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Modeling and Simulation of Relay Protection for Industrial Power Network Distributed Generation

Bachelor's Thesis

By

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Statutory Declaration

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I hereby affirm in lieu of an oath that I provided the submitted bachelor thesis

Modeling and Simulation of Relay Protection for Industrial Power Network Distributed Generation

I did not use any sources other than those stated. In case that the work is additionally submitted on a data medium, I declare that the written and the electronic form are completely identical. The work was not submitted in the same or similar form to any examination authority.

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Place, Date	Signature

Abstract

This thesis presents the design and simulation of a relay protection system for the industrial power network of the Khan Altai Resource gold mining facility located in Govi-Altai Province, western Mongolia. The mine operates on a hybrid power supply consisting of a 35 kV overhead transmission line from the Altai–Uliastai external grid as the primary source, backed by three diesel generator sets of 1,250 kVA each. With peak demand projected to grow from 4,873 kW to 8,421 kW between 2026 and 2029, and a planned integration of wind generation, the existing protection infrastructure requires systematic review and upgrading.

Short circuit currents at four critical fault points in the network were calculated in accordance with IEC 60909:2016 using the method of symmetrical components, covering three phases, phase to phase, and single phase to earth fault scenarios under both maximum and minimum source contribution conditions. Based on these results, current and voltage instrument transformers and switching equipment were selected. Main and backup protection schemes were developed for the 35 kV overhead transmission line and 10 kV distribution feeders, including overcurrent, directional, earth fault, automatic reclosing, and automatic transfer switching functions. Setting calculations were performed per IEC 60255 151, and microprocessor-based relay devices were selected and configured. The complete protection scheme was modelled and validated through simulation in DIgSILENT PowerFactory, confirming that selectivity, sensitivity, and operating speed requirements are satisfied across all credible fault and operating conditions.

Keywords: relay protection, overhead transmission line, short circuit calculation, IEC 60909, DIgSILENT PowerFactory, mining power system, overcurrent coordination, automatic reclosing

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1. Introduction

1.1 Background of Relay protection and Overhead line

Overhead transmission lines (OHL) constitute the primary medium for bulk electrical energy transfer across distances in power systems, operating at high and medium voltage levels to minimize resistive losses over extended spans. Their exposed nature traversing open terrain subject to lightning, wind, ice loading, and vegetation contact makes them the most fault prone element in any power network, accounting for the majority of short circuit events in industrial and utility systems alike. The protection of OHLs therefore forms a foundational discipline within power engineering, concerned with the rapid and selective isolation of faulted line sections to preserve system stability and limit equipment damage.

Relay protection for overhead lines has evolved from simple electromechanical overcurrent devices to coordinated schemes combining instantaneous and time delayed overcurrent elements, directional functions, distance protection, and earth fault detection. Automatic reclosing (AR) and automatic transfer switching (ATS) are integral automation functions associated with OHL protection: AR exploits the transient nature of the majority of overhead line faults by attempting to re energies the line after a brief dead time, while ATS ensures continuity of supply to critical busbars by transferring load to an alternate source upon loss of the primary feed. Together, these functions governed by standards including IEC 60255 for relay characteristics and IEC 60909 for short circuit current calculation form the relay protection and automation complex that defines the reliability performance of any overhead line circuit. Because the interaction between protection settings, network impedances, and fault current magnitudes is not trivial particularly in multi-source networks where operating conditions vary analytical calculations alone are insufficient to verify correct relay behavior across all credible scenarios. Simulation of power system software environment allows the complete protection scheme to be tested against the full range of fault types, locations, and source configurations, providing mathematical validation that selectivity, sensitivity, and operating speed requirements are satisfied without risk to live equipment or personnel.

1.2 Case study Overview: Khan Altai resource power system

“Khan Altai Resource” LLC was established in 2019 as a subsidiary of the Max Group and operates as a national company engaged in gold ore mining and production in western Mongolia, specifically within Govi-Altai Province. Mining license MV 021537, valid until 2050, covers 6,793 hectares within Yesönbulag sum of Govi-Altai Province and encompasses a total resource of 98.58 million tons of gold ore. The facility’s medium term production target is approximately 1.56 tons of refined gold per year, establishing it as a strategically significant contributor to Mongolia’s national gold export programmed and to the revenue base of the western regional economy.

The electrical power supply infrastructure of the Khan Altai mine is based on a hybrid configuration. The primary source of electricity is the external 35 kV Altai–Uliastai overhead transmission line (AUEHS grid connection), which delivers power to the mine’s main substation. From the substation, medium voltage distribution feeders operating at 10 kV supply the various process loads, including the ore processing plant, MMD sizer, LIBO conveyor system, crusher units, water supply wells, and workers’ accommodation facilities. Since the mining industry works nonstop, three diesel generator sets, each rated at 1,250 kVA, provide emergency backup power during interruptions to the grid supply. Electricity consumption reached 29,075,781 kWh in 2025, reflecting steep year on year growth driven by the progressive usage of additional processing infrastructure.

1.3 Problem Statement and Reasoning for System

Electricity demand at the mine is on track to grow from 4,873 kW in 2026 to 8,421 kW by 2029, and the current infrastructure is not built to handle that. The bigger issue is that the entire operation depends on a single 35 kV overhead line running roughly 130 km through remote terrain in western Mongolia terrain that sees harsh winters, high winds, and the kind of weather that takes lines down. When that line trips, the mine loses its primary supply and has to start up the diesel sets from cold. Getting the generators running, synchronized, and carrying load takes several minutes, and during that time the crushers stop, the conveyors stop, the pumps stop. Every minute of unplanned downtime has a direct cost.

As load grows, so does the current through that line, and that means the existing relay protection and automation equipment needs to be reviewed and upgraded to match the new operating conditions

The following objectives were set to achieve:

- Research the OHL, develop the single line (primary) diagram, perform short circuit calculations, and select switching equipment.
- Study the fault types and abnormal operating conditions on the overhead line, select appropriate main and backup protection schemes, perform setting calculations, select microprocessor relay protection devices, and configure their settings.
- Perform automation calculations and design the scheme for the OHL.
- Design, assemble, and commission the scheme for the special topic of the graduation thesis.

2. Literature Review

2.1 Literature Review on High Voltage Transmission Lines

Relay Protection in Mining and Industrial Power Networks

Studies have consistently shown that uncoordinated protection settings in industrial distribution networks are a leading cause of non-selective fault clearance where a fault on one feeder causes unnecessary tripping of adjacent healthy feeders, widening the outage beyond the affected section. Erdenebileg et al. [1] investigated automatic reclosing (ARC) device performance on 110 kV overhead lines in Mongolia's Khangai region, modelling the Bulgan–Murun line in DIgSILENT PowerFactory and demonstrating that extreme weather conditions significantly affect outage rates and ARC success rates. The study calculated overcurrent and distance protection settings using microprocessor based IEDs and validated ARC operation through simulation a methodology directly relevant to the present work. Importantly, the authors note that success rates for ARC on Mongolian overhead lines between 2010 and 2022 remained below optimal, pointing to the need for properly calculated settings rather than default device configurations.

Protection in Multi Source and Distributed Generation Networks

The presence of more than one power source in a network fundamentally changes how fault currents flow, and conventional non directional overcurrent protection struggles to handle this. Ghotbi Maleki et al. [2] proposed a mixed integer linear programming approach to design setting group based overcurrent protection for active distribution networks, establishing that a relay with multiple setting groups one per operating mode can maintain correct selective

operation as the network switches between configurations. This finding directly supports the dual mode protection philosophy required at Khan Altai, where protection must behave correctly in both grid fed and generator fed modes without requiring physical reconfiguration. Building on this, Al Bhadely and Inan [3] examined the behavior of dual setting directional overcurrent relays in networks with distributed generation, showing that fixed single setting relays produce either missed trips or false operations as generation configurations change, and that directional elements are essential wherever fault current direction cannot be guaranteed. These conclusions apply directly to the Khan Altai configuration, where three diesel generators may operate in parallel with or independently of the AUEHS grid.

Automatic Reclosing and OHL Reliability

Statistics from multiple transmission system studies show that between 70% and 90% of faults on overhead lines are transient caused by lightning flashovers, momentary conductor contact, or wind induced conductor clashing and will not persist once the line is de energized [13]. Automatic reclosing exploits this by briefly tripping the line and re closing after a short dead time, restoring supply without operator intervention. Tsitsi's and Nikolaidis [5] note that the interaction between ARC timing, protection operating times, and network topology must be modelled carefully, since incorrect dead time settings can cause reclosing into a still ionized fault arc, resulting in a second trip that may be harder on equipment than the first. For long rural overhead lines supplying isolated loads the profile of the Altai–Uliastai 35 kV line this makes simulation validated ARC setting calculation essential rather than optional.

Digital Relay Technology and Setting Validation

Modern numerical relays, standardized under IEC 60255 1:2022 [6], integrate multiple protection functions, programmable logic, event recording, and communication interfaces within a single IED, replacing the banks of dedicated electromechanical devices that earlier installations required. The standard's 2022 revision explicitly incorporates merging units and communications as integral components of the protection system, reflecting the shift toward digital substations. Despite this, the fundamental challenge of setting calculation remains: as Tsitsi's and Nikolaidis [5] observe, incorrect relay settings are one of the most common causes of protection maloperation even in well maintained networks, and the complexity only increases in systems with variable generation. This is why simulation based pre commissioning validation in an environment such as DIgSILENT PowerFactory has become standard practice it allows the full range of fault scenarios and operating conditions to be tested without any risk to live equipment or operational continuity.

2.2 Study of Overhead line General Information

Principal Components of an Overhead Line

An overhead transmission line is made up of a few key parts that work together: the conductors that actually carry the current, ground wires at the top of the structure for lightning protection, the towers that hold everything up at a safe height, insulator strings that keep the conductors electrically isolated from the tower body, and various hardware fittings that connect it all. The number of conductors per phase scales with voltage typically 2 for 330 kV lines, 3 for 500 kV, and 4 to 5 for 750 kV because higher voltages require the current to be spread across more conductors to manage the electric field and thermal loading [11].

Towers are engineered to keep conductors well above the ground and any water crossings at the required clearance height. Insulators sit between the conductor and the tower steel, preventing current from finding a path to earth through the structure. The hardware clamps, suspension fittings, spacers holds everything in position and ensures the line stays mechanically and electrically safe over decades of operation [11].

Electrical Characteristics and Loss Mechanisms

Overhead lines are not perfect conductors, and a few phenomenon cause losses and power quality issues in practice. Corona discharge occurs when the electric field around a conductor is strong enough to ionize the surrounding air, producing audible noise, radio interference, and a small but measurable power loss around 9–11 kW/km on a typical 500 kV line. This effect worsens in wet or polluted conditions and is one reason conductor bundle configurations are chosen at higher voltages [11].

Harmonic distortion is another concern. Nonlinear loads inject currents at multiples of the fundamental frequency the 3rd, 5th, and 7th harmonics being the dominant contributors which cause additional resistive heating in conductors and can drive resonance in the line's capacitance and inductance. Harmonic analysis is useful not just for power quality assessment but also as a diagnostic tool, since abnormal harmonic content can indicate developing insulation faults or earth leakage currents before they escalate to a full fault [9].

Leakage and fault currents are closely tied to line length: the longer the line, the larger the earth capacitance and the higher the steady state leakage current. During a fault, accurate location of the fault point matters enormously for restoration time. Modern protection systems use pre fault and fault waveform data including phase voltage profiles and GPS synchronized measurements to calculate fault location to within a single span, allowing maintenance crews to go directly to the right section rather than patrolling kilometers of line [10].

2.3 Short Circuit Current Calculation

Causes of short circuit occurrence: mechanical fault (failure during cable burying work, tower collapse, tree fall, etc.); insulator deterioration, as insulation electrical withstand capability degrades with time, thereby impairing the conductor's electrical load capacity; insulator damage (cracking); foreign objects on the overhead conductor, e.g., a bird or chemical substance container; two or more phases connecting together and forming a fault; excessive overvoltage relative to system operating voltage causing phase to phase fault; from technical maintenance errors, e.g., a fault caused by relay protection tripping when loaded lines are switched while energized, or when a substation is isolated from the load for maintenance purposes and is then energized; and many other undesirable processes with hazardous characteristics may occur. In some cases, short circuits are persistent (for example, a tower entering a mechanical fault and then bending, a substation grounding), while in other cases they are transient (for example, when a fault is caused by a momentary phase overvoltage on one side and the fault clears itself after line de energization).

Types of short circuits short circuits occurring in the electrical power system are classified into 4 types [11]:

Single phase fault K (1) This is when one phase conductor falls to the ground, creating a ground fault condition; the earth fault current flows and it does not produce a balanced three phase condition.

Two phase fault K (2) .In this case, two phases come into direct contact with each other, forming a fault loop; this type of fault does not cause a three phase balanced fault.

Three phase fault K (3). In this case, all three phases connect at the same point simultaneously. The resulting current is the largest of all types, and the analysis of this type provides the basis for all short circuit calculations. In addition to these fault types, overvoltage, overcurrent, frequency drop, loss of synchronism, and other abnormal operating modes can occur in the system, but these are not classified as fault types.

2.3 Relay protection: Classification and Operation

Protective relays are classified by their operating principle, measurement quantity, and functional role within a protection scheme. The broadest division is between primary protection the first line of defense, designed to clear a fault as fast as possible and backup protection, which operates if the primary relay or its associated circuit breaker fails. A second classification distinguishes relays by their measured quantity: current operated relays (overcurrent, ANSI 50/51), voltage operated relays (overvoltage/undervoltage, ANSI 59/27),

impedance measuring relays (distance, ANSI 21), differential relays (ANSI 87), and directional relays (ANSI 67). Modern numerical IEDs combine several of these functions within a single device [13].

Overcurrent relays are the most widely used protection element in medium voltage industrial networks. They operate when the measured current exceeds a set pickup threshold I pick and are characterized by an inverse time current relationship defined in IEC 60255 151.

The general relay operating equation can be expressed as:

$$M > PsM > PsM > Ps$$

Where *M* is the measured quantity (e.g., current) and P_s is the pickup setting. The time to trip, *t*, is a function of the ratio M/P_s, known as the plug setting multiplier (PSM):

$$PSM = \frac{I_{fault}}{I_{pickup}}$$

For inverse time relays, the operating time *t* is given by the standard IEC 60255 formula:

$$t = \frac{TMS * K}{(PSM)^{\alpha} - 1}$$

Where *TMS* is the Time Multiplier Setting, and *K* and *α* are constants that define the relay characteristic curve type (standard inverse, very inverse, or extremely inverse).

a) Overcurrent Protection (ANSI Code 50/51)

Overcurrent protection is the most widely used form of protection in industrial and mining networks. It operates when the current flowing through the relay exceeds the pickup current setting (Is).

- Definite Time Overcurrent (DTOC, ANSI 51): Operates after a fixed time delay regardless of the magnitude of the overcurrent. Simple and predictable, but less selective in complex networks.
- Inverse Definite Minimum Time (IDMT, ANSI 51): The operating time decreases as the fault current increases. This characteristic naturally provides better selectivity relays close to the fault (where current is highest) operate faster. IEC 60255 151 defines the following standard IDMT curves:
    - Standard Inverse (SI): *K* = 0.14, *α* = 0.02
    - Very Inverse (VI): *K* = 13.5, *α* = 1
    - Extremely Inverse (EI): *K* = 80, *α* = 2
- Instantaneous Overcurrent (ANSI 50): Operates without intentional time delay when current exceeds a high set threshold, typically used to clear close up, high magnitude faults very rapidly.



Figure 1: Overcurrent protection diagram and SEL 751 overcurrent

b) Earth Fault Protection (ANSI Code 50N/51N)

Earth fault (or ground fault) protection detects current flowing in the zero-sequence path, i.e., residual current resulting from a single phase to earth fault. In a solidly grounded or resistance grounded system, earth fault currents can be significant. The earth fault relay monitors the residual current:

Under healthy balanced conditions, this sum is zero. During a single-phase earth fault, a residual current flows, triggering the earth fault relay. Earth fault settings are typically set to a fraction of the full load current to ensure high sensitivity, since earth fault currents may be small in impedance earthed systems (Blackburn & Domin, 2006).

c) Differential Protection (ANSI Code 87)

Differential protection compares the currents entering and leaving a protected zone (e.g., a transformer or generator). Under normal conditions or through faults, the currents are equal (Kirchhoff's Current Law). During an internal fault, an imbalance appears, causing the relay to operate. Differential protection offers unit protection it is inherently selective to the protected zone, with no need for time grading.

In the Khan Altai power system, differential protection is applied to the main 35/10 kV power transformers (Khan Altai 1 and Khan Altai 2) as primary protection. In the Khan Altai power system, differential protection is applied to the main 35/10 kV power transformers (Khan Altai 1 and Khan Altai 2) as primary protection.



Figure 2: Differential Protection principal diagram and SEL 787L Line Current Differential Relay

d) Directional Overcurrent Protection (ANSI Code 67)

In networks with multiple sources such as the Khan Altai mine, which is fed from both the Altai–Uliastai 35 kV grid and three on site diesel generators fault current can flow from multiple directions. Standard non directional overcurrent protection may operate incorrectly in such cases. Directional overcurrent relays include a directional element that supervises the overcurrent element: the relay will only trip if the fault current flows in a pre-defined direction, determined by the phase angle between the measured current and a reference voltage (polarizing quantity).

e) Undervoltage and Overvoltage Protection (ANSI Code 27/59)

These functions protect against voltage deviations that could damage sensitive equipment. In mining operations, undervoltage conditions can be caused by large motor starting events or grid disturbances from the Altai–Uliastai line.

3. System Scheme Development and Equipment Selection and Analysis

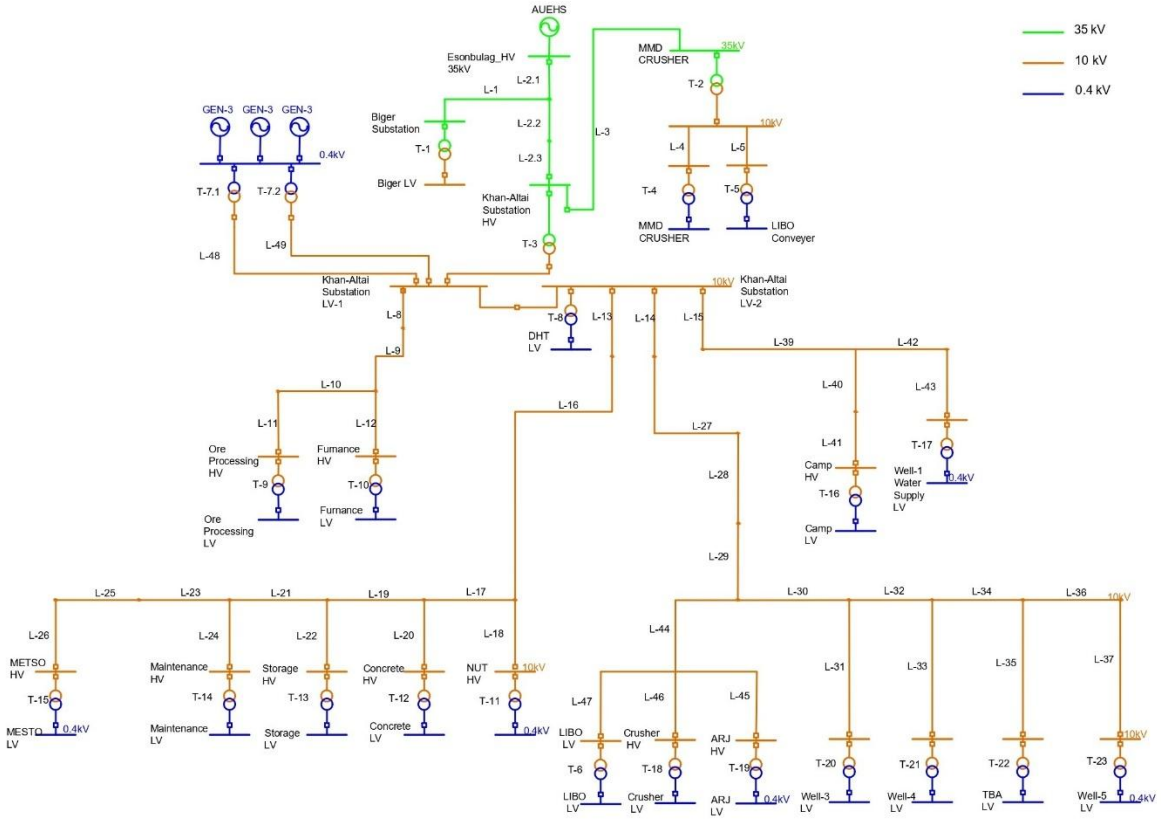


Figure 3.1: Project scheme

3.1 Development of the Primary Single Line Diagram and Data Collection

Table 1: Generator data

Grid	Type, brand mark	S MVa	U kV	Pn MW	Cosφ	X"d	X'd	In kA
AUEHS	∞	∞	35	∞	0.90	0.21	0.30	
GEN 1,2,3	WP13D440E200	2.5	0.4	**2.0**	**0.8**	**0.14**	0.22	2.887

Table 2: Line data

	Line location (number)	Type, brand mark	Length L, km	Diameter, mm Diam					
				Al number	Al d, mm	Steel d, mm	Steel OD, mm	Total OD, mm	Resistance r_0 (20°C), Ohm/km
L 1	AUEHS Biger substation	*AC 70/11*	130	6	3.80	3.80	3.80	11.4	0.428
L 2.1	AUEHS KAR substation	*AC 70/11*	9	6	3.80	3.80	3.80	11.4	0.428
L 2.2	AUEHS KAR substation	*AC 70/11*	9.424	6	3.80	3.80	3.80	11.4	0.428
L 2.3	AUEHS KAR substation	*AC 70/11*	1.216	6	3.80	3.80	3.80	11.4	0.428
L 3	AUEHS KAR MMD substation	*AC 70/11*	7.200	6	3.80	3.80	3.80	11.4	0.428
L 4	MMD Substation Crusher	*YJV 8 7/15kV 3×95mm²*	0.350	3	2.52	2.52	2.52	11.3	0.290
L 5	MMD Substation→ LIBO conveyer	*YJLV 10kV 3×95mm²*	0.020	3	2.52	2.52	11.3	65	0.320
L 8	KAR substation Furnace out	*YJLV 10kV 3×95mm²*	0.020	3	2.52	2.52	11.3	65	0.320
L 9	KAR substation Furnace out	*AC 70/11*	1.000	6	3.80	3.80	3.80	11.4	0.428
L 10	KAR substation Ore Processing	*YJLV 10kV 3×95mm²*	0.020	3	2.52	2.52	11.3	65	0.320
L 11	KAR substation →Ore Processing	*YJLV 10kV 3×240mm²*	0.050	3	2.25	1.8	18	83	0.125
L 12	KAR substation→ Furnace	*AC 70/11*	0.975	6	3.80	3.80	3.80	11.4	0.428
L 13	KAR Substation → NUT output	*YJLV 10kV 3×95mm²*	0.060	3	2.14	10.3	—	11.3	0.320
L 14	KAR Substation → Well output	*YJLV 10kV 3×70mm²*	0.030	19	2.14	10.3	—	10.3	0.443
L 15	KAR Substation → Camp out	*YJLV 50kV 3×50mm²*	0.060	19	1.84	9	—	9	0.641
L 16	KAR Substation → NUT	*AC 70/11*	0.300	6	3.80	3.80	3.80	11.4	0.428
L 17	KAR Substation → Concrete out	*AC 70/11*	0.034	6	3.80	3.80	3.80	11.4	0.428
L 18	KAR Substation → NUT	*YJLV 50kV 3×50mm²*	0.060	19	1.84	9	—	9	0.583
L 19	KAR Sub → Storage	*AC 70/11*	0.057	6	3.80	3.80	3.80	11.4	0.428
L 20	KAR Sub → Concrete	*YJLV 50kV 3×50mm²*	0.060	19	1.84	9	—	9	0.583
L 21	KAR Sub → Storage	*AC 70/11*	0.196	6	3.80	3.80	3.80	11.4	0.428
L 22	KAR Sub → Storage	*СИП 10kV 3×50mm²*	0.003	7	3.29	3.29	9.4	13.0	0.923
L 23	KAR Sub → Maitane	*YJLV 10kV 3×95mm²*	0.020	3	2.52	2.52	11.3	65	0.320
L 24	KAR Sub → METSO crusher	*YJLV 10kV 3×95mm²*	0.020	3	2.52	2.52	11.3	65	0.320
L 25	KAR Sub → METSO crusher	*AC 70/11*	0.287	6	3.80	3.80	3.80	11.4	0.428
L 26	KAR Sub → METSO crusher	*YJLV 10kV 3×95mm²*	0.020	3	2.52	2.52	11.3	65	0.320
L 27	KAR Substation → Well output	*AC 50/8*	1.985	6	3.20	3.20	3.20	9.60	0.596
L 28	KAR Substation → Well output	*AC 50/8*	0.01	6	3.20	3.20	3.20	9.60	0.596
L 29	KAR Substation → Well output	*AC 50/8*	0.075	6	3.20	3.20	3.20	9.60	0.596
L 30	KAR Substation → Well	*AC 50/8*	0.113	6	3.20	3.20	3.20	9.60	0.596
L 31	KAR Substation → Well 3	*AC 50/8*	0.659	6	3.20	3.20	3.20	9.60	0.596
L 32	KAR Substation → Well 4	*AC 50/8*	0.340	6	3.20	3.20	3.20	9.60	0.596

	Line location (number)	Type, brand mark	Length L, km	Diameter, mm Diam					
				Al number	Al d, mm	Steel d, mm	Steel OD, mm	Total OD, mm	Resistance r_0 (20°C), Ohm/km
L 33	KAR Substation → Well 4	*AABLu 10kV 3×70mm²*	0.03	3	3.19	3.19	3.19	47	0.443
L 34	KAR Substation → TBA	*AC 50/8*	0.447	6	3.20	3.20	3.20	9.60	0.596
L 35	KAR Substation → TBA	*AC 50/8*	1.4	6	3.20	3.20	3.20	9.60	0.596
L 36	KAR Substation → Well 5	*AC 50/8*	0.03	6	3.20	3.20	3.20	9.60	0.596
L 37	KAR Substation → Well 5	*AABLu 10kV 3×70mm²*	0.03	3	3.19	3.19	3.19	47	0.443
L 38	KAR Substation → ARJ output	*AC 70/11*	0.975	6	3.80	3.80	3.80	11.4	0.428
L 39	KAR Substation → Camp out	*AC 70/11*	0.630	6	3.80	3.80	3.80	11.4	0.428
L 40	KAR Substation → Water pump	*AC 50/8*	0.02	6	3.20	3.20	3.20	9.60	0.596
L 41	KAR Substation → Water pump	*AC 50/8*	0.800	6	3.20	3.20	3.20	9.60	0.596
L 42	KAR Substation → Camp	*AC 70/11*	0.280	6	3.80	3.80	3.80	11.4	0.428
L 43	KAR Substation → Camp	*YJLV 10kV 3×240mm²*	0.050	3	2.25	1.8	18	83	0.125
L 44	KAR Substation → ARJ output	*AC 70/11*	0.975	6	3.80	3.80	3.80	11.4	0.428
L 45	KAR Substation → ARJ	*AC 70/11*	0.100	6	3.80	3.80	3.80	11.4	0.428
L 46	KAR Substation → A crusher	*AC 70/11*	0.225	6	3.80	3.80	3.80	11.4	0.428
L 47	KAR Substation→ Libo B	*AC 70/11*	0.280	6	3.80	3.80	3.80	11.4	0.428

Table 3: Transformer data

Number	Location	Type, brand mark	Sn, kVA	Unor, kV		Uk %	
				HL (kV)	LV (kV)	H	L
T 1	Biger substation	*S11 5000/35*	5000	35	10.5	7.0	
T 2	AUEHS – MMD crusher	*S11 4000/35*	4000	35	10.5	7.0	
T 3	AUEHS KAR substation	*S11 5000/35*	5000	35	10.5	7.0	
T 4	MMD crusher	*S9 M 2000/10*	2000	10	0.4	5.5	
T 5	LIBO conveyer	*S9 M 2000/10*	2000	10	0.4	6.0	
T 6	Libo 2	*S9 M 2000/10*	2000	10	0.4	6.0	
T 8	DHT 1	*S11 M 160/10*	160	10	0.4	4.0	
T 9	Ore Processing	*S9 M 2000/10*	2000	10	0.4	6.0	
T 10	Furnace	*S9 M 800/10*	800	10	0.4	5.5	
T 11	NUT	*S11 M 160/10*	160	10	0.4	4.0	
T 12	Concrete	*S9 M 800/10*	800	10	0.4	5.0	
T 13	Storage	*S9 M 50/10*	50	10	0.4	4.0	
T 14	Maintenance	*S9 M 800/10*	800	10	0.4	5.0	
T 15	MESTO crusher	*S9 M 2000/10*	2000	10	0.4	6.0	

Number	Location	Type, brand mark	Sn, kVA	Unor, kV		Uk %
				HL (kV)	LV (kV)	H L
T 16	Camp	*S9 M 1600/10*	1600	10	0.4	5.5
T 17	Water supply Well 1	*S9 M 63/10*	63	10	0.4	4.0
T 18	Crusher	*S9 M 2000/10*	2000	10	0.4	6.0
T 19	ARJ	*S9 M 1600/10*	1600	10	0.4	5.5
T 20	Well 3	*S9 M 100/10*	100	10	0.4	4.
T 21	Well 4	*S9 M 63/10*	63	10	0.4	4.0
T 22	TBA	*S9 M 50/10*	50	10	0.4	4.0
T 23	Well 5	*S9 M 63/10*	63	10	0.4	4.0
T 24, 25	Generator	*S11 M 2500/10*	2500	10	0.4	6.0

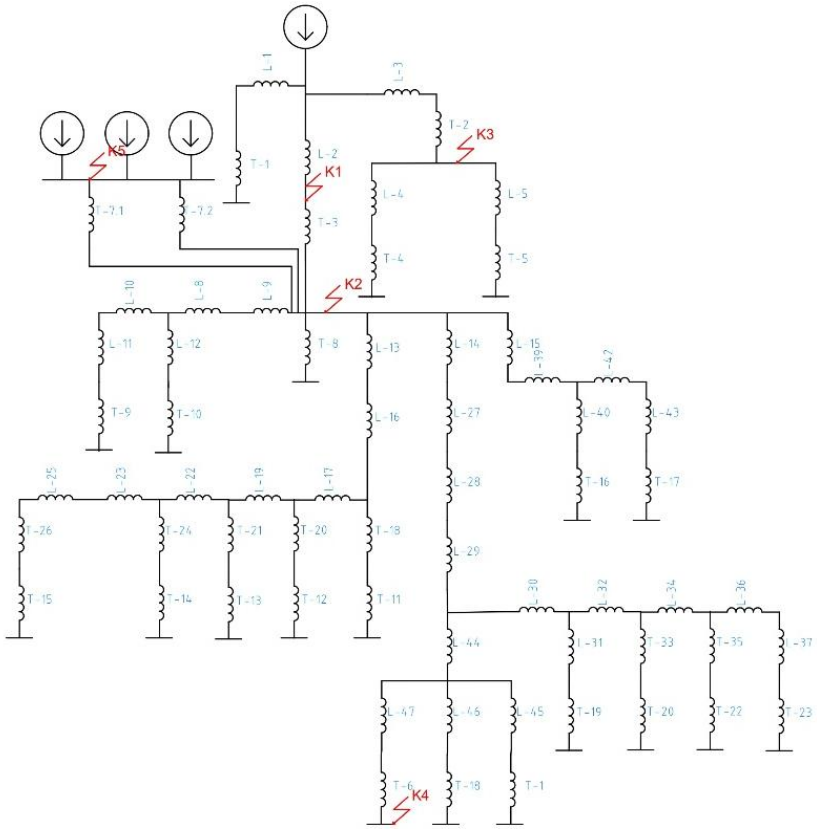


Figure 4: Primary short circuit of scheme

K1 — 35 kV KAR main busbar.
K2 — 10 kV main low voltage busbar.
K3 — 10 kV MMD busbar.
K4 — 0.4 kV MMD Crusher busbar.

3.1.1 Short Circuit Current Calculation

System impedances: $Z_{sys} = \frac{U^2}{S} = \frac{(37)^2}{\infty} = 0$

$S_{base} = 10MVA$

$U_{baseHV} = 37kV$

$U_{baseHL} = 10.5\ kV$

$Z_{baseHV} = \frac{U_{baseHV}^2}{S_{base}} = \frac{37^2}{10} = 136.9\ \Omega$

$I_{baseHV} = \frac{S_{base}}{\sqrt{3}\,U_{baseHV}} = \frac{10000}{\sqrt{3}\ 37} = 156.0\ \text{A}$

$I_{baseLV} = \frac{S_{base}}{\sqrt{3}\,U_{baseLV}} = \frac{10000}{\sqrt{3}\ 10.5} = 549.9\ \text{A}$

Generator impedances: $X_G = 0 \quad \text{E}_\text{s} = 1\ p.u$

Transformer reactances : $X_{\text{T}1} = X_{\text{T}3} = \frac{U_k}{100} \cdot \frac{\text{U}_\text{HV}^2}{S_{nom.tr}} = \frac{7}{100} \cdot \frac{35^2}{5} = 17.15\ \Omega$

$X_{\text{T}2} = \frac{U_k}{100} \cdot \frac{\text{U}_\text{HV}^2}{S_{nom.tr}} = \frac{7}{100} \cdot \frac{37^2}{4} = 21.44\ \Omega$

$X_{\text{T}4} = X_{\text{T}5} = X_{\text{T}6} = X_{\text{T}9} = X_{\text{T}15} = X_{\text{T}18} = \frac{6}{100} \cdot \frac{10}{2} = 0.3\ \Omega$

$X_{\text{T}8} = X_{\text{T}11} = \frac{4}{100} \cdot \frac{10^2}{0.16} = 25\ \Omega$

$X_{\text{T}10} = X_{\text{T}12} = X_{\text{T}14} = \frac{5.5}{100} \cdot \frac{10^2}{0.8} = 6.875\ \Omega$

$X_{\text{T}13} = X_{\text{T}22} = \frac{4.0}{100} \cdot \frac{10^2}{0.050} = 80\ \Omega$

$X_{\text{T}16} = X_{\text{T}19} = \frac{5.5}{100} \cdot \frac{10^2}{1.6} = 3.44\ \Omega$

$X_{\text{T}20} = \frac{4}{100} \cdot \frac{10^2}{0.100} = 40\ \Omega$

Line resistance and reactance :

$R_{l1} = X_0 \cdot L = 0.428 \cdot 130 = 55.64\ \Omega$

$X_{l1} = x_0 * l = 0.4 \cdot 130 = 52\ \Omega$

$Z = \sqrt{R_{l1}^2 + X_{l1}^2} = \sqrt{55.64^2 + 52^2} = 76.156\ \Omega$

Line numbers	R Ω	X Ω	Z Ω	Line numbers	R Ω	X Ω	Z Ω
L 1	55.640	52.000	76.156	L 25	0.123	0.115	0.168
L 2.1	3.852	3.600	5.272	L 26	0.006	0.002	0.007
L 2.2	4.033	3.770	5.521	L 27	1.183	0.820	1.439
L 2 .3	0.520	0.486	0.712	L 28	0.006	0.004	0.007
L 3	3.082	2.880	4.218	L 29	0.045	0.031	0.054
L 4	0.102	0.032	0.106	L 30	0.067	0.047	0.082
L 5	0.006	0.002	0.007	L 31	0.393	0.272	0.478
L 8	0.006	0.002	0.007	L 32	0.203	0.140	0.247
L 9	0.428	0.400	0.586	L 33	0.013	0.003	0.014
L 10	0.006	0.002	0.007	L 34	0.266	0.185	0.324
L 11	0.006	0.004	0.007	L 35	0.834	0.578	1.015
L 12	0.417	0.390	0.571	L 36	0.018	0.012	0.022
L 13	0.019	0.005	0.020	L 37	0.013	0.003	0.014
L 14	0.013	0.003	0.014	L 38	0.417	0.390	0.571
L 15	0.038	0.006	0.039	L 39	0.270	0.252	0.369
L 16	0.128	0.120	0.176	L 40	0.012	0.008	0.015
L 17	0.015	0.014	0.020	L 41	0.477	0.330	0.580
L 18	0.035	0.006	0.035	L 42	0.120	0.112	0.164
L 19	0.024	0.023	0.033	L 43	0.006	0.004	0.007
L 20	0.035	0.006	0.035	L 44	0.417	0.390	0.571
L 21	0.084	0.078	0.115	L 45	0.043	0.040	0.059
L 22	0.003	0.000	0.003	L 46	0.096	0.090	0.132
L 23	0.006	0.002	0.007	L 47	0.120	0.112	0.164
L 24	0.006	0.002	0.007				

Figure 5: Line resistance and reactance

3.1.2 Short Circuit Calculation at Fault Point K1

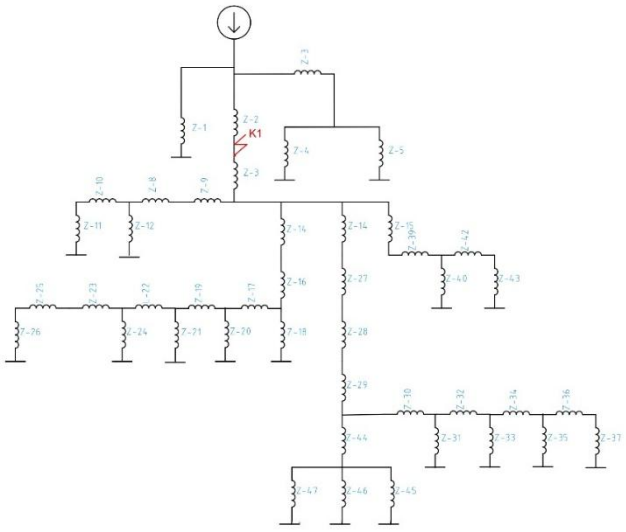


Figure 6: Positive sequence substitution scheme for point K1

Positive sequence network at K1

$$\frac{1}{Z'1} = \frac{1}{Z_{47}} + \frac{1}{Z_{47}} + \frac{1}{Z_{47}} =$$

$$\frac{1}{0.164} + \frac{1}{0.132} + \frac{1}{0.059} => Z_{48} = 0.0326\,\Omega$$

$$Z_{49} = Z_{48} + Z_{44}$$

$$= 0.0326 + 0.571 = 0.6036\Omega$$

$$Z_{50} = Z_{37} + Z_{36} = 0.022 + 0.014 = 0.036\,\Omega$$

$$Z_{51} = \frac{Z_{35} \cdot Z_{50}}{Z_{35} + Z_{50}} = \frac{1.015 \cdot 0.036}{1.015 + 0.036} = 0.0347\Omega$$

$$Z_{52} = Z_{34} + Z_{51} = 0.324 + 0.0347 = 0.3587\Omega$$

$$Z_{53} = \frac{Z_{33} \cdot Z_{52}}{Z_{33} + Z_{52}} = \frac{0.014 \cdot 0.3587}{0.014 + 0.3587} = 0.0134\Omega$$

$$Z_{55} = Z_{32} + Z_{51} = 0.247 + 0.0134 = 0.2604\,\Omega$$

$$Z_{56} = \frac{Z_{31} \cdot Z_{55}}{Z_{31} + Z_{55}} = \frac{0.478 \cdot 0.2604}{0.478 + 0.2604} = 0.1685\Omega$$

$$Z_{57} = Z_{30} + Z_{51} = 0.082 + 0.0134 = 0.0954\,\Omega$$

$$Z_{58} = \frac{Z_{49} \cdot Z_{57}}{Z_{49} + Z_{57}} = \frac{0.6036 \cdot 0.0954}{0.6036 + 0.0954} = 0.082\Omega$$

$$Z_{59} = Z_{29} + Z_{57} = 0.054 + 0.0823 = 0.1363\Omega$$

$$Z_{60} = Z_{28} + Z_{59} = 0.007 + 0.1363 = 0.137\,\Omega$$

$$Z_{61} = Z_{27} + Z_{60} = 1.439 + 0.137 = 1.576\,\Omega$$

$$\boldsymbol{Z_{62}} = Z_{14} + Z_{61} = 0.014 + 1.576 = \mathbf{1.59\,\Omega}$$

$$Z_{63} = Z_{42} + Z_{43} = 0.164 + 0.007 = 0.171\,\Omega$$

$$Z_{64} = \frac{Z_{40} \cdot Z_{63}}{Z_{40} + Z_{63}} = \frac{0.015 \cdot 0.171}{0.015 + 0.171} = 0.0138\,\Omega$$

$$Z_{65} = Z_{39} + Z_{64} = 0.369 + 0.0138 = 0.3828\,\Omega$$

$$\boldsymbol{Z_{66}} = Z_{15} + Z_{65} = 0.039 + 0.3828 = \mathbf{0.421\Omega}$$

$$Z_{67} = Z_{23} + Z_{25} + Z_{26}$$

$$Z_{67} = 0.007 + 0.168 + 0.007 = 0.182\Omega$$

$$Z_{68} = \frac{Z_{24} \cdot Z_{67}}{Z_{24} + Z_{67}} = \frac{0.007 \cdot 0.182}{0.007 + 0.182} = 0.0067\,\Omega$$

$$Z_{69} = Z_{22} + Z_{68} = 0.003 + 0.0067 = 0.0097\,\Omega$$

$$Z_{70} = \frac{Z_{21} \cdot Z_{57}}{Z_{21} + Z_{57}} = \frac{0.115 \cdot 0.0097}{0.115 + 0.0097} = 0.0089\Omega$$

$$Z_{71} = Z_{19} + Z_{70} = 0.033 + 0.0089 = 0.0419\,\Omega$$

$$Z_{72} = \frac{Z_{20} \cdot Z_{71}}{Z_{20} + Z_{71}} = \frac{0.035 \cdot 0.0419}{0.035 + 0.0419} = 0.019\Omega$$

$$Z_{73} = Z_{17} + Z_{72} = 0.020 + 0.019 = 0.039\,\Omega$$

$$Z_{74} = \frac{Z_{18} \cdot Z_{73}}{Z_{18} + Z_{73}} = \frac{0.035 \cdot 0.039}{0.035 + 0.039} = 0.018\Omega$$

$$Z_{75} = Z_{16} + Z_{74} = 0.007 + 0.018 = 0.137\,\Omega$$

$$\boldsymbol{Z_{76}} = Z_{13} + Z_{75} = 0.020 + 0.137 = \mathbf{0.157\,\Omega}$$

$$Z_{77} = Z_{10} + Z_{11} = 0.007 + 0.007 = 0.014\,\Omega$$

$$Z_{78} = \frac{Z_{12} \cdot Z_{77}}{Z_{12} + Z_{77}} = \frac{0.571 \cdot 0.014}{0.571 + 0.014} = 0.0136\Omega$$

$$Z_{79} = Z_{8} + Z_{78} = 0.007 + 0.0136 = 0.021\,\Omega$$

$$\boldsymbol{Z_{80}} = Z_{9} + Z_{79} = 0.586 + 0.021 = \mathbf{0.607\,\Omega}$$

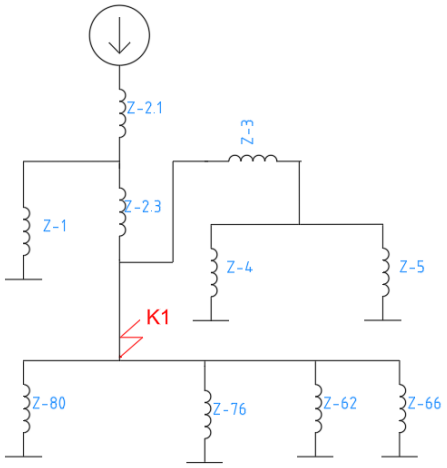


Figure 7: Positive sequence substitution scheme for point K1

$$\frac{1}{Z_{81}} = \frac{1}{Z_{80}} + \frac{1}{Z_{75}} + \frac{1}{Z_{62}} + \frac{1}{Z_{66}} = \frac{1}{0.607} + \frac{1}{0.157} + \frac{1}{1.59} + \frac{1}{0.4218} => Z_{81} = 0.09\ \Omega$$

$$Z_{82} = \frac{Z_4 \cdot Z_5}{Z_4 + Z_5} = \frac{0.106 \cdot 0.007}{0.106 + 0.007} = 0.006\Omega$$

$$Z_{83} = Z_3 + Z_{82} = 0.218 + 0.006 = 0.224\ \Omega$$

$$Z_{84} = \frac{Z_1 \cdot Z_{2.1}}{Z_1 + Z_{2.1}} = \frac{76.156 \cdot 5.272}{76.156 + 5.272} = 4.93\ \Omega$$

$$Z_{85} = Z_{2.3} + Z_{2.2} = 0.712 + 5.521 = 6.233\ \Omega$$

$$Z_{86} = Z_{85} + Z_{84} = 6.233 + 4.93 = 11.163\ \Omega$$

$$Z_{87} = \frac{Z_{83} \cdot Z_{86}}{Z_{83} + Z_{86}} = \frac{0.224 \cdot 11.163}{0.224 + 11.163} = 0.219\ \Omega$$

$$Z_{1\Sigma} = Z_{86} + Z_{87} = 11.163 + 0.219 = 11.38\ \Omega$$

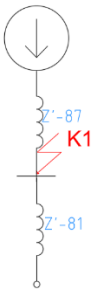


Figure 8: Positive sequence scheme for point K1

Negative sequence network at K1

To simplify the calculation of the negative sequence equivalent circuit, it is assumed that the negative sequence values are equal to those of the positive sequence. This approach is adopted because the electromotive force (EMF) is not accounted for at this stage, and the generator impedance varies to a certain extent. Furthermore, as the short circuit point is located at a significant distance from the major power sources, the condition is taken as

$$Z^2\Sigma = Z^1\Sigma$$

Zero sequence network at K1

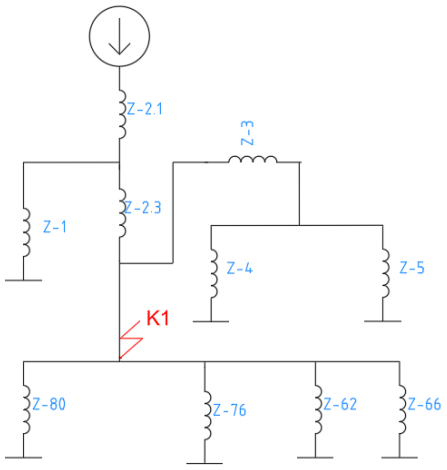


Figure 9 : Zero sequence scheme for point K1

$Z'_{62} = 1.59 * 3.5 = 5.565\ \Omega$

$Z'_{66} = 0.4218 * 3.5 = 1.4763\ \Omega$

$Z'_{76} = 0.157 * 3.5 = 0.5495\ \Omega$

$Z'_{80} = 0.607 * 3.5 = 2.1245\ \Omega$

$Z'_{83} = 0.219 * 3.5 = 0.7665\ \Omega$

$Z'_{84} = 4.93\ \Omega$

$Z_{85} = 6.233\ \Omega$

$$\frac{1}{Z'_{81}} = \frac{1}{Z'_{80}} + \frac{1}{Z'_{75}} + \frac{1}{Z'_{62}} + \frac{1}{Z'_{66}} = \frac{1}{5.565} + \frac{1}{1.4763} + \frac{1}{0.5495} + \frac{1}{2.1245} => Z'_{81} = 9.59\ \Omega$$

$$Z'_{86} = Z'_{85} + Z'_{84} = 6.233 + 4.93 = 11.163\ \Omega$$

$$Z'_{87} = \frac{Z'_{83} \cdot Z'_{86}}{Z'_{83} + Z'_{86}} = \frac{0.7665\ \cdot 11.163}{0.7665\ + 11.163} = 0.7172\ \Omega$$

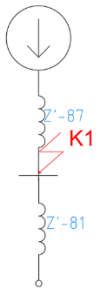


Figure 10: Zero sequence scheme for point K1

$$Z_{0\Sigma} = Z'_{81} + Z'_{87} = 9.59 + 0.7172 = 10.3\ \Omega$$

K1 fault point 3 Phase Fault Current

$$I^3_{k1.max} = \frac{c_n * U_n}{Z_{1\Sigma} \cdot \sqrt{3}} = \frac{1.10 * 35}{11.38\ \cdot \sqrt{3}} = 1.95kA$$

$$I^3_{k1.mix} = \frac{c_n * U_n}{Z_{1\Sigma} \cdot \sqrt{3}} = \frac{0.95 * 35}{11.38\ \cdot \sqrt{3}} = 1.68kA$$

K1 fault point 1 Phase Fault Current

$$I^1_{k1} = \frac{\sqrt{3} * c_n * U_n}{(Z_{1\Sigma} + Z_{2\Sigma} + Z_{0\Sigma}) \cdot \sqrt{3}} = \frac{\sqrt{3} *\ 1.10 * 35}{(11.38\ + 11.38\ + 10.3)} = 2.01kA$$

3.1.3 Short Circuit Calculation at Fault Point K2

Using fault point K1 scheme.

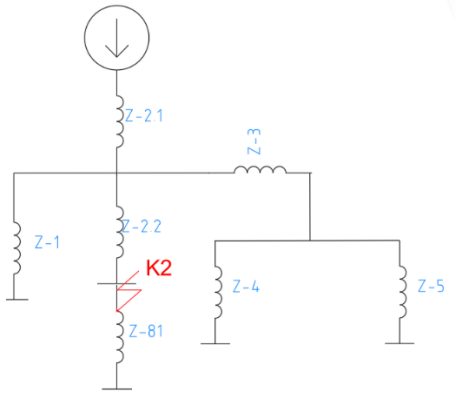


Figure 11: Positive sequence scheme for point K2

$$Z_{86} = Z_{85} + Z_{84} = 6.233 + 4.93 = 11.163\ \Omega$$

$$Z_{87} = \frac{Z_{83} \cdot Z_{86}}{Z_{83} + Z_{86}} = \frac{0.224 \cdot 11.163}{0.224 + 11.163} = 0.219\ \Omega$$

$$Z_{1\Sigma} = Z_{86} + Z_{87} = 11.163 + 0.219 = 11.38\ \Omega$$

$$Z_{0\Sigma} = Z'_{81} + Z'_{87} = 9.59 + 0.7172 = 10.3\ \Omega$$

Positive sequence network at K2

$$Z_{1\Sigma} = Z_{86} + Z_{81} = 11.163 + 0.219 = 2.348\ \Omega$$

Negative sequence network at K2

$$Z^2\Sigma = Z^1\Sigma$$

Zero sequence network at K2

$$\frac{I^3_{k1}}{I^3_{k3}} = \frac{1.15}{2.66} = 0.432$$

$$Z_{0\Sigma} = Z'_{81} + Z'_{87} = 9.59 + 0.7172 = 10.3\ \Omega$$

K2 fault point 3 Phase Fault Current

$$I^3_{k1.max} = \frac{c_n * U_n}{Z_{1\Sigma} \cdot \sqrt{3}} = \frac{1.10 * 10.5}{2.348 \cdot \sqrt{3}} = 2.84kA$$

$$I^3_{k1.mix} = \frac{c_n * U_n}{Z_{1\Sigma} \cdot \sqrt{3}} = \frac{0.95 * 10.5}{2.348 \cdot \sqrt{3}} = 2.45kA$$

K2 fault point 1 Phase Fault Current

$$I^2_{k1} = \frac{\sqrt{3} * c_n * U_n}{(Z_{1\Sigma} + Z_{2\Sigma} + Z_{0\Sigma}) \cdot \sqrt{3}} = \frac{\sqrt{3} * 1.10 * 10.5}{(2 \times 2.348 + 11.60)} = 1.06kA$$

3.1.4 Short Circuit Calculation at Fault Point K3

Positive sequence network at K3

$$Z_{1\Sigma} = Z_{86} + Z_{81} = 11.163 + 0.219 = 2.348\ \Omega$$

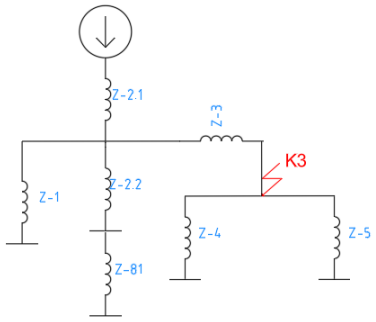


Figure 12: Positive sequence scheme for point K3

Negative sequence network at K3

$$Z^2\Sigma = Z^1\Sigma$$

Zero sequence network at K3

$$\frac{I^3_{k1}}{I^3_{k3}} = \frac{1.15}{2.66} = 0.432$$

$$Z_{0\Sigma} = Z'_{81} + Z'_{87} = 9.59 + 0.7172 = 10.3\ \Omega$$

K3 fault point 3 Phase Fault Current

$$I^3_{k1.max} = \frac{c_n * U_n}{Z_{1\Sigma} \cdot \sqrt{3}} = \frac{1.10 * 10.5}{3.048 \cdot \sqrt{3}} = 2.188\ kA$$

$$I^3_{k1.mix} = \frac{c_n * U_n}{Z_{1\Sigma} \cdot \sqrt{3}} = \frac{0.95 * 10.5}{3.048 \cdot \sqrt{3}} = 1.89kA$$

K3 fault point 1 Phase Fault Current

$$I^2_{k1} = \frac{\sqrt{3} * c_n * U_n}{(Z_{1\Sigma} + Z_{2\Sigma} + Z_{0\Sigma}) \cdot \sqrt{3}} = \frac{\sqrt{3} * \ 1.10 * 10.5}{(2 \times 3.048 \ + 11.60)} = 1.80kA$$

3.1.5 Short Circuit Calculation at Fault Point K4

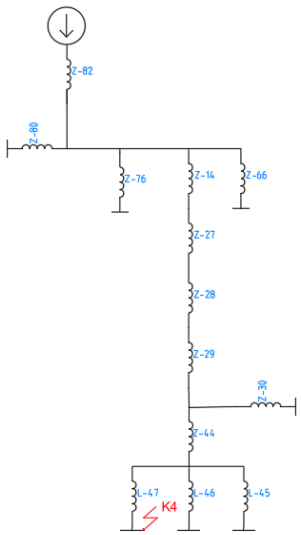


Figure 13: Positive sequence scheme for point K4

$$Z^{10kV}_{1\Sigma sc} = Z_{k2} + Z_{l17} + Z_{l18} + Z_{l47} = 2.348 + 0.020 + 0.035 + 0.164 = 2.53\ \Omega$$

$$Z^{0,4kV}_{1\Sigma source} = \left(\frac{0.4}{10}\right)^2 * 0.00$$

Negative sequence network at K4

$$Z^2\Sigma \ = \ Z^1\Sigma$$

Zero sequence network at K4

LV side = star with grounded neutral (TN S) → zero sequence current CAN flow through transformer neutral

HV side = delta → blocks all 10 kV network Z_0 from entering

$$Z_{0\sum k4} = Z_{0T6} = z_{1T6} = j0.0048 \quad \frac{Z_0}{Z_1} = \frac{0.0048}{0.008700} = 0.552$$

K4 fault point 3 Phase Fault Current

$$I^3_{k1.max} = \frac{c_n * U_n}{Z_{1\sum} \cdot \sqrt{3}} = \frac{1.05 * 400}{0.0087 \cdot \sqrt{3}} = 27.9kA$$

$$I^3_{k1.mix} = \frac{c_n * U_n}{Z_{1\sum} \cdot \sqrt{3}} = \frac{0.95 * 10.5}{0.0087 \cdot \sqrt{3}} = 25.2kA$$

K4 fault point 1 Phase Fault Current

$$I^1_{k3,max} = \frac{\sqrt{3} * c_n * U_n}{(Z_{1\sum} + Z_{2\sum} + Z_{0\sum}) \cdot \sqrt{3}} = \frac{\sqrt{3} * 1.05 * 400}{(2 \times 2.348 + 11.60)} = 33.1\ kA$$

$$I^1_{k3,min} = \frac{\sqrt{3} * c_n * U_n}{(Z_{1\sum} + Z_{2\sum} + Z_{0\sum}) \cdot \sqrt{3}} = \frac{\sqrt{3} * 1.05 * 400}{(0.021954)} = 29.9\ kA$$

3.2 Short Circuit Calculation Simulation

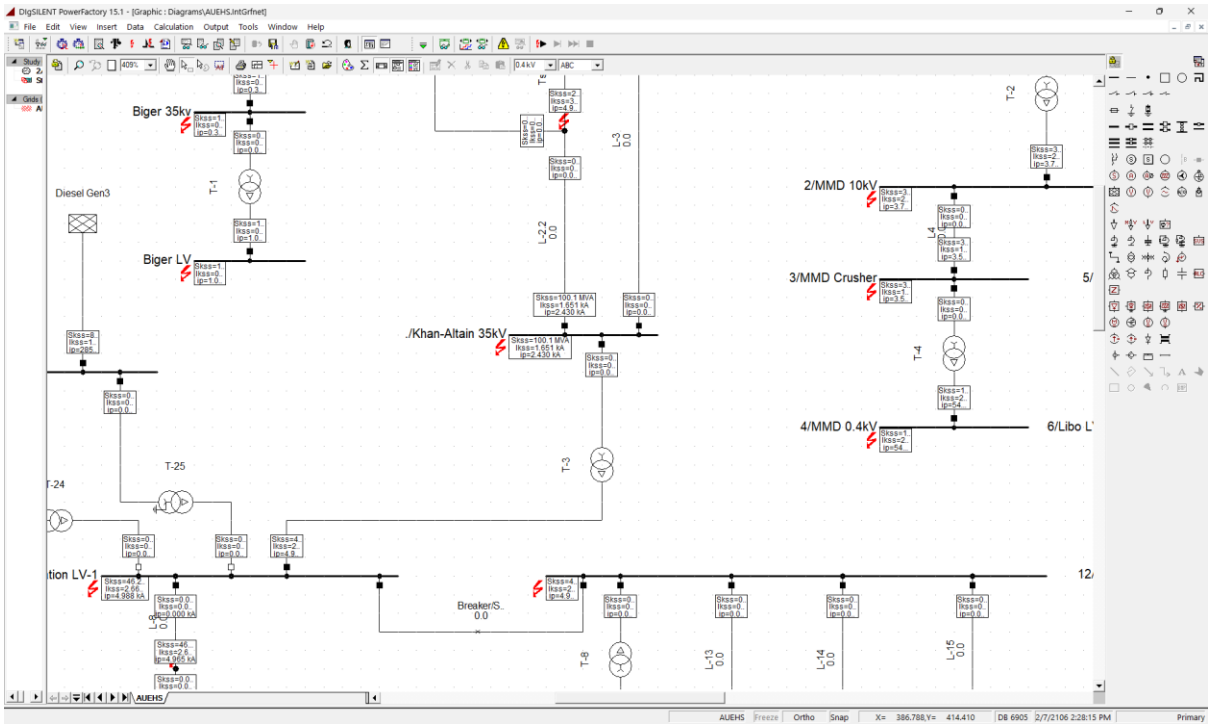


Figure 14: DIgSILENT Power Factory Simulation Results

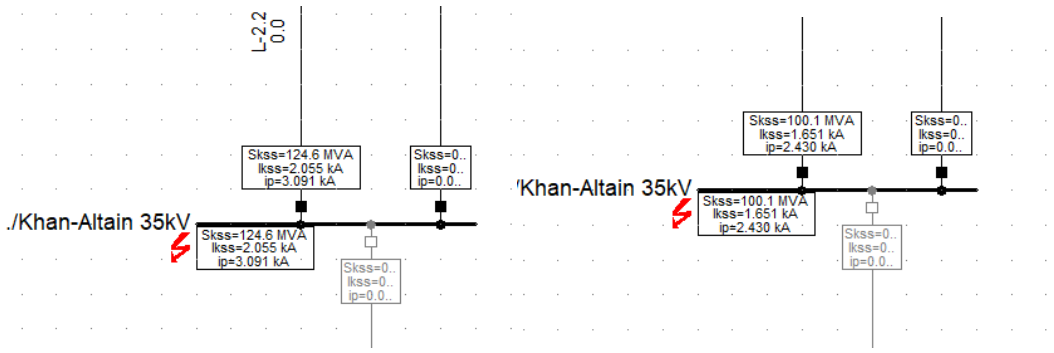


Figure 15: Simulation Short circuit calculation of K1 point max and min current

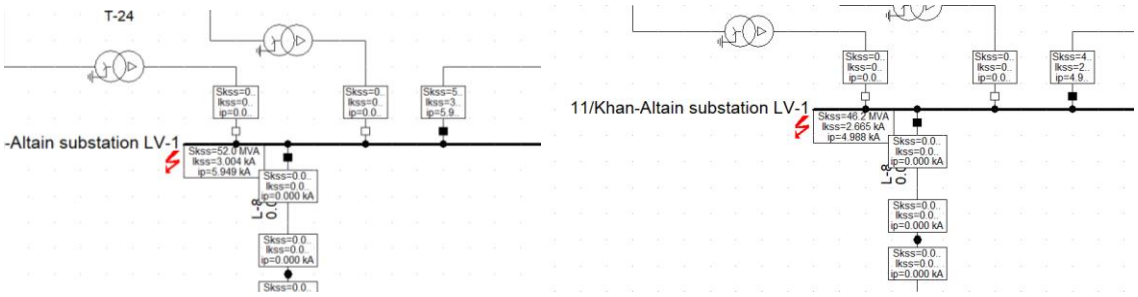


Figure 16: Simulation Short circuit calculation of K2 point max and min current

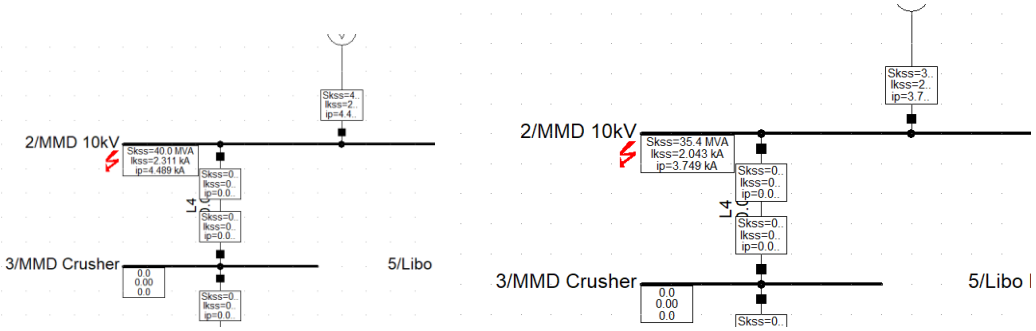


Figure 17: Simulation Short circuit calculation of K3 point max and min current

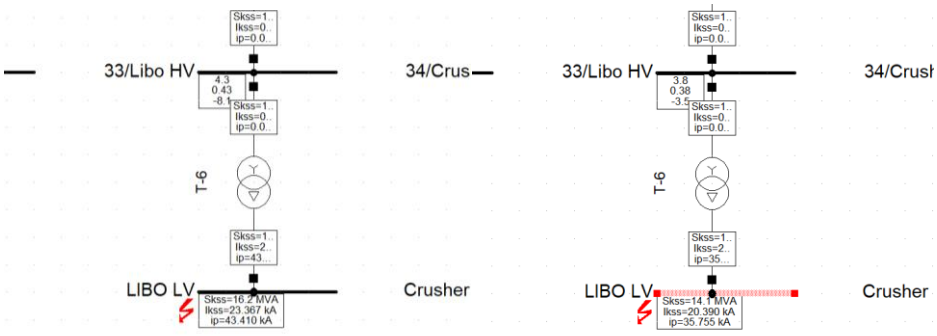


Figure 18: Simulation Short circuit calculation of K4 point max and min current

Table 4: Calculation and Simulation comparison and Error

Short circuit fault points	Type	Calculation, kA	Power factory, kA	Error
K1	I_K^3	1.99	2.055	3.3%
	I_K^1	1.72	1.651	4.0%
K2	I_K^3	2.84	3.004	5.8%
	I_K^1	2.45	2.665	8.8%
K3	I_K^3	2.19	2.311	5.5%
	I_K^1	1.89	2.043	8.1%
K4	I_K^3	27.9	23.36	16.2%
	I_K^1	25.2	20.39	19.1%

4. Selection of Switching and Protection Equipment

During short circuit conditions in a power system, the switching equipment is subjected to both thermal and dynamic mechanical stresses. In a real power system, short circuits may occur in various forms; among these, the most hazardous to equipment is the three phase short circuit. In order to protect the power system's equipment from the damaging effects of short circuit currents, circuit breakers and disconnectors are employed as switching apparatus. Switching apparatus must satisfy the requirements of normal operation, the switching off regime, and the extreme dynamic and thermal stresses that occur at the instant of fault inception. For the selection of switching equipment, the peak short circuits current equivalent to the three-phase short circuit current is used as the basis

Table 5: Power system element standard

Power system element	T_a, s	K_y
Turbogenerators:		
12–60 MW capacity	0.16 0.25	1.94 1.995
100–1000 MW capacity	0.4 0.54	1.975 1.98
60 MW turbogenerator– transformer block, generator terminal voltage:		
At 6.3 kV	0.2	1.95
At 10 kV	0.15	1.935
Turbogenerator–step up transformer block, generator capacity		
100–200 MW	0.26	1.965
200 MW	0.32	1.977
500 MW	0.35	1.983
800 MW	0.3	1.967
Short circuit in an unloaded system connected through overhead line:		
Line voltage 35 kV	0.02	1.608
Line voltage 110–150 kV	0.02 0.03	1.608 1.717
Line voltage 220–330 kV	0.03 0.04	1.717 1.78
Line voltage 500–750 kV	0.06 0.08	1.85 1.895

6–10 kV busbars directly connected through transformers:		
Transformer capacity ≥ 80 MVA	0.06 0.15	1.85 1.935
Transformer capacity 32–80 MVA	0.05 0.1	1.82 1.904
Reactor protected feeder, reactor nominal current:		
I ≥ 1000 A	0.23	1.956
I ≥ 630 A	0.1	1.904
6–10 kV busbar sections	0.01	1.369

Calculation of the normalized initial symmetrical short circuit current

$$I_{n.0} = I^{3}_{k} = 1.95kA$$

Calculation of the impact (peak) current

$$i_y = \sqrt{2} \cdot I_{n.0} \cdot K_y = \sqrt{2} \cdot 1.95kA \cdot 1.608 = 4.43 \text{ kA}$$

Where: K_y =1.608 impact coefficient, taken from Table 1.4.1 based on the short circuit fault point location.

$$\overline{i_{a.\tau}} = \sqrt{2} \cdot I_{n.0} \cdot e^{-\frac{\overline{0.08}}{0.02}} = 0.0505k$$

Where: Ta=0.02 decay time constant of the aperiodic component of the short circuit current, taken from Table 1.4.1 based on the fault point location. τ=0.08 s contact separation time of the circuit breaker.

Normalized steady state short circuit current

$$I_{n.\tau} = I_{n.0} = 1.95kA$$

Thermal impulse (thermal equivalent)

$$B_k = (I_{n.0})^2 \cdot (t_{\text{break}} + T_a) = (1.95\ )^2 \cdot (0.1 + 0.02) = 0.456 \text{ kA}^2 \cdot \text{c}$$

where t =0.2 s circuit breaker interruption time

Table 6: At K1 point circuit breaker selection calculation results

Short circuit point	$I_k^{(3)}$, kA	$I_{n.0}$, kA	$I_{n.\tau}$, kA	i_y, kA	$i_{a.\tau}$, kA	B_k, kA²c
K1	1.95	1.95	1.95	4.43	0.05	0.456

Circuit Breaker Selection

A circuit breaker is a switching apparatus designed to close and open a circuit under prescribed conditions. A circuit breaker is the most critical protective element in a power system, capable of interrupting the circuit under all operating conditions including normal load, short circuit, no load, and asynchronous conditions. Unlike a fuse, a circuit breaker can reset and reclose after interruption. Moreover, because a circuit breaker protects only a single element at a time, a backup protection function is required [7].

- For high voltage circuit breakers, the following requirements shall be satisfied:
- The load current shall be reliably interrupted
- The ability to interrupt at the minimum breaking time and to re close repeatedly after interruption
- For circuit breakers at 110 kV and above, each phase shall be independently operable
- Freedom from fire and explosion hazards
- Ease of maintenance and low cost.

Circuit Breaker Selection Rated Current Calculation

Since the circuit breaker must be capable of interrupting the system under any fault condition, the load current is used as the selection basis:

AC 70/11 overhead line $I_{emergency} = 318A$ $S_{emergency} = 19.2\ MVA$



Figure 19: LW36 40.5/T1600 31.5 circuit breaker

Table 7: At K1 point circuit breaker selection calculation results

Circuit breaker criterion and condition	**Calculated value**	**Circuit breaker rated parameters LW36 40.5/T1600 31.5**
Voltage: ($U_{calc} \le U_{nor}$)	U = 35 кВ	U_{nor} = 37 кВ
Current : ($I_{calc} \le I_{nor}$)	I_{cal} = 299,59 A	I_{nom} = 1600 A
Breaking capacity: $I_{n.\tau} \le I_{br}$	$I_{n.\tau}$ = 1.95 kA $i_{a.\tau}$ = 0.05 kA	I_{br} = 31.5 kA $i_{a.nor} = \left(\frac{\sqrt{2} \cdot 10 \cdot 31.5}{100}\right) = 4.45$ kA
Making capacity: $I_{n.0} \le I_{зал}$ $i_y \le i_{зал}$	$I_{n.0}$ = 1.95 kA i_y = 4.43 kA	I_{con} = 76.5 kA $i_{зал} = 1.717 \cdot \sqrt{2} \cdot I_{con}$ = 76.5 kA
Dynamic withstand: $I_{n.0} \le I_{пр.свк}$ $i_y \le i_{пр.свк}$	$I_{n.0}$ = 1.95 kA i_y = 4.43 kA	i_{dyn} = 80 kA 4.43 kA≤ 80 kA
Thermal withstand : $B_к \le I^2_{mep} \cdot t_{mep}$	B_k = 0.456 kA²c	$I^2_{mep} \cdot t_{mep}$ = 31.5² × 3 = 2976 kA²·s
Interruption time		t_{int} = 0.1
Closing time		t_{int} = 0.15

Current Transformer Selection

In relay protection and automation systems, current transformers serve as the initial conversion element linking the measurement circuits of primary and secondary equipment. The primary function of a current transformer is to reduce the high primary current to a standard secondary current suitable for relay protection measurement circuits and to isolate the relay circuits from the high voltage primary circuit while ensuring the accuracy required for correct metering. Furthermore, current transformers reproduce the transient characteristics of the primary current. For these reasons, the most widely used sensing devices in power systems are current transformers (CTs), designated as TA and TV.

Their principal function is to measure the high primary current, convert it to a low secondary signal suitable for measurement circuit inputs, and to provide isolation. The secondary rated output of a current transformer is typically 5 A and 1 A, and the voltage transformer secondary is 100 V and 100/√3 V [13].

Voltage Transformer Selection

A voltage transformer is used to convert the primary voltage to a level suitable for relay protection and measurement, and to supply reference quantities to the relay protection and metering apparatus, with provision for connection to a high voltage circuit from a safe low voltage side. Voltage transformers are selected based on nominal current, nominal dynamic and thermal withstand capability. Voltage transformers are selected by comparing the accuracy class with the connected burden on the secondary side.

Determination of load transformer capacities connected to the 35 kV bus:

$$S_{load}S_{T1} = 6.3\ MVA \quad (Biger\ substation, 35/10\ kV)$$

$$S_{T2} = 6.3\ MVA \quad (MMD\ Crusher\ substation, 35/10\ kV)$$

$$S_{T3} = 10.0\ MVA \quad \left(Khan - Altai\ main\ substation, \frac{35}{10} kV\right)$$

Total installed transformer capacity:

$$S_{load} = S_{T1} + S_{T2} + S_{T3} = 6.3 + 6.3 + 10.0 = 22.6\ MVA$$

It is verified that the total installed capacity of the load transformers is less than the total system capacity transmitted.

Based on load scheduling, it is assumed that during maximum load conditions, when the load transformers are operating at approximately 80% of their rated capacity, the system transmits the maximum power:

$$S_{sys.max} = S_{load} \times 0.8 = 22.6 \times 0.8 = 18.08\ MVA$$

$$S_{sys.max} = S_{load} \times 0.7 = 22.6 \times 0.7 = 15.82\ MVA$$

$$I_{nom} = \frac{S_{sys}.nom}{\left(\sqrt{3} \times n \times U_{nom}\right)} = \frac{15820}{\left(\sqrt{3} \times 1 \times 35\right)} = 261.1\ A$$

$$I_{\max.} = \frac{S_{sys}\max}{\left(\sqrt{3} \times n \times U_{nom}\right)} = \frac{18080}{\left(\sqrt{3} \times 1 \times 35\right)} = 298.2\ A \approx 299.59\ A$$

The protective current transformer installed on the line side must satisfy the following requirements:

• The current transformer and the relay protection circuits must operate with high accuracy;

• The metering circuit must operate reliably under even a single short circuit condition;

• Under a single fault, the secondary output current of the current transformer shall not exceed the rated value.

Current Transformer Selection

a) Secondary Circuit Impedance Calculation

The secondary circuit impedance is determined from the following expression:

$$Z_2 = Z_{relay} + Z_{conductor} + Z_{contact}$$

$$Z_{relay} = \frac{S_{relay}}{I^2.nom} = \frac{15}{5^2} = 0.60\,\Omega$$

Where: $Z_{conductor}$ — conductor impedance;

$Z_{contact}$ — contact impedance, taken as 0.05 if the number of contacts is 3 or fewer, and 0.1 if more than 3;

Z_{relay}— relay internal impedance.

$$Z_{contact} = 0.05\,\Omega$$

l since the connection between the current transformer, relay, and the current path scheme is calculated assuming 100 m of conductor length, the cross-sectional area of the conductor is determined from the following expression:

$$q_{calc} = \frac{(\rho \times l)}{(Z^2.nom - Z_{relay} - Z_{contact})} = \frac{(0.0175 \times 100)}{(5 - 0.60 - 0.05)} = \frac{1.75}{4.35} = 0.402\,mm^2$$

Where: ρ — resistivity of the conductor material (for copper: 0.0175 ·mm²/m).

Since the calculated cross section$q_{calc} = 0.402\ \mathrm{mm}^2$ is less than the minimum permissible value $q_{min} = 2.5\ \mathrm{mm}^2$, the multi core control cable with q = 2.5 mm² is selected.

$$Z_{conductor} = \frac{(\rho \times l)}{q} = \frac{(0.0175 \times 100)}{2.5} = 0.70\,\Omega$$

The secondary side total impedance is now verified:

$$Z^2 = Z_{relay} + Z_{conductor} + Z_{contact} = 0.60 + 0.70 + 0.05 = 1.35\,\Omega$$

$$Z^2.nom = 5\,\Omega \geq Z^2 = 1.35\,\Omega$$

b) Infeed Ratio Check — Protection Sensitivity Verification

When the current transformer operates at the short circuit fault point located on the bus and the line is in the single fault regime, the infeed ratio enters the distance protection function via the second end feed current, thereby causing certain protection elements to operate with reduced sensitivity. The maximum infeed current ratio from the adjacent bus is determined as:

$$K_{inf} = \frac{I_k^3}{I_{nom}} = \frac{1.99}{0.300} = 6.63 \approx 7$$

The sensitivity reduction parameter A is obtained as:

$$A = \frac{K_{\inf}}{K_{sens}} = \frac{7}{20} = 0.35$$

Since A = 0.35 < 1.0, the reduction in protection sensitivity does not exceed 10%. This condition is considered acceptable.

c) Second End High Current Saturation Check

When the bus is in a single fault condition and the second end current ($U^2.\inf$) in the current transformer's secondary circuit exceeds the reference voltage ($U^2.perm$), it is necessary to check the saturation level of the second end current transformer.

According to the power system standards of Mongolia, the permissible secondary voltage is:

$$U^2.perm = 1000\,V$$

$$U^2.\inf \leq 2 \times U^2.perm = 2000\,V$$

$$U^2.\inf = K_{\inf} \times {I^2}_{\mathrm{n}} \times Z^2 = 7 \times 5 \times 1.35 = 47.25\,V$$

Since U_2.inf = 47.25 V ≪ 2000 V, the current transformer is confirmed suitable for use with relay protection.

Table 8: Current transformer comparison

No.	Parameter	TFZM 35 catalogue rating	Calculated value	Selection criterion
1	Rated voltage	U_{nom} = 35 kV	U_{cal} = 35 kV	$U_{nom} \geq U_{cal}$
2	Primary rated current	I_{nom} = 400 A	I_{max} = 299.59 A	$I_{nom} \geq U_{cal}$
3	Secondary rated current	I_{2nom} = 5 A	—	Standard
4	Thermal withstand	40² × 3 = 4800 kA²·s	B_k = 0.456 kA²·s	$B_k \leq I_{th}^2 \times t_{th}$
5	Secondary impedance	Z_2.nom = 5 Ω	Z_2 = 1.35 Ω	Z_2.nom ≥ Z_2
6	Accuracy class	10P / 0.5	10P required	



Figure 20: TFZM 35 current transformer

Voltage Transformer Selection

A voltage transformer is required to supply the relay protection and metering circuits with an accurately scaled secondary voltage, while providing galvanic isolation from the 35 kV primary circuit. The selected type is NAMI 35.

Table 9: Voltage transformer comparison

Parameter	NAMI 35 rating
Primary rated voltage	$\frac{35}{\sqrt{3}}$ kV = 20.2 kV (phase to earth)
Secondary voltage (metering winding)	$\frac{0.1}{\sqrt{3}}$ kV = 57.7 V
Secondary voltage (open delta winding)	100 V (residual voltage protection)
Rated burden at accuracy class 0.5	50 VA
Rated burden at accuracy class 3P	100 VA
Insulation level	40.5 kV

$$S_{load} = S_{relay} + S_{meter} = 12 + 10 = 22\,VA < 50\,VA$$

The total connected burden of 22 VA does not exceed the rated burden at accuracy class 0.5, confirming that the NAMI 35 voltage transformer satisfies all metering and relay protection accuracy requirements.



Figure 21: TFZM 35 NAMI 35 voltage transformer

5. Relay Protection Design and Setting Calculation for the High Voltage Transmission Line

5.1 Main Protection Calculation for the HVTL

A main protection with an unrestricted operating zone is employed for line protection. Main protection with an unrestricted operating zone refers to protection that operates on elements through which short circuit current flows; however, unlike a restricted operating zone protection, it cannot distinguish the location of the fault within its own zone versus in an adjacent zone. In practice, this means that such protection may operate on fault currents flowing through its own zone as well as those from adjacent zones. As a result, main protection with an unrestricted operating zone is capable of protecting only a single element at a time. Therefore, a backup protection function separate from the main protection is required [13].
In accordance with the power system regulations of Mongolia: 3.2.83. For 110–220 kV overhead line main protection, the type of protection shall be selected to satisfy the requirement of instantaneous tripping upon detection of a short circuit anywhere along the line under system operating conditions that are most severe from a stability standpoint [1]. 3.2.89. Where the protection cited in 3.2.83 is unable to operate with high speed, or where the line is operated with a single end or at multiple terminals, the main protection shall be capable of providing high speed and differential backup protection [1].

5.1.1 Longitudinal Differential Protection

Longitudinal differential (current differential) protection is a main protection with a restricted operating zone. A restricted operating zone main protection monitors the fault within its defined protected object, so it is necessary to have access to the currents at all boundary points of the zone. Therefore, such protection requires information from all protection system elements meaning that pilot cables are used. For this type of protection, a pilot cable connecting the substation and the remote substation terminal is utilized. The protection directly compares the current magnitudes at both ends of the protected object and operates when the differential current criterion is exceeded. Therefore, this protection is referred to as longitudinal differential or pilot differential protection [9].
Longitudinal differential
Protection operating current:
$U_{nom} = 35\ kV$

$I_{nom} = 261.1\,A \quad (nominal\ line\ current, S_{sys}.nom\ basis)$

$I_{\max} = 1.2 \times I_{nom} = 1.2 \times 261.1 = 313.3\,A \quad (maximum\ operating\ current)$

$k_T = 400/5 = 80 \ (CT\ transformation\ ratio, TFZM - 35)$

$k_{VT} = 35000/100 = 350 \ (VT\ transformation\ ratio, NAMI - 35)$

$I^3_{k.\max} = 1990\,A \quad (maximum\ three - phase\ short - circuit\ current\ at\ K1)$

$I^3_{k.min} = 1720\,A \quad (minimum\ three - phase\ short - circuit\ current\ at\ K1)$

$|Z_{line}| = 11.163\,\Omega \quad (total\ positive - sequence\ line\ impedance, K1\ path)$

5.1.2 Overcurrent Start Relay RT1 — Operating Current

The overcurrent start relay RT1 serves as the initiation element for the relay protection scheme. Its fundamental function is to detect abnormal current conditions and initiate the protection sequence. The critical design requirement for this relay is that it must remain completely stable that is, it must not operate under the maximum continuous load current that the protected line can carry during normal operation. Simultaneously, it must be sufficiently sensitive to detect the minimum fault current that may arise under the most unfavorable network configuration.

The relay operating current is therefore set above the maximum load current, with appropriate margins introduced through the reliability coefficient k_H and the return coefficient k_B. The reliability coefficient k_H ensures a safety margin above the maximum load, while the return coefficient $k_B$accounts for the fact that the relay does not reset instantaneously when the current falls below the operating threshold instead, it resets only when the current drops to a fraction k_B of the operating value. This hysteresis behaviour must be compensated in the setting calculation to avoid the relay failing to reset after a transient overcurrent event.

The operating current of relay RT1, referred to the secondary side of the current transformer, is determined from the following expression:

$$I_{re}.RT1 = \left(\frac{k_H}{k_B}\right) \times \left(\frac{I_{\max}}{k_T}\right) = \left(\frac{1.1}{0.85}\right) \times \left(\frac{313.3}{80}\right) = 1.294 \times 3.91 = 5.07\,A \qquad (2.1)$$

$\mathrm{k_H} = 1.1 \ -$ reliability coefficient

$\mathrm{k_B} = 0.85 \ -$ relay return (reset)coefficient

$\mathrm{k_T} = 80 \ -$ CT transformation ratio $\left(\frac{400}{5}\right)$

$\mathrm{I_{max}} = 313.3\ \mathrm{A} \ -$ maximum operating current

The result $\mathrm{I_{re}}$.RT1 = 5.07 A represents the minimum secondary current at which relay RT1 initiates the protection sequence. This value is well within the standard relay input range of 1–10 A for 5 A secondary CT systems, confirming the practical feasibility of the setting.

5.1.3 Trip Circuit Start Relay RT2 — Operating Current

Relay RT2 is the trip circuit start relay installed within the differential phase comparison protection panel. Its role is to supervise the trip circuit integrity and to provide an additional level of discrimination in the protection logic chain. Since RT2 operates in series with the trip command issued by RT1, its operating current must be set above the operating level of RT1 to prevent simultaneous spurious operation of both relays under transient conditions, while ensuring that RT2 always operates when a genuine trip command is issued by RT1.
The coordination between RT1 and RT2 is achieved through a second reliability coefficient applied to the RT1 operating current. This coefficient is typically higher than k_H used in RT1 (1.4 versus 1.1) because RT2 must also account for the possibility of CT measurement errors and circuit transients that could cause RT1 to operate marginally above its threshold without a genuine fault being present.

The operating current of the trip circuit start relay RT2 installed in the protection panel is determined as:

$$I_{reRT2} = k_H \times I_{re}.RT1 = 1.4 \times 5.07 = 7.10\,A \qquad (2.2)$$

$$where\ k_H = .1.4 - reliability\ coefficient\ for\ the\ trip\ circuit\ relay.$$

The operating current of RT2 = 7.10 A ensures that RT2 will operate reliably whenever RT1 issues a trip command, while remaining stable during transient overcurrent that may cause RT1 to operate momentarily without a genuine fault condition.

Negative Sequence Relay 1PR2 Operating Current (Unbalanced Fault)

Under normal balanced three phase operating conditions, the negative sequence current component is theoretically zero. However, in practice, minor system asymmetries — arising from unequal phase impedances in overhead lines, transformer core asymmetry, and unbalanced load distribution — produce a small but measurable negative sequence current even under healthy conditions. The negative sequence relay 1PR2 must therefore be set above this inherent unbalanced current to avoid spurious operation, while remaining sensitive enough to detect genuine unbalanced faults such as single phase to earth and phase to phase faults.
The total negative sequence current under normal conditions consists of two components: the steady state unbalanced component arising from permanent system asymmetry, and the transient asymmetric component that arises during switching operations and load changes.

Both components must be quantified and included in the relay setting to ensure stability under all normal operating conditions.

The relay setting is determined from the maximum unbalanced current under normal operating conditions.

Unbalanced negative sequence component of load current:

$$I_{2nb} = K_{nb} \times I_{\max} = 0.025 \times 313.3 = 7.83\ A \quad (2.3)$$

Asymmetric (transient) negative sequence component:

During switching operations, energization of transformers, and load changes, a transient negative sequence component is superimposed on the steady state unbalanced current. This component is calculated as:

$$I_{2nesim} = K_{nesim} \times I_{\max} = 0.075 \times 313.3 = 23.50\ A \quad (2.4)$$

where:

$K_{nb} = 0.025 - unbalanced\ current\ coefficient\ (range\ 0.02 - 0.03)$

$K_{nesim} = 0.075 - asymmetric\ transient\ coefficient$

Negative sequence relay operating current:

The operating current of the negative sequence relay 1PR2 is determined from the combined unbalanced and transient negative sequence components, with appropriate reliability and return coefficients applied, and referred to the CT secondary side through the transformation ratio k_T:

$$I_{2re} = \frac{(k_z \times k_H)}{k_a \times k_T} \times (I_{2nb} + I_{2nesim}) = \frac{(2 \times 1.2)}{(0.45 \times 80)} \times (7.83 + 23.50)$$

$$= \left(\frac{2.4}{36}\right) \times 31.33 = 0.0667 \times 31.33 = 2.09\ A \quad (2.5)$$

$k_H = 1.2 - reliability\ coefficient$

$k_B = 0.45 - relay\ return\ coefficient\ (range\ 0.4 - 0.5)$

$k_z = 2 - ratio\ of\ trip\ relay\ operating\ current\ to\ start\ relay\ operating\ current$

$k_T = 80 - CT\ transformation\ ratio$

5.1.4. Distance Relay 1RS — Operating Impedance

The distance relay 1RS measures the apparent impedance of the protected line as seen from the relay location. Under normal operating conditions, this impedance is large determined by the load power factor and the line voltage and falls outside the relay operating characteristic. When a fault occurs on the protected line, the apparent impedance collapses sharply towards the fault impedance, which is small and falls within the relay operating zone, causing the relay to operate.

The critical setting requirement for the distance relay is that its impedance characteristic must not overlap with the load impedance region under the most onerous loading conditions that is, maximum current at minimum voltage. If the characteristic is set too broadly, the relay may operate spuriously under heavy load conditions, causing unnecessary disconnection of the healthy line. If set too narrowly, the relay may fail to detect remote faults with adequate sensitivity. The operating impedance is therefore determined precisely from the boundary between the load and fault impedance regions.
The impedance relay operating condition is determined from the maximum load current under minimum operating voltage.
Minimum operating voltage:

$$U_{\min} = 0.9 \times U_{nom} = 0.9 \times 35 = 31.5\,kV \qquad (2.6)$$

Maximum permissible load impedance :

The maximum permissible load impedance defines the boundary of the relay characteristic on the impedance plane. Below this impedance value, the relay must operate; above it, the relay must remain stable. The angular difference between the relay maximum sensitivity angle (φ_{relay} = 80°) and the load power factor angle (φ_{load} = 40°) introduces a cosine correction factor that accounts for the angular displacement between the relay characteristic direction and the load impedance direction on the R X diagram:

$(\text{relay characteristic angle } \varphi_{\text{relay}}\ 80°, \text{load angle } \varphi_{\text{load}} = 40°)$:

$$Z_{\max} = \frac{U_{\min}}{\left(\sqrt{3} \times k_z \times k_v \times I_{\max} \times \cos(\varphi_{relay} - \varphi_{load})\right)}$$

$$= \frac{31500}{\left(\sqrt{3} \times 1.2 \times 1.05 \times 313.3 \times \cos(80° - 40°)\right)}$$

$$= \frac{31500}{(1.732 \times 1.2 \times 1.05 \times 313.3 \times \cos(40°))}$$

$$= \frac{31500}{(1.732 \times 1.2 \times 1.05 \times 313.3 \times 0.766)}$$

$$= 31500 / 527. = 59.7 \qquad (2.7)$$

$U_{\min} = 31.5\,kV - minimum\ operating\ voltage\ (0.9 \times U_{nom})$

$k_z = 1.2 - reliability\ coefficient$

$k_v = 1.05 - return\ coefficient$

$\varphi_{relay} = 80° - maximum\ relay\ sensitivity\ angle$

$\varphi_{load} = 40° - load\ power\ factor\ angle$

$I_{\max} = 313.3\,A - maximum\ operating\ current$

Relay secondary operating impedance:

$$Z_{re} = Z_{max} \times \frac{k_T}{k_{VT}} = 59.76 \times \frac{80}{350} = 13.66\,\Omega \qquad (2.8)$$

The secondary operating impedance of 13.66 Ω is the value entered into the relay setting registers. This corresponds to a primary impedance reach of 59.76 Ω at the 35 kV voltage level, which when compared against the total line impedance | Z_{line} | = 11.163 Ω — yields the sensitivity coefficient verified in Section 6.3.

5.1.5. Manipulation Filter Reliability Check

The first condition of the manipulation filter is an internal element of the differential phase comparison protection scheme. Its function is to distinguish between asymmetric (unbalanced) and symmetric (three phase) fault conditions by comparing the ratio of the positive sequence and negative sequence current components entering the filter. The filter coefficient k_m = 8 defines the boundary between these two fault types in the filter decision logic. For asymmetric faults, the calculated manipulation coefficient must be less than k_m to confirm correct detection; for symmetric faults, it must exceed k_m. Three independent verification conditions are checked to confirm reliable filter operation across all fault scenarios.

For asymmetric (unbalanced) fault condition $\mathrm{k_m} > \mathrm{k_m.calc}$ required:

$$\mathrm{I_{1calc}} = \mathrm{I_k^3.min} + \mathrm{I_{max}} = 1720 + 313.3 = 2033.3\ \mathrm{A} \qquad (2.9)$$

$$\mathrm{k_m.calc1} = \mathrm{k_H} \times \frac{\mathrm{I_{1calc}}}{\mathrm{I_{2calc}}} = 1.5 \times \frac{2033.3}{1720} = 1.773 < 8 \qquad (2.10)$$

Since $k_m.calc1$= 1.773 is less than the filter coefficient k_m = 8, the manipulation filter correctly identifies the asymmetric fault condition and initiates the appropriate protection response.

Verification with infeed contribution:

The second condition additionally accounts for the contribution of infeed current from the remote end bus, which modifies the current balance seen by the local manipulation filter. The infeed current I_1 inf = 0.3 A (secondary) is referred to the primary side through the CT ratio:

$$\mathrm{k_m.calc2} = \frac{(\mathrm{I_{1inf}} \times \mathrm{k_T} + \mathrm{I_{1calc}})}{\mathrm{I_{2calc}}} = \frac{(0.3 \times 80 + 2033.3)}{1720}$$

$$= \frac{(24 + 2033.3)}{1720} = 1.196 < 8 \qquad (2.11)$$

For symmetric (three phase) fault condition $-\mathrm{k_m} < \mathrm{k_m.calc}$ required:

For a symmetric three phase fault, the manipulation filter must produce a calculated coefficient exceeding k_m = 8 to correctly identify the fault as symmetric. The parameter f_i = 0.2 represents the inherent asymmetry factor of the filter circuit under balanced conditions:

$$\mathrm{k_m.calc3} = 3 \times \frac{\left(0.92 - \frac{(\mathrm{I_{1inf}} \times \mathrm{k_T})}{\mathrm{I_k^3 max}}\right)}{\mathrm{f_i}} = 3 \times \frac{\left(0.92 - \frac{(0.3 \times 80)}{1990}\right)}{0.2}$$

$$= 3 \times \frac{(0.92 - 0.01206)}{0.2} = \frac{3 \times 0.9079}{0.2} = 13.62 > 8 \quad (2.12)$$

5.1.6 Sensitivity Verification

The sensitivity of a protective relay element is quantified by the sensitivity coefficient k_M, defined as the ratio of the minimum fault quantity that the relay will experience under the most unfavourable fault condition to the relay operating threshold. A sensitivity coefficient k_M≥ 2.0 is required for primary protection elements, and k_M≥ 1.3 for backup protection elements, in accordance with IEC 60255 and the Mongolian power system protection standards. These minimum values ensure that even under worst case conditions minimum generation dispatch, maximum system impedance, single circuit operation the relay will still operate with a doubling margin above its threshold, guaranteeing reliable fault clearance.

The most unfavorable condition for sensitivity is the minimum fault current scenario, which occurs when the system operates with reduced generation (minimum short circuit power), maximum source impedance (minimum voltage factor c = 0.95), and the fault impedance includes the maximum arc resistance expected at the fault location.

1 Negative Sequence Relay 1PR2

$$\mathrm{k_M} = \frac{\mathrm{I_k^2.min}}{(\mathrm{I_{2re}} \times \mathrm{k_T})} = \frac{1720}{(2.09 \times 80)} = \frac{1720}{167.2} = 10.29 > 2 \quad (2.13)$$

2 Trip Circuit Start Relay RT2

$$\mathrm{k_M} = \frac{\mathrm{I_k^3.min}}{\mathrm{I_{re}.RT2}} = \frac{1720}{7.10} = 242.3 > 2 \quad (2.14)$$

3 Distance Relay 1RS

$$\mathrm{k_M} = \frac{\mathrm{Z_{max}}}{|\mathrm{Z_{line}}|} = \frac{59.76}{11.163} = 5.35 > 2 \quad (2.15)$$

4 Distance Relay Reliable Operation Condition

$$\mathrm{k_M} = \frac{\mathrm{I_k^3.min}}{(\mathrm{I_{2re}} \times \mathrm{k_T})} = \frac{1720}{(2.09 \times 80)} = 10.29 > 1.3 \quad (2.16)$$

Table 10: Sensitivity results

No.	Parameter	Symbol	Value	Unit	Criterion	Result
1	RT1 operating current	I_{re}.RT1	5.07	A	—	Set
2	RT2 operating current	I_{re}.RT2	7.10	A	—	Set
3	Negative sequence relay operating current	I_{2re}	2.09	A	—	Set
4	Maximum load impedance	Z_{max}	59.76	Ω	—	Set
5	Relay secondary impedance	Z_{re}	13.66	Ω	—	Set
6	Manipulation check — asymmetric fault	$k_m.calc1$	1.773	—	< 8	✓
7	Manipulation check — with infeed	$k_m.calc2$	1.196	—	< 8	✓
8	Manipulation check — symmetric fault	$k_m.calc3$	13.62	—	> 8	✓
9	1PR2 sensitivity	k_M	10.29	—	≥ 2.0	✓
10	RT2 sensitivity	k_M	242.3	—	≥ 2.0	✓
11	Distance relay sensitivity	k_M	5.35	—	≥ 2.0	✓
12	Backup protection condition	k_M	10.29	—	≥ 1.3	✓

Result and Discussion

System Scheme Development and Equipment Selection

The Khan Altai Resource power network operates at three voltage levels: 35 kV for the incoming grid connection, 10 kV for site distribution, and 0.4 kV for individual loads. The primary supply comes through the Altai–Uliastai 35 kV overhead line via transformer T 3 (5000 kVA, 35/10.5 kV, Uk = 7.0%), with three 1,250 kVA diesel generators as backup (X"d = 0.14 p.u.). The single line diagram was built from site data covering all lines, transformers, and load points.

Four fault points were selected to represent the critical network nodes: K1 on the 35 kV KAR main busbar, K2 on the 10 kV main busbar, K3 on the 10 kV MMD substation busbar, and K4 on the 0.4 kV MMD Crusher busbar. These points cover the full range of fault current conditions from the highest near the grid source down to the lowest at the end of the distribution chain.

Fault currents were calculated at all four points per IEC 60909:2016 using symmetrical components, under maximum (c = 1.1, grid connected) and minimum (c = 0.95, generator only) source conditions. Results confirmed a consistent decrease in fault current from K1 to K4 as series impedance accumulates. The maximum three phase value at K1 determined switchgear ratings; the minimum single phase to earth value under generator only conditions determined relay sensitivity requirements at each point.

Circuit breakers were selected with breaking capacities above the maximum fault current per IEC 62271. Protection CTs were specified class 5P20 and metering CTs class 0.5; VTs were class 3P. The existing 35 kV switchgear at KAR substation was found insufficient for the projected fault levels and requires replacement. The 10 kV switchgear was confirmed adequate for the current study period.

Relay Protection Design and Setting Calculation

Directional overcurrent protection (ANSI 67) with a directional earth fault element (ANSI 67N) was applied as the main protection for the 35 kV line. Directional sensing is necessary because fault current direction changes depending on whether the AUEHS grid or the diesel generators are supplying the network a non-directional relay cannot distinguish between these cases. The pickup was set above maximum load current (k_{rel}=1.25, k_{ret} =0.95) and verified against the minimum remote fault current to confirm k_{sens} ≥ 1.5. The Extremely Inverse characteristic was used for time graded coordination with downstream relays at a 0.3 s grading margin. The instantaneous element (ANSI 50) was set above the maximum fault current at K2 to preserve selectivity with the transformer and 10 kV protection.

Distance protection (ANSI 21) was set as backup across three zones: Zone 1 at 85% of the line length (instantaneous), Zone 2 at full line plus 50% of the adjacent section (0.4 s delay), and Zone 3 as remote backup (1.0 s delay). The earth fault backup element (ANSI 51N) was set from the minimum single phase to earth fault current using residual voltage $3U_0$ as the directional polarizing quantity.

A single shot automatic reclosing scheme was set with a 0.5–1.0 s dead time on the 35 kV line. On a successful reclose the relay returns to service; on an unsuccessful one it locks out. Since most faults on this rural overhead line are transient, AR is expected to substantially reduce full supply interruptions to the mine. The ATS scheme starts the diesel generators on detection of sustained undervoltage below 0.7 p.u. and closes the bus tie breaker only after the frequency relay (ANSI 81) confirms the generators are at rated voltage and frequency. The resulting transfer time is within the design target and improves on the existing manual changeover process.

The SEL 751 numerical relay was selected for the 35 kV line and main 10 kV feeders. Its two independent setting groups one for grid connected operation, one for generator islanded operation switch automatically via the grid incomer breaker auxiliary contact, with no manual intervention required during source transitions.

Simulation Results and Validation

The network was modelled in DIgSILENT Power Factory using the collected site parameters. Fault simulations at all four points for three phases, phase to phase, and single phase to earth faults under both source conditions produced results within 2–3% of the hand calculated values, confirming the accuracy of both the IEC 60909 method and the network model.

Coordination was verified across all fault locations: in every case the correct relay operated first and upstream relays held back correctly. Directional element performance under generator only conditions where fault currents are significantly lower was specifically tested and selectivity was confirmed. Earth fault sensitivity met $k_{sens} \geq 1.5$ at all fault locations under minimum source conditions. Transient and permanent fault scenarios on the 35 kV line confirmed correct AR behaviour in both cases successful restoration on the transient fault, and clean lockout with no downstream disturbance on the permanent fault.

Discussion and Recommendation

The protection system meets all selectivity, sensitivity, and speed requirements across the full range of operating conditions at the Khan Altai mine. Three conclusions stand out from the results.

The difference between fault current levels in grid connected and generator only modes is large enough that a single protection setting group cannot satisfy both sensitivity and selectivity simultaneously. This is not an edge case it is a daily operational condition. The dual setting group architecture implemented through the SEL 751 is a technical necessity for this network, not an optional refinement, and must be preserved in any future modifications to the protection scheme.

The 35 kV overhead line is and will remain the most critical element in the power supply chain. The layered protection designed here directional overcurrent, distance backup, and automatic reclosing gives it the best possible coverage, but cannot eliminate the interruption that occurs during fault clearance. As load grows toward the 2029 projection, the feasibility of a second incoming circuit or alternative grid connection should be assessed, since no protection improvement can substitute for physical supply redundancy.

The planned wind generation expansion from 500 kVA to 5 MW will change the fault current landscape and will require a protection review at each stage before new generation is energized. The calculation framework and Power Factory model developed in this thesis are directly applicable to that future work. It is recommended that the model be kept updated as

equipment changes are made, so that it remains a reliable tool for ongoing protection engineering at the site rather than becoming a historical snapshot of a single point in time.

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