

Article

Adaptive Overcurrent Protection of Distribution Substations with Definite-Time Characteristics

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Abstract

The increasing penetration of distributed energy resources (DERs) introduces new challenges for the operation and protection of power systems. The main challenges for protection systems arise from varying power flows and short-circuit current levels, which may prevent conventional protection schemes from fulfilling the fundamental protection requirements under certain operating conditions. Therefore, the aim of this study is to develop an adaptive protection method that enables the protection of distribution substations to be adjusted to the integration of DERs. The proposed adaptive protection method consists of defining a classification index for ranking operating conditions, grouping operating conditions, and determining optimal protection function settings. The method employs non-directional or directional overcurrent protection with definite-time (DT) characteristics. The developed method is implemented on a simulation model based on the actual SS Mikanovci 35/20 kV distribution substation case study. The classification index is determined based on the relationships between protection devices and the probabilities of occurrence of individual operating conditions. The k-means algorithm is employed for operating-condition clustering, while the optimal protection settings are determined by considering the minimum required coordination time interval between primary and backup relays, as well as the constraints imposed by the surrounding network and the capabilities of the protection devices.

Keywords: adaptive protection; classification index; k-means algorithm; definite-time characteristic; non-directional and directional overcurrent protection; distribution substation



Academic Editor: Jie Yu

Received: 16 September 2026

Revised: 18 October 2026

Accepted: 22 October 2026

Published: 26 October 2026

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1. Introduction

In recent years, the integration of distributed energy resources (DERs) has been significantly increasing, driving the development of power systems toward a structure in which centralized power generation is increasingly being replaced by a larger number of DERs, predominantly based on renewable energy sources. According to the International Energy Agency, global renewable power capacity is expected to increase by approximately 4600 GW between 2025 and 2030, representing nearly twice the capacity added during the previous five-year period (2019–2024) [1].

Integration of DERs into power systems can contribute to increased energy efficiency, system reliability and resilience, improved power quality, and reduced operating costs [2]. However, the integration of DERs also introduces new challenges and requirements for

power system control and protection [3]. The main challenge for protection systems arises from the increased number of possible operating states of distribution networks, which directly affects the expected power flow and short-circuit current levels. As a result, conventional protection schemes based on static overcurrent and earth-fault protection functions may no longer be sufficient to ensure sensitive, selective, fast and reliable fault detection and clearance in power systems. Consequently, addressing this issue has become the subject of numerous research studies [4].

The remainder of this section is organized as follows. The Literature Review provides a brief overview of previous studies related to the subject of this paper, while the subsection Problem Definition describes the main challenges associated with protection systems that motivate the research presented in this paper. Section 2, Proposed Solution, presents the structure of the proposed approach to determine the adaptive protection system and provides an overview of the classification indices of the operating-state, the clustering methods of the operating-state and the approaches for determining optimal overcurrent protection settings used in previous studies. In Section 3, calculations and simulations are performed to determine and ultimately verify the settings of the adaptive protection system using non-directional overcurrent protection. The same procedure is applied in Section 4, considering the implementation of directional overcurrent protection. Section 5 discusses the main findings, advantages, limitations, and practical implementation challenges of the proposed method and outlines directions for future research. Finally, Section 6 summarizes the main conclusions of the paper.

1.1. Literature Review

Part of the research reported in the literature focuses on improving protection systems through combinations of conventional protection functions (overcurrent, distance, differential, voltage, and frequency protection). However, such systems have limited capabilities and cannot achieve the required sensitivity and selectivity of distribution network protection systems under all operating conditions [5,6]. To address this issue, an increasing number of authors have proposed the use of various artificial intelligence (AI) methods in protection systems in recent years. The most widely used methods include decision trees [7], artificial neural networks [8], and support vector machines [9]. These protection systems rely on the continuous acquisition of a large number of measured quantities from the power system and their subsequent transformation to generate input data for the development and training of the selected method. Consequently, such systems require the integration of central control units into the power system capable of continuously collecting and processing data, training the AI method, and controlling the protection system. This would require significant investments in the existing power system.

In addition to the aforementioned protection methods, adaptive protection methods have also been discussed in the literature [10]. These methods can adjust the protection device settings according to the operating state of the network [11]. Most of these methods employ conventional time-dependent overcurrent protection. However, some studies have also considered other protection functions, such as distance protection [12] and differential protection [13]. Furthermore, the literature includes protection methods that use more complex formulations to determine the tripping time, such as overcurrent functions based on current and voltage measurements [14]. It should be emphasized that a prerequisite for the implementation of adaptive protection methods is the presence of numerical protection devices in the network equipped with multiple protection functions and setting groups (SGs). In addition, the network must have communication infrastructure [15] that enables communication between the protection devices and a central computer [16] or communication among the protection devices themselves [17].

Closely related setting-group concepts are reported in [18,19]. Ref. [18] classifies grid topologies from time coordination of definite-time overcurrent protection, while Ref. [19] proposes a clustering-based multi-setting overcurrent approach with optimisation and experimental validation. In contrast to these works, the present paper defines the classification index from relative main/backup relationships without pre-calculating protection settings for all operating states, incorporates occurrence probability to group low-probability states together, enforces surrounding-network constraints for every SG, and evaluates non-directional and directional definite-time protection on the same substation case. A direct quantitative comparison is therefore not made because the test systems differ.

Depending on whether a central computer is used to manage the settings of the protection devices within a given part of the network, adaptive protection methods can be classified as centralized [20] and decentralized [21]. Almost every newly constructed or reconstructed primary distribution substation is equipped with a central substation computer, numerical protection relays with multiple protection functions and SGs. These substations also generally have communication infrastructure for information exchange among all devices within them and with the distribution control center. Therefore, all the necessary infrastructure prerequisites for implementing adaptive protection methods in such distribution substations are already in place.

1.2. Problem Definition

In standard protection-setting calculations for distribution substations, the most unfavorable and/or most frequently occurring operating condition is defined first. A short-circuit calculation is then performed for this condition, and the settings of the protection functions of the protection devices are determined accordingly [22]. However, protection function settings defined in this manner often fail to meet the fundamental protection requirements under all possible operating conditions of the network. This problem becomes more pronounced with the integration of DERs, which introduces bidirectional power flows into the network, increases voltage and frequency fluctuations, and results in lower short-circuit current magnitudes that must be detected [23]. Furthermore, the integration of each additional DER doubles the number of possible network operating states. Considering that a typical distribution substation has at least two power supply sources and two power transformers, which can operate either independently or in parallel, the addition of a new DER results in a two-digit number of possible operating states of the distribution substation [24].

To satisfy the fundamental protection requirements under every operating condition, short-circuit calculations must be performed for the relevant operating states, and the settings of the protection devices must then be determined accordingly. The main limitation in this approach is the capability of the protection devices themselves. Protection devices can have a maximum of eight protection SGs [25], while the current and time settings of the protection functions are also constrained by their minimum and maximum values and by the available setting resolution. Therefore, since the number of operating states is generally significantly greater than the number of available SGs in protection relays, the operating states must be grouped while taking into account the maximum number of protection SGs available in the protection devices [26].

For an adaptive protection system to be implemented in practice, it is not sufficient to define the protection settings within the observed part of the network (e.g., a substation or microgrid)—the constraints and settings of the surrounding network must also be taken into account. This can be challenging to coordinate, since a large number of operating states generally results in a large number of different SGs, all of which need to be coordinated with the settings of the surrounding network. In addition, another issue is that the litera-

ture most commonly proposes overcurrent protection with time-dependent (inverse-time) characteristics as part of adaptive protection systems. However, such protection functions are less effective in detecting and clearing nonlinear faults resulting from the increasing integration of DERs.

To address these issues, this paper proposes an adaptive protection method employing definite-time (DT) overcurrent protection with settings determined in accordance with the capabilities of numerical protection relays and the constraints imposed by the surrounding network. In addition to conventional non-directional overcurrent protection, a protection system comprising overcurrent protection functions with directional characteristics is also proposed. The main symbols used in Sections 2–5 are summarized in Table 1.

Table 1. Main symbols used in the paper.

Symbol	Meaning
N_{PS}	Number of external power supply states
N_{DR}	Number of distributed energy resources considered
N_{TS}	Number of transformer and bus-coupler topology states
N_{TC}	Total number of transformers and bus-couplers
N_{OS}	Total number of operating states
k_{RR}	Relay-interrelationship index
k_{OP}	Occurrence probability, in percent [%]
min_t	Minimum time coordination margin between main and backup relays
$I_{>}, t_{I>}$	Low-set definite-time pickup and time delay
$I_{>>}, t_{I>>}$	High-set definite-time pickup and time delay

2. Proposed Solution

To address the problems and adverse conditions currently encountered in distribution substations, this paper proposes a solution that combines the grouping of all possible operating states with the optimal coordination of protection relay overcurrent settings. The proposed approach is demonstrated through a simulation based on the actual distribution substation SS Mikanovci 35/20 kV.

The starting point for developing an adaptive protection system for a distribution substation is to define all possible operating states. The number of possible operating states of a distribution substation is determined by all sources that can supply the substation, as well as by the operating states of the transformers and bus couplers within the substation. Regarding the power sources, at a minimum, all DERs directly connected to the substation (i.e., generating units) that affect the short-circuit current at the substation busbars should be taken into account. It is also necessary to distinguish between operating states depending on whether the substation is supplied from the main power source or from one of the backup power sources. In addition to the power sources that affect the short-circuit current, the operating states of the transformers and bus couplers have a direct impact on the short-circuit current and the coordination between protection devices and, consequently, on the number of possible operating states of the substation.

When all power sources and the operating states of the transformers and bus couplers are taken into account, the resulting number of operating states is significantly greater than the capabilities of the protection relays. Therefore, the operating states must be grouped into no more groups than the maximum number of SGs that can be configured in the protection relays. After grouping the operating states, the optimal protection device settings must be determined for each group [27]. In this paper, two stages of overcurrent protection with DT characteristics are optimized. Network constraints are taken into account when determining the settings to ensure that the resulting protection relay settings are coordinated and selective with the protection settings in the surrounding network.

Supply configuration, transformer status and bus-coupler position change not only the magnitude of the short-circuit current but also its distribution among the relays and, hence, the relative main/backup relationships for the same fault location. A single bounding setting covering all non-DER combinations would require the highest current threshold and the longest delay, which would violate sensitivity in low-current states and selectivity margins with the surrounding network. Grouping is therefore already required without DERs, while DERs multiply the state space by $2^{N_{DR}}$. Directional supervision subsequently allows a reduced index because direction is supervised separately, which is not available to the non-directional definite-time system.

For overcurrent protection with DT characteristics, the primary parameter for determining the settings of protection relay functions is the relative coordination between the protection relays. Therefore, the grouping of operating states should also be based on combining operating states with similar relative relationships between the protection relays. If the number of combinations of relative relationships between the protection relays exceeds the number of available protection SGs, an appropriate operating-state clustering method must be employed.

2.1. Operating State Classification Index

The definition of an operating state classification index is the basis for grouping the operating states of the considered part of the network. In scientific studies, the mean tripping times of protection relays are most commonly used to determine the classification index. The classification index can be defined directly as the mean tripping time of the protection devices or calculated as the sum of the mean values of the differences in tripping times between pairs of protection relays and the standard deviation [25]. In some studies, the classification index is obtained from the differences in the tripping times of the protection relays, without adding the standard deviation term [28]. Furthermore, a classification index based on the tripping times of protection relays can be derived in different ways, depending on which time factor is used in the equation for determining the tripping time of time-dependent overcurrent protection [29].

On the other hand, the literature also includes studies in which the classification index is determined based on short-circuit currents or solely on the relative relationships between protection devices. In [30], the operating state classification index is defined by a vector comprising the maximum short-circuit current through each relay and the short-circuit currents through each pair of protection relays. In [18], the operating states are grouped solely according to the relative relationships between the primary and backup relays, with the aim of ensuring that these relationships remain identical across all operating states within the same protection SG.

In the vast majority of scientific studies, determining the classification index first requires calculating the protection settings for all possible operating states and then deriving a value from these settings that represents the classification index. Given the number of possible operating states, this can be quite demanding and significantly complicates the design of an adaptive protection system. Therefore, this paper proposes using the relative relationships between protection devices to define the classification index. Although all operating states still need to be considered, it is not necessary to determine the protection settings beforehand, which considerably simplifies the procedure.

This refers only to the definition of k_{RR} for grouping. Final SG settings are determined afterwards in Section 3.

In addition, the probability of occurrence of a particular operating state is also incorporated into the classification index proposed in this paper. Although a large number of operating states may exist within the considered part of the network, not all of them are

equally probable and, therefore, should not be assigned equal weight. It is often the case that only a few possible operating states occur for more than half of the operating time. Accordingly, one of the ideas proposed in this paper is to use the classification index to group low-probability operating states together.

2.2. Operating State Clustering Methods

After defining the classification index, the operating states must be divided into groups. For this purpose, the literature proposes various clustering methods, most commonly using the k-means algorithm [31,32]. In some cases, this algorithm is used in combination with other techniques, such as principal component analysis [33]. Furthermore, some studies employ the k-means algorithm alongside the similar k-medoids algorithm [34], while others use the k-medoids algorithm exclusively [12].

In addition to these conventional data-clustering methods, the literature also employs algorithms such as self-organizing maps, which are based on neural networks [35,36], and hierarchical algorithms [19], which perform clustering based on the distances between individual values. On the other hand, scientific studies also consider metaheuristic algorithms, i.e., optimization techniques, such as particle swarm optimization [11] and genetic algorithms (GAs) [28], which have demonstrated their effectiveness in solving more complex clustering problems.

The k-means algorithm has proven to be a fast and effective solution for clustering the operating states of distribution substations and microgrids in the majority of studies reported in the literature. Therefore, its use is also proposed in this paper for clustering the operating states of the distribution substation based on classification indices derived from the relative relationships between protection relays and the probability of occurrence of each operating state.

2.3. Optimal Overcurrent Protection Settings

After defining the protection SGs, the optimal settings for each group must be determined. For this purpose, GAs are the most commonly used [35–37], with a micro-genetic algorithm specifically developed and presented in [38]. In addition to GAs, linear programming methods are also commonly employed in scientific studies to optimize protection settings [39,40].

On the other hand, the literature also includes bio-inspired optimization techniques, such as the water cycle algorithm and transit search optimization [19], as well as mathematical optimization approaches, such as the Lagrangian function, which is used to minimize the total tripping time [41].

All of the aforementioned algorithms are relevant and necessary when the protection system is based on time-dependent overcurrent protection, i.e., when the tripping time of the protection device is determined by an inverse-time characteristic dependent on the fault current. In this paper, the protection system consists of DT overcurrent protection, and therefore there is no need to implement optimization algorithms. Instead, the optimal protection settings are determined based on predefined constraints and set to the lowest possible values while ensuring that all fundamental protection requirements are satisfied.

3. Case Study: Non-Directional Overcurrent Protection

In this paper, the settings of the adaptive protection system are calculated using a simulation model based on the actual distribution substation (SS) Mikanovci in Croatia as a case study. This substation has voltage levels of 35/20 kV, with six bays at the 35 kV voltage level and eleven bays at the 20 kV voltage level. The single-line diagram of the existing SS Mikanovci is shown in Figure 1.

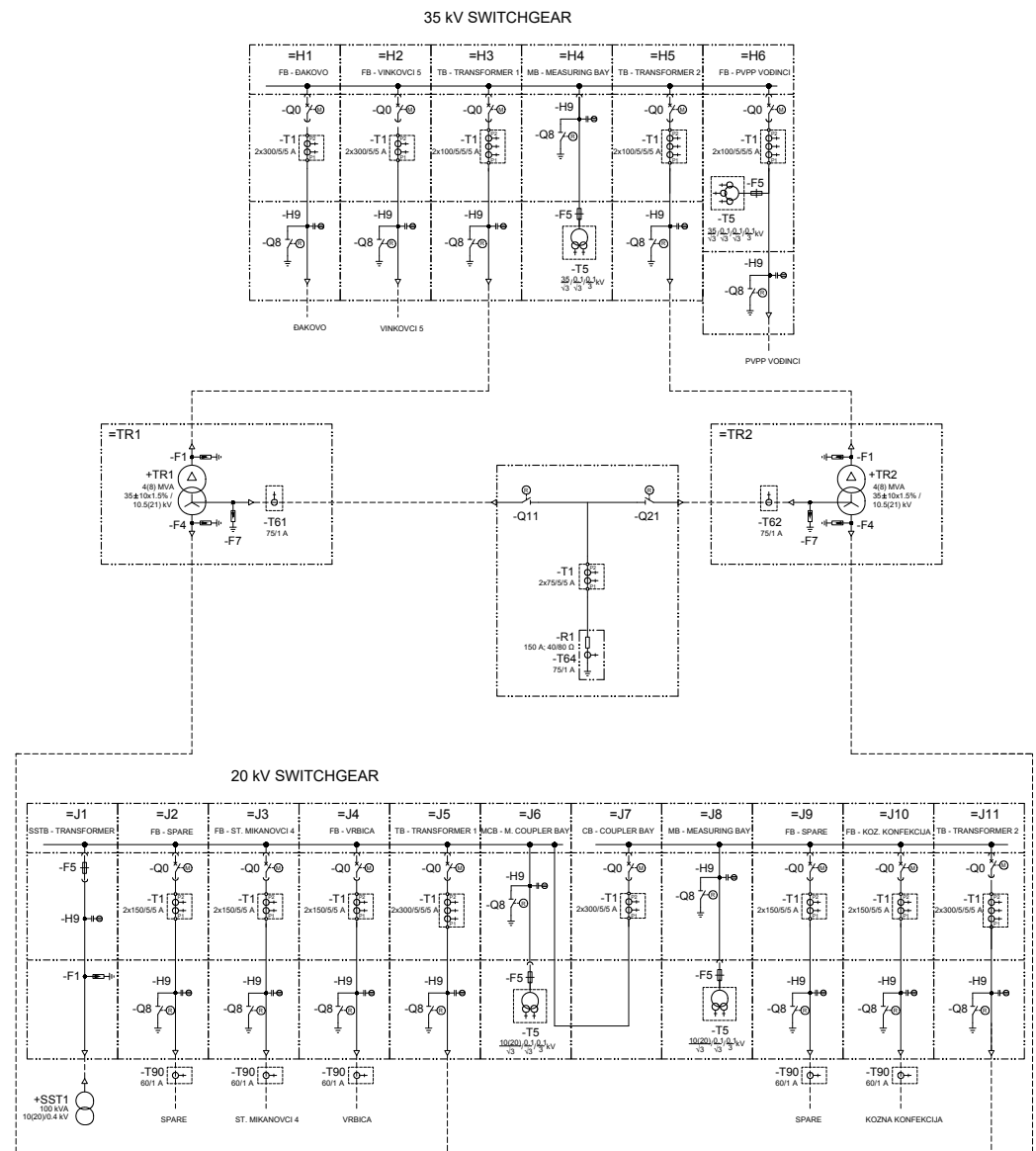


Figure 1. Single-line diagram of the existing SS Mikanovci 35/20 kV.

In the 35 kV switchgear, bays H1 and H2 represent the incoming feeders, while bays H3 and H5 are associated with power transformers TR1 and TR2. Bay H6 represents the connection of the PVPP. In the 20 kV switchgear, bays J3, J4, and J10 represent outgoing feeders, bays J5 and J11 are associated with power transformers TR1 and TR2, and bay J7 represents the bus coupler. These bay designations are also used to identify the corresponding protection devices considered in the protection coordination analysis.

The substation has two power supply feeders at the 35 kV voltage level, one serving as the main power supply and the other as the backup supply. It is also possible to operate the substation with both 35 kV feeders energized. In this operating condition, the substation serves as a power supply through point, allowing the section of the network normally supplied by the backup source of the substation to be supplied from the main source through the substation. In this case, the backup power supply is disconnected.

There is one large DER connected to this substation: a photovoltaic power plant (PVPP) with generation capacity of 10 MVA, connected at 35 kV. To model a distribution substation in which DERs have a more significant impact on the short-circuit current, a new DER in the form of a 5 MVA biomass power plant (BPP) was connected to the 20 kV busbars of the substation. To ensure that the substation parameters correspond to the

updated parameters of the surrounding distribution network, the rated power of the power transformers was increased from 4 MVA to 8 MVA. All other parameters of the substation and the surrounding distribution network remained unchanged and correspond to the actual parameters of SS Mikanovci and its surrounding distribution network.

For the distribution substation defined above, the first step is to determine the total number of operating states. The total number of operating states is influenced by the main power supply configuration, the connection status of the DERs, and the operating states of the power transformers and bus couplers. The number of different operating states of the main power supply can be denoted by N_{PS} , the number of DERs by N_{DR} , and the number of operating states of the transformers and bus couplers by N_{TS} . If the total number of operating states of the distribution substation is denoted by N_{OS} , the following equation for the total number of operating states can be obtained:

$$N_{OS} = N_{PS} \times 2^{N_{DR}} \times N_{TS} \quad (1)$$

The number of operating states of the transformers and bus couplers is determined from the total number of transformers and bus couplers, denoted by N_{TC} :

$$N_{TS} = 2^{N_{TC}} \quad (2)$$

In the modeled distribution substation there are three different power supply operating states: main, backup, and combined, i.e., with both feeders energized. In addition, there are two DERs: a PVPP connected at 35 kV and a BPP connected at 20 kV. Furthermore, since the substation has two 35/20 kV power transformers and one 20 kV bus coupler, Equation (2) yields a total of eight possible operating states for these components. The possible operating states of the power transformers and bus coupler are presented in Table 2.

Table 2. Possible operating states of the transformers and bus coupler.

No.	TR1 ¹	TR2 ²	BC ³	TS ⁴
1	ON	ON	OFF	A
2	ON	ON	ON	B
3	ON	OFF	ON	C
4	ON	OFF	OFF	D
5	OFF	ON	OFF	E
6	OFF	ON	ON	F
7	OFF	OFF	ON	G
8	OFF	OFF	OFF	H

¹ Transformer 1 circuit breakers; ² Transformer 2 circuit breakers; ³ Bus coupler circuit breaker;

⁴ Operating state of the transformers and bus coupler designation.

By substituting all the relevant parameters into Equation (1), a total of 96 different operating states are obtained for the modeled distribution substation. All possible operating states of the considered substation are presented in Table 3. Some of these operating states are not considered normal operating conditions and are not expected to occur during actual operation. Therefore, such operating states do not need to be considered separately and are assigned to similar operating states that are possible under normal operating conditions. These operating states are crossed out and highlighted in gray in Table 3.

Table 3. All possible operating states of the modeled distribution substation.

No.	PS ¹	DR1 ²	DR2 ³	TS	No.	PS	DR1	DR2	TS	No.	PS	DR1	DR2	TS	No.	PS	DR1	DR2	TS
1	MS ⁴	OFF	OFF	A	25	MS	OFF	OFF	C	49	MS	OFF	OFF	E	73	MS	OFF	OFF	G
2	BS ⁵	OFF	OFF	A	26	BS	OFF	OFF	C	50	BS	OFF	OFF	E	74	BS	OFF	OFF	G
3	CS ⁶	OFF	OFF	A	27	CS	OFF	OFF	C	51	CS	OFF	OFF	E	75	CS	OFF	OFF	G
4	MS	ON	OFF	A	28	MS	ON	OFF	C	52	MS	ON	OFF	E	76	MS	ON	OFF	G
5	BS	ON	OFF	A	29	BS	ON	OFF	C	53	BS	ON	OFF	E	77	BS	ON	OFF	G
6	CS	ON	OFF	A	30	CS	ON	OFF	C	54	CS	ON	OFF	E	78	CS	ON	OFF	G
7	MS	OFF	ON	A	31	MS	OFF	ON	C	55	MS	OFF	ON	E	79	MS	OFF	ON	G
8	BS	OFF	ON	A	32	BS	OFF	ON	C	56	BS	OFF	ON	E	80	BS	OFF	ON	G
9	CS	OFF	ON	A	33	CS	OFF	ON	C	57	CS	OFF	ON	E	81	CS	OFF	ON	G
10	MS	ON	ON	A	34	MS	ON	ON	C	58	MS	ON	ON	E	82	MS	ON	ON	G
11	BS	ON	ON	A	35	BS	ON	ON	C	59	BS	ON	ON	E	83	BS	ON	ON	G
12	CS	ON	ON	A	36	CS	ON	ON	C	60	CS	ON	ON	E	84	CS	ON	ON	G
13	MS	OFF	OFF	B	37	MS	OFF	OFF	D	61	MS	OFF	OFF	F	85	MS	OFF	OFF	H
14	BS	OFF	OFF	B	38	BS	OFF	OFF	D	62	BS	OFF	OFF	F	86	BS	OFF	OFF	H
15	CS	OFF	OFF	B	39	CS	OFF	OFF	D	63	CS	OFF	OFF	F	87	CS	OFF	OFF	H
16	MS	ON	OFF	B	40	MS	ON	OFF	D	64	MS	ON	OFF	F	88	MS	ON	OFF	H
17	BS	ON	OFF	B	41	BS	ON	OFF	D	65	BS	ON	OFF	F	89	BS	ON	OFF	H
18	CS	ON	OFF	B	42	CS	ON	OFF	D	66	CS	ON	OFF	F	90	CS	ON	OFF	H
19	MS	OFF	ON	B	43	MS	OFF	ON	D	67	MS	OFF	ON	F	91	MS	OFF	ON	H
20	BS	OFF	ON	B	44	BS	OFF	ON	D	68	BS	OFF	ON	F	92	BS	OFF	ON	H
21	CS	OFF	ON	B	45	CS	OFF	ON	D	69	CS	OFF	ON	F	93	CS	OFF	ON	H
22	MS	ON	ON	B	46	MS	ON	ON	D	70	MS	ON	ON	F	94	MS	ON	ON	H
23	BS	ON	ON	B	47	BS	ON	ON	D	71	BS	ON	ON	F	95	BS	ON	ON	H
24	CS	ON	ON	B	48	CS	ON	ON	D	72	CS	ON	ON	F	96	CS	ON	ON	H

¹ Substation power supply; ² Distributed energy resource 1 (PVPP on 35 kV) circuit breakers;

³ Distributed energy resource 2 (BPP on 20 kV) circuit breakers; ⁴ Main power supply; ⁵ Backup power supply; ⁶ Combined power supply.

According to Table 3, after excluding the operating states that are not expected to occur under normal operating conditions, a total of 70 distinct operating states remain for which protection settings need to be determined. Since protection relays can have a maximum of eight SGs, the operating states must be grouped into no more than eight groups and the optimal protection settings must be determined for each group.

For each operating state, the relative relationships and the short-circuit currents are determined as input for grouping and for subsequent SG setting calculation; individual optimal settings per operating state are not pre-calculated for defining k_{RR} . In this paper, two stages of overcurrent protection with DT characteristics are used: overload protection and short-circuit protection. Their settings can be determined based on the relative coordination between protection relays (time delay settings), as well as through short-circuit calculations and the definition of permissible element loading (current settings). Short-circuit calculations were performed using NEPLAN 360 (version V10.9.9.4, NEPLAN AG, Küssnacht, Switzerland), and the SS Mikanovci 35/20 kV simulation model is shown in Figure 2.

3.1. Selection of the Classification Index

An operating state in a protection system with DT characteristics can also be classified solely based on the relative relationships between the protection relays listed in Table 4. The relative relationships between the protection relays are represented by assigning the number 1 to the protection relay that, whenever it detects a current exceeding its set value, should operate first and trip its circuit breaker. The first protection relay coordinated with it is assigned the number 2, and so on, until the last protection relay is reached, which should trip its circuit breaker with the longest time delay.

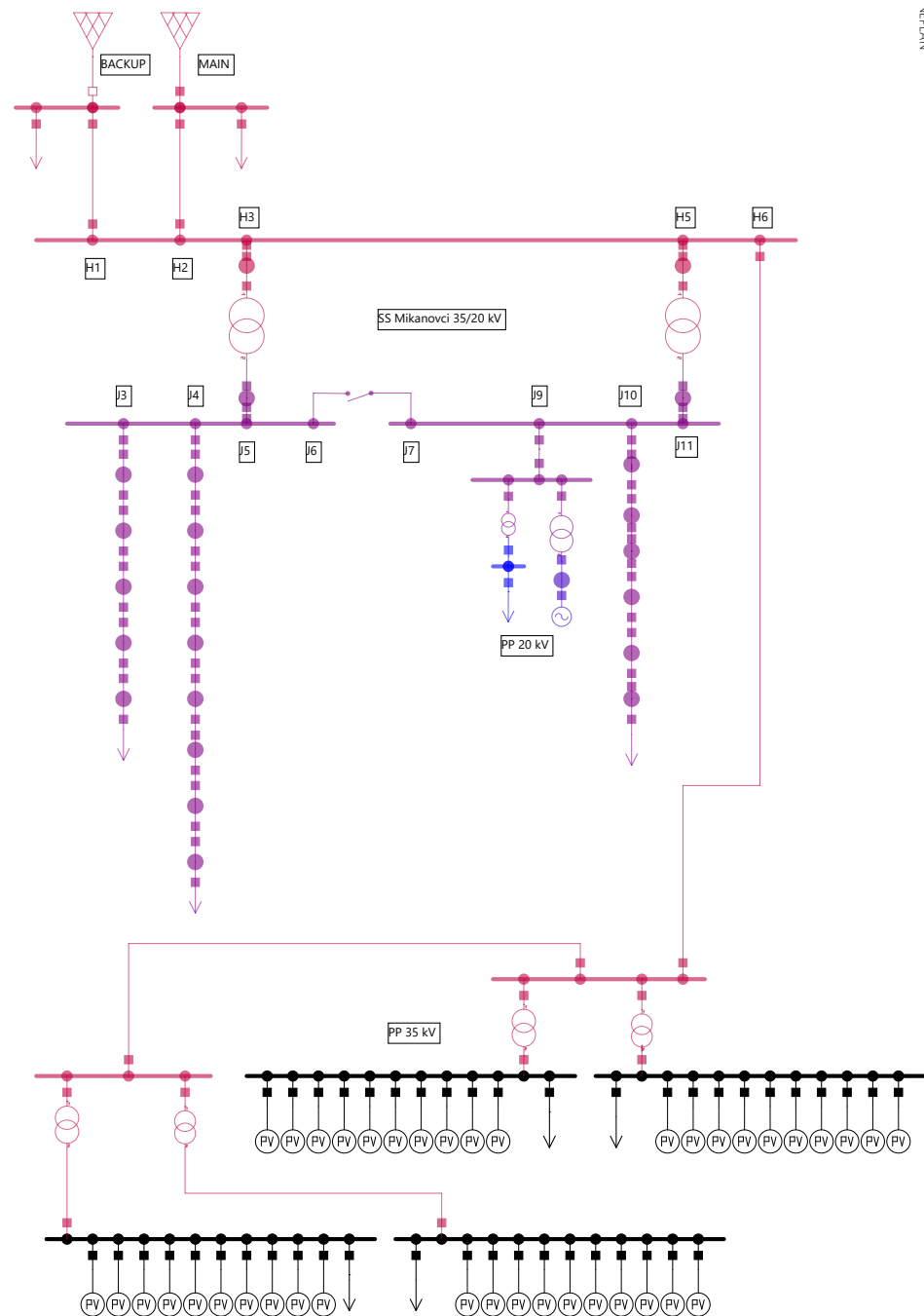


Figure 2. Simulation model of SS Mikanovci 35/20 kV.

Defining the relative relationships between protection relays in this manner can result in multiple levels of selectivity, which poses a challenge when determining the time delays of short-circuit protection. That is, this protection must clear faults as quickly as possible, and multiple time-based selectivity levels are not acceptable from the perspective of the protection system operating speed. For this purpose, when determining the relative relationships between protection relays for short-circuit protection, it is assumed that conditional busbar protection is implemented in the 20 kV switchgear. Accordingly, the operation of the short-circuit protection functions in the transformer and bus-coupler bays is blocked by the starting signal from protection functions at a lower selectivity level. Therefore, the short-circuit protection functions in the transformer and bus-coupler bays can be assigned the same time delay as the protection functions at the lower selectivity level.

Table 4. Relative relationships between the protection relays in all operating states.

No.	H1		H2		H3		H5		H6		J3, J4		J5		J7		J9		J10		J11	
	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»
1	X	X	4	2	3	1I	3	1I	X	X	1	1	X	X	4	2	3	1I	3	1I	X	X
2	4	2	X	X	3	1I	3	1I	X	X	1	1	4	2	X	X	3	1I	3	1I	X	X
3	1	1	4	2	3	1I	3	1I	X	X	1	1	1	1	4	2	3	1I	3	1I	X	X
4	X	X	5	3	3	1I	3	1I	4	2	1	1	X	X	5	3	3	1I	3	1I	4	2
5	5	3	X	X	3	1I	3	1I	4	2	1	1	5	3	X	X	3	1I	3	1I	4	2
6	1	1	5	3	3	1I	3	1I	4	2	1	1	1	1	5	3	3	1I	3	1I	4	2
7	X	X	5	2	3	1I	4	1I	X	X	1	1	X	X	5	2	3	1I	4	1I	X	X
8	5	2	X	X	3	1I	4	1I	X	X	1	1	5	2	X	X	3	1I	4	1I	X	X
9	1	1	5	2	3	1I	4	1I	X	X	1	1	1	1	5	2	3	1I	4	1I	X	X
10	X	X	6	3	3	1I	4	1I	5	2	1	1	X	X	6	3	3	1I	4	1I	5	2
11	6	3	X	X	3	1I	4	1I	5	2	1	1	6	3	X	X	3	1I	4	1I	5	2
12	1	1	6	3	3	1I	4	1I	5	2	1	1	1	1	6	3	3	1I	4	1I	5	2
13	X	X	5	2	4	1I	4	1I	X	X	1	1	X	X	5	2	4	1I	4	1I	X	X
14	5	2	X	X	4	1I	4	1I	X	X	1	1	5	2	X	X	4	1I	4	1I	X	X
15	1	1	5	2	4	1I	4	1I	X	X	1	1	1	1	5	2	4	1I	4	1I	X	X
16	X	X	6	3	4	1I	4	1I	5	2	1	1	X	X	6	3	4	1I	4	1I	5	2
17	6	3	X	X	4	1I	4	1I	5	2	1	1	6	3	X	X	4	1I	4	1I	5	2
18	1	1	6	3	4	1I	4	1I	5	2	1	1	1	1	6	3	4	1I	4	1I	5	2
19	X	X	6	2	5	1I	5	1I	X	X	1	1	X	X	6	2	5	1I	5	1I	X	X
20	6	2	X	X	5	1I	5	1I	X	X	1	1	6	2	X	X	5	1I	5	1I	X	X
21	1	1	6	2	5	1I	5	1I	X	X	1	1	1	1	6	2	5	1I	5	1I	X	X
22	X	X	7	3	5	1I	5	1I	6	2	1	1	X	X	7	3	5	1I	5	1I	6	2
23	7	3	X	X	5	1I	5	1I	6	2	1	1	7	3	X	X	5	1I	5	1I	6	2
24	1	1	7	3	5	1I	5	1I	6	2	1	1	1	1	7	3	5	1I	5	1I	6	2
25	X	X	5	2	4	1I	X	X	X	X	1	1	X	X	5	2	4	1I	X	X	X	X
26	5	2	X	X	4	1I	X	X	X	X	1	1	5	2	X	X	4	1I	X	X	X	X
27	1	1	5	2	4	1I	X	X	X	X	1	1	1	1	5	2	4	1I	X	X	X	X
28	X	X	6	3	4	1I	X	X	5	2	1	1	X	X	6	3	4	1I	X	X	5	2
29	6	3	X	X	4	1I	X	X	5	2	1	1	6	3	X	X	4	1I	X	X	5	2
30	1	1	6	3	4	1I	X	X	5	2	1	1	1	1	6	3	4	1I	X	X	5	2
31	X	X	6	2	5	1I	X	X	X	X	1	1	X	X	6	2	5	1I	X	X	X	X
32	6	2	X	X	5	1I	X	X	X	X	1	1	6	2	X	X	5	1I	X	X	X	X
33	1	1	6	2	5	1I	X	X	X	X	1	1	1	1	6	2	5	1I	X	X	X	X
34	X	X	7	3	5	1I	X	X	6	2	1	1	X	X	7	3	5	1I	X	X	6	2
35	7	3	X	X	5	1I	X	X	6	2	1	1	7	3	X	X	5	1I	X	X	6	2
36	1	1	7	3	5	1I	X	X	6	2	1	1	1	1	7	3	5	1I	X	X	6	2
37	X	X	4	2	3	1I	X	X	X	X	1	1	X	X	4	2	3	1I	X	X	X	X
38	4	2	X	X	3	1I	X	X	X	X	1	1	4	2	X	X	3	1I	X	X	X	X
39	1	1	4	2	3	1I	X	X	X	X	1	1	1	1	4	2	3	1I	X	X	X	X
40	X	X	5	3	3	1I	X	X	4	2	1	1	X	X	5	3	3	1I	X	X	4	2
41	5	3	X	X	3	1I	X	X	4	2	1	1	5	3	X	X	3	1I	X	X	4	2
42	1	1	5	3	3	1I	X	X	4	2	1	1	1	1	5	3	3	1I	X	X	4	2
49	X	X	4	2	X	X	3	1I	X	X	X	X	X	X	X	X	X	X	1	1	2	1B
50	4	2	X	X	X	X	3	1I	X	X	X	X	X	X	X	X	X	X	1	1	2	1B
51	1	1	4	2	X	X	3	1I	X	X	X	X	X	X	X	X	X	X	1	1	2	1B
52	X	X	5	3	X	X	3	1I	4	2	X	X	X	X	X	X	X	X	1	1	2	1B
53	5	3	X	X	X	X	3	1I	4	2	X	X	X	X	X	X	X	X	1	1	2	1B
54	1	1	5	3	X	X	3	1I	4	2	X	X	X	X	X	X	X	X	1	1	2	1B
55	X	X	5	2	X	X	4	1I	X	X	X	X	X	X	X	X	2	1I	1	1	3	1B
56	5	2	X	X	X	X	4	1I	X	X	X	X	X	X	X	X	2	1I	1	1	3	1B
57	1	1	5	2	X	X	4	1I	X	X	X	X	X	X	X	X	2	1I	1	1	3	1B
58	X	X	6	3	X	X	4	1I	5	2	X	X	X	X	X	X	2	1I	1	1	3	1B
59	6	3	X	X	X	X	4	1I	5	2	X	X	X	X	X	X	2	1I	1	1	3	1B
60	1	1	6	3	X	X	4	1I	5	2	X	X	X	X	X	X	2	1I	1	1	3	1B
61	X	X	5	2	X	X	4	1I	X	X	1	1	X	X	2	1B	X	X	1	1	3	1B

Table 4. Cont.

No.	H1		H2		H3		H5		H6		J3, J4		J5		J7		J9		J10		J11	
	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»
62	5	2	X	X	X	X	4	1I	X	X	1	1	X	X	2	1B	X	X	1	1	3	1B
63	1	1	5	2	X	X	4	1I	X	X	1	1	X	X	2	1B	X	X	1	1	3	1B
64	X	X	6	3	X	X	4	1I	5	2	1	1	X	X	2	1B	X	X	1	1	3	1B
65	6	3	X	X	X	X	4	1I	5	2	1	1	X	X	2	1B	X	X	1	1	3	1B
66	1	1	6	3	X	X	4	1I	5	2	1	1	X	X	2	1B	X	X	1	1	3	1B
67	X	X	5	2	X	X	4	1I	X	X	1	1	X	X	2	1B	2	1I	1	1	3	1B
68	5	2	X	X	X	X	4	1I	X	X	1	1	X	X	2	1B	2	1I	1	1	3	1B
69	1	1	5	2	X	X	4	1I	X	X	1	1	X	X	2	1B	2	1I	1	1	3	1B
70	X	X	6	3	X	X	4	1I	5	2	1	1	X	X	2	1B	2	1I	1	1	3	1B
71	6	3	X	X	X	X	4	1I	5	2	1	1	X	X	2	1B	2	1I	1	1	3	1B
72	1	1	6	3	X	X	4	1I	5	2	1	1	X	X	2	1B	2	1I	1	1	3	1B
87	1	1	2	2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
88	X	X	2	2	X	X	X	X	1	1	X	X	X	X	X	X	X	X	X	X	X	X
89	2	2	X	X	X	X	X	X	1	1	X	X	X	X	X	X	X	X	X	X	X	X
90	1	1	3	3	X	X	X	X	2	2	X	X	X	X	X	X	X	X	X	X	X	X

In addition, selectivity between the short-circuit protection functions in the 35 kV switchgear and those in the 20 kV switchgear is achieved based on the current protection settings. Therefore, the protection relays in the transformer bays of the 35 kV switchgear can be assigned the minimum time delay. The same approach is applied to DERs, which contribute less to the short-circuit current than the stiff grid. Consequently, selectivity between the short-circuit protection functions in their protection relays and the other protection relays is achieved based on the current protection settings.

The relative relationships between the protection relays depend on the connection status of the DERs, the main power supply configuration, and the operating states of the power transformers and bus couplers. Based on these factors, a formula can be defined to determine the operating state classification index based on the relative relationships between the protection relays.

$$k_{RR} = \sum_{x=1}^{N_{DR}} \left(2^{x-1} \cdot DRx_{ON} \right) + 2^{N_{DR}} \cdot MS_{ON} + 2^{N_{DR}+1} \cdot \sum_{y=1}^{N_T} TyB_{ON} + 2^{N_{DR}+1+N_T} \cdot T_{OFF} \quad (3)$$

where the binary variables are defined as follows:

- DRx_{ON} —DER x is connected and affects the coordination between the protection relays;
- MS_{ON} —main power supply connected;
- TyB_{ON} —transformer y and bus coupler connected;
- T_{OFF} —all transformers disconnected.

In Equation (3), the influence of DER x on the coordination between the protection relays is represented by the variable DRx_{ON} , while the influence of the main power supply configuration is determined by the variable MS_{ON} . The remaining variables TyB_{ON} and T_{OFF} characterize the influence of the operating states of the transformers and bus coupler on the operating state classification index based on the relative relationships between the protection relays.

The modeled distribution substation is equipped with two 35/20 kV power transformers and has a BPP connected at the 20 kV voltage level and a PVPP connected at the 35 kV voltage level. Accordingly, for the modeled substation, the formula for defining

the operating state classification index based on the relative relationships between the protection relays is:

$$k_{RR} = BPP_{ON} + 2 \cdot PVPP_{ON} + 4 \cdot MS_{ON} + 8 \cdot (T_1 B_{ON} + T_2 B_{ON}) + 32 \cdot T_{OFF} \quad (4)$$

Using Equation (4), the classification indices for the operating states expected to occur during operation of the modeled substation are obtained, as presented in Table 5. In this way, 27 different operating state classification indices based on the relative relationships between the protection relays are obtained from the 70 different operating states.

Table 5. Operating state classification indices based on the relative relationships between the protection relays.

No.	k_{RR}	No.	k_{RR}	No.	k_{RR}	No.	k_{RR}	No.	k_{RR}
1	4	15	20	29	10	49	4	63	12
2	0	16	22	30	14	50	0	64	14
3	4	17	18	31	13	51	4	65	10
4	6	18	22	32	9	52	6	66	14
5	2	19	21	33	13	53	2	67	12
6	6	20	17	34	15	54	6	68	8
7	5	21	21	35	11	55	5	69	12
8	1	22	23	36	15	56	1	70	14
9	5	23	19	37	4	57	5	71	10
10	7	24	23	38	0	58	7	72	14
11	3	25	12	39	4	59	3	87	36
12	7	26	8	40	6	60	7	88	36
13	20	27	12	41	2	61	12	89	32
14	16	28	14	42	6	62	8	90	38

However, it is important to emphasize that not all operating states of the distribution substation are equally likely to occur during operation. Some operating states can be expected to occur frequently under normal operating conditions, whereas others are generally possible only in exceptional situations, such as faults in the network or substation, maintenance activities on network or substation components, or short-duration conditions arising during certain switching operations. Accordingly, the operating state classification index can also be determined based on the probability of occurrence of each operating state.

The operating state classification index based on the probability of occurrence of an operating state can be calculated from historical data on the operating states of the substation or from statistical data on the connection status of DERs, main power supplies, transformers, and bus couplers of a conventional distribution substation. The operating state classification index is then obtained as the product of the individual probability factors associated with the basic parameters that determine the operating state, as expressed in Equation (5).

$$k_{OP} = PS_{\%} \cdot \prod_{x=1}^{N_{DR}} DRx_{\%} \cdot TS_{\%} \cdot 100[\%] \quad (5)$$

where the variables are defined as follows:

- $PS_{\%}$ —probability of occurrence of a particular substation external power supply configuration (p.u.);
- $DR_{\%}$ —probability of a distributed energy resource being in operation or out of operation (p.u.);

- $TS_{\%}$ —probability of occurrence of a particular transformers and bus-couplers operating state (p.u.).

For the modeled distribution substation, the operating state classification index based on the probability of occurrence was determined by combining historical data from the previous five years with statistical data. Based on the operating data from the previous five years, an operating state probability factor was determined as a function of the main power supply configuration and the operating states of the power transformers and bus coupler. The overall classification index was then obtained by multiplying this historical probability factor by statistical data on the connection status of the DERs, as expressed in Equation (6).

$$k_{OP} = PS_{\%} \cdot BPP_{\%} \cdot PVPP_{\%} \cdot TS_{\%} \cdot 100[\%] \quad (6)$$

where:

- $PS_{\%}$ —probability of a substation external power supply configuration based on five years of historical data (p.u.);
- $BPP_{\%}$ —statistical probability of a 5 MVA biomass power plant being in operation or out of operation (p.u.);
- $PVPP_{\%}$ —statistical probability of a 10 MVA photovoltaic power plant being in operation or out of operation (p.u.);
- $TS_{\%}$ —probability of a particular transformer and bus-coupler operating state based on five years of historical data (p.u.).

The operating state classification indices based on the probability of occurrence are presented in Table 6.

Table 6. Operating state classification indices based on the occurrence probability expressed in percent [%].

No.	k_{OP} [%]	No.	k_{OP} [%]	No.	k_{OP} [%]	No.	k_{OP} [%]	No.	k_{OP} [%]
1	0.1421	15	0.0054	29	0.1204	49	0.0050	63	0.2279
2	0.0135	16	0.0431	30	0.4644	50	0.0005	64	1.8173
3	0.0520	17	0.0041	31	5.7720	51	0.0018	65	0.1724
4	0.4144	18	0.0158	32	0.5474	52	0.0147	66	0.6647
5	0.0393	19	0.1960	33	2.1111	53	0.0014	67	8.2616
6	0.1516	20	0.0186	34	16.833	54	0.0054	68	0.7835
7	1.8839	21	0.0717	35	1.5964	55	0.0668	69	3.0217
8	0.1787	22	0.5715	36	6.1566	56	0.0063	70	24.094
9	0.6890	23	0.0542	37	0.0040	57	0.0244	71	2.2850
10	5.4940	24	0.2090	38	0.0004	58	0.1948	72	8.8121
11	0.5210	25	0.4354	39	0.0015	59	0.0185	87	0.0006
12	2.0094	26	0.0413	40	0.0118	60	0.0713	88	0.0049
13	0.0148	27	0.1592	41	0.0011	61	0.6232	89	0.0005
14	0.0014	28	1.2697	42	0.0043	62	0.0591	90	0.0018

3.2. Operating State Clustering

To divide the operating states of the distribution substation into several SGs, various data-clustering methods can be used. In this paper, the k-means algorithm is employed with the objective of dividing all operating states into as many SGs as can be supported by the numerical protection relay. The k-means algorithm initially selects a “centroid” for each group at random. Each data point is then assigned to the nearest centroid, after which a new centroid is calculated for each group. This process is repeated until the groups remain unchanged between successive iterations. The k-means algorithm was implemented in

MATLAB (version R2025b, The MathWorks, Inc., Natick, MA, USA) using k-means++ initialization, 200 replicates, and a fixed random seed of 1.

The objective function of the k-means algorithm is:

$$\sum_{i=1}^K \sum_{x \in C_i} \|x - \mu_i\|^2 \quad (7)$$

where:

- K —number of clusters,
- C_i —set of elements within the i -th cluster,
- μ_i —centroid of the i -th cluster,
- $\|x - \mu_i\|^2$ —squared Euclidean distance.

Figure 3 graphically presents the operating states of the modeled substation using classification indices based on the relative relationships between the protection relays, as listed in Table 5.

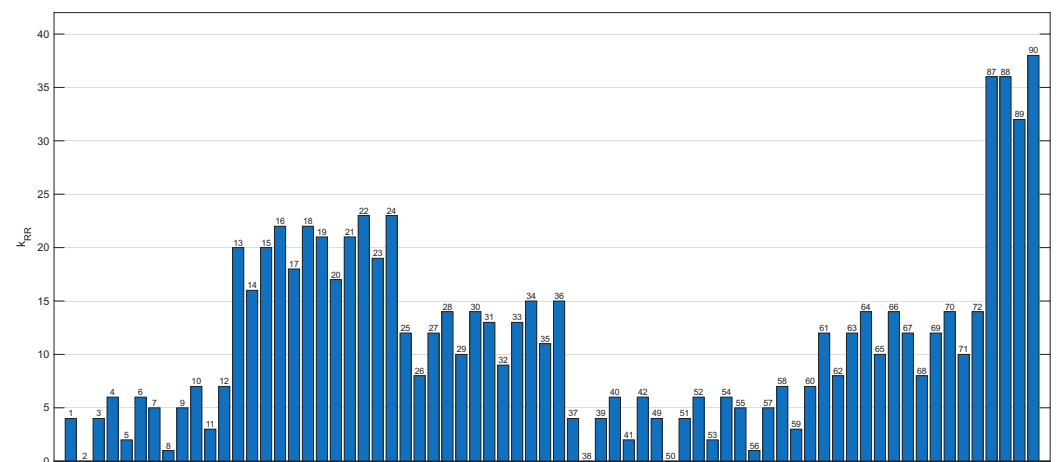


Figure 3. Operating states with classification indices based on the relay interrelationships.

In this paper, a protection relay that supports a maximum of eight SGs is considered. Accordingly, the operating states of the modeled distribution substation are divided into a maximum of eight groups, and the objective function of the k-means algorithm is defined as:

$$\sum_{i=1}^8 \sum_{x \in C_i} \|x - \mu_i\|^2 \quad (8)$$

Using the k-means algorithm on the set of operating states shown in Figure 3, the operating states are clustered into eight groups, and the final result is presented graphically in Figure 4. The clustered operating states are also presented in Table 7.

Table 7. Setting groups with classification indices based on the relay interrelationships.

SG	Operating states
1	87, 88, 89, 90, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86, 91, 92, 93, 94, 95, 96
2	16, 18, 19, 21, 22, 24
3	13, 15, 17, 20, 23
4	14, 28, 30, 31, 33, 34, 36, 64, 66, 70, 72
5	25, 27, 29, 35, 61, 63, 65, 67, 69, 71
6	4, 6, 10, 12, 26, 32, 40, 42, 52, 54, 58, 60, 62, 68, 46, 48
7	1, 3, 7, 9, 11, 37, 39, 49, 51, 55, 57, 59, 43, 45
8	2, 5, 8, 38, 41, 50, 53, 56, 44, 47

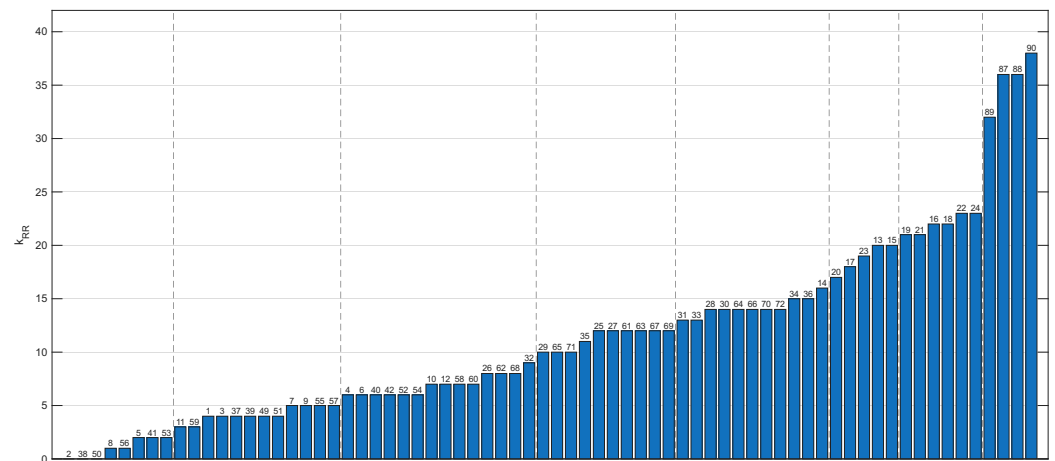


Figure 4. Groups of operating states with classification indices based on the relay interrelationships.

In Table 7, the protection SG numbers are assigned such that the operating states with the highest classification indices are assigned to the SG with the lowest number, while those with the lowest classification indices are assigned to the SG with the highest number. This table also includes operating states that are not expected to occur during operation. Each of these operating states is assigned to the SG containing the most similar operating state that is expected to occur during normal operation.

In addition to the operating state classification index based on the relative relationships between the protection relays, the operating states of the modeled substation were also classified in the previous section using an index based on the probability of occurrence of each operating state. Figure 5 graphically presents the operating states of the modeled substation with the operating state classification indices based on the probability of occurrence, as listed in Table 6.

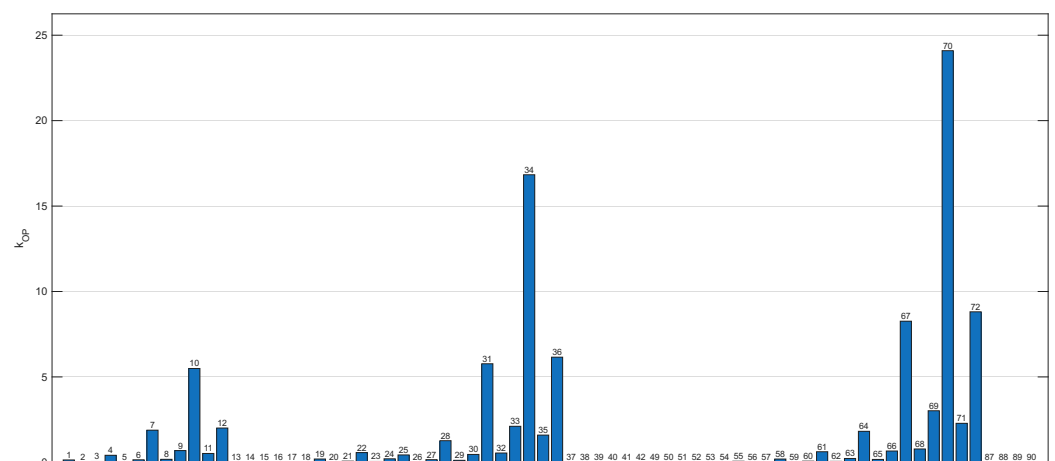


Figure 5. Operating states using classification indices based on their occurrence probabilities.

When the k-means algorithm is applied to the operating states shown in Figure 5, they are clustered into eight SGs, as illustrated in Figure 6.

In addition to the graphical representation, the clustered operating states are also presented in Table 8, where the operating states shown in Figure 6 are supplemented with operating states that are not expected to occur during operation. When the operating states are clustered solely based on their occurrence probabilities, 71 of the 96 operating states are assigned to the eighth protection SG, while three SGs contain only a single operating state each. This is a consequence of the highly uneven distribution of the occurrence probabilities among the operating states.

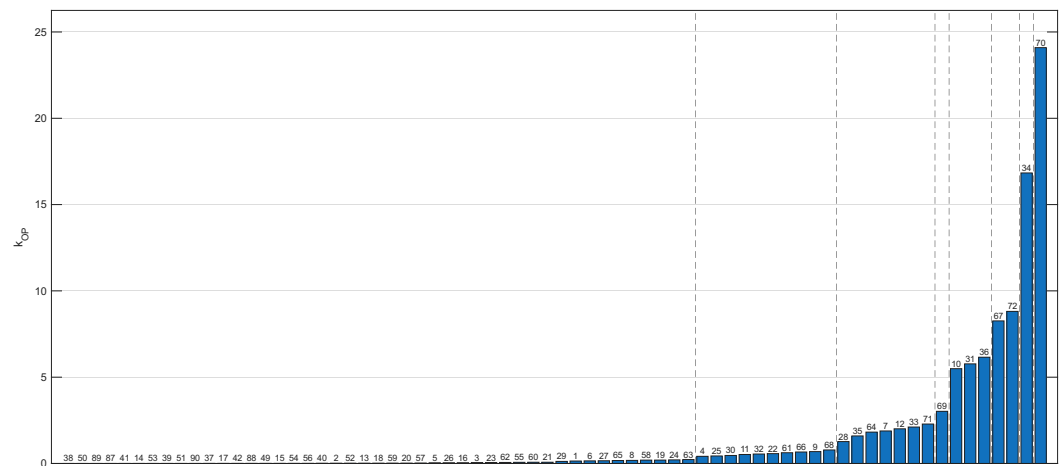


Figure 6. Operating states groups using classification indices based on their occurrence probabilities.

Table 8. Setting groups with classification indices based on the operating state occurrence probabilities.

SG	Operating States
1	70
2	34
3	67, 72
4	10, 31, 36
5	69
6	7, 12, 28, 33, 35, 64, 71
7	4, 9, 11, 22, 25, 30, 32, 61, 66, 68
8	1, 2, 3, 5, 6, 8, 13, 14, 15, 16, 17, 18, 19, 20, 21, 23, 24, 26, 27, 29, 37, 38, 39, 40, 41, 42, 49, 50, 51, 52, 53, 54, 55, 56, 57, 58, 59, 60, 62, 63, 65, 87, 88, 89, 90, 43, 44, 45, 46, 47, 48, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86, 91, 92, 93, 94, 95, 96

The operating states can also be clustered by defining all operating states using both of the previously described classification indices. The operating states defined in this manner are represented in a two-dimensional space, as shown in Figure 7. The x-axis of the graph represents the classification index based on the relative relationships between the protection relays (k_{RR}), while the y-axis represents the classification index based on the probability of occurrence of the operating state (k_{OP}). Operating states that have the same k_{RR} and similar k_{OP} are represented by a single point, next to which the numbers of the corresponding operating states are indicated.

Applying the k-means algorithm to this set of operating states, they are clustered into eight protection SGs, as illustrated in Figure 8, with each SG represented by a different color.

The clustered operating states are also presented in Table 9, where the operating states expected to occur during operation are supplemented with those that are not expected to occur, as in the previous cases.

Since the relative relationships between the protection relays form the basis for determining their protection settings and achieving selectivity between them, the operating states can first be organized before applying any clustering method by combining all operating states with the same k_{RR} , with their common k_{OP} obtained as the sum of each individual k_{OP} . Figure 9 graphically presents the two-dimensional space in which the operating states defined in this manner are positioned. The x-axis of the graph represents k_{RR} , while the y-axis represents the k_{OP} of the operating states.

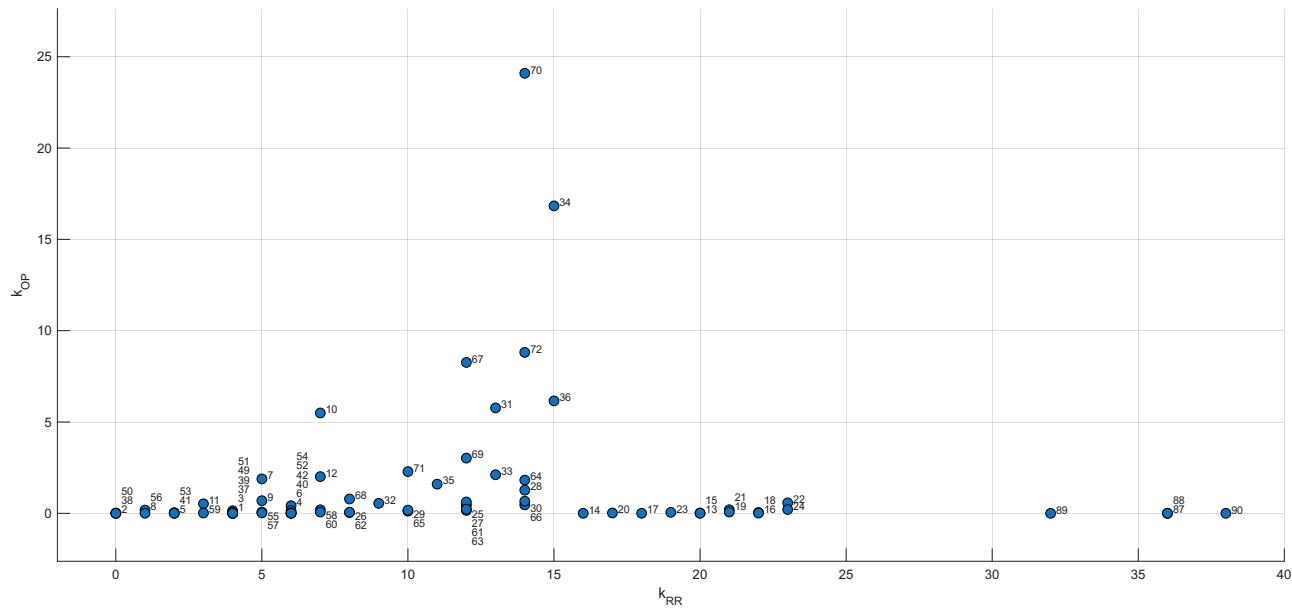


Figure 7. Operating states using classification indices based on the relay interrelationships and operating state occurrence probabilities.

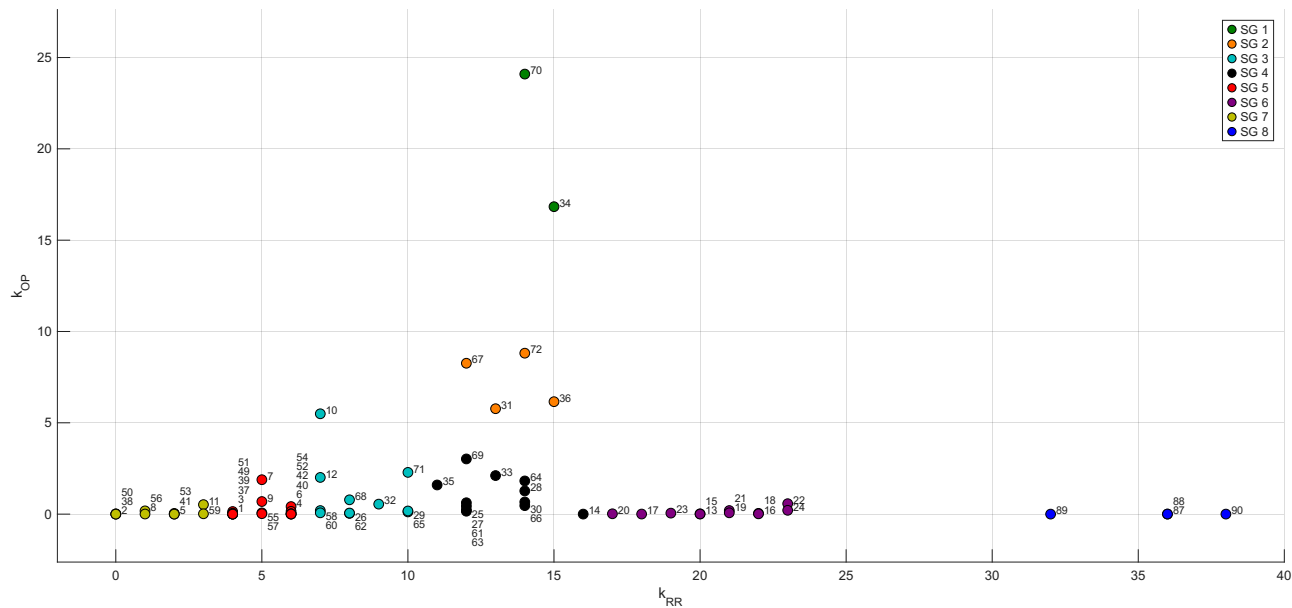


Figure 8. Operating state groups using classification indices based on the relay interrelationships and operating state occurrence probabilities.

Table 9. Setting groups with classification indices based on the relay interrelationships and operating state occurrence probabilities.

SG	Operating States
1	34, 70
2	31, 36, 67, 72
3	10, 12, 26, 29, 32, 58, 60, 62, 65, 68, 71
4	14, 25, 27, 28, 30, 33, 35, 61, 63, 64, 66, 69
5	1, 3, 4, 6, 7, 9, 37, 39, 40, 42, 49, 51, 52, 54, 55, 57, 43, 45, 46, 48
6	13, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24
7	2, 5, 8, 11, 38, 41, 50, 53, 56, 59, 44, 47
8	87, 88, 89, 90, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86, 91, 92, 93, 94, 95, 96

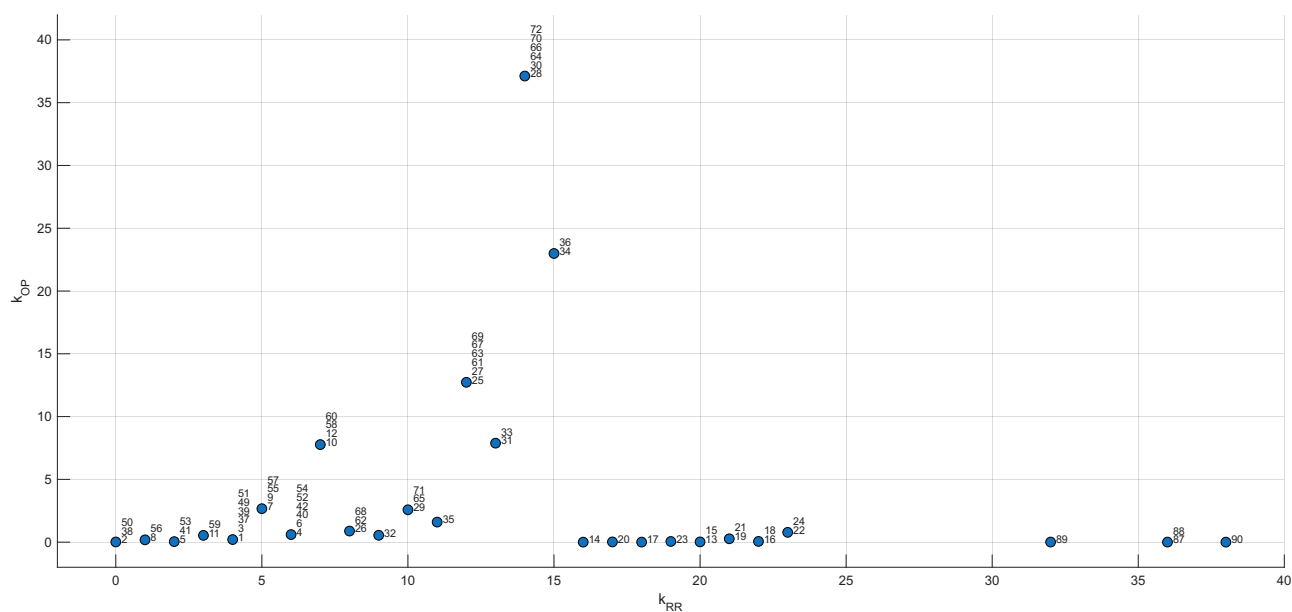


Figure 9. Operating states with preliminary grouping and classification indices based on the relay interrelationships and operating state occurrence probabilities.

Figure 10 shows the clustering of the operating states presented in Figure 9, obtained using the k-means algorithm.

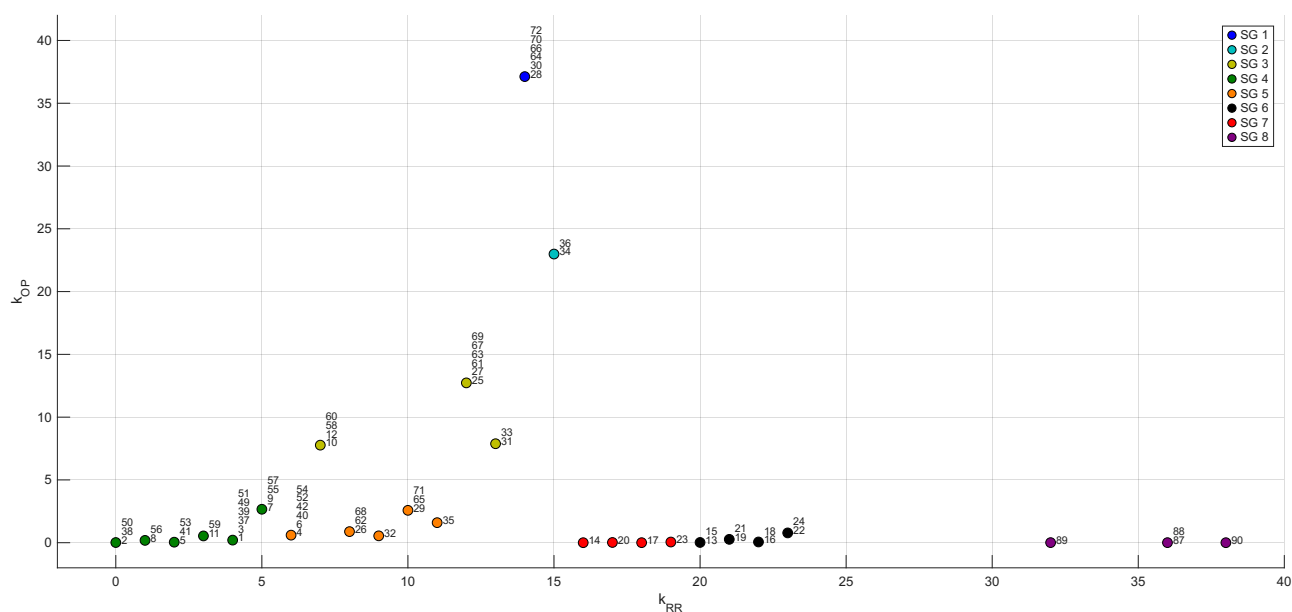


Figure 10. Operating state groups with preliminary grouping and classification indices based on the relay interrelationships and operating state occurrence probabilities.

The same is presented in Table 10, with the operating states that are not expected to occur during operation also included.

Table 10. Setting groups with preliminary grouping and classification indices based on the relay interrelationships and operating state occurrence probabilities.

SG	Operating States
1	28, 30, 64, 66, 70, 72
2	34, 36
3	10, 12, 25, 27, 31, 33, 58, 60, 61, 63, 67, 69
4	1, 2, 3, 5, 7, 8, 9, 11, 37, 38, 39, 41, 49, 50, 51, 53, 55, 56, 57, 59, 43, 44, 45, 47
5	4, 6, 26, 29, 32, 35, 40, 42, 52, 54, 62, 65, 68, 71, 46, 48
6	13, 15, 16, 18, 19, 21, 22, 24
7	14, 17, 20, 23
8	87, 88, 89, 90, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86, 91, 92, 93, 94, 95, 96

3.3. Determination of Optimal Protection Settings

After the operating states of the distribution substation have been clustered into eight SGs, the overcurrent protection settings can be determined for each group. The basis for defining the settings is the relative relationships between the protection relays, which are presented for all operating states in Table 4. For each SG, the relative relationship number of each protection relay is set to the maximum value assigned to that relay within the group. The differences between SGs are therefore minimum coordination and sensitivity margins, not redundancy. Merging SGs would require retaining the maximum delay and the maximum pickup of the merged groups, which would reduce selectivity and sensitivity compared to the verified eight-group solution. In this way, for all clustering approaches presented in the previous section, the relative relationships between the protection relays for each SG are obtained, as shown in Table 11.

Table 11. Relay interrelationships for each setting group across all clustering approaches.

SG	H1		H2		H3		H5		H6		J3, J4		J5		J7		J9		J10		J11	
	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»
Relative relationship classification indices (Table 6)																						
1	2	2	3	3	X	X	X	X	2	2	X	X	X	X	X	X	X	X	X	X	X	X
2	1	1	7	3	5	II	5	II	6	2	1	1	4	2	3	1B	2	II	1	1	4	2
3	7	3	5	2	5	II	5	II	6	2	1	1	4	2	3	1B	2	II	1	1	4	2
4	5	2	7	3	5	II	4	II	6	2	1	1	4	1B	3	1B	2	II	1	1	3	1B
5	7	3	5	2	5	II	4	II	6	2	1	1	4	1B	3	1B	2	II	1	1	3	1B
6	6	2	6	3	5	II	4	II	5	2	1	1	4	1B	3	1B	2	II	1	1	3	1B
7	6	3	5	2	3	II	4	II	5	2	1	1	2	1B	X	X	2	II	1	1	3	1B
8	5	3	X	X	3	II	4	II	4	2	1	1	2	1B	X	X	2	II	1	1	3	1B
Occurrence probability classification indices (Table 7)																						
1	X	X	6	3	X	X	4	II	5	2	1	1	X	X	2	1B	2	II	1	1	3	1B
2	X	X	7	3	5	II	X	X	6	2	1	1	4	1B	3	1B	2	II	1	1	X	X
3	1	1	6	3	X	X	4	II	5	2	1	1	X	X	2	1B	2	II	1	1	3	1B
4	1	1	7	3	5	II	4	II	6	2	1	1	4	1B	3	1B	2	II	1	1	3	1B
5	1	1	5	2	X	X	4	II	X	X	1	1	X	X	2	1B	2	II	1	1	3	1B
6	6	3	6	3	5	II	4	II	6	2	1	1	4	1B	3	1B	2	II	1	1	3	1B
7	6	3	7	3	5	II	5	II	6	2	1	1	4	1B	3	1B	2	II	1	1	4	2
8	7	3	7	3	5	II	5	II	6	2	1	1	4	2	3	1B	2	II	1	1	4	2
Relative relationships and occurrence probability classification indices (Table 8)																						
1	X	X	7	3	5	II	4	II	6	2	1	1	4	1B	3	1B	2	II	1	1	3	1B
2	1	1	7	3	5	II	4	II	6	2	1	1	4	1B	3	1B	2	II	1	1	3	1B
3	6	3	6	3	5	II	4	II	5	2	1	1	4	1B	3	1B	2	II	1	1	3	1B
4	7	3	6	3	5	II	4	II	6	2	1	1	4	1B	3	1B	2	II	1	1	3	1B
5	1	1	5	3	3	II	4	II	4	2	1	1	2	1B	X	X	2	II	1	1	3	1B
6	7	3	7	3	5	II	5	II	6	2	1	1	4	2	3	1B	2	II	1	1	4	2
7	6	3	X	X	3	II	4	II	5	2	1	1	2	1B	X	X	2	II	1	1	3	1B
8	2	2	3	3	X	X	X	X	2	2	X	X	X	X	X	X	X	X	X	X	X	X

Table 11. Cont.

SG	H1		H2		H3		H5		H6		J3, J4		J5		J7		J9		J10		J11	
	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»
Preliminary grouping + relative relationships and occurrence probability classification indices (Table 9)																						
1	1	1	6	3	4	1I	4	1I	5	2	1	1	3	1B	2	1B	2	1I	1	1	3	1B
2	1	1	7	3	5	1I	X	X	6	2	1	1	4	1B	3	1B	2	1I	1	1	X	X
3	1	1	6	3	5	1I	4	1I	5	2	1	1	4	1B	3	1B	2	1I	1	1	3	1B
4	6	3	5	2	3	1I	4	1I	5	2	1	1	2	1B	X	X	2	1I	1	1	3	1B
5	7	3	5	3	5	1I	4	1I	6	2	1	1	4	1B	3	1B	2	1I	1	1	3	1B
6	1	1	7	3	5	1I	5	1I	6	2	1	1	4	2	3	1B	2	1I	1	1	4	2
7	7	3	X	X	5	1I	5	1I	6	2	1	1	4	2	3	1B	2	1I	1	1	4	2
8	2	2	3	3	X	X	X	X	2	2	X	X	X	X	X	X	X	X	X	X	X	X

The relative relationships between the protection relays form the basis for determining the time delays of the overload and short-circuit overcurrent protection functions, while the current amplitude settings are defined based on short-circuit calculations and the rated parameters of the network components. Short-circuit calculations were performed using the NEPLAN 360 for all possible operating states. Since the currents for multiphase short circuits are lowest in the case of a two-phase short circuit, the current settings of the overcurrent protection functions of each protection relay are set below the minimum calculated two-phase short-circuit current among all operating states within a given SG.

The short-circuit calculations were performed in NEPLAN 360 in accordance with IEC 60909:2016 [42]. The minimum two-phase short-circuit currents were calculated using a voltage factor of $c = 1.0$ and assuming zero fault impedance ($Z_f = 0 \Omega$). The BPP was modeled as a synchronous generator, while the PVPP was modeled as an inverter-based generation unit with its short-circuit current contribution limited to 1.1 p.u. of its rated current. This limitation represents the current-limiting characteristics of the PVPP inverter during short-circuit conditions.

When determining the protection settings, the surrounding network constraints must also be considered. In this case, these constraints are represented by the settings of the protection relays at the remote ends of the 35 kV incoming feeders. It is therefore essential to achieve selectivity between these protection relays and the protection relays on the 35 kV incoming feeders of the modeled substation. Selectivity is achieved only with respect to the overload protection, since the short-circuit protection at the remote ends of the 35 kV incoming feeders has instantaneous operation, allowing the protection relay to respond immediately to short circuits on the incoming feeders. The overload protection settings of the protection relays at the remote ends of the 35 kV incoming feeders are given in Table 12.

Table 12. Overload protection settings of the protection relays at the remote ends of the 35 kV incoming feeders.

Feeder Remote End	H1 (I>)		H2 (I>)	
	I [A]	t [s]	I [A]	t [s]
Setting	360	2	400	1.7

In addition, the selection of protection settings is subject to the limitations of the protection relay itself. The selected protection relay has a relatively wide setting range, allowing the time delays of the overcurrent protection functions to be set from 0 to 100 s, with a step size of 0.01 s. The current amplitude settings, on the other hand, depend on the rated values of the connected current transformers (CTs). All CTs in the modeled substation have a 5 A secondary rating. Accordingly, the overcurrent protection current setting in the protection relay can be set between 3% and 3500% of the rated current of

the CT, with a setting step corresponding to 0.1 A on the primary side. Since the CTs in the modeled substation have rated primary currents ranging from 100/5 A to 300/5 A, it can be concluded that the overcurrent protection functions in all protection relays of the modeled substation can safely be set within the range of 9 A to 3500 A.

In the event of a fault or operating disturbance within the substation or in the surrounding distribution network, it is expected that more than one protection relay will detect the condition. The protection relay closest to the fault must operate first and selectively clear the fault or disturbance before the other protection relays, thereby ensuring that normal operation of the remaining parts of the substation and network can be maintained. The protection relay closest to the fault or disturbance can be referred to as the main relay, while the first relay upstream that also detects the fault or disturbance can be referred to as the backup relay. Selectivity within the substation is ensured by appropriately selecting the time difference between the overcurrent protection settings of the main and backup relays.

The minimum time difference between the overcurrent protection settings of the main and backup relays min_t can be expressed as:

$$min_t \leq t_B - t_M \quad (9)$$

where:

- t_M —is the operating time of the main overcurrent protection relay;
- t_B —is the operating time of the backup overcurrent protection relay.

From the moment the protection relay detects a fault or disturbance and the overcurrent protection operating time delay elapses until the fault or disturbance is actually cleared, an additional time will be required due to errors in the CTs, the protection relay algorithm itself, the operating time of its output contacts, and, most importantly, the operating time of the circuit breaker that clears the fault or disturbance. In the modeled substation, the calculated and measured additional operating time of the relay is less than 0.1 s. Therefore, since this substation is equipped with state-of-the-art numerical relays, CTs with appropriate protection classes, and fast-operating vacuum circuit breakers, the following value can be selected:

$$min_t = 0.15 \text{ s} \quad (10)$$

Since conditional busbar protection is implemented in the 20 kV switchgear, the shortest time delay of the short-circuit protection is not set to instantaneous operation but to a delay of 0.05 s, allowing sufficient time for blocking the protection functions in the upstream bays. Table 13 presents the optimal protection settings for all clustering approaches, taking into account the constraints of the network and the protection relays, requirements of min_t and the short-circuit calculations.

Table 13. Protection relay settings for each setting group across all clustering approaches.

SG	Current I [A]/Operating Time t [s]																					
	H1		H2		H3		H5		H6		J3, J4		J5		J7		J9		J10		J11	
	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»
Relative relationship classification indices (Table 6)																						
1	350	1960	350	1800	150	1920	150	1920	180	1790	200	1110	250	1050	250	1050	200	2070	200	880	250	1050
	0.75	0.20	0.90	0.35	1.20	0.05	1.20	0.05	0.75	0.20	0.60	0.05	1.05	0.20	0.90	0.05B	0.75	0.05	0.60	0.05	1.05	0.20
2	350	1960	350	1800	150	1920	150	1920	180	1790	200	1110	250	1050	250	1050	200	2070	200	880	250	1050
	0.60	0.05	1.50	0.35	1.20	0.05	1.20	0.05	1.35	0.20	0.60	0.05	1.05	0.20	0.90	0.05B	0.75	0.05	0.60	0.05	1.05	0.20
3	350	1960	350	1800	150	1800	150	1800	180	1940	200	1080	250	1010	250	1010	200	2180	200	860	250	1010
	1.50	0.35	1.20	0.20	1.20	0.05	1.20	0.05	1.35	0.20	0.60	0.05	1.05	0.20	0.90	0.05B	0.75	0.05	0.60	0.05	1.05	0.20
4	350	1960	350	1800	150	1870	150	1920	180	1790	200	970	250	1070	250	1070	200	1600	200	800	250	1070
	1.20	0.20	1.50	0.35	1.20	0.05	1.05	0.05	1.35	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
5	350	1960	350	1800	150	1800	150	1800	180	1940	200	950	250	1540	250	1540	200	1600	200	780	250	1540
	1.50	0.35	1.20	0.20	1.20	0.05	1.05	0.05	1.35	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
6	350	1960	350	1800	150	1920	150	1800	180	1790	200	970	250	1570	250	1680	200	1630	200	780	250	1540
	1.35	0.20	1.35	0.35	1.20	0.05	1.05	0.05	1.20	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
7	350	2020	350	1800	150	1800	150	1800	180	2130	200	950	250	1540	250	1050	200	1600	200	780	250	1540
	1.35	0.35	1.20	0.20	0.90	0.05	1.05	0.05	1.20	0.20	0.60	0.05	0.75	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
8	350	1960	350	1800	150	1960	150	1960	180	1940	200	970	250	1600	250	1050	200	1660	200	800	250	1600
	1.20	0.35	0.90	0.35	0.90	0.05	1.05	0.05	1.05	0.20	0.60	0.05	0.75	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
Occurrence probability classification indices (Table 7)																						
1	350	2020	350	1860	150	1990	150	1990	180	1970	200	1080	250	1650	250	1930	200	1630	200	870	250	1650
	0.60	0.20	1.35	0.35	1.20	0.05	1.05	0.05	1.20	0.20	0.60	0.05	1.05	0.05B	0.75	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
2	350	2020	350	1860	150	1990	150	1990	180	1970	200	1080	250	1650	250	1930	200	1630	200	870	250	1650
	0.60	0.20	1.50	0.35	1.20	0.05	1.05	0.05	1.35	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
3	350	2020	350	1860	150	1990	150	1870	180	1970	200	1060	250	1650	250	1900	200	1600	200	860	250	1620
	0.60	0.20	1.35	0.35	1.20	0.05	1.05	0.05	1.20	0.20	0.60	0.05	1.05	0.05B	0.75	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
4	350	2020	350	1860	150	1870	150	1990	180	1970	200	1000	250	1620	250	1900	200	1600	200	860	250	1650
	0.60	0.20	1.50	0.35	1.20	0.05	1.05	0.05	1.35	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
5	350	2020	350	1870	150	1990	150	1870	180	1970	200	1060	250	1650	250	1900	200	1600	200	860	250	1620
	0.60	0.20	1.20	0.20	1.20	0.05	1.05	0.05	1.20	0.20	0.60	0.05	1.05	0.05B	0.75	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
6	350	2020	350	1800	150	1870	150	1870	180	1790	200	970	250	1570	250	1570	200	1600	200	800	250	1570
	1.35	0.35	1.35	0.35	1.20	0.05	1.05	0.05	1.35	0.20	0.60	0.05	1.05	0.05B	0.75	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
7	350	2020	350	1800	150	1800	150	1800	180	1790	200	950	250	1090	250	1090	200	1600	200	780	250	1090
	1.35	0.35	1.50	0.35	1.20	0.05	1.20	0.05	1.35	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	1.05	0.20
8	350	1960	350	1800	150	1800	150	1800	180	1790	200	950	250	1010	250	1010	200	1600	200	780	250	1010
	1.50	0.35	1.50	0.35	1.20	0.05	1.20	0.05	1.35	0.20	0.60	0.05	1.05	0.20	0.90	0.05B	0.75	0.05	0.60	0.05	1.05	0.20

Table 13. Cont.

SG	Current I [A]/Operating Time t [s]																					
	H1		H2		H3		H5		H6		J3, J4		J5		J7		J9		J10		J11	
	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»	I>	I»
Relative relationships and occurrence probability classification indices (Table 8)																						
1	350	1960	350	1860	150	1990	150	1990	180	1970	200	1080	250	1650	250	1650	200	1630	200	870	250	1650
	0.60	0.05	1.50	0.35	1.20	0.05	1.05	0.05	1.35	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
2	350	1960	350	1860	150	1870	150	1870	180	1970	200	1060	250	1620	250	1620	200	1600	200	860	250	1620
	0.60	0.05	1.50	0.35	1.20	0.05	1.05	0.05	1.35	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
3	350	1960	350	1860	150	2030	150	1960	180	1940	200	970	250	1640	250	1640	200	1630	200	800	250	1600
	1.35	0.35	1.35	0.35	1.20	0.05	1.05	0.05	1.20	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
4	350	1960	350	1800	150	1800	150	1800	180	1790	200	950	250	1070	250	1070	200	1600	200	780	250	1070
	1.50	0.35	1.35	0.35	1.20	0.05	1.05	0.05	1.35	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
5	350	1960	350	1800	150	1800	150	1800	180	1790	200	950	250	1540	250	1650	200	1600	200	780	250	1540
	0.60	0.05	1.20	0.35	0.90	0.05	1.05	0.05	1.05	0.20	0.60	0.05	0.75	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
6	350	1960	350	1800	150	1800	150	1800	180	1790	200	1080	250	1010	250	1010	200	2070	200	860	250	1010
	1.50	0.35	1.50	0.35	1.20	0.05	1.20	0.05	1.35	0.20	0.60	0.05	1.05	0.20	0.90	0.05B	0.75	0.05	0.60	0.05	1.05	0.20
7	350	1960	350	1860	150	1960	150	1960	180	1940	200	970	250	1600	250	1650	200	1660	200	800	250	1600
	1.35	0.35	1.50	0.35	0.90	0.05	1.05	0.05	1.20	0.20	0.60	0.05	0.75	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
8	350	1960	350	1800	150	1990	150	1990	180	1790	200	1080	250	1650	250	1650	200	1630	200	870	250	1650
	0.75	0.20	0.90	0.35	1.20	0.05	1.05	0.05	0.75	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
Preliminary grouping + relative relationships and occurrence probability classification indices (Table 9)																						
1	350	1960	350	1800	150	1920	150	1920	180	1790	200	970	250	1570	250	1570	200	1630	200	800	250	1570
	0.60	0.05	1.35	0.35	1.05	0.05	1.05	0.05	1.20	0.20	0.60	0.05	0.90	0.05B	0.75	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
2	350	1960	350	1860	150	1990	150	1920	180	1970	200	1080	250	1650	250	1650	200	1630	200	870	250	1570
	0.60	0.05	1.50	0.35	1.20	0.05	1.05	0.05	1.35	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
3	350	1960	350	1800	150	1800	150	1800	180	1970	200	950	250	1540	250	1540	200	1600	200	780	250	1540
	0.60	0.05	1.35	0.35	1.20	0.05	1.05	0.05	1.20	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
4	350	1960	350	1800	150	1800	150	1800	180	1940	200	950	250	1540	250	1570	200	1600	200	780	250	1540
	1.35	0.35	1.20	0.20	0.90	0.05	1.05	0.05	1.20	0.20	0.60	0.05	0.75	0.05B	0.75	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
5	350	1960	350	1800	150	1920	150	1920	180	1790	200	970	250	1570	250	1640	200	1660	200	800	250	1570
	1.50	0.35	1.20	0.35	1.20	0.05	1.05	0.05	1.35	0.20	0.60	0.05	1.05	0.05B	0.90	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B
6	350	1960	350	1800	150	1800	150	1800	180	1790	200	1080	250	1010	250	1010	200	2070	200	860	250	1010
	0.60	0.05	1.50	0.35	1.20	0.05	1.20	0.05	1.35	0.20	0.60	0.05	1.05	0.20	0.90	0.05B	0.75	0.05	0.60	0.05	1.05	0.20
7	350	1960	350	1800	150	1960	150	1960	180	1940	200	1110	250	1070	250	1070	200	2180	200	880	250	1070
	1.50	0.35	1.35	0.35	1.20	0.05	1.20	0.05	1.35	0.20	0.60	0.05	1.05	0.20	0.90	0.05B	0.75	0.05	0.60	0.05	1.05	0.20
8	350	1960	350	1800	150	1920	150	1920	180	1790	200	970	250	1570	250	1570	200	1630	200	800	250	1570
	0.75	0.20	0.90	0.35	1.05	0.05	1.05	0.05	0.75	0.20	0.60	0.05	0.90	0.05B	0.75	0.05B	0.75	0.05	0.60	0.05	0.90	0.05B

3.4. Verification of the Calculated Protection Settings

Based on the previously calculated operating state classification indices, the operating states were clustered using four different approaches, and the optimal overcurrent protection settings were determined for each resulting cluster. The resulting clusters and corresponding protection settings can be verified using various methods. In this paper, the selectivity of individual operating states is analyzed, and the average operating time of the overcurrent protection functions is calculated.

The final selectivity of the obtained protection relay settings is verified for each operating state by checking whether the required selectivity is achieved among all protection relays with the defined overcurrent protection settings. The calculated selectivity for all operating state clustering approaches considered previously is presented as the percentage of fully selective operating states relative to all operating states expected to occur under normal operating conditions, as given in Table 14.

Table 14. Calculated selectivity for all operating state clustering approaches.

Clustering	k_{RR}	k_{OP}	k_{RR} and k_{OP}	$k_{RR} + k_{RR}$ and k_{OP}
Selectivity [%]	50.00	57.14	50.00	62.86

Based on the calculated percentages of final selectivity for all clustering approaches, it can be concluded that the highest selectivity is achieved for the case in which the operating states are clustered based on k_{RR} and k_{OP} , with preliminary clustering based on k_{RR} . To additionally verify the protection coordination obtained by the proposed methodology, dynamic fault simulations were performed for two representative operating states using this clustering approach. Operating state 70 was selected as a representative case of selective protection operation because it has the highest k_{OP} among all considered operating states.

Also, operating state 9 was selected as a representative case of non-selective protection operation, specifically between relays H1 and H2. This state is one of the most probable operating states among those exhibiting non-selective operation and it is selected because selectivity at the 20 kV voltage level is less suitable for graphical representation, since most of the numerical relays on 20 kV have the same short-circuit protection time delays and their coordination is mainly achieved through conditional busbar protection.

As shown in Figure 11, the main and backup protection relays for the fault on the H6 outgoing feeder are coordinated over the entire overcurrent characteristic, and the main relay operates before the corresponding backup relay even for the minimum two-phase short-circuit current, confirming selective protection operation for operating state 70. In contrast, Figure 12 shows that selective operation between the main and backup protection relays for the fault on the H1 outgoing feeder is not achieved in operating state 9, confirming the non-selective operation previously identified by the proposed coordination assessment.

In addition, for all clustering approaches, the obtained protection relay settings can be verified using the average operating time of the overcurrent protection functions, considered separately for overload protection and short-circuit protection. Table 15 presents the average operating times of the overcurrent protection functions for all operating state clustering approaches considered.

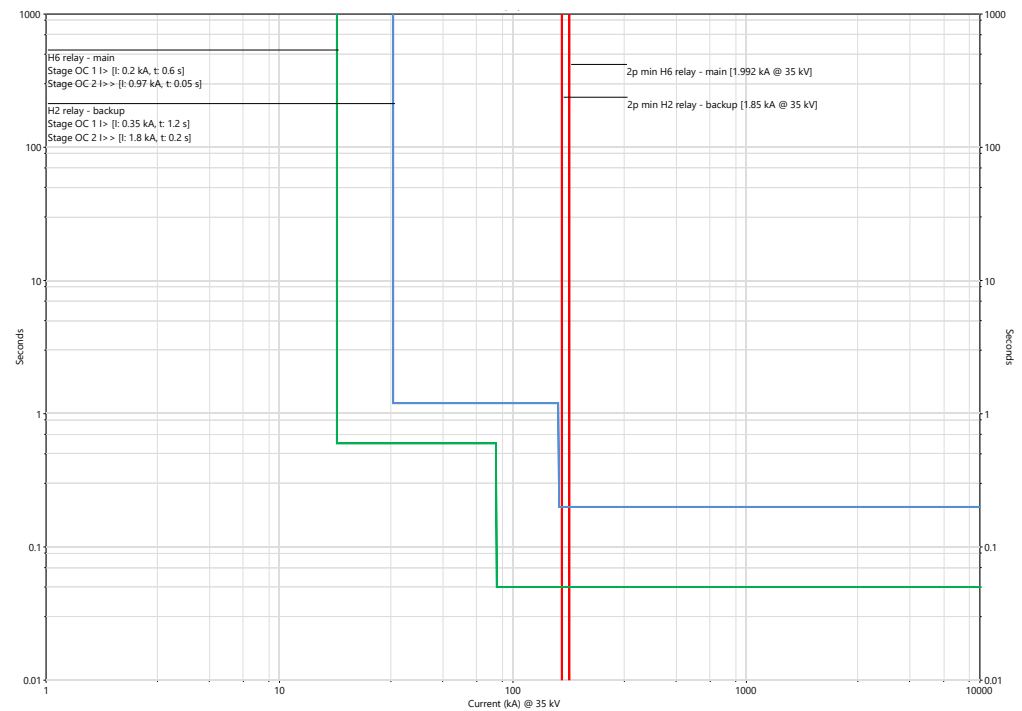


Figure 11. Dynamic simulation of selective non-directional overcurrent protection operation for operating state 70.

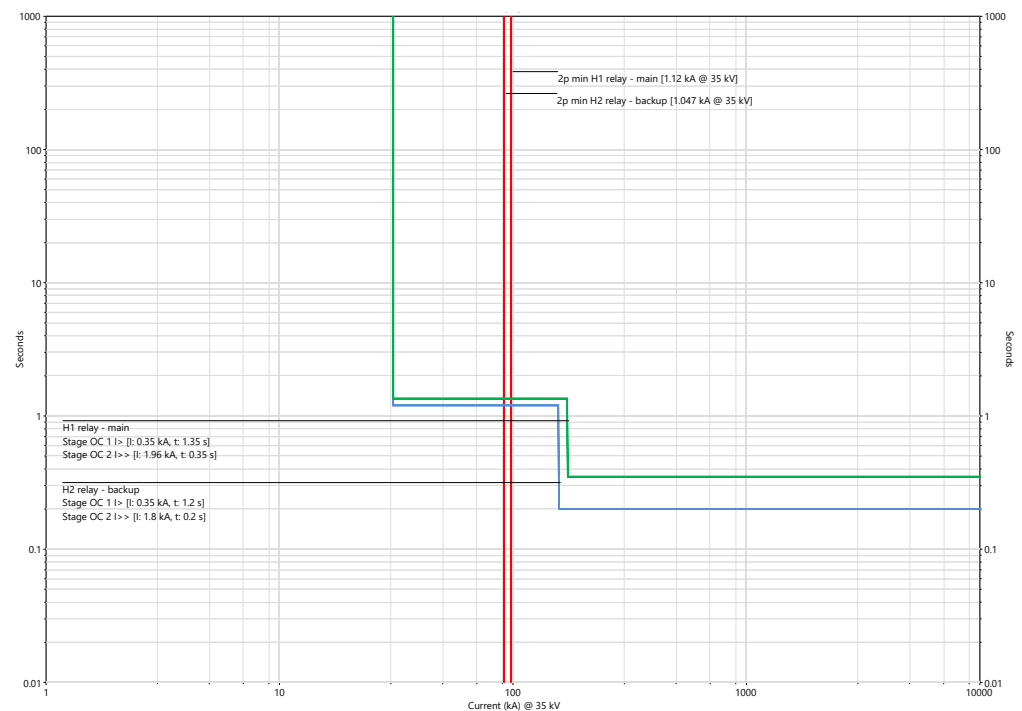


Figure 12. Dynamic simulation of non-selective non-directional overcurrent protection operation for operating state 9.

Table 15. Calculated average operating times for all operating state clustering approaches.

Clustering	k_{RR}	k_{OP}	k_{RR} and k_{OP}	$k_{RR} + k_{RR}$ and k_{OP}
$t_{I>} [s]$	0.965	0.968	0.956	0.943
$t_{I>>} [s]$	0.115	0.113	0.110	0.108

As in the calculation of final selectivity, the best result in terms of the average operating time of the protection relays is obtained for the case in which the operating states are clustered based on k_{RR} and k_{OP} , with preliminary clustering based on k_{RR} .

4. Case Study: Directional Overcurrent Protection

The proposed adaptive protection system for the distribution substation can be further improved by using directional overcurrent protection instead of non-directional overcurrent protection in the protection relays. This means that each protection relay has two overload protection functions and two short-circuit protection functions, with one function at each stage operating in the forward direction toward the protected object and the other in the reverse direction toward the busbars.

The starting point for defining the protection settings is to determine the relative relationships between the protection relays, with selectivity considered separately for each stage and direction of the overcurrent protection. To accelerate the operation of the short-circuit protection, conditional busbar protection is also proposed in this case. Table 16 presents the relative relationships between the protection relays for the case study of directional overcurrent protection.

4.1. Classification and Clustering of Operating States

As in the case study of non-directional overcurrent protection, an operating state classification index based on the relative relationships between the protection relays can also be determined for directional overcurrent protection. With the introduction of directional overcurrent protection into the protection system, the connection status of the DERs and the main power supply configuration no longer affect the classification of operating states. This is because the introduction of directional overcurrent protection in both directions at each protection relay eliminates the influence of different power flows caused by DERs and different main power supply configurations. Accordingly, the previously defined Equation (3) for determining the operating state classification index based on the relative relationships between the protection relays can be modified for directional overcurrent protection, resulting in a new Equation (11) for determining the operating state classification index based on the relative relationships between the protection relays.

$$k_{RR} = \sum_{y=1}^{N_T} TyB_{ON} + 2^{N_T} \cdot T_{OFF} \quad (11)$$

where the binary variables are defined as follows:

- TyB_{ON} —transformer y and bus coupler connected;
- T_{OFF} —all transformers disconnected.

For the modeled distribution substation, the equation for determining the operating state classification index based on the relative relationships between the protection relays for directional overcurrent protection is:

$$k_{RR} = (T_1B_{ON} + T_2B_{ON}) + 4 \cdot T_{OFF} \quad (12)$$

Substituting the corresponding values into Equation (12) for all operating states expected to occur during operation yields the classification indices presented in Table 17. It can be observed from this table that a total of four different classification indices are obtained for all 70 modeled operating states.

Table 16. Relay interrelationships in case of directional overcurrent protection.

No.	H1				H2				H3				H5				H6				J3, J4				J5				J7				J9				J10				J11			
	I>		I»		I>		I»		I>		I»		I>		I»		I>		I»		I>		I»		I>		I»		I>		I»		I>		I»		I>		I»					
	F	B	F	B	F	B	F	B	F	B	F	B	F	B	F	B	F	B	F	B	F	B	F	B	F	B	F	B	F	B	F	B	F	B	F	B	F	B						
1	X	X	X	X	X	4	X	2	3	X	1I	X	3	X	1I	X	X	X	X	1	X	1	X	X	2	X	1B	X	X	X	X	1	X	1	X	1	X	X	2	X	1B			
2	X	4	X	2	X	X	X	X	3	X	1I	X	3	X	1I	X	X	X	X	1	X	1	X	X	2	X	1B	X	X	X	X	1	X	1	X	1	X	X	2	X	1B			
3	1	4	1	2	1	4	1	2	3	X	1I	X	3	X	1I	X	X	X	X	1	X	1	X	X	2	X	1B	X	X	X	X	1	X	1	X	1	X	X	2	X	1B			
4	X	X	X	X	1	4	1	2	3	X	1I	X	3	X	1I	X	1	4	1	2	1	X	1	X	X	2	X	1B	X	X	X	X	1	X	1	X	1	X	X	2	X	1B		
5	1	4	1	2	X	X	X	X	3	X	1I	X	3	X	1I	X	1	4	1	2	1	X	1	X	X	2	X	1B	X	X	X	X	1	X	1	X	1	X	X	2	X	1B		
6	1	4	1	2	1	4	1	2	3	X	1I	X	3	X	1I	X	1	4	1	2	1	X	1	X	X	2	X	1B	X	X	X	X	1	X	1	X	1	X	X	2	X	1B		
7	X	X	X	X	1	4	1	2	3	X	1I	X	3	2	1I	2	X	X	X	X	1	X	1	X	X	2	X	1B	X	X	X	X	1	2	1	1B	1	X	1	X	1	2	1I	1B
8	1	4	1	2	X	X	X	X	3	X	1I	X	3	2	1I	2	X	X	X	X	1	X	1	X	X	2	X	1B	X	X	X	X	1	2	1	1B	1	X	1	X	1	2	1I	1B
9	1	4	1	2	1	4	1	2	3	X	1I	X	3	2	1I	2	X	X	X	X	1	X	1	X	X	2	X	1B	X	X	X	X	1	2	1	1B	1	X	1	X	1	2	1I	1B
10	X	X	X	X	1	4	1	2	3	X	1I	X	3	2	1I	2	1	4	1	2	1	X	1	X	X	2	X	1B	X	X	X	X	1	2	1	1B	1	X	1	X	1	2	1I	1B
11	1	4	1	2	X	X	X	X	3	X	1I	X	3	2	1I	2	1	4	1	2	1	X	1	X	X	2	X	1B	X	X	X	X	1	2	1	1B	1	X	1	X	1	2	1I	1B
12	1	4	1	2	1	4	1	2	3	X	1I	X	3	2	1I	2	1	4	1	2	1	X	1	X	X	2	X	1B	X	X	X	X	1	2	1	1B	1	X	1	X	1	2	1I	1B
13	X	X	X	X	X	5	X	2	4	X	1I	X	4	X	1I	X	X	X	X	1	X	1	X	1	3	1	1B	2	2	2	2	1	X	1	X	1	X	1	X	1	3	1	1B	
14	X	5	X	2	X	X	X	X	4	X	1I	X	4	X	1I	X	X	X	X	1	X	1	X	1	3	1	1B	2	2	2	2	1	X	1	X	1	X	1	X	1	3	1	1B	
15	1	5	1	2	1	5	1	2	4	X	1I	X	4	X	1I	X	X	X	X	1	X	1	X	1	3	1	1B	2	2	2	2	1	X	1	X	1	X	1	X	1	3	1	1B	
16	X	X	X	X	1	5	1	2	4	X	1I	X	4	X	1I	X	1	5	1	2	1	X	1	X	1	3	1	1B	2	2	2	2	1	X	1	X	1	X	1	X	1	3	1	1B
17	1	5	1	2	X	X	X	X	4	X	1I	X	4	X	1I	X	1	5	1	2	1	X	1	X	1	3	1	1B	2	2	2	2	1	X	1	X	1	X	1	X	1	3	1	1B
18	1	5	1	2	1	5	1	2	4	X	1I	X	4	X	1I	X	1	5	1	2	1	X	1	X	1	3	1	1B	2	2	2	2	1	X	1	X	1	X	1	3	1	1B		
19	X	X	X	X	1	5	1	2	4	2	1I	2	4	2	1I	2	X	X	X	X	1	X	1	X	1	3	1I	1B	2	2	2	2	1	3	1	2B	1	X	1	X	1	3	1I	1B
20	1	5	1	2	X	X	X	X	4	2	1I	2	4	2	1I	2	X	X	X	X	1	X	1	X	1	3	1I	1B	2	2	2	2	1	3	1	2B	1	X	1	X	1	3	1I	1B
21	1	5	1	2	1	5	1	2	4	2	1I	2	4	2	1I	2	X	X	X	X	1	X	1	X	1	3	1I	1B	2	2	2	2	1	3	1	2B	1	X	1	X	1	3	1I	1B
22	X	X	X	X	1	5	1	2	4	2	1I	2	4	2	1I	2	1	5	1	2	1	X	1	X	1	3	1I	1B	2	2	2	2	1	3	1	2B	1	X	1	X	1	3	1I	1B
23	1	5	1	2	X	X	X	X	4	2	1I	2	4	2	1I	2	1	5	1	2	1	X	1	X	1	3	1I	1B	2	2	2	2	1	3	1	2B	1	X	1	X	1	3	1I	1B
24	1	5	1	2	1	5	1	2	4	2	1I	2	4	2	1I	2	1	5	1	2	1	X	1	X	1	3	1I	1B	2	2	2	2	1	3	1	2B	1	X	1	X	1	3	1I	1B
25	X	X	X	X	X	5	X	2	4	X	1I	X	X	X	X	X	X	X	X	X	1	X	1	X	X	3	X	1B	X	2	X	1B	1	X	1	X	1	X	1	X	X	X	X	
26	X	5	X	2	X	X	X	X	4	X	1I	X	X	X	X	X	X	X	X	X	1	X	1	X	X	3	X	1B	X	2	X	1B	1	X	1	X	1	X	1	X	X	X	X	
27	1	5	1	2	1	5	1	2	4	X	1I	X	X	X	X	X	X	X	X	X	1	X	1	X	X	3	X	1B	X	2	X	1B	1	X	1	X	1	X	1	X	X	X	X	
28	X	X	X	X	1	5	1	2	4	X	1I	X	X	X	X	X	1	5	1	2	1	X	1	X	X	3	X	1B	X	2	X	1B	1	X	1	X	1	X	1	X	X	X	X	
29	1	5	1	2	X	X	X	X	4	X	1I	X	X	X	X	X	1	5	1	2	1	X	1	X	X	3	X	1B	X	2	X	1B	1	X	1	X	1	X	1	X	X	X	X	
30	1	5	1	2	1	5	1	2	4	X	1I	X	X	X	X	X	1	5	1	2	1	X	1	X	X	3	X	1B	X	2	X	1B	1	X	1	X	1	X	1	X	X	X	X	
31	X	X	X	X	1	5	1	2	4	2	1I	2	X	X	X	X	X	X	X	X	1	X	1	X	1	3	1I	1B	2	2	1B	1B	1	3	1	1B	1	X	1	X	X	X	X	
32	1	5	1	2	X	X	X	X	4	2	1I	2	X	X	X	X	X	X	X	X	1	X	1	X	1	3	1I	1B	2	2	1B	1B	1	3	1	1B	1	X	1	X	X	X	X	
33	1	5	1	2	1	5	1	2	4	2	1I	2	X	X	X	X	X	X	X	1	X	1	X	1	3	1I	1B	2	2	1B	1B	1	3	1	1B	1	X	1	X	X	X	X		
34	X	X	X	X	1	5	1	2	4	2	1I	2	X	X	X	X	1	5	1	2	1	X	1	X	1	3	1I	1B	2	2	1B	1B	1	3	1	1B	1	X	1	X	X	X	X	
35	1	5	1	2	X	X	X	X	4	2	1I	2	X	X	X	X	1	5	1	2	1	X	1	X	1	3	1I	1B	2	2	1B	1B	1	3	1	1B	1	X	1	X	X	X	X	
36	1	5	1	2	1	5	1	2	4	2	1I	2	X	X	X	X	1	5	1	2	1	X	1	X	1	3	1I	1B	2	2	1B	1B	1	3	1	1B	1	X	1	X	X	X	X	
37	X	X	X	X	X	4	X	2	3	X	1I	X	X	X	X	X	X	X	X	X	1	X	1	X	X	X	X	X	X	X	X	X	1	X	1	X	X	X	X	X	2	X	1B	X
38	X	4	X	2	X	X	X	X	3	X	1I	X	X	X	X	X	X	X	X	X	1	X	1	X	X	X	X	X	X	X	X	X	1	X	1	X	X	X	X	2	X	1B	X	
39	1	4	1	2	1	4	1	2	3	X	1I	X	X	X	X	X	X	X	X	X	1	X	1	X	X	X	X	X	X	X	X	1	X	1	X	X	X	X	X	2	X	1B	X	
40	X	X	X	X	1	4	1	2	3	X	1I	X	X	X																														

Table 16. Cont.

No.	H1				H2				H3				H5				H6				J3, J4				J5				J7				J9				J10				J11			
	F	I>	B	I»	F	I>	B	I»	F	I>	B	I»	F	I>	B	I»	F	I>	B	I»	F	I>	B	I»	F	I>	B	I»	F	I>	B	I»	F	I>	B	I»	F	I>	B	I»				
54	1		4	1	2	1	4	1	2	X	X	X	X	3	X	1I	X	1	4	1	2	1	X	1	X	X	X	X	X	1	X	1	X	X	X	X	X	X	X	2	X	1B	X	
55	X	X	X	X	1	4	1	2	X	X	X	X	3	2	1I	2	X	X	X	X	1	X	1	X	X	X	X	X	X	1	2	1	1B	X	X	X	X	1	2	1I	1B			
56	1	X	1	2	X	X	X	X	X	X	X	X	3	2	1I	2	X	X	X	X	1	X	1	X	X	X	X	X	1	2	1	1B	X	X	X	X	1	2	1I	1B				
57	1	4	1	2	1	4	1	2	X	X	X	X	3	2	1I	2	X	X	X	X	1	X	1	X	X	X	X	X	1	2	1	1B	X	X	X	X	1	2	1I	1B				
58	X	X	X	X	1	4	1	2	X	X	X	X	3	2	1I	2	1	4	1	2	1	X	1	X	X	X	X	X	1	2	1	1B	X	X	X	X	1	2	1I	1B				
59	1	4	1	2	X	X	X	X	X	X	X	X	3	2	1I	2	1	4	1	2	1	X	1	X	X	X	X	X	1	2	1	1B	X	X	X	X	1	2	1I	1B				
60	1	4	1	2	1	4	1	2	X	X	X	X	3	2	1I	2	1	4	1	2	1	X	1	X	X	X	X	X	1	2	1	1B	X	X	X	X	1	2	1I	1B				
61	X	X	X	X	X	5	X	2	X	X	X	X	4	X	1I	X	X	X	X	X	1	X	1	X	X	X	X	2	X	1B	X	1	X	1	X	1	X	1	X	3	X	1B		
62	X	5	X	2	X	X	X	X	X	X	X	X	4	X	1I	X	X	X	X	X	1	X	1	X	X	X	X	2	X	1B	X	1	X	1	X	1	X	1	X	3	X	1B		
63	1	5	1	2	1	5	1	2	X	X	X	X	4	X	1I	X	X	X	X	X	1	X	1	X	X	X	X	2	X	1B	X	1	X	1	X	1	X	1	X	3	X	1B		
64	X	X	X	X	1	5	1	2	X	X	X	X	4	X	1I	X	1	5	1	2	1	X	1	X	X	X	X	2	X	1B	X	1	X	1	X	1	X	1	X	3	X	1B		
65	1	5	1	2	X	X	X	X	X	X	X	X	4	X	1I	X	1	5	1	2	1	X	1	X	X	X	X	2	X	1B	X	1	X	1	X	1	X	1	X	3	X	1B		
66	1	5	1	2	1	5	1	2	X	X	X	X	4	X	1I	X	1	5	1	2	1	X	1	X	X	X	X	2	X	1B	X	1	X	1	X	1	X	1	X	3	X	1B		
67	X	X	X	X	1	5	1	2	X	X	X	X	4	2	1I	2	X	X	X	X	1	X	1	X	X	X	X	2	X	1B	X	1	3	1	1B	1	X	1	X	1	3	1I	1B	
68	1	5	1	2	X	X	X	X	X	X	X	X	4	2	1I	2	X	X	X	X	1	X	1	X	X	X	X	2	X	1B	X	1	3	1	1B	1	X	1	X	1	3	1I	1B	
69	1	5	1	2	1	5	1	2	X	X	X	X	4	2	1I	2	X	X	X	X	1	X	1	X	X	X	X	2	X	1B	X	1	3	1	1B	1	X	1	X	1	3	1I	1B	
70	X	X	X	X	1	5	1	2	X	X	X	X	4	2	1I	2	1	5	1	2	1	X	1	X	X	X	X	2	X	1B	X	1	3	1	1B	1	X	1	X	1	3	1I	1B	
71	1	5	1	2	X	X	X	X	X	X	X	X	4	2	1I	2	1	5	1	2	1	X	1	X	X	X	X	2	X	1B	X	1	3	1	1B	1	X	1	X	1	3	1I	1B	
72	1	5	1	2	1	5	1	2	X	X	X	X	4	2	1I	2	1	5	1	2	1	X	1	X	X	X	X	2	X	1B	X	1	3	1	1B	1	X	1	X	1	3	1I	1B	
87	1	2	1	2	1	2	1	2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		
88	X	X	X	X	1	2	1	2	X	X	X	X	X	X	X	X	1	2	1	2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
89	1	2	1	2	X	X	X	X	X	X	X	X	X	X	X	X	1	2	1	2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
90	1	2	1	2	1	2	1	2	X	X	X	X	X	X	X	X	1	2	1	2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	

Table 17. Operating state classification indices in case of directional overcurrent protection.

No.	k_{MO}	No.	k_{MO}	No.	k_{MO}	No.	k_{MO}	No.	k_{MO}
1	0	15	2	29	1	49	0	63	1
2	0	16	2	30	1	50	0	64	1
3	0	17	2	31	1	51	0	65	1
4	0	18	2	32	1	52	0	66	1
5	0	19	2	33	1	53	0	67	1
6	0	20	2	34	1	54	0	68	1
7	0	21	2	35	1	55	0	69	1
8	0	22	2	36	1	56	0	70	1
9	0	23	2	37	0	57	0	71	1
10	0	24	2	38	0	58	0	72	1
11	0	25	1	39	0	59	0	87	4
12	0	26	1	40	0	60	0	88	4
13	2	27	1	41	0	61	1	89	4
14	2	28	1	42	0	62	1	90	4

Since only four different classification indices were obtained for the modeled distribution substation, the operating states can be divided into four SGs without using any data-clustering method. The clustered operating states are presented in Table 18, where the SG numbers are assigned such that the operating states with the highest occurrence probability factor are assigned to the SG with the lowest number, while those with the lowest occurrence probability factor are assigned to the SG with the highest number. In addition to the operating states listed in previous table, Table 18 also includes operating states that are not expected to occur during operation. Each of these operating states is assigned to the SG containing the most similar operating state that is expected to occur during operation.

Table 18. Setting groups in case of directional overcurrent protection.

SG	Operating States
1	25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36, 61, 62, 63, 64, 65, 66, 67, 68, 69, 70, 71, 72
2	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 37, 38, 39, 40, 41, 42, 49, 50, 51, 52, 53, 54, 55, 56, 57, 58, 59, 60, 43, 44, 45, 46, 47, 48
3	13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24
4	87, 88, 89, 90, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86, 91, 92, 93, 94, 95, 96

4.2. Determination of Optimal Protection Settings

After clustering the operating states, the settings of the overload and short-circuit overcurrent protection functions must be determined for each of the four SGs. The time delays of the protection functions are determined based on the relative relationships between the protection relays, which are presented for all operating states in Table 16. Additionally, the current settings are determined based on the short-circuit calculations performed using the NEPLAN 360. For each SG the protection settings are defined such that the time delay of each protection relay is equal to the maximum time delay among the operating states within that group. The relative relationships between the protection relays for each SG are presented in Table 19.

Table 19. Relay interrelationships for all directional overcurrent protection setting groups.

Relay	Stage	SG 1		SG 2		SG 3		SG 4	
		F	B	F	B	F	B	F	B
H1	I>	1	5	1	4	1	5	1	2
	I»	1	2	1	2	1	2	1	2
H2	I>	1	5	1	4	1	5	1	2
	I»	1	2	1	2	1	2	1	2
H3	I>	4	2	3	X	4	2	X	X
	I»	1I	2	1I	X	1I	2	X	X
H5	I>	4	2	3	2	4	2	X	X
	I»	1I	2	1I	2	1I	2	X	X
H6	I>	1	5	1	4	1	5	1	2
	I»	1	2	1	2	1	2	1	2
J3, J4	I>	1	X	1	X	1	X	X	X
	I»	1	X	1	X	1	X	X	X
J5	I>	1	3	X	2	1	3	X	X
	I»	1I	1B	X	1B	1I	1B	X	X
J7	I>	2	2	X	X	2	2	X	X
	I»	1B	1B	X	X	2	2	X	X
J9	I>	1	3	1	2	1	3	X	X
	I»	1	1B	1	1B	1	2B	X	X
J10	I>	1	X	1	X	1	X	X	X
	I»	1	X	1	X	1	X	X	X
J11	I>	1	3	1	2	1	3	X	X
	I»	1I	1B	1I	1B	1I	1B	X	X

As in the case of non-directional protection, the constraints of the surrounding network and the capabilities of the protection relays must also be taken into account when determining the protection settings. Since the introduction of directional protection reduces the overall number of selectivity levels between the protection relays in the modeled distribution substation, the minimum difference between the time settings of the overcurrent protection functions of the main and backup relays can be selected as:

$$\min_t = 0.20 \text{ s} \quad (13)$$

This increases the safety margin between the time settings, ensuring that the backup protection relay does not operate during the time required for the main relay to detect the fault and trip the circuit breaker. Since conditional busbar protection is also implemented in the 20 kV switchgear in this case, the first time delay of the short-circuit protection is set to 0.05 s. Table 20 presents the optimal settings of the directional protection functions, taking into account the constraints of the network and the protection relays.

Table 20. Protection relay settings in case of directional overcurrent protection.

Relay	Stage	Current I [A]/Operating Time t [s]							
		SG 1		SG 2		SG 3		SG 4	
		F	B	F	B	F	B	F	B
H1	I>	350	350	350	350	350	350	350	350
		0.7	1.5	0.7	1.3	0.7	1.5	0.7	0.9
	I»	350	1960	350	1960	350	1960	350	1960
H2	I>	0.05	0.25	0.05	0.25	0.05	0.25	0.05	0.25
		350	350	350	350	350	350	350	350
	I>	0.7	1.5	0.7	1.3	0.7	1.5	0.7	0.9
		350	1540	350	1800	350	1800	350	1800
	I»	0.05	0.25	0.05	0.25	0.05	0.25	0.05	0.25

Table 20. Cont.

Relay	Stage	Current I [A]/Operating Time t [s]							
		SG 1		SG 2		SG 3		SG 4	
		F	B	F	B	F	B	F	B
H3	I>	150	150	150		150	150		
		1.3	0.9	1.1	X	1.3	0.9	X	X
		1800	150	1800		1800	150		
H5	I>	0.05	0.25	0.05	X	0.05	0.25	X	X
		150	150	150	150	150	150		
		1.3	0.9	1.1	0.9	1.3	0.9	X	X
H6	I>	1800	150	1800	150	1800	150	X	X
		0.05	0.25	0.05	0.25	0.05	0.25		
		180	180	180	180	180	180	180	180
J3, J4	I>	0.7	1.5	0.7	1.3	0.7	1.5	0.7	0.9
		1790	180	1790	180	1790	180	1790	180
		0.05	0.25	0.05	0.25	0.05	0.25	0.05	0.25
J5	I>	200	X	200	X	200	X	X	X
		0.7		0.7		0.7			
		950	X	950	X	1080	X	X	X
J7	I>	0.05		0.05		0.05			
		250	250	X	250	250	250	X	X
		0.7	1.1		0.9	0.7	1.1		
J9	I>	300	1540	X	1540	1010	1010	X	X
		0.05	0.05B		0.05B	0.05	0.05B		
		250	250	X	X	250	250	X	X
J10	I>	0.9	0.9			0.9	0.9		
		300	1540	X	X	1010	1010	X	X
		0.05B	0.05B			0.25	0.25		
J11	I>	200	200	200	200	200	200	X	X
		0.7	1.1	0.7	0.9	0.7	1.1		
		1600	300	1600	300	2070	310	X	X
J12	I>	0.05	0.05B	0.05	0.05B	0.05	0.25B		
		200	X	200	X	200	X	X	X
		0.7		0.7		0.7			
J13	I>	780	X	780	X	860	X	X	X
		0.05		0.05		0.05			
		250	250	250	250	250	250	X	X
J14	I>	0.7	1.1	0.7	0.9	0.7	1.1		
		300	1540	300	1540	1010	1010	X	X
		0.05	0.05B	0.05	0.05B	0.05	0.05B		

4.3. Verification of Adaptive Protection Methods

Similarly to non-directional protection, directional protection can be verified by calculating the final selectivity of the operating states and the average operating time delay of the overcurrent protection functions. By checking the selectivity for all operating states, it can be concluded that the implementation of the proposed adaptive protection system ensures complete selectivity of the protection relays for all operating states expected to occur under normal operating conditions. Accordingly, the calculated selectivity is 100%.

Since the maximum selectivity achieved with the adaptive protection system based on non-directional overcurrent protection was 62.86%, it is evident that directional overcurrent protection provides significantly better performance in terms of achieving the required selectivity. The directional overcurrent protection achieves 100% selectivity for both $\min_t = 0.15$ s and $\min_t = 0.20$ s. Therefore, the reported selectivity values of 62.86% for non-directional protection and 100% for directional protection, both evaluated using $\min_t = 0.15$ s, are directly comparable.

To further validate the improvement achieved by introducing directional overcurrent protection, dynamic fault simulations were performed for operating state 9 using the corresponding directional protection settings. The same operating state was previously analyzed in Section 3.4, where the dynamic simulation demonstrated non-selective operation between relays H1 and H2 when non-directional overcurrent protection was applied.

As shown in Figure 13, selective operation between relays H1 and H2 is achieved when directional overcurrent protection is applied. Compared with the non-directional protection response for the same operating state shown in Figure 12, the dynamic simulation confirms that the introduction of the directional criterion resolves the identified protection coordination issue.

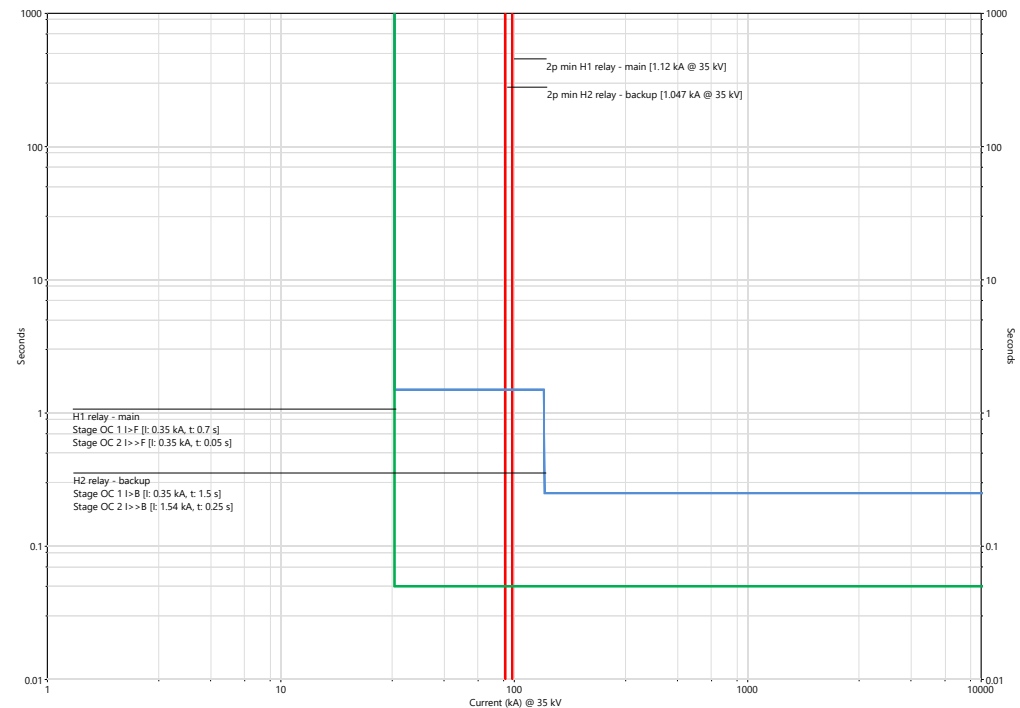


Figure 13. Dynamic simulation of selective directional overcurrent protection operation for operating state 9.

The average operating time of the directional overcurrent protection functions is determined separately for overload protection and short-circuit protection, regardless of the protection direction.

Since the same $\min_t$ was not used for the aforementioned non-directional and directional overcurrent adaptive protection methods, to enable a direct comparison of the proposed adaptive protection methods, the settings of the directional overcurrent protection were also calculated for $\min_t = 0.15$ s. Table 21 presents the average operating times of the directional overcurrent protection for the proposed adaptive method and for the adaptive method in which the protection time settings were determined in the same manner as for the non-directional overcurrent protection.

Table 21. Calculated average operating times for directional overcurrent protection.

Grouping	$\min_t = 0.20$	$\min_t = 0.15$
$t_{I>} [s]$	0.945	0.784
$t_{I>>} [s]$	0.115	0.098

A comparison of the average operating times of the adaptive protection systems based on directional and non-directional overcurrent protection, presented in Table 15, shows that directional overcurrent protection provides faster clearance of disturbances and faults than all operating state clustering approaches considered for non-directional overcurrent protection.

To quantitatively evaluate the benefits of adaptive grouping independently of directional supervision, an additional comparison was performed with a fixed directional

protection scheme employing a single SG for all 70 considered operating states. The fixed SG was determined based on the protection settings obtained for the adaptive directional protection scheme, considering the requirements of all operating states.

The results confirm that both the fixed and adaptive directional protection schemes achieve 100% selectivity. However, the adaptive approach provides shorter protection operating times in 58 out of 70 operating states, corresponding to 82.86% of the considered states. When the probabilities of occurrence of individual operating states are taken into account, these states represent 98.79% of the expected operating time of the distribution substation.

These results demonstrate that although directional supervision enables full selectivity, adaptive grouping provides an additional benefit by reducing protection operating times under the majority of expected operating conditions.

5. Discussion

The results obtained in the case studies demonstrate the applicability of the proposed adaptive protection method to distribution substations characterized by a large number of possible operating states resulting from different network configurations and the integration of DERs. The proposed method enables the operating states to be grouped into a limited number of SGs while taking into account the relative relationships between the protection relays, the probability of occurrence of individual operating states, the constraints imposed by the surrounding network and the capabilities of the protection devices. In this way, the number of required SGs can be reduced to a level compatible with the capabilities of numerical protection relays.

The results obtained also demonstrate the importance of selecting an appropriate classification index for operating-state clustering. For non-directional overcurrent protection, the best results were obtained when the operating states were clustered based on both k_{RR} and k_{OP} , with preliminary clustering based on k_{RR} . This approach resulted in the highest final selectivity of 62.86% and the lowest average operating times of the overload and short-circuit protection functions, equal to 0.943 s and 0.108 s, respectively.

For interpretation, the 62.86% refers to the best adaptive non-directional eight-group solution. A single fixed SG covering all 70 states would retain the largest delay and the largest pickup and therefore cannot exceed this selectivity while preserving sensitivity to the minimum two-phase fault current.

The best verified non-directional selectivity of 62.86% means that more than one third of considered states remain non-selective under eight SGs. This is acceptable only as a documented limitation of non-directional DT protection for this substation and DER configuration, not as a deployable performance claim. The deployable solution proposed in this paper is the directional scheme in Section 4, for which the same state set, grouping principle, and constraint enforcement are retained while direction supervision resolves the remaining main/backup conflicts.

Selectivity is kept unweighted for verification: each of the 70 considered states counts equally, irrespective of k_{OP} . k_{OP} guides only the assignment of limited SGs during clustering; it does not discount rare states in the final selectivity assessment.

5.1. Advantages and Practical Significance

One of the main advantages of the proposed method is that it is based on protection functions and SGs that are already available in modern numerical protection relays. Therefore, the proposed adaptive protection concept does not require the introduction of a completely new protection principle or the replacement of existing protection devices. Instead, protection function settings can be calculated in advance during the preparation of the protection setting study and subsequently configured and tested in the protection

devices. During operation, the adaptation of the protection system can then be achieved by selecting the SG corresponding to the current operating state.

Another advantage is that the proposed method takes into account the constraints of the surrounding network when determining the protection settings. Protection co-ordination within a distribution substation cannot be considered independently of the protection settings of the upstream and downstream network. Therefore, the protection settings determined for each SG are constrained by both the relative coordination between the protection relays within the considered substation and the settings imposed by the surrounding network. This enables the proposed method to be implemented within a specific section of the network without requiring modification of the protection settings in other parts of the network.

The use of DT characteristics also provides a relatively simple and transparent basis for protection coordination. Since the operating time of a DT overcurrent protection function is independent of the magnitude of the fault current once the pickup threshold is exceeded, the coordination between protection relays can be directly represented by their relative time relationships. Moreover, the comparison between non-directional and directional overcurrent protection provides an additional insight into the applicability of the proposed adaptive protection method.

Although the adaptation of the protection settings improves the performance of non-directional overcurrent protection under different operating conditions, the obtained results indicate that changing the protection settings alone cannot completely overcome the limitations associated with the absence of directional information. In contrast to non-directional overcurrent protection, the adaptive protection method based on directional overcurrent protection achieved complete selectivity for all operating states expected to occur under normal operating conditions.

In addition to improving selectivity, directional overcurrent protection also resulted in shorter average operating times. For the same minimum coordination time interval of 0.15 s, the average operating times of the directional overload and short-circuit protection functions were 0.784 s and 0.098 s, respectively. Therefore, the use of directional information not only improves the ability of the protection system to distinguish between different fault directions but also provides greater flexibility in determining the protection time settings.

The comparison between fixed and adaptive directional protection demonstrates that the benefits of directional supervision and adaptive grouping should be considered separately. While directional supervision enables full selectivity, adaptive grouping allows protection time delays to be adjusted to the requirements of individual operating states, thereby avoiding unnecessarily long operating times associated with the considered fixed SG.

This improvement is particularly important because faster fault clearance reduces the duration of thermal and mechanical stresses on electrical equipment, limits voltage disturbances, and contributes to the safe and reliable operation of distribution substations. Furthermore, the probability-weighted comparison indicates that the benefits of adaptive grouping are particularly pronounced under the most frequently occurring operating conditions. Therefore, even when full selectivity can be achieved using a fixed directional protection scheme, adaptive grouping provides an additional benefit by improving the operating speed of the protection system without compromising selectivity.

These results are particularly relevant for distribution substations with integrated DERs. The integration of additional generation sources can introduce bidirectional power flows and change the magnitude and direction of short-circuit currents. Under such conditions, the relative relationships between protection relays may change depending on the operating state of the network. Directional overcurrent protection provides additional information that can be

used to distinguish between these conditions, thereby reducing the coordination constraints that are present when only non-directional overcurrent protection is applied.

5.2. Limitations and Practical Implementation Challenges

Although the obtained results demonstrate the potential of the proposed method, several limitations should be considered. First, the method was evaluated using a single model based on the actual SS Mikanovci distribution substation case study. The considered substation includes multiple power supply sources, transformers, bus couplers, and DERs and therefore represents a complex protection coordination problem. Nevertheless, distribution substations may differ significantly in terms of topology, number and type of DERs, protection philosophy, and characteristics of the surrounding network. Consequently, additional case studies are required to evaluate the applicability of the proposed method to other network configurations.

Another limitation is that the proposed approach assumes that all operating states relevant for protection coordination can be identified in advance. The protection settings for each SG are calculated offline based on the operating states considered during the preparation of the protection setting study. Consequently, an operating state that was not considered during the setting calculation may not be represented by an appropriate predefined SG. This issue becomes increasingly important in highly dynamic distribution networks in which the network topology or the number of connected DERs may change during the lifetime of the protection system.

The limited number of available SGs represents a practical constraint of the proposed approach. Although clustering enables a large number of operating states to be represented by fewer SGs, several operating states with different protection requirements may be assigned to the same group. Consequently, the protection settings must satisfy the most restrictive requirements within each group, which may increase the required time delays or prevent complete selectivity, as observed for non-directional overcurrent protection. The use of directional overcurrent protection significantly reduces this limitation, although its implementation requires protection relays with directional functions and reliable voltage and current measurements for determining the fault direction.

A further challenge is the reliable identification of the current operating state, which requires accurate and timely information on the position of the circuit breaker and bus coupler, the operating state of the transformer and the availability of DER. Incorrect or delayed information, as well as communication failures, could result in the activation of an inappropriate SG and affect protection performance. During SG switching the protection functions remain active, i.e., no protection dead time is introduced: the previously active verified SG remains effective until activation of the new SG is confirmed in the relay. The transient relevant for coordination is therefore the network topology change itself, together with the time needed for operating-state identification, and SG activation. At the switching instant, main and backup relays must change as one coherent SG set derived from the same identified operating state, so that the $\min_t$ margins verified offline in Section 3 are preserved. If the operating state cannot be reliably identified, or confirmation is missing, the fallback is to retain the last valid SG and, where defined, to use a predefined conservative SG, without blocking tripping. Detailed switching and communication times are implementation-dependent and are left for real-time and hardware-in-the-loop (HIL) validation stated as future work. Therefore, practical implementation should include a fallback strategy defining the SG to be activated when the operating state cannot be reliably determined, while also considering transitions between operating states.

Finally, the proposed adaptive protection system was evaluated by simulation using a model based on an actual distribution substation. Although this provides a realistic basis for

evaluating the protection coordination and the calculated settings, the complete adaptive protection process, including automatic identification of the operating state, communication between devices, and automatic SG switching, has not yet been experimentally validated. Therefore, real-time and HIL testing represents an important next step toward practical implementation.

5.3. Future Research and Development

Future research will primarily focus on extending the developed methodology from the calculation and verification of adaptive protection settings to the automatic operation of the adaptive protection system. The first step will be the development of a control algorithm capable of collecting and analyzing the information required to identify the current operating state of the distribution substation and select the corresponding SG.

The proposed concept is based on calculating, configuring, and testing the protection settings for all SGs before the adaptive protection system is placed into operation. During operation, the control algorithm would only identify the current operating state and activate the corresponding predefined and verified SG, without calculating new settings in real time. This preserves the deterministic nature of conventional protection coordination while enabling automatic adaptation to changes in network operating conditions.

The operating state identification and SG selection algorithm could be implemented either centrally in the substation computer or distributed among the protection devices. Future research should compare these approaches in terms of protection performance, communication requirements, reliability, implementation complexity, and costs. While a centralized approach facilitates coordinated SG selection, a decentralized approach can reduce dependence on a single central device and improve system resilience.

Particular attention should also be given to the behavior of the adaptive protection system during communication failures and transitions between operating states. Appropriate fallback settings should be defined to ensure that the protection system remains operational even when some of the information required for operating state identification is unavailable. In addition, the time required to identify a change in network topology, select the appropriate SG, transmit the corresponding commands, and activate the new settings should be evaluated to ensure that the transition does not compromise protection performance.

The next stage of validation should include real-time simulation and HIL testing with actual numerical protection relays. Such testing would enable the complete sequence from a change in network topology to automatic SG activation and protection relay operation to be evaluated. It would also enable communication delays, switching times, incorrect status indications, and communication failures to be included in the assessment of the adaptive protection system.

In the longer term, the proposed approach can be extended toward a fully adaptive protection system capable of responding not only to predefined operating states but also to previously unconsidered changes in network topology. Such an extension would require the protection system to identify when the existing SGs are no longer appropriate and determine whether new protection settings are required. However, any automatically determined settings would have to satisfy the same coordination, selectivity, sensitivity, and device constraints considered in the present study.

6. Conclusions

In this paper, an adaptive protection method based on overcurrent protection with DT characteristics was developed for distribution substations with integrated DERs. The proposed method combines operating-state classification and clustering with the determination of optimal protection settings. The classification indices are based on the relative

relationships between protection relays and the probability of occurrence of individual operating states, while the k-means algorithm is used to reduce the number of operating states to a number of SGs compatible with the capabilities of numerical protection relays.

The method was applied to a model based on the actual SS Mikanovci distribution substation case study using both non-directional and directional overcurrent protection. For non-directional protection, the best results were obtained when the operating states were preliminary grouped and clustered based on the interrelationships between protection relays and occurrence probabilities. This approach resulted in a final selectivity of 62.86% and the lowest average operating times among the considered clustering approaches.

The application of directional overcurrent protection resulted in a significant improvement in protection performance. Complete selectivity was achieved for all operating states expected to occur under normal operating conditions. Furthermore, for the same minimum coordination time interval, directional overcurrent protection provided shorter average operating times than the considered non-directional protection approaches. These results demonstrate the advantages of including directional information when adaptive protection is applied to distribution networks characterized by changing topology and bidirectional fault-current paths.

The proposed method enables adaptive protection to be implemented using conventional protection functions and the multiple SG capability of numerical protection relays, while taking into account the constraints of the surrounding network. Therefore, the developed approach provides a practical basis for improving the selectivity and speed of distribution substation protection under changing operating conditions and increasing DER penetration.

Author Contributions: Conceptualization, A.D. and M.B.; methodology, A.D.; validation, A.D., M.B. and J.H.; formal analysis, A.D.; investigation, A.D.; resources, A.D. and J.H.; data curation, A.D.; writing—original draft preparation, A.D. and M.B.; writing—review and editing, A.D. and M.B.; visualization, A.D. and M.B.; supervision, J.H.; project administration, J.H. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Institutional Review Board Statement: Not applicable.

Data Availability Statement: The original contributions presented in this study are included in the article. The raw data and simulation model supporting the conclusions of this article will be made available by the authors upon request.

Conflicts of Interest: Author A.D. was employed by Elektrogen Ltd. during the conduct of this study. All authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as potential conflicts of interest.

Abbreviations

The following abbreviations are used in this manuscript:

AI	Artificial Intelligence
BPP	Biomass Power Plant
CT	Current Transformer
DER	Distributed Energy Resource
DT	Definite-Time
GA	Genetic Algorithm
HIL	Hardware-in-the-Loop
PVPP	Photovoltaic Power Plant
SG	Setting Group

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