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FAULT LOCATION ISOLATION AND SERVICE RESTORATION (FLISR) FOR BVES

BIG BEAR LAKE, CA

BEAR VALLEY ELECTRIC SERVICE (BVES)

SWITCH PLACEMENT AND OVERCURRENT PROTECTION COORDINATION STUDY

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FINAL REPORT

APRIL 20, 2020

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1. Executive Summary

S&C Electric Company (S&C) has performed a Fault Location Isolation and Service Restoration (FLISR) deployment study for the 34.5 kV distribution network of the Bear Valley Electric Service (BVES). The scope of the study includes a switch placement study followed by an overcurrent protection coordination study of the distribution network. One-line diagram and geographic layout diagram of the system within the scope of the study are provided in Appendix A.

The scope of the switch placement study includes identifying locations within the BVES network to install eleven (11) IntelliRupter® PulseCloser® Fault Interrupter (IR) devices. The purpose of the switch placement study is to determine the optimal locations of the automated switching devices to best increase the reliability of the BVES distribution network by automatically locating and isolating faulted sections followed by restoring service to the rest of the network. A Vista Pad-mounted switchgear unit with S&C Model 6802 automatic switch controls is also included within the FLISR scheme. The Vista switchgear is already installed at the Village substation and therefore the existing location of this device was not considered to be variable in the switch placement study.

The BVES distribution network is supplied through three separate feeders including Shay, Baldwin, and Radford. During the winter season, the Shay and Baldwin feeders supply most of the system except for the Village substation which is supplied through the Radford feeder. During the summer season, the entire system is supplied by Shay and Baldwin feeders only. The Village substation is supplied through the Shay feeder in the summer. Under normal operating conditions, the Radford feeder is switched off during the summer and does not supply any loads.

BVES indicated that the Radford feeder only supplies the Village substation (during the Winter season) at present, but there is a possibility that it may supply additional loads in the future. The study is conducted with the present configuration of the system (i.e., Radford will only supply the Village substation). The FLISR scheme should be revised if Radford is made to supply additional loads in the future.

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2. Methodology

2.1. Switch Placement

The main purpose of the switch placement study is to improve the reliability of the distribution network. Based on recommendations of BVES, the loads supplied by the system are classified in to three classes as Critical, Somewhat Critical, and Less Critical. Priority was given to critical loads while performing the switch placement study. The following criteria are used to determine appropriate switch locations:

1. Automated IRs are placed at the beginning of each feeder. These feeders include Shay, Baldwin, and Radford.

2. Two normally open tie-switches are replaced by automated IRs. These are two different locations that can be used to tie the Shay and Baldwin feeders in the event of a fault or an outage of either feeder. Under normal operating conditions, the tie-IRs will be normally open. In the event of loss of the Shay or Baldwin source, due to a fault or other reasons, the IRs will be closed to restore service from the alternate source.

3. Each Critical Load location is served by a dedicated Team, to the extent possible. When implementing FLISR using IRs, a Team can be defined as a group of adjacent (neighboring) IRs that are directly connected through a component (or multiple components) of the distribution network such as cables, overhead lines, and/or transformers. Priority is given to locations in order of the criticality of their loads. Locations whose loads are classified as Critical or Somewhat Critical are made to be supplied through a single Team. For the Less Critical loads, one team can serve multiple load centers.

4. In general, the reliability of a network is directly correlated to the number of segments (Teams). The more Teams there are, the better the reliability of the network. Another factor that affects reliability is the area spanned by a Team. Teams that span a wider area have higher probability of experiencing faults causing the loads supplied by such Teams to experience higher duration of outages. The switch placement study considered the use of shorter segments (Teams) to supply Critical load locations.

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2.2. FLISR METHODOLOGY

There are several options that can be used to locate and isolate faults when implementing FLISR using IRs. In the study, three different options are considered. All the options use IntelliTeam® for service restoration. IntelliTeam uses peer-to-peer communication with distributed intelligence to track system conditions and quickly initiate service restoration. The options considered to implement FLISR include:

1. Time-current Coordination
2. Instantaneous Trip
3. Communication Enhanced Coordination (CEC)

2.2.1. TIME-CURRENT COORDINATION

Conventional overcurrent protection coordination is used to clear faults, followed by system restoration through IntelliTeam. This method is preferred when there are fewer overcurrent protection devices in series such that selective coordination can be achieved. If series devices are not selectively coordinated, several IRs will trip for the same fault, increasing the extent of outage. This will cause unnecessary temporary outage of unfaulted locations. Once the fault is cleared, IntelliTeam will isolate the faulted section and restore service to unfaulted locations. Another disadvantage of this method is that upstream IRs (IRs closer to the source) may have slower fault clearing times, in order to achieve selective coordination with downstream devices. This causes unnecessary stress and/or damage to equipment during fault conditions.

2.2.2. INSTANTANEOUS TRIP

In this case, all IRs are programmed to trip instantaneously without any intentional delay followed by service restoration to unfaulted sections using IntelliTeam. The main advantage of this approach is that it provides the fastest fault clearing time, minimizing possible damage to equipment. However, this approach causes momentary outage of an entire feeder every time a fault occurs on the feeder. In the event of a fault, all IRs upstream of the fault will trip open regardless of the location of the fault. IntelliTeam will then isolate the faulted section and restore service to the rest of the system.

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2.2.3. Communication Enhanced Coordination (CEC)

When selective coordination between series IRs is not possible, CEC enables a group of IRs to share the same coordination curve but only the device closest to the fault will trip to clear the fault. With CEC, more IRs can be installed on a feeder, which reduces line-segment (Team) size, so fewer customers will be involved when a fault is isolated.

CEC does not have to be used by all the IRs on a feeder. However, when CEC is used, both IRs in a CEC pair must have the following parameters active: CEC enabled, use the correct General Profile (i.e., not Hot Line Tag) and have no errors. CEC messages are sent from the load-side IR to the source-side IR and if the device is not ready, CEC will go out of ready for that pair, and no further CEC messages will be sent.

All the CEC-configured IRs sense fault at the same time and send a curve-shift request to their source-side neighbor which causes the recipient of the request to delay its trip curve. The IR at the faulted line segment will not receive a curve-shift message because it does not have a load-side neighbor sensing fault current. Therefore, it will not change to the slow protection curve and it will trip before the other source-side IRs.

When a fault-opened CEC coordinated IR is testing fault persistence, it sends messages to its source-side neighbor to keep the slower curve in use. If the fault is persistent and the IR locks-out, it sends an Event Done transmission to all the CEC IRs, and they curve-shift back to the fast curve and become ready for a second event. If the fault is temporary and the IR can close, the Event Done transmission will be sent after the Sequence Timer expires.

2.3. Protective Device Coordination

2.3.1. Software Analysis Tools

The time-current characteristic (TCC) plots for the overcurrent protective device coordination study are generated using CYMTCC software Ver. 5.1 Rev. 13. TCC plots showing time-current coordination of overcurrent protection devices are provided in Appendix B.

2.3.2. Short-Circuit Current Levels Considered

Coordination between each overcurrent protective device is required to be achieved up to the maximum available fault current level. The fault current at the Shay and Baldwin substations is calculated to be 4.5-kA based on the upstream Gold Hill substation fault current information provided by Southern California Edison (SCE). The fault current of the Radford feeder was not made available for the study. Hence, the same fault current as the other two feeders was assumed. BVES should review the fault current information and indicate if the available fault currents at the substations are substantially different than used in the study. All TCC curves in Appendix B have been truncated at the maximum fault current of the substations.

2.3.3. Upstream Overcurrent Protection Settings

The protection settings of overcurrent devices upstream of the Shay, Baldwin, and Radford substations are provided by BVES, as shown in Table 1.

Table 1: Upstream Utility Relay Settings

<table>
<tr><th>Feeder Name</th><th>Relay Type</th><th>Phase/Ground Element</th><th>Relay Function</th><th>Settings</th></tr>
<tr><td rowspan="4">Shay and Baldwin</td><td rowspan="2">ABB CO-8</td><td rowspan="2">Phase settings</td><td>Pickup</td><td>840</td></tr>
<tr><td>Time Dial</td><td>0.8</td></tr>
<tr><td rowspan="2">ABB CO-9</td><td rowspan="2">Ground settings</td><td>Pickup</td><td>120</td></tr>
<tr><td>Time Dial</td><td>5.5</td></tr>
<tr><td rowspan="6">Radford</td><td rowspan="3">SEL 351R</td><td rowspan="3">Phase settings</td><td>Pickup</td><td>220</td></tr>
<tr><td>Curve Type</td><td>U3</td></tr>
<tr><td>Time Dial</td><td>1.9</td></tr>
<tr><td rowspan="3">SEL 351R</td><td rowspan="3">Ground settings</td><td>Pickup</td><td>12</td></tr>
<tr><td>Curve Type</td><td>U3</td></tr>
<tr><td>Time Dial</td><td>4</td></tr>
</table>

2.3.4. Time-Overcurrent Coordination using Protective Device Tolerances

In the plots shown in Appendix B, three separate TCC curves are drawn for each overcurrent relay. The middle curve represents the nominal relay response time. The lower curve represents the fastest relay response time including all worst-case tolerances. The upper curve represents the longest expected fault clearing time including all worst-case tolerances. These curves consider a CT tolerance of +10%, the circuit breaker or fault interrupter fault-clearing time, the current and timing accuracy of electronic relays as specified by the relay manufacturer, and a 100-milliseconds of time to account for relay overtravel in the case of mechanical relays.

Coordination is achieved between two devices when the maximum clearing time of the downstream device is less than the minimum response time of the upstream device.

Table 2 shows the overall relay tolerances (including CT tolerance, circuit breaker clearing time, relay accuracy, and mechanical relay overtravel) that are used as criteria to coordinate the overcurrent protection devices. A 40 milliseconds operating time is used for the IR fault interrupters as specified by the manufacturer. A 5-cycle operating time is used for the upstream SCE circuit breakers, as per the maximum interrupting time recommended in IEEE Std C37.06.

Table 2: Protective Device Tolerances Used for Coordination

Device	Maximum Response Time Positive Tolerances*	Minimum Response Time Negative Tolerances*
ABB CO-8 and ABB CO-9	+10% in current +10% and +83 ms in time	-10% in current -10% and -100 ms in time
SEL-351R	+13% and +10 A in current +4% and +108.3 ms in time	-3% and -10 A in current -4% and -25 ms in time
S&C IntelliRupter PulseCloser Fault Interrupter	+2% in current +2% and +40 ms in time	-2% in current -2% and -8.33 ms in time

*Includes relay and CT tolerances. Positive tolerance also includes the fault-interrupter and circuit breaker clearing time.

3. Results

3.1. Switch Placement

The recommended IR locations are determined based on the criteria described in Section 2.1. Approximate IR locations on the BVES network are graphically indicated in Appendix A. In Appendix A, red-filled circles indicate normally-closed IR locations, blue-open rectangles indicate normally-open IR locations, and red-filled triangles indicate the location of the existing S&C Model 6802 switch controls of the Vista switchgear at Village substation.

Automatic system restoration schemes are expected to re-configure a system during contingencies. Under a new system configuration, the loading of conductors will be different than the normal operating conditions. Thus, BVES should verify that all conductors within the system are adequately rated and will not be overloaded during circuit re-configuration.

3.2. FLISR Method

After consulting with BVES, it was determined that CEC is the most appropriate method to be used for FLISR within the 34.5 kV system. This will enable the system to have a fast fault clearing time without causing unnecessary outages of unfaulted locations. The selected FLISR scheme (CEC) does not rely on reclose operation to locate, isolate, and restore power. The reclosing (PulseClosing®) function of the IRs can be disabled if necessary or desired. Disabling reclosing prevents multiple re-energizations of faulted equipment or feeders as the device cycles to lockout. This will prevent the immediate restoration of service following temporary faults and all faults will be considered as permanent faults. This is likely to have a negative impact on the reliability of the distribution network (compared to overall reliability if PulseClosing were enabled).

Based on the FLISR RFP (Request for Proposal) document provided by BVES, reclose operation will be disabled during the summer season. During the winter season, reclosing will be enabled. Accordingly, the IRs will use PulseClosing to verify a line is clear of faults before initiating a closing operation during the winter season only. PulseClosing uses precisely timed, quick close and open operation of the IRs and analysis of the resulting current pulse to determine whether a fault is present. A PulseClosing Technology operation subjects the system to a small fraction of the fault energy experienced during conventional reclosing. If no fault is detected, the device will close and restore service to the unfaulted locations.

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The CEC scheme will be used by ten (10) IRs within the BVES system. This includes all IRs in the system with the exception of the IR at the Radford substation. At the moment, CEC can only be used if all devices in a system are IRs. Because there is a Vista switchgear unit at the Village substation, CEC cannot be implemented on that section of the system. Thus, the Vista switchgear at Village substation and the IR at Radford substation will not be included in the CEC scheme. Instead of using CEC, the Model 6802 switch controls of the Vista switchgear will be set to operate as a source transfer switch. This will have the same impact as using CEC as far as system reliability is concerned. The system reliability will not be impacted whether CEC or source transfer is used at the Village substation under the present operating conditions of the system. This is because the Radford feeder only supplies the Village substation at present. If the Radford feeder is made to supply additional loads in the future, the FLISR scheme should be revised and modified accordingly.

3.3. Overcurrent Protection Settings

The recommended overcurrent protection settings are intended to provide selective coordination with the upstream utility relays. Table 3 shows the recommended overcurrent protection settings of CEC-configured IRs (all IRs with the exception of the IR at the Radford substation). Recommended overcurrent protection settings of the Radford IR are provided in Table 4. TCC plots showing the coordination of overcurrent devices are provided in Appendix B.

As indicated in Section 2.2.3, CEC-configured IRs sense fault at the same time and send a curve-shift request to the corresponding source-side neighbor which causes the recipient of the request to delay its trip curve. The recommended overcurrent settings provided in Table 3 include Fast protection settings and Delayed protection settings. All IRs will trip using the Fast trip settings unless a curve-shift request is received from its load-side neighbor. If an IR receives a curve-shift request, it will change its protection settings to the Delayed trip settings. Since the Fast and Delayed trip settings are selectively coordinated, the IR closest to the fault will be the only IR to trip. The overcurrent protection settings of the CEC-configured IRs (both the Fast and Delayed settings) also selectively coordinate with the upstream relays at SCE's Goldhill substation.

Table 3: Overcurrent Settings of CEC-configured IRs

IR Element	Function	Fast Trip Settings	Delayed Trip Settings
Phase	Curve Type	U5	U5
	Pickup (Amps)	580	650
	Time Multiplier	0.6	1.5
	Minimum Response Time (Seconds)	0.06	0.15
Ground	Curve Type	U1	U1
	Pickup (Amps)	100	120
	Time Multiplier	0.8	1.3

Table 4: Overcurrent Settings of IR at Radford

IR Element	Function	Trip Settings
Phase	Curve Type	U3
	Pickup (Amps)	175
	Time Multiplier	1
Ground	Curve Type	U3
	Pickup (Amps)	10
	Time Multiplier	2

The phase overcurrent protection settings of the Radford IR do not selectively coordinate with both the upstream relay (owned by SCE) and the Vista relays at the Village substation, for high magnitude fault currents. The SCE relay is set to have a fast response time for high magnitude fault currents and the Radford IR will not have sufficient time to clear a downstream fault before the SCE relay responds to the fault. To avoid unnecessary interruption of the circuit, it is recommended that the SCE relay be sufficiently delayed and allow the Radford IR to clear downstream faults. One way to achieve this is to add a minimum response time setting of 200 milliseconds to the SCE relay. This will allow the Radford IR to selectively coordinate with both the SCE relay and the Village Vista relays. The recommended overcurrent settings of the Radford IR provided in Table 4 are selected based on the present settings of the SCE relay. BVES should indicate if SCE agrees to implement the recommended minimum response time setting. If SCE agrees to include the minimum response time in to the settings of the relay, the recommended Radford IR settings will be revised to achieve selective coordination.

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The recommended ground overcurrent settings of the Radford IR do not selectively coordinate with the upstream SCE relay for low magnitude fault currents. The SCE relay has a very sensitive ground pickup setting that is likely to respond to low magnitude ground faults downstream of the Radford substation. This miscoordination will only impact the system during the initial trip operation of the devices.

The existing overcurrent protection settings and fault detection settings of the Vista switchgear at the Village substation are also revised in order to provide optimal operation with the new overcurrent protection settings of the Radford IR. Recommended overcurrent protection settings of the Vista switchgear relays are provided in Table 5. Also, recommended fault detection settings of the S&C Model 6802 switch control of the Vista switchgear are provided in Table 6.

Table 5: Overcurrent Settings of Vista Switchgear at Village Substation

IR Element	Function	Settings
Phase	Curve Type	U4
	Pickup (Amps)	125
	Time Multiplier	0.5
	Instantaneous Trip	1000
	Time Delay	0
Ground	Curve Type	U5
	Pickup (Amps)	66
	Time Multiplier	0.5

Table 6: Fault Detection Settings of S&C Model 6802 Switch Control

Switch Element	Function	Settings
Phase	Phase Fault Detection Current Level (Amps)	160
	Phase Fault Duration Time Threshold (milliseconds)	50
	Phase Current Inrush Restraint Time (milliseconds)	500
	Phase Current Inrush Restraint Multiplier	2x
Ground	Ground Fault Detection Current Level (Amps)	10
	Ground Fault Duration Time Threshold (milliseconds)	50
	Ground Current Inrush Restraint Time (milliseconds)	300
	Ground Current Inrush Restraint Multiplier	4x

4. Conclusions

- S&C has performed a FLISR deployment study for BVES. The scope of the study includes a switch placement study followed by overcurrent protection coordination study.
- To avoid conductor overloads, BVES should verify that all conductors are adequately rated to carry all loads during system reconfiguration.
- CEC will be used to implement FLISR on most of the system. The Radford IR and the Vista switchgear at Village substation are not included in the CEC scheme. This will have no impact on system performance so long as the Radford feeder only supplies the Village substation. If the Radford feeder is made to supply additional loads in the future, the FLISR scheme should be revised.
- The Radford IR does not selectively coordinate with the upstream SCE relay. It is recommended that a minimum response time setting of 200 milliseconds be added to the present settings of the relay. If SCE agrees to implement the recommended settings, the Radford IR settings will be revised to selectively coordinate with both upstream and downstream relays.

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5. References

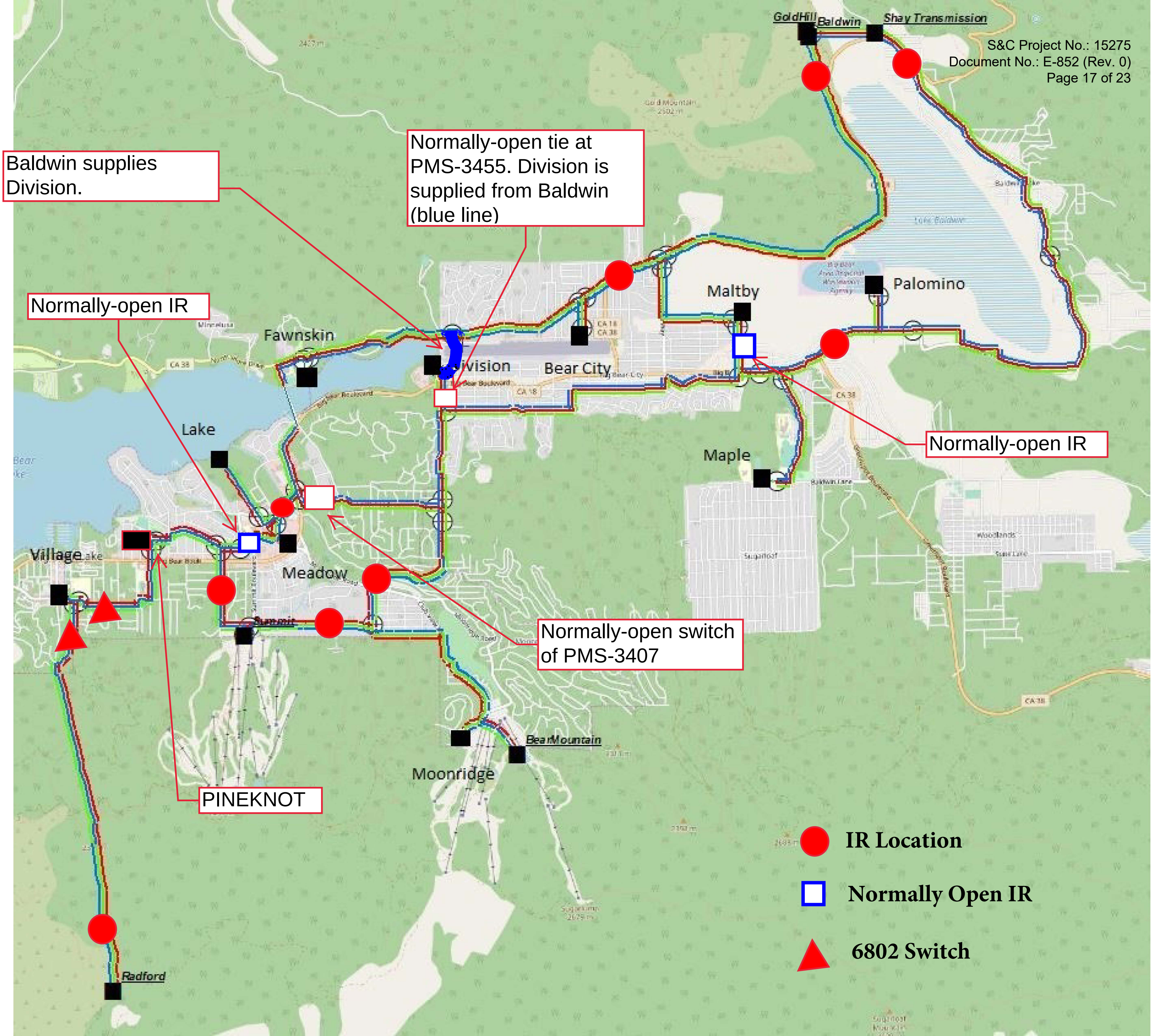
1. S&C Information Bulletin 766-211, "S&C IntelliRupter® PulseCloser® Fault Interrupter, Outdoor Distribution (15 kV, 27 kV, and 38 kV) Time-Current Characteristic Curves."

2. S&C Instruction Sheet 766-540, "S&C IntelliRupter® PulseCloser® Fault Interrupter: Operation."

3. S&C Instruction Sheet 1045-530, "S&C 6800 Series Automatic Switch Controls with IntelliTeam® SG Automatic Restoration System."

4. NFPA 70, "National Electrical Code (NEC), 2017 Edition."

APPENDIX A: SWITCH PLACEMENT LOCATIONS


GoldHill
Baldwin
Shay Transmission
Baldwin supplies Division.
Normally-open tie at PMS-3455. Division is supplied from Baldwin (blue line)
Normally-open IR
Fawnskin
Division
Bear City
Maltby
Palomino
Lake
Maple
Normally-open IR
Village
Meadow
Summit
Normally-open switch of PMS-3407
BearMountain
Moonridge
PINEKNOT
Radford
IR Location
Normally Open IR
6802 Switch

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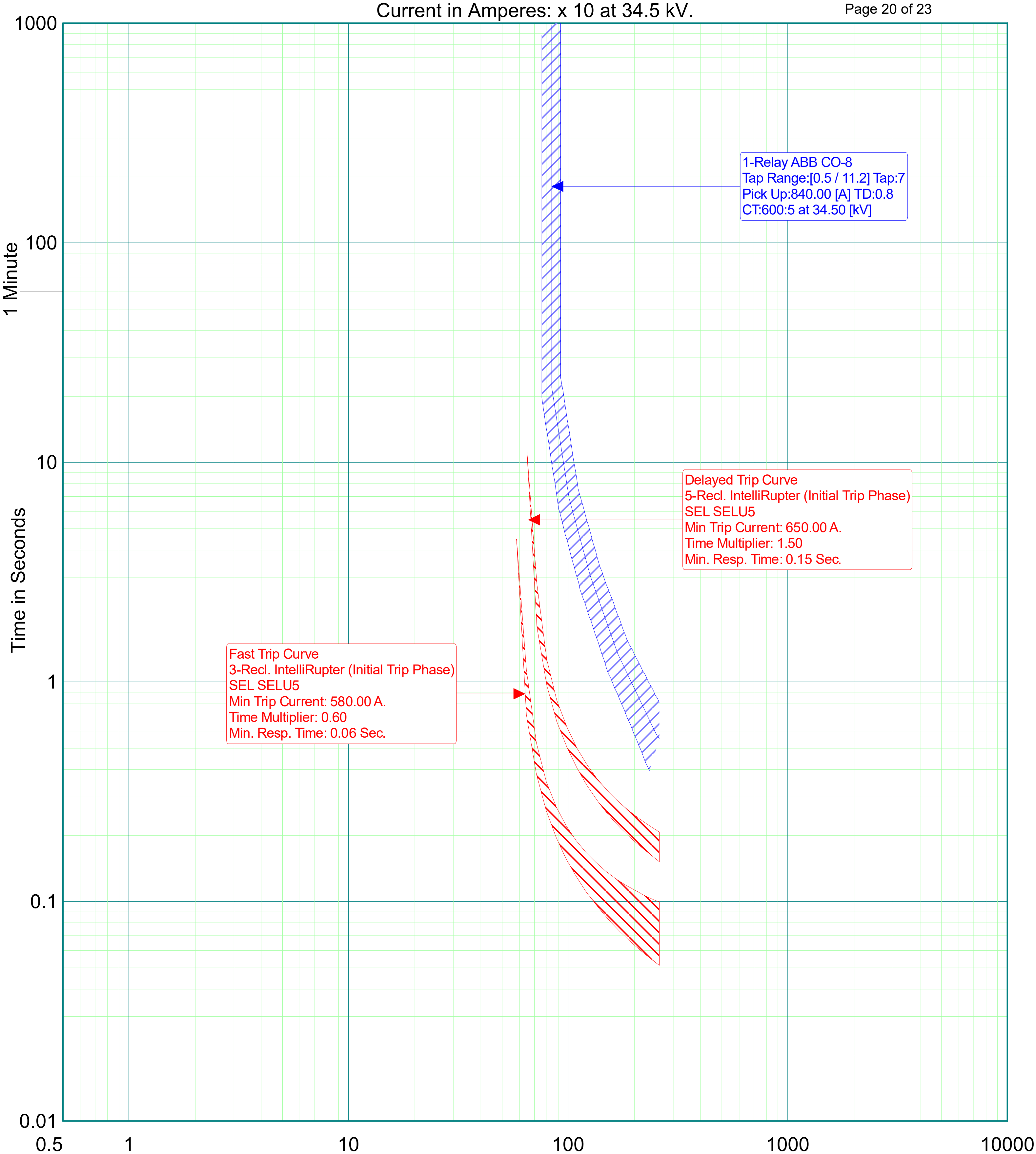
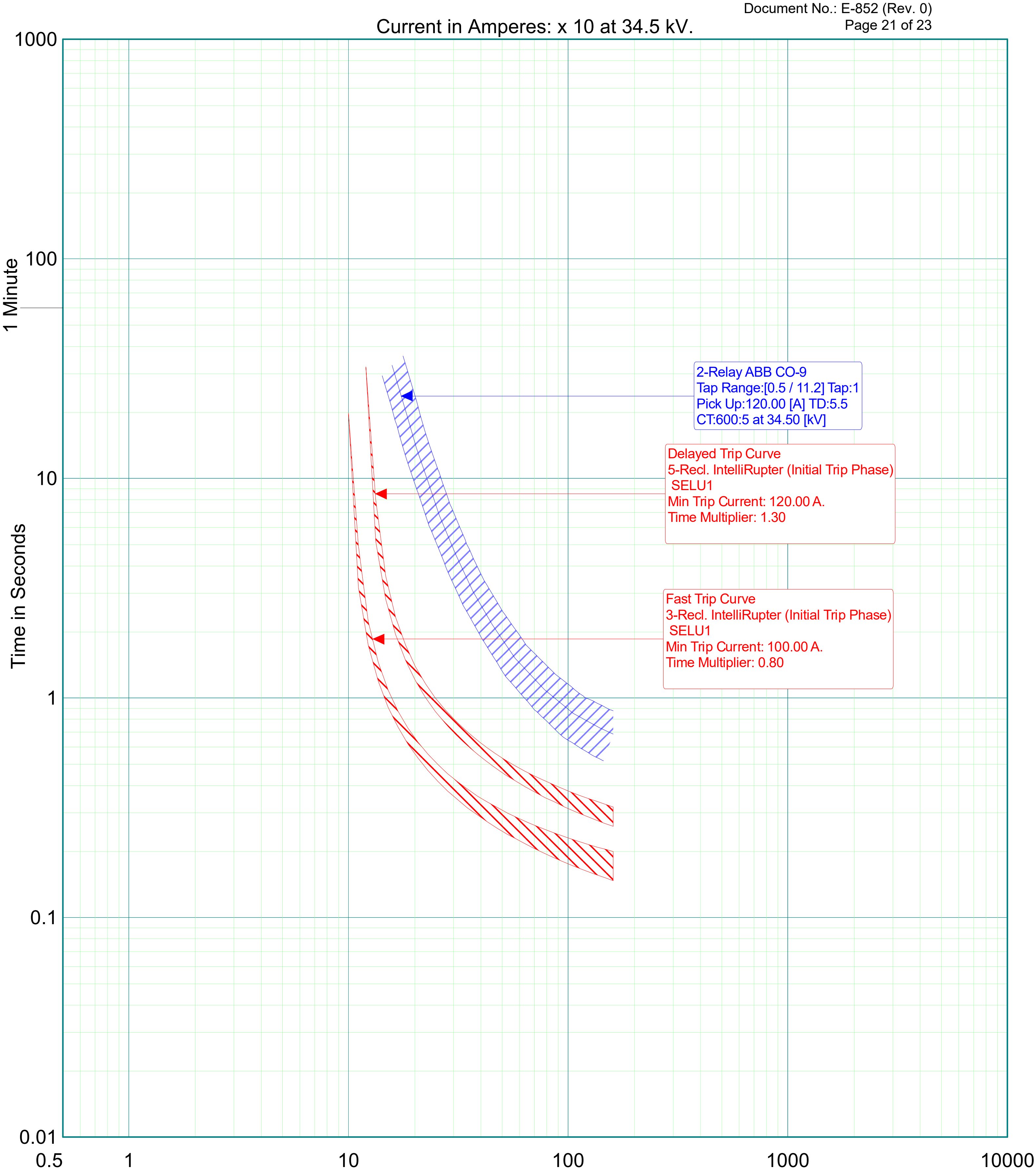
DO NOT PARALLEL
PS3459LB
KNICKERBOCKER S/O PENNSYLVANIA
SATAC 174
13740'
2 CU
RADFORD AR3470
170 PH - 101,132, 0 FAST, 2LOCKOUT
10 GD - 102,106 10 Sec RECLOSE
170
10G
VILLAGE
WEST BANK
3750 KVA
Z = 6.3%
668 AMP
167 KVA
640 PH
320 GD
R100
BOULDER 4KV
R120
HARNISH 4KV
R140
LAGONITA 4KV
EAST BANK
PMS3460
PS3433LB
5000 KVA
Z = 5.9 %
300Amp
167 KVA
50E
570 PH
340 GD
R800
NORTH SHORE
FAWNSKIN
BEAR CITY
65E
2.5/2.8 MVA
Z - 7.0%
55/65 C
438Amp
333 KVA
560 PH
280 GD
R1000
HOLCOLM
P3405LB
N. SHORE
E/O STANDFIELD CUTOFF
PS3404KPF
N. SHORE E/O DIVISION
PS3432
PS3402LB
N.S. E/O MICHAEL
PS3401LB
PARADISE
PS3400LB
HWY E/O PARADISE
PS3403
N.S. W/O MICHAEL
SATAC 174
P3406LB
N.SHORE W/O SUB
THIS LINE NOT SHOWN ON APP-E
N. SHORE
E/O EAGLE MT.
V3406
LAKE
300Amp
75KVA
2000 KVA
Z - 5.1
PS3434KPF
R700
PUMP HOUSE
280 PH
560 GD
50E
PS3464KPF
FOXFARM E/O GARSTIN
PS3451LB
PARADISE S/O HWY
MALTBY
DIVISION
PS3463KPF
MALTBY W/O SHORE
BALDWIN
AR3430
540 PH - 114 3-LOCKOUT
120 GD - 136
15 Sec RECLOSE
MEADOW
PMS 3450
190AMP
PS3408KPF
FOX FARM W/O BLVD
PMS 3455
3750 KVA
Z = 5.7%
548 AMP
416 KVA
R920
COUNTRY CLUB
400 PH
800 GD
120AMP
R900
CASTLE GLEN
PMS 3480
3750 KVA
Z = 6.5 %
668Amp
167KVA
R1120
ERWIN
580 PF
300 GD
R1100
PARADISE
400Amp
100KVA
SCE GOLDHILL SWITCHING ONLY 34 KV
580 PH
300 GD
0FAST
R640
FOXFARM UG
R620
INTERLAKEN
R600
GARSTIN
1332/1492AMP
3-333/416 KVA
7500-10000
KVA OA-FA
Z - 6.9%
5000/7400 OA/FA
34.5Y/19.9 - 4.16kV
Z - 5.4%
SHAY
PS3420KPF
PS3468LB
YARD
PS3452LB
SHORE S/O MALTBY
SHAY
AR3440
540 PH - 114 3-LOCKOUT
120 GD - 136
15 Sec RECLOSE
180 PH
120 GD
CB 22
CB 88
44 CB
66 CB
BANK #2
BANK #1
PMS-3407
PS3427KPF
DIVISION S/O SUGARLOAF
PS3426KPF
SUGARLOAF E/O DIVISION
PS3425KPF
SHORE S/O BLVD
PS 3421KPF
BALDWIN LK / BORON
PS3467KPF
MCALLISTER N/O FOXFARM
V3407
PS3461KPF
FOXFARM W/O McALLISTER
PS3428KPF
MCALLISTER S/O FOXFARM
PS3465LB
BLVD W/O MAPLE
PS3422LB
BALDWIN LK E/O SHAY RD
PS3413LB
TO SHAY AR3440
PS3412
GEORGIA S/O LAHONTAN
PS3409KPF
PARK E/O TANAGER
PS3423LB
SHAY S/O MIDWAY
PS3441KPF
PALOMINO
PS3411KPF
LAHONTAN E/O GEORGIA
PS3410KPF
PARK & CHICKADEE
PS3429KPF
ELM N/O CEDAR
PS3424KPF
MAPLE S/O BLVD
PS3445
125E
10,000 KVA
Z = 6.36%
1300AMP
3 - 333 KVA
PINEKNOT
PS3457KPF
BRUSH S/O PARK
PS3458KPF
SUMMIT Parking Lot
SWITZ. W/O ELM
PS3446
300 D
gt. blocked
BEAR MOUNTAIN
PS3442KPF
80E
2000 KVA
300Amp
75KVA
400 PH
800 GD
R1300
PIONEER
BBARWA
2.0 MVA
R220
EAGLE
R200
GEORGIA
PS3444KPF
65E
2500 KVA
Z = 6.1
400Amp
75 KVA
SUMMIT
MOONRIDGE
PMS 3490
PS3447KPF
MAPLE
3750/4200 KVA
Z = 5.7 %
548 Amp
3 - 416 KVA
5000 KVA
3PH
Z = 6.0%
7500 KVA
3PH
Z = 8.7
7500 KVA
3PH
Z = 7.41
3PH
3x875Amp
657 KVA
3x219Amp
1332/1665Amp
333KVA
2000 PH
GD
R500
GERONIMO
630 PH
280 GD
R400
GOLDMINE
R420
CLUBVIEW
280 PH
560 GD
R320
LIFT
TOU
400 PH
800 GD
R300
SKYLINE
RES.
580 PH
300 GD
R1220
SUNSET
R1200
SUNRISE
NOTES: ALL DISTRIBUTION IS 4160Y/2400 VOLTS
TRANSFORMER SYMBOL
VOLTAGE REGULATOR SYMBOL
FUSE SYMBOL
RECLOSER SYMBOL
SWITCH SYMBOL - (CLOSED)
SWITCH SYMBOL - (OPEN)
UNDERGROUND 34KV
BALDWIN
RADFORD
SHAY
PAD
Bear Valley Electric Service
34KV TRANSMISSION ONE LINE
WINTER MODE
Revised by:
TCHOU
Drawn by:
PP/DB
Updated:
04/02/2019

APPENDIX B: TIME-CURRENT CHARACTERISTIC PLOTS



15275 - Bear Valley Electric Service FLISR Study	PLOTTING VOLTAGE:34.5 kV
Phase Overcurrent Settings	BY: SHB
CEC-Enabled IntelliRupters	APPROVED BY: JKN
	NO: TCC-CEC-Phase
	DATE: 4/17/2020



15275 - Bear Valley Electric Service FLISR Study	PLOTTING VOLTAGE:34.5 kV	
Ground Overcurrent Settings	BY: SHB	APPROVED BY: JKN
CEC-Enabled IntelliRupters		NO: TCC-CEC-Ground
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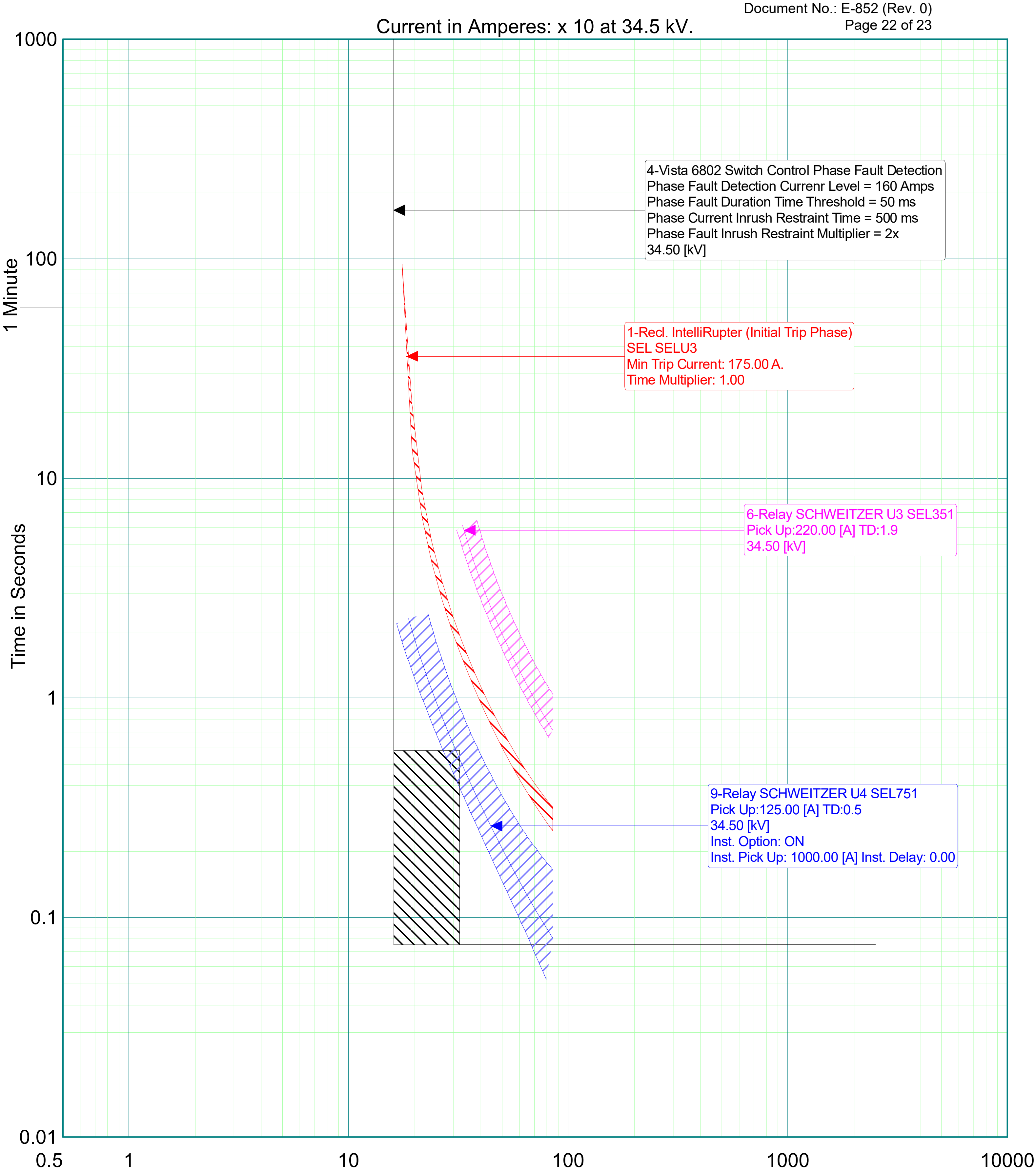
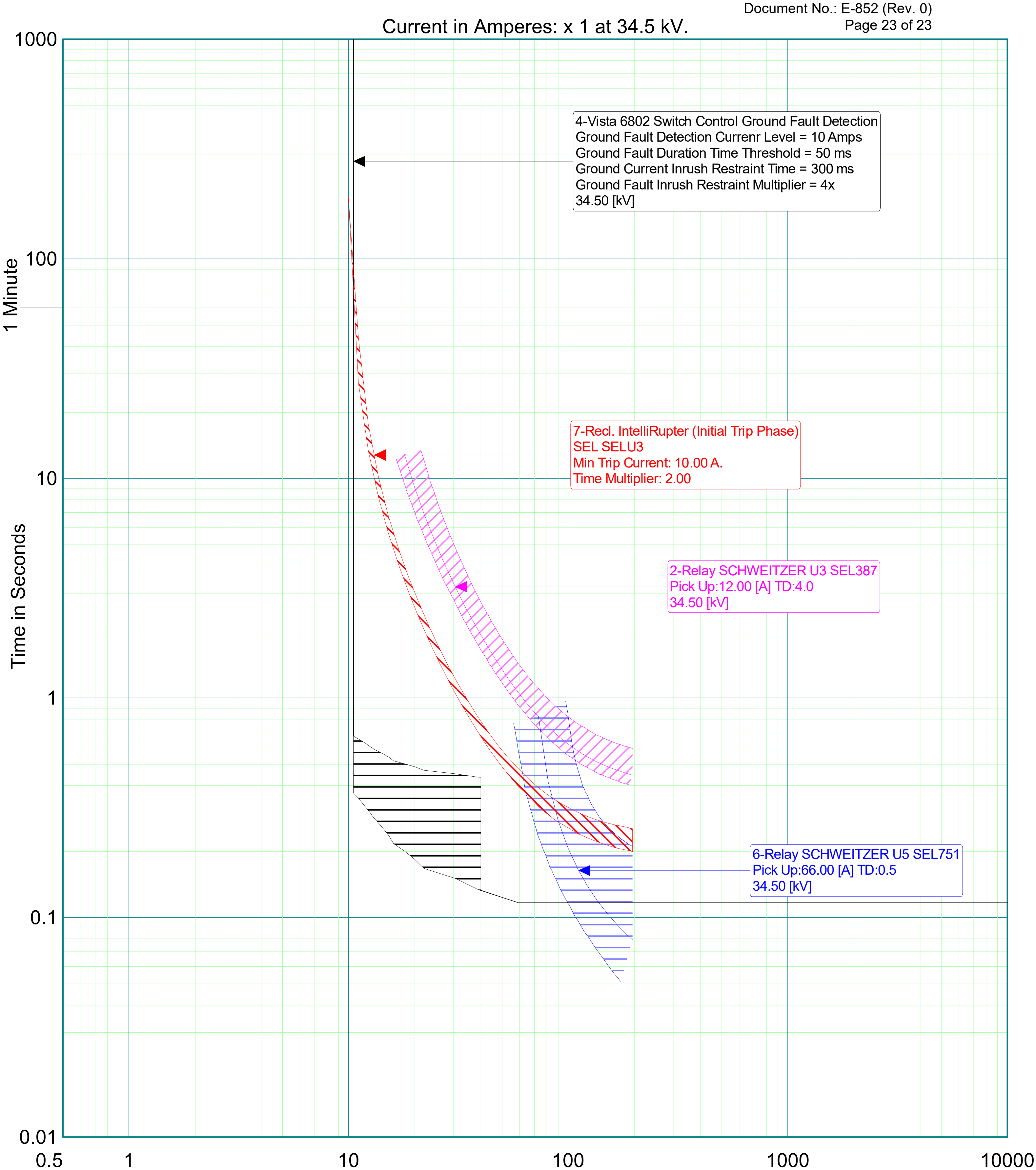


15275 - Bear Valley Electric Service FLISR Study
Phase Overcurrent Settings
Radford IntelliRupter

PLOTTING VOLTAGE:34.5 kV
BY: SHB

APPROVED BY: JKN
NO: TCC-Radford-Phase
DATE: 1/3/2020



15275 - Bear Valley Electric Service FLISR Study	PLOTTING VOLTAGE:34.5 kV	
Ground Overcurrent Settings	BY: SHB	APPROVED BY: JKN
Radford IntelliRupter		NO: TCC-Radford-Ground
		DATE: 1/3/2020