent (on 115 kV transformer BCT's):
 - 51P pickup – This is identical to the E-M relay setting or 240 amps for a 20 MVA and 360 amps for a 30 MVA.
 - 51P TL – This has to coordinate with the feeder phase for a maximum feeder fault with 0.4 seconds coordination. In this case we could consider this to be a $3\emptyset$ fault since we will have negative sequence relays on the feeder to take care of the \emptyset - \emptyset fault.
 - 50P1 pickup – This is the direct trip phase element and is set to not detect a 13.8 kV fault similar to the E-M instantaneous setting. However, this does not respond to DC offset so our setting is $\cong 1.3 \cdot \text{MAX } 13.8 \text{ kV fault}$.
 - 50P2 pickup – This is the torque controlled element. We have set this to account for inrush and still be as sensitive as possible.
 - **Inrush** - For this unit we need to consider transformer inrush current since it can operate 'fast' ($\cong 4$ cycles time delay). A rule of thumb we have used is that a typical transformer inrush RMS current can be as high as $\cong 8$ times the transformer base rating (old E-M differential relays had the unrestrained overcurrent trip fixed at ten times the TAP of the restrained trip and the TAP would be set at \cong transformer full load). Note that the SEL 351 only responds to the 60 HZ fundamental and that this fundamental portion of inrush current is $\cong 60\%$ of the total. So to calculate a setting for a SEL 351, we could use the 8 times rule of thumb along with the 60% value. For a 12/16/20 MVA transformer, the calculation would be $8 \cdot 12 \cdot 5 \cdot 0.6 = 288$ amps. For an

18/24/30 it would be $8 \times 18 \times 5 \times 0.6 = 432$ amps. Generally, we would set this unit at about 1.5 times the time unit to be safe. So for a 12/16/20 we would set $1.5 \times 240 = 360$ amps and for an 18/24/30 we would set $1.5 \times 360 = 540$ amps.

NOTE: For comparison I have included some inrush characteristics from a SEL 351 that energized 6 – 2.25 MVA (13.5 MVA total) 480/13.8 kV transformers from the 13.8 kV side (see Figures 23 & 24). These transformers were connected delta (480V)/wye(13.8 kV). The A phase was the highest current. The filtered current (that the elements respond to) to the relay showed a maximum AØ of 944 amps and this died down to 250 amps in 26 cycles. See Figure 24. The highest current was $944 \div 41.8 = 22.6$ MVA which is $22.6 \div 13.5 = 1.67$ times the transformer total rating. Using these values for a 12 MVA we would have $1.67 \times 12 \times 5 = 100$ amps. The unfiltered current to the relay showed a maximum A-phase current of 2016 amps, which died down to 504 amps in 26 cycles. See Figure 23. This maximum is $2016 \div 41.8 = 48.2$ MVA = $48.2 \div 13.5 = 3.6$ times the total transformer rating.

2. SEL 351 ground (residual) overcurrent (on 115 kV BCT's) NOTE: This is calculated from the phase quantities:
 - 51G pickup – We can set this very low since it doesn't have to coordinate with anything. We have been setting $\cong 120$ amps primary.
 - 51G TL – Also can set low. Have been setting at TL 1.0.
 - 50G pickup – This can also be set low. We have been choosing a setting equal to the 50P2 TC setting simply because we don't feel we need more sensitivity but it really can be set as low as the time unit since the inrush to the delta doesn't contain any 3I0 current. A typical setting is 120 to 360 amps.
3. SEL 351 neutral overcurrent (on 13.8 kV BCT's):
 - 51N pickup – We can set as low as possible and still coordinate with the feeder ground settings (not phase). Since the transformer can have more unbalance than the feeder we have been setting $\cong 1.33$ times the feeder ground pickup or 640 amps when coordinate with 500 amp feeders.
 - 51N TL – We coordinate with the feeder ground with 0.4 seconds margin.
 - 50N1 – We can't set a direct trip element so we use this as a torque controlled element only. Again we need to set above the feeder ground setting and to be a little conservative we have been setting $\cong 720$ amps with 4 cycles time delay.
4. SEL 351 negative sequence (on 115 kV BCT's):
 - 51Q pickup – We can set this as low as possible and still coordinate with the feeder negative sequence relay. The worst case is for a Ø-Ø fault. If we simply take the transformer ratio of 8.33:1 and the 830 amp feeder setting, we could set this down to $830 \div 8.33 = 100$ amps. However, because of the transformer, we are a little more conservative and have used about 200 amps or 2.0 times. For comparison with the phase overcurrent sensitivity for 13.8 kV Ø-Ø fault we have the following example: At Moscow (if we had MP relays) on a 12/16/20 for a 13.8 kV Ø-Ø fault the 115 kV sees 619 amps Ø flow and 309 amps I2. See Figures 13 & 14. The margin for the phase OC PU to see the fault is $619 \div 240 = 2.58$. The margin for the negative sequence OC PU would be: $3 \times 309 \times 200 = 4.64$

or 1.8 times greater than the phase OC. NOTE: It would be 2 times like the feeder but one of the phases sees the same current as for a 3 \emptyset fault.

- 51Q TL – Set for 0.4 seconds coordination.
- 50Q1 pickup and time – This is a direct trip element and is set not to detect a 13.8 kV fault. A typical setting would be \cong 1200 – 1800 amps or 1.3*MAX 13.8 kV fault. NOTE: We time delay this by 2 cycles (along with the high setting) to avoid false trips.
- 50Q2 pickup and time – This is a torque controlled element and can be set low with 4 cycles time delay. Since the unit responds to inrush and can see as much as the phase instantaneous units, we need to set similar to the 50P2 unit (360 & 540).

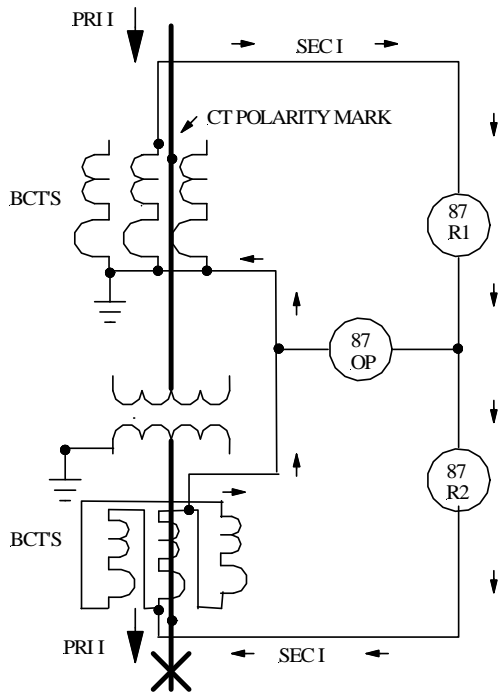
NOTE: On the transformer inrush tests we observed a maximum I₂ filtered current of 331 so 3I₂ = 993 (the max \emptyset was 944) so in terms of transformer rating this is 1.75 times the total rating. This says that we really should be using the same pickup values as the \emptyset .

- SEL 587 – This relay is connected to both the high and low side transformer BCT's. Basically a normal E-M transformer differential relay contains a harmonic restrained differential unit which uses a 2nd harmonic restraint to prevent a trip during transformer inrush and a variable percentage trip characteristic to prevent a trip for external faults in the presence of CT saturation. That is; the higher the current through the restraint coils, the greater percentage of that current needs to flow in the operate coil to get a trip. The relay also has taps for the two windings to correct the high and low current magnitudes so similar currents flow in each restraint winding for external faults. There are generally about 8 taps between 2.9 and 8.7 amps. There is also an unrestrained differential unit set around 10 times the upper tap value which was generally chosen to be the same as the transformer full load current. Normally the unrestrained unit would operate slightly faster for high magnitude transformer faults. Since the distribution transformer is connected delta – wye the transformer CT's have to set wye – delta to compensate for the phase shift. See Figure 33.
- Some of the advantages and ways we use the MP SEL 587 relay over the E-M relays are:
 - In addition to similar differential units as above, it contains independent overcurrent units for both windings similar to a MP overcurrent relay. Thus it can also operate for external faults and completely backup the transformer overcurrent relay.
 - Different differential slopes can be set in the relay, which provides greater flexibility.
 - You can use more than one harmonic to restrain the differential.
 - The transformer phase angle can be set in the relay, which allows you to set all CT's in wye.
 - The unrestrained OC element can be set independently from the differential tap value. We use this feature to set this based on the transformer BASE rating and not the FOA rating to avoid tripping on transformer inrush. That is; on a 12/16/20 we use the 12 MVA rating and not the 20 MVA rating because the inrush characteristic is a function of the base rating.

FEEDER AND TRANSFORMER PROTECTION WITH MP RELAYS

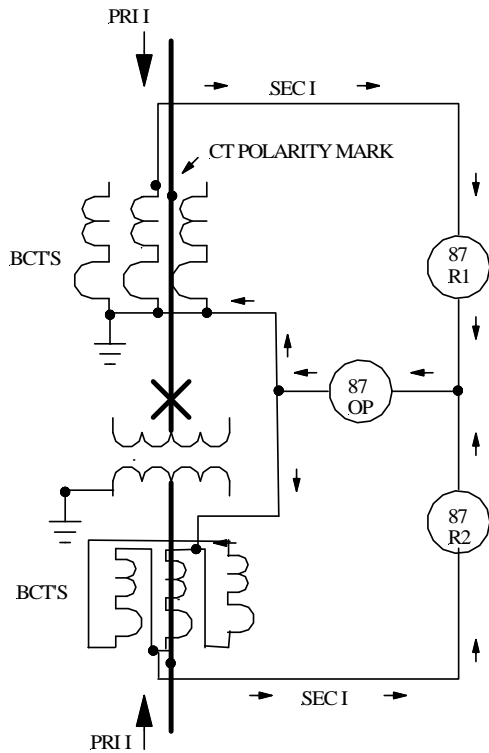
- Again you can torque control the instantaneous elements like we did for the 351 but we didn't feel this was needed. Instead we used direct trip inst elements on the high side winding while the low side winding can't use inst elements.

FEEDER AND TRANSFORMER PROTECTION WITH MP RELAYS



CURRENT FLOW THROUGH AN E/M 87 DIFFERENTIAL RELAY FOR AN INTERNAL AND EXTERNAL FAULT

EXTERNAL FAULT
THE SECONDARY CURRENTS FLOW THROUGH BOTH RESTRAINT COILS IN THE SAME DIRECTION AND THEN CIRCULATE BACK THROUGH THE CT'S. THEY DO NOT FLOW THROUGH THE OPERATE COIL



INTERNAL FAULT
THE SECONDARY CURRENTS FLOW THROUGH BOTH RESTRAINT COILS IN OPPOSITE DIRECTIONS, ADD AND THEN FLOW THROUGH THE OPERATE COIL AND BACK TO THE RESPECTIVE CT'S

Figure 33. Current Flow Through an E-M Differential Relay for an External and an Internal Fault.

FEEDER AND TRANSFORMER PROTECTION WITH MP RELAYS

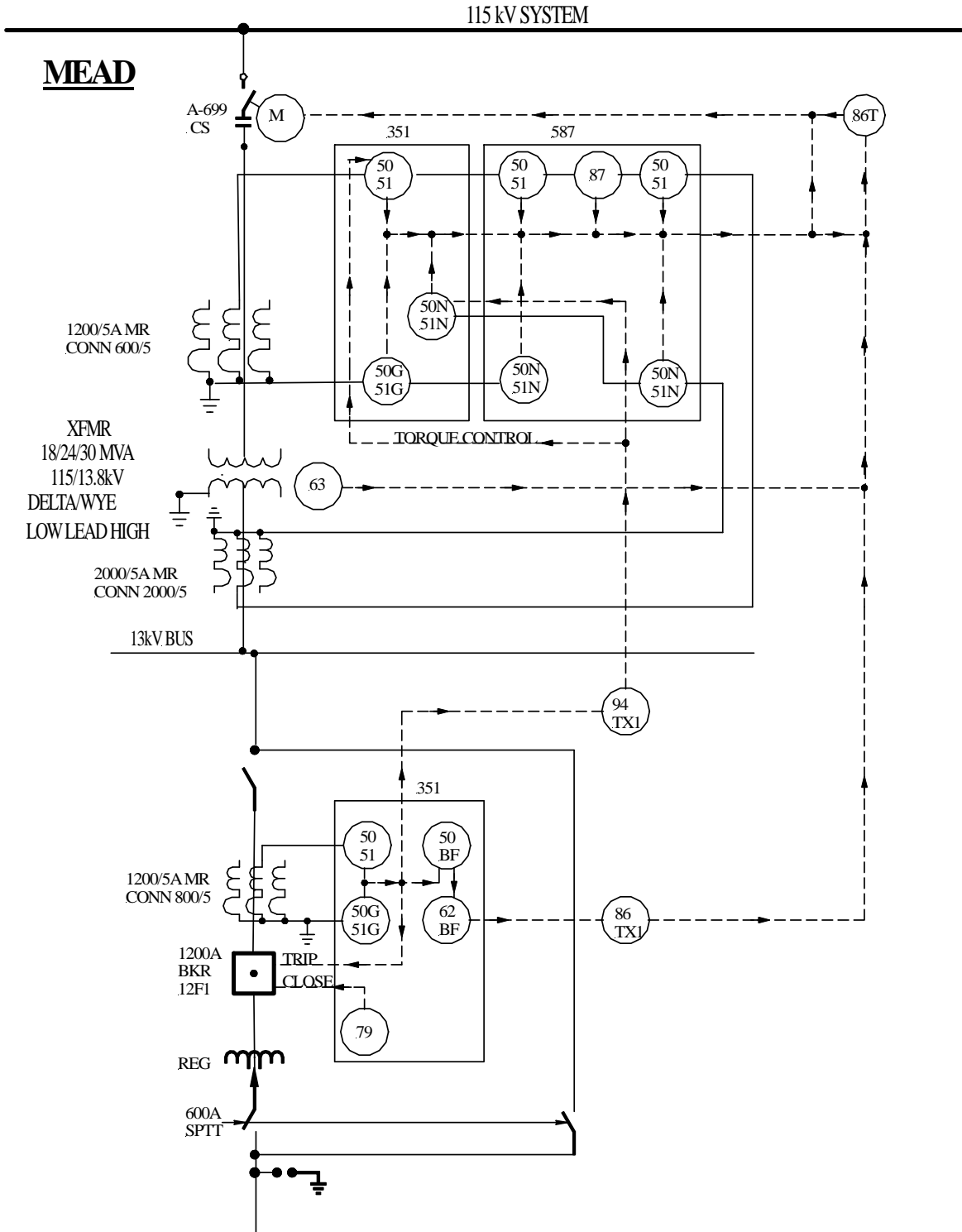


Figure 34. Mead 115/13.8 kV Partial One Line.

FEEDER AND TRANSFORMER PROTECTION WITH MP RELAYS

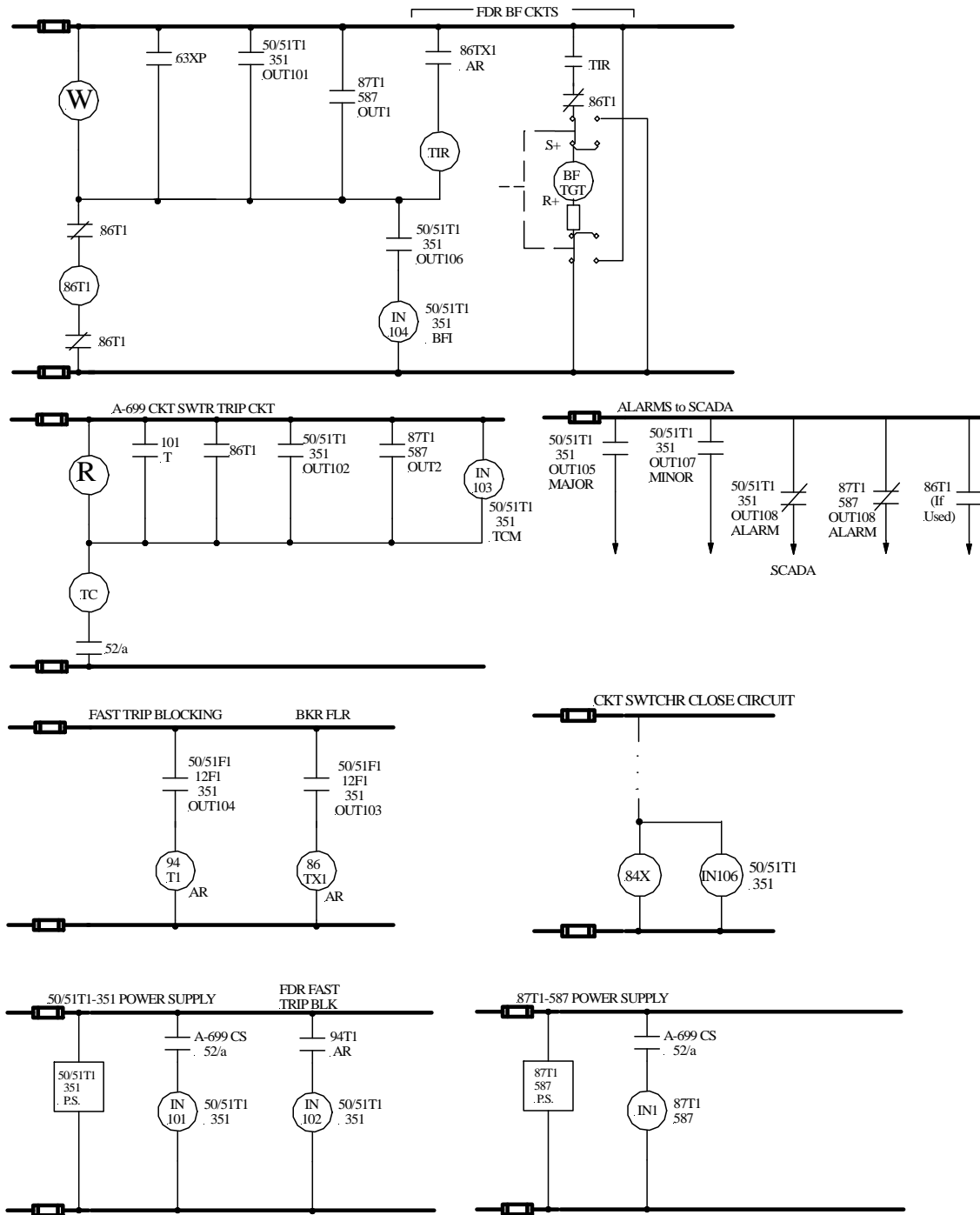


Figure 35. Mead circuit switcher and lockout circuit partial schematic.

FEEDER AND TRANSFORMER PROTECTION WITH MP RELAYS

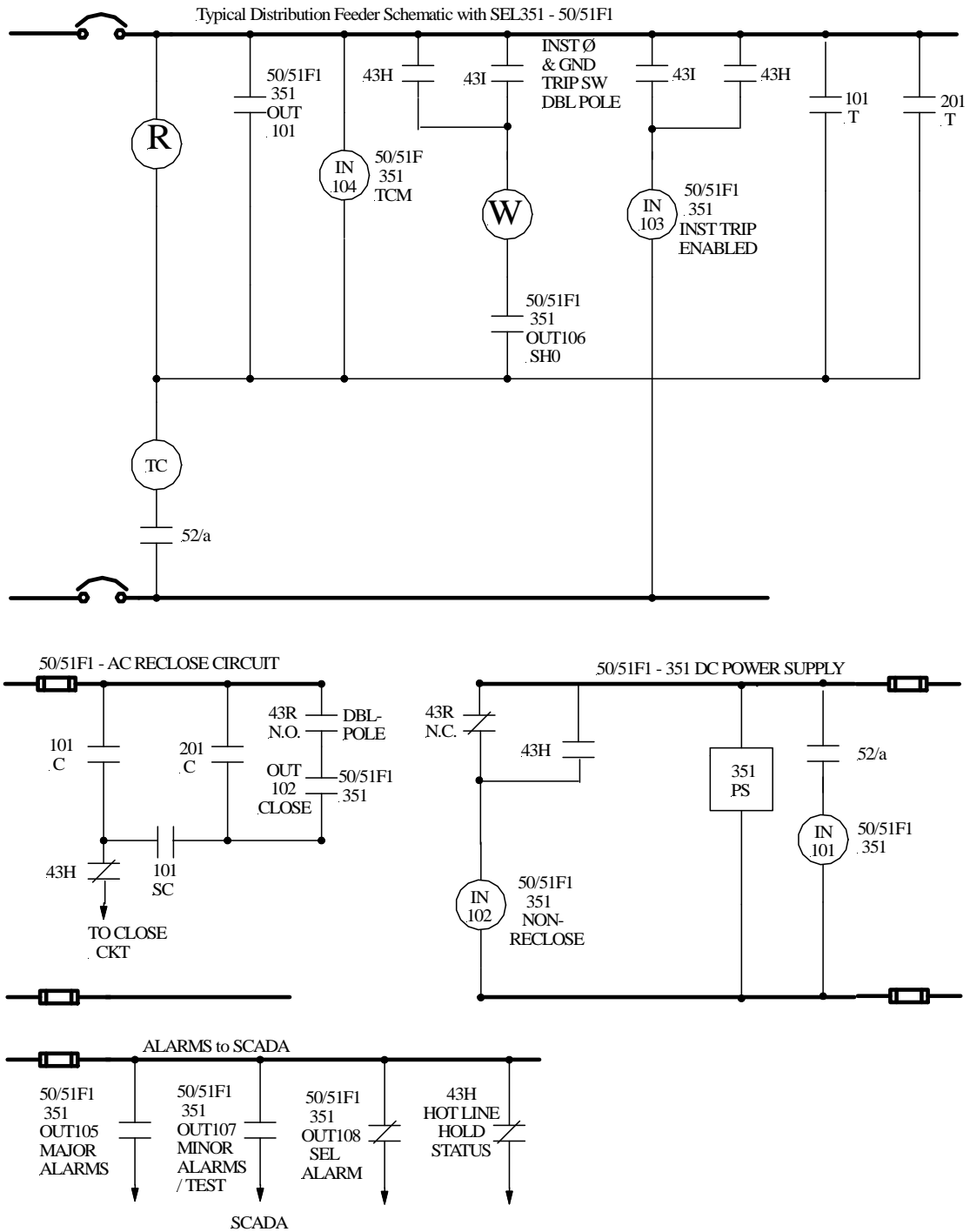
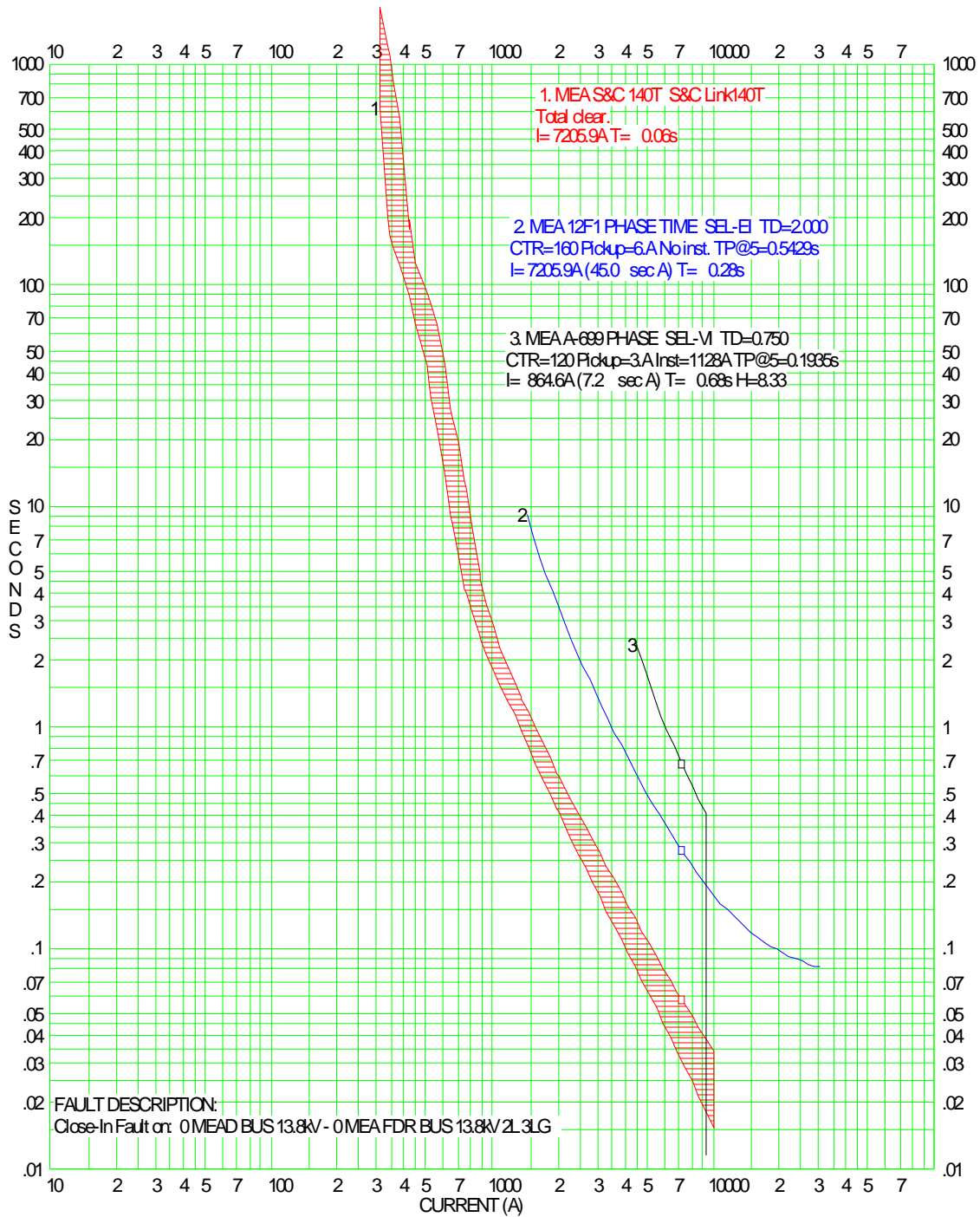


Figure 36. Mead Feeder Partial Schematic.

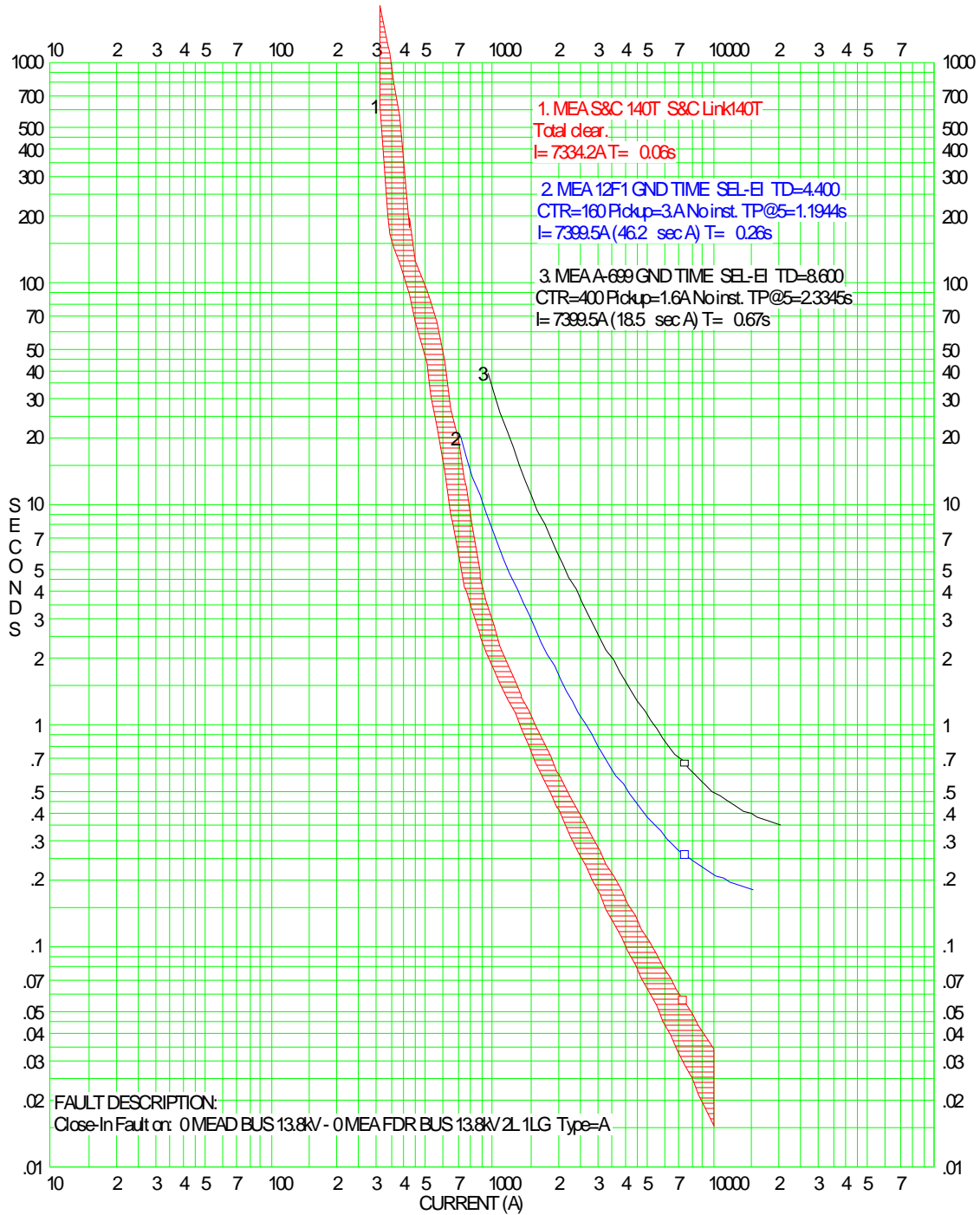
FEEDER AND TRANSFORMER PROTECTION WITH MP RELAYS



TIME-CURRENT CURVES @ Voltage 13.8kV		By DLH
For Coordinating Mead A-699 with 12F1 with S&C 140T		No.
Comment Three Phase Fault		Date 12/12/05

Figure 37. Coordinating MP Relays for a 500 Amp Feeder Using a 140T fuse and Coordinating a CS Using MP Relays with the 500 Amp Feeder for a Three Phase Fault.

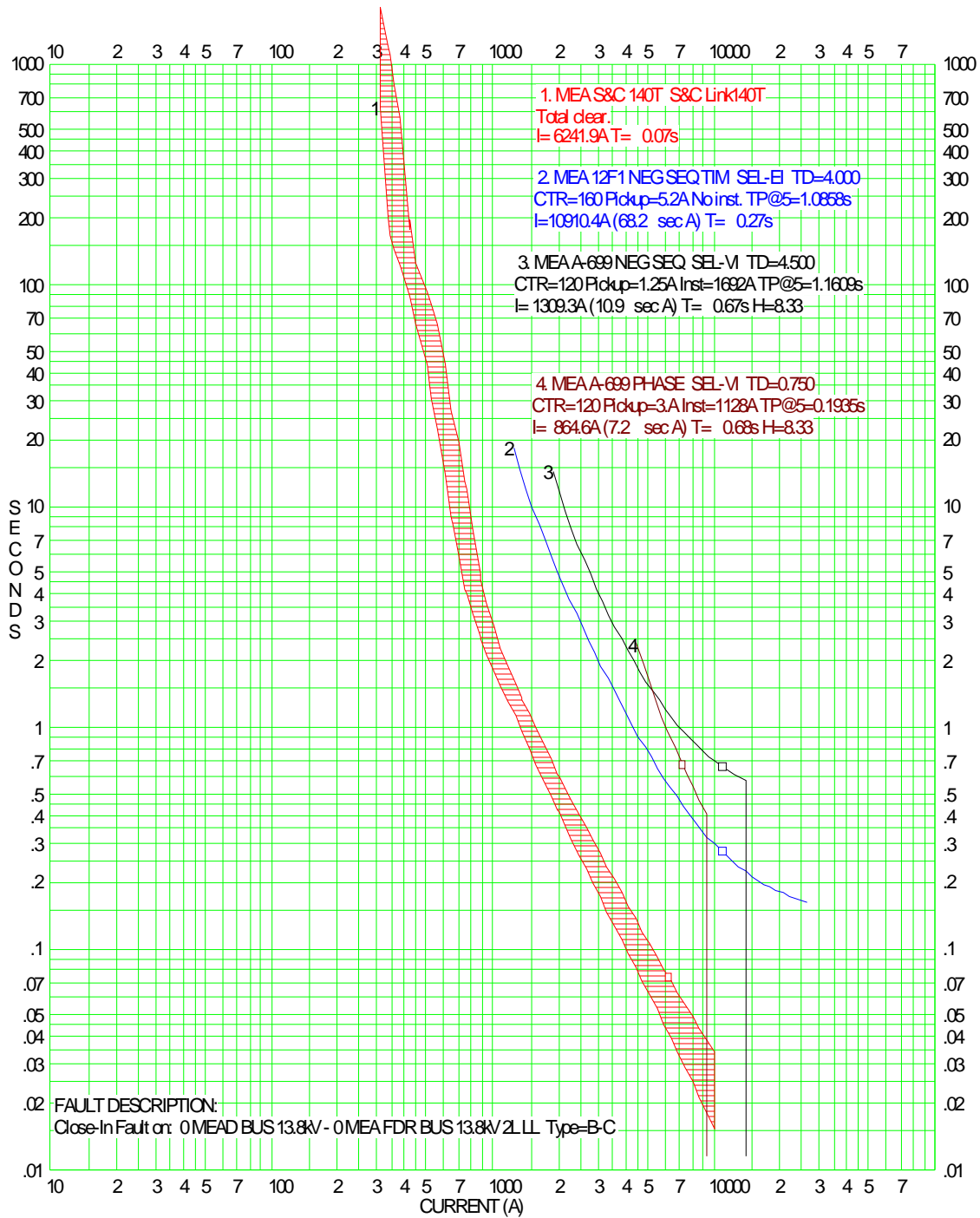
FEEDER AND TRANSFORMER PROTECTION WITH MP RELAYS



TIME-CURRENT CURVES @ Voltage 13.8kV		By DLH
For Coordinating Mead A-699 with 12F1 with S&C 140T		No.
Comment Single Line to Ground Fault		Date 12/12/05

Figure 38. Coordinating MP Relays for a 500 Amp Feeder Using a 140T fuse and Coordinating a CS Using MP Relays with the 500 Amp Feeder for a SLG Fault.

FEEDER AND TRANSFORMER PROTECTION WITH MP RELAYS



TIME-CURRENT CURVES @ Voltage 13.8kV		By DLH
For Coordinating Mead A-699 with 12F1 with S&C 140T		No.
Comment PhasetoPhaseFault		Date 12/12/05

Figure 39. Coordinating MP Relays for a 500 Amp Feeder Using a 140T fuse and Coordinating a CS Using MP Relays with the 500 Amp Feeder for a Ø-Ø Fault.

PROBLEM – MOSCOW EXAMPLE

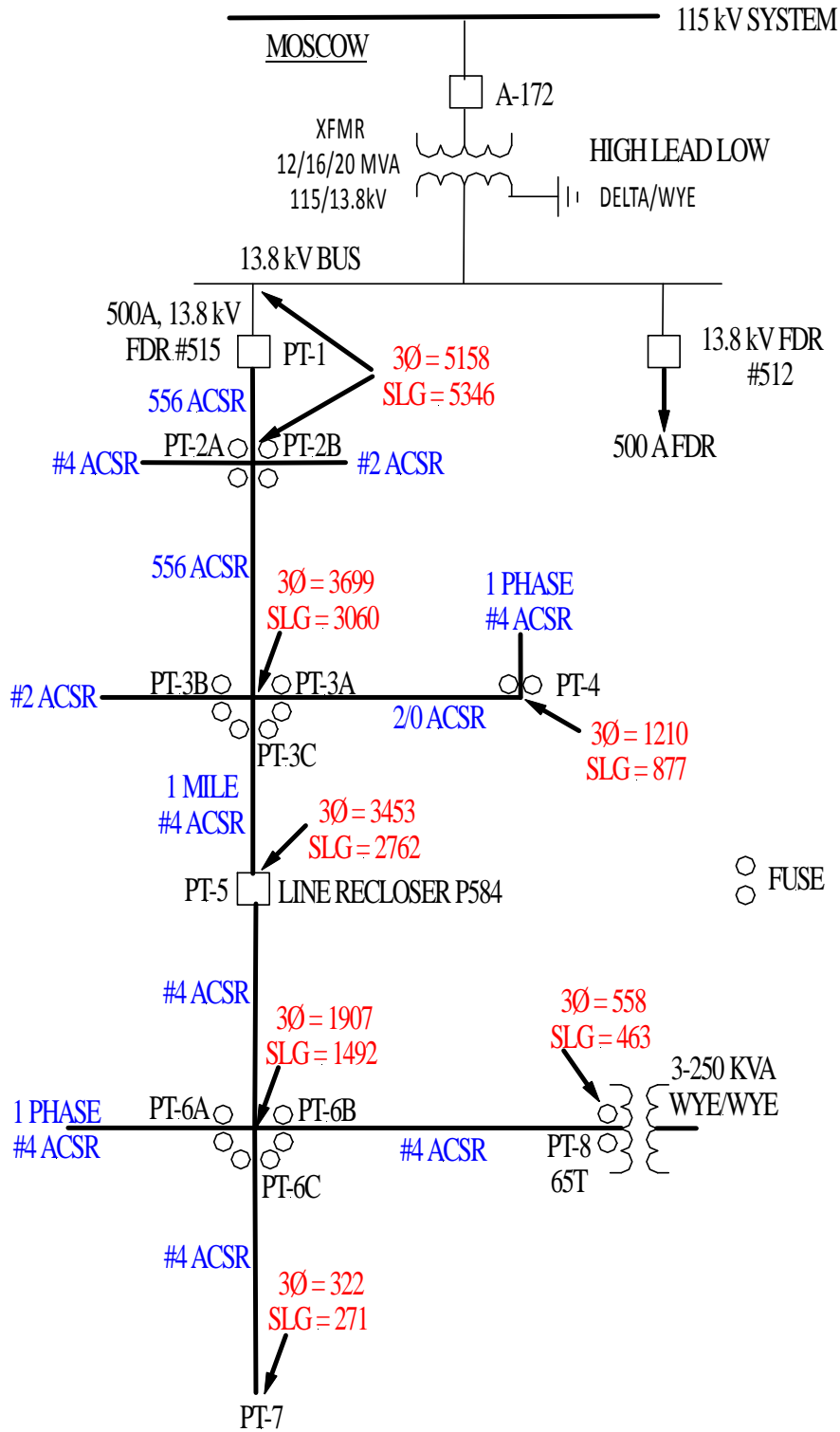


Figure 40. Moscow feeder 515 (same as Figure 1)

Generally before we start the protection design on a feeder we know some things about the feeder such as:

- The general feeder rating (300 or 500 amps). If it's a 500 amp feeder we know the phase pickup will be around 960 amps. In this case the Moscow feeder #515 is a 500 amp feeder and it has existed for some time.
- We know what the bus fault duty is. In this case the 3 \emptyset fault is 5,188 amps and the SLG is 5,346. This tells us that the highest fuse size will probably be a 140T so the ground pickup will be about 480 amps or higher. NOTE: In rare cases we may have to use a 200 amp fuse or larger but we don't like to use them if we don't have to because we have to raise the ground pickup to coordinate with it and this reduces our sensitivity to detect faults.
- This feeder already was using a line recloser at the location shown and we found out from the Field Engineer that they wanted to keep a recloser there. In fact the reason we were looking at this feeder was because we were replacing the older recloser with a newer relayed recloser.
- We then have to run feeder fault studies (normally done by a Distribution Engineer) and look at the feeder configuration so we know what fusing and relay settings to use.
- We then generally start near the end of the feeder and work back towards the substation. A lot of times though we have to go back and forth because our first choice of a fuse size may not work correctly when we figure out the protection towards the substation and we have to make compromises.

The following is an example of how we arrive at those answers. NOTE: The actual Moscow feeder 515 does not look exactly like this even though the substation and line recloser settings we will arrive at are the actual settings.

- POINT 8: This is a customers load and we are using 3-250 KVA transformers to serve the load. The full load of this size of bank is 31.4 amps. The Avista transformer-fusing standard says to use a 65T on this transformer so that's what we'll choose.
- POINT 7: This is the end of a 3 \emptyset lateral and the fault duty is: 3 \emptyset = 322 amps and SLG = 271 amps.
- POINT 6A: The fault duty at PT 6 is: 3 \emptyset = 1,907 amps and SLG is 1,492. It is feeding a short single phase #4 ACSR lateral with not much load on it (that's why we didn't include the fault current at the end of the lateral).
 - Temporary Faults - From Table 1 we see that a 65T fuse can be protected up to 1,650 amps for temporary faults and the SLG is 1,492 amps (SLG because it's a single phase lateral).
 - Conductor Protection - From Table 7 we see that #4 ACSR can be protected by a 100T or smaller fuse.
 - Fault Detection - We aren't worried about detecting the fault at the end of the feeder or coordinating with other fuses.
 - Loading – Assume the load is small so don't need to worry.
 - So what fuse size should we use?

- POINT 6B: Here we have a 3Ø lateral feeding to a 65T at the end so what fuse size should we use?
 - Temporary Faults - From Table 1 we see that an 80T fuse can be protected up to 2,050 amps for temporary faults and the 3Ø fault is 1,907 amps so we could choose an 80T or higher from that standpoint.
 - Coordination - From Table 2 we see that an 80T will coordinate with a 65T at 2,700 amps with no preloading or 1,400 amps with preloading and the maximum fault at the 65T is 558 amps. So we could choose an 80T or higher.
 - Conductor Protection - From Table 7 we see that #4 ACSR can be protected by a 100T or smaller fuse.
 - Fault Detection - Under the Relay Setting Criteria we want to detect the minimum end fault with a 2:1 margin. The SLG is 463 so the maximum fuse we could use would be: $463/2$ (2:1 margin) = 231 amps so the largest fuse we could use is $231/2$ (blows at twice the rating) = 115 so we could use a 100T or smaller fuse for this criteria.
 - Loading – Assume the load at the end is all there is so no need to worry.
 - So what fuse size should we use?

- POINT 6C: Here we have a 3Ø lateral feeding to point 7 with a SLG of 271 amps.
 - Temporary Faults - From Table 1 we see that an 80T fuse can be protected up to 2,050 amps for temporary faults and the 3Ø fault is 1,907 amps so we could choose an 80T or higher from that standpoint.
 - Conductor Protection - From Table 7 we see that #4 ACSR can be protected by a 100T or smaller fuse.
 - Fault Detection - Under the Relay Setting Criteria we want to detect the end fault with a 2:1 margin. The SLG is 271 so the maximum fuse we could use would be: $271/2$ (2:1 margin) = 135 amps so the largest fuse we could use is $135/2$ (blows at twice the rating) = 67 so we could use a 65T or smaller fuse for this criteria. NOTE: Protecting the fuse for temporary faults is not as important as detecting the fault with adequate margin so we would sacrifice the fuse protection in order to gain sensitivity to detect the fault.
 - Loading – Assume the load is small so don't need to worry.
 - So what fuse size should we use?

- POINT 5: This is the point of the line recloser. Here we have a 3Ø line of #4 ACSR feeding to point 6.
 - Temporary Faults - The fault duties at the recloser are: $3Ø = 3,453$ amps and $SLG = 2,762$. We will assume we have a fused lateral just beyond the line recloser and we want to protect it for temporary faults. From Table 1 we see that we can protect a 100T fuse up to 2,650 and a 140T up to 3,500 amps. Therefore, from this standpoint we would want to be able to use a 140T fuse beyond the recloser.
 - Conductor Protection - From Table 7 we see that #4 ACSR can be protected by a 100T or smaller fuse. That means that we won't be able to set the line recloser to coordinate with a 140T and still protect the conductor. Therefore, we have to compromise and we will sacrifice the fuse protection for

temporary faults in order to gain protection for the conductor. NOTE: This normally isn't too bad because most faults are SLG and are somewhat less than the calculated value because of fault resistance and distance to the fault out on the lateral.

- Coordination – We will try and coordinate with a 100T fuse and still protect the #4 ACSR conductor. Once we determine the overcurrent pickup values, we will choose a Time Lever to provide 0.2 seconds (see Table 6) coordination with the fuse and then will recheck to determine if we are satisfied with the conductor protection.
 - Fault Detection & Loading - The loading information we obtained from the Distribution Group is 84 amps normal and cold load \cong 2 times = 168 amps. Therefore, we can set the phase PU down to \cong 200 amps which would carry the load and pick it up cold load. However, #4 ACSR can carry around 140 amps (see Table 4) so we would probably want to set about 300 amps to allow for load growth. Also the minimum pickup we can use and still coordinate with a 100T is 300 amps (see Figure 32). NOTE: We do not set the phase overcurrent to protect the conductor from normal or emergency loading.
 - The \emptyset - \emptyset fault at point 6 is $0.866 * 1907 = 1,651$ so our margin to detect that fault would be $1651/300 = 5.5:1$ so no problem with the 300 amps \emptyset PU from that standpoint (used \emptyset - \emptyset because it's the minimum multi phase fault).
 - SLG Fault Detection – The SLG at point 6 is 1,492 so we could set the ground up to $1492/2 = 745$ amps and still detect the fault. However, our criteria says to set as low as possible and still coordinate with the largest downstream device and from above we're trying to use a 100T. Again this is 300 amps so in this case the ground PU will be set the same as the phase.
 - Instantaneous Units – The phase instantaneous will be set at 350 A and the ground instantaneous unit will be set at 300 A. Note that they can't reach all the way to point 7 so they can't protect the point 6C fuse from temporary faults occurring near the end of the lateral.
- POINT 4: The fault duty at PT 4 is: $3\emptyset = 1,210$ amps and SLG is 877. It is feeding a short single-phase #4 ACSR lateral with not much load on it (that's why we didn't include the fault current at the end of the lateral).
 - Temporary Faults - From Table 1 we see that a 40T fuse can be protected up to 1,040 amps for temporary faults and the SLG is 877 amps (single phase lateral).
 - Conductor Protection - From Table 7 we see that #4 ACSR can be protected by a 100T or smaller fuse.
 - Fault Detection - We aren't worried about detecting the fault at the end of the feeder or coordinating with other fuses.
 - Loading – Assume the load is small so don't need to worry.
 - So what fuse size should we use?

- POINT 3A: The fault duty at point 3 is: $3\phi = 3,699$ amps and the SLG is 3,060. Here we have a 2/0 ACSR 3ϕ lateral feeding to the next fuse with a SLG of 877 amps.
 - Temporary Faults - From Table 1 we see that a 140T fuse can be protected up to 3,500 amps for temporary faults and the 3ϕ fault is 3,699 amps. This appears to indicate we would want to use a 200T fuse. However, this is a very large fuse and raises the substation ground relay settings a lot (480 to 720 amps) so we don't like to use it. Therefore, we will sacrifice the fuse protection in order to gain more sensitive settings at the substation recloser so will tentatively choose a 140T and check a couple of other things.
 - Coordination - From Table 2 we see that a 140T will coordinate with a 100T at 5,800 amps with no preloading or 3,800 amps with preloading. Thus if we added another lateral just beyond point 3A and used a 100T we could coordinate with it with the 140T. Note however that the 100T can be protected up to 2,650 amps so the protection for temporary faults would be further compromised on that branch.
 - Conductor Protection - From Table 7 we see that 1/0 ACSR (or higher) can be protected with the 500 amp feeder settings at the substation so we won't worry about the conductor protection.
 - Fault Detection - Under the Relay Setting Criteria we want to detect the end fault with a 2:1 margin. The SLG is 877 so the largest fuse we could use would be: $877/2$ (2:1 margin) = 438 amps so the largest fuse we could use is $438/2$ (blows at twice the rating) = 219 so we could use a 200T or smaller fuse for this criteria.
 - Loading – 2/0 ACSR can carry about 270 amps (see Table 4). Therefore, if this lateral starts to load up to it's rating we wouldn't be able to carry the load with a 140T or even a 200T fuse. The substation settings could protect the conductor but wouldn't be able to detect a fault at point 4 with adequate margin. We would be forced to add another line recloser or maybe move the fuse out on the lateral until it could carry the load and then check to see if the substation could detect the faults at that point.
 - So what fuse size should we use?

- POINT 3B: Here we have a #2 ACSR 3ϕ short lateral with only a small amount of load.
 - Temporary Faults – Same story as for point 3A. Would choose a 140T fuse.
 - Coordination – There is nothing to coordinate with so no problem.
 - Conductor Protection - From Table 7 we see that #2 ACSR can be protected with a 140T.
 - Fault Detection – It's a short lateral so no problem.
 - Loading – No problem.
 - So what fuse size should we use?

- POINT 3C: The fault duty at point 3 is: $3\phi = 3,699$ amps and the SLG is 3,060. Here we have a 1 mile #4 ACSR 3ϕ lateral (main lateral) feeding to the line recloser with a SLG of 3,060 amps.

- Temporary Faults - From Table 1 we see that a 140T fuse can be protected up to 3,500 amps for temporary faults and the 3Ø fault is 3,699 amps. This again appears to indicate we would want to use a 200T fuse.
- Coordination – We set the line recloser up to coordinate with a 100T fuse so we wouldn't be able to coordinate with the recloser by using a 140T so this would indicate we need a 200T.
- Conductor Protection - From Table 7 we see that #4 ACSR requires a 100T fuse or smaller to be protected.
- The above coordination and conductor protection dilemma means that we can't solve this problem by fusing this lateral. We also can't remove the fuse because the substation settings can't protect the conductor either.
- What are some possible solutions?

- POINT 2A: Here we have a #4 ACSR 3Ø short lateral with only a small amount of load. The fault duty at point 2 is: 3Ø = 5,158 amps and SLG = 5,346 (same as at the 13.8 kV bus).
 - Temporary Faults – Basically same story as for point 3A. Would choose a 140T fuse because don't want to use a 200T.
 - Coordination – There is nothing to coordinate with so no problem.
 - Conductor Protection - From Table 7 we see that #4 ACSR can be protected with a 100T fuse. Since the conductor protection is more important than fuse protection we have to lower this down to a 100T even though our fuse protection is greatly compromised.
 - Fault Detection – It's a short lateral so no problem.
 - Loading – No problem.
 - So what fuse size should we use?

- POINT 2B: Here we have a #2 ACSR 3Ø short lateral with only a small amount of load.
 - Temporary Faults – Basically same story as for point 3A. Would choose a 140T fuse because don't want to use a 200T.
 - Coordination – There is nothing to coordinate with so no problem.
 - Conductor Protection - From Table 7 we see that #2 ACSR can be protected with a 140T fuse.
 - Fault Detection – It's a short lateral so no problem.
 - Loading – No problem.
 - So what fuse size should we use?

- POINT 1: Substation recloser. We already know this is a 500 amp feeder so we have to set to carry that load (even if the feeder is not presently loaded that amount).

NOTE: Per the Distribution group the load is 325 amps and cold load 650.

 - Temporary Faults – We have decided that a 140T fuse is the maximum fuse we will use on the feeder even though it can't be protected at the maximum fault duties.

MOSCOW FEEDER 515 PROTECTION EXAMPLE

- Conductor Protection – The main trunk is 556 ACSR and from Table 7 a 500 amp feeder setting can protect 1/0 ACSR or higher so no problem since all laterals are fused.
- Coordination – We will coordinate with a 140T fuse at the maximum SLG fault duty of 5,346 amps with 0.2 seconds coordination time per Table 4. We will also coordinate with the line recloser settings with 0.3 seconds coordination time again per Table 4.
- Fault Detection & Loading – We will set the phase pickup to carry 500 amps normally plus pick up cold load so will set at 960 amps.
- The $\emptyset\text{-}\emptyset$ fault at point 5 is $0.866 \times 3453 = 2990$ so our margin to detect that fault would be $2990/960 = 3.1:1$ so no problem.
- SLG Fault Detection – Again per our criteria we will set as low as possible and still coordinate with the maximum downstream devices with the same coordination times as above (see 825).
- The SLG at point 5 is 2,762 so our margin to detect that fault is: $2762/480 = 5.7:1$ so no problem.
- Instantaneous Units – The phase instantaneous will be set at 1,120A and the ground instantaneous unit will be set at 480 A.