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LCC Based Multi-Terminal HVDC Operation without Telecommunication

Master's thesis in Electric Power Engineering

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Department of Energy and Environment
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Abstract

A continuous increase in power demand, especially in the developing countries, and rapid growth of renewable energy source integration resulted into a rebirth of High Voltage Direct Current (HVDC) transmissions in the last two decades. Nowadays, a Line-Commutated Converter (LCC) HVDC is a dominant technology for high power transmission over long distances. Typically, point-to-point configuration HVDC systems are used. However, in a case when generated electricity has to be supplied to several different locations, a Multi-Terminal LCC HVDC (MTDC) can be one more economical solution. Such HVDC systems are more complex and requires continuous communication between the terminals for the stable operation. Since it is impossible to completely avoid malfunction of the telecommunication, all the HVDC systems should be able to operate even when the telecom is not available.

Consequently, this project aims to develop and implement control methods for a stable operation of multi-terminal LCC HVDC when telecommunication failure occurs. Additionally, the system should be able to withstand different disturbances and transient events.

The proposed solution of this project is to change the operation of the stations when telecommunication is lost. When this happens, the rectifier is shifted from current control to voltage control, while inverters are moved from constant beta control to current control. In addition to these changes of operation, several improvements have to be made to the existing controls to achieve a proper dynamic response of the system. This includes tuning of a voltage regulator and sub-functions such as reduced voltage recovery, reduced nominal extinction angle and current order limiter. After all these changes were implemented, the multi-terminal HVDC system used for the simulations was able to withstand all the applied disturbances and transient events during operation without telecommunication.

Keywords: Line Commutated Converters, LCC, Multi-terminal HVDC, telecommunication, HVDC controls, constant beta control, rectifier voltage control.

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Contents

List of Figures

List of Tables

1

Introduction

1.1 Background

In the past decade, an interest in technologies for high power transmission over long distances became higher than ever before. The world's power consumption is increasing every year, especially in the countries with rapidly growing economies like China, India or Brazil. It is predicted that by the end of 2035 the electricity consumption worldwide will increase by 44% [1]. In order to meet the demand, more and more generating units are installed. However, these new power plants are commonly located not in areas with the highest power demand and as a result, generated electricity should be transmitted over long distances. Furthermore, environmental problems, the global warming and increased concerns for the safety of nuclear power generation leads to a rapid growth in integration of renewable energy sources. One of the confirmed goals of the European Union and the G8 is a decrease in the greenhouse gas emissions by 80% until 2050 [2]. However, it is common that renewable energy sources are located remotely and large power transmission capabilities over long distances or through cable are required, especially this is true for off-shore wind power where wind farms could be based more than 100 km from shore [2]. For such cases, a High Voltage Direct Current (HVDC) technology is the most economical solution to use.

The HVDC transmissions have several advantages over High Voltage Alternating Current (HVAC) transmissions. First of all, no limitations for transmission distance, especially for cable connected systems. The maximum cable distance for the HVAC is about 80 km due to capacitive current [3]. Secondly, smaller losses in conductors (no skin effect) for the HVDC that lead to higher power transfer capabilities than the HVAC. Furthermore, some configurations of the HVDC have partial power transmission possibilities even when one of the conductors is disconnected. Moreover, the HVDC gives a possibility to interconnect asynchronous AC networks [4]. Finally, fast and accurate controllability of the active power is achieved using HVDC systems [5].

In general, HVDC is not a new technology, but due to fast growing economies and the need for renewable energy source integration into power systems, it has experienced a rebirth in the last two decades and it continues to grow [6]. The HVDC is based on two different technologies: Line Commutated Converter (LCC) where thyristors are used as valves and Voltage Source Converter (VSC) where Insulated Gate Bipolar Transistors (IGBT's) are used as valves [6]. The VSC HVDC is the latest technology and is expected to be dominant in the future due to its control abilities of active and reactive power, black start capability, no need of fast telecommunication, no problems with commutation failures, simpler harmonic filter since Pulse Width Modulation (PWM) is used [5][7]. However, as IGBT's are used for the VSC, where turn on and turn off times are controlled and the switching frequency is higher, the total losses of such topology HVDC are higher what limits its power rating and application for very high power transmissions. The losses in the VSC HVDC is approximately 1.7% while in the LCC HVDC is about 0.7% [5][8]. Moreover, the LCC HVDC technology is assumed to be very reliable since it is in use for more than fifty years and only minimum maintenance over its lifetime is required [6]. Finally, the DC inductor, which is needed for the LCC HVDC to smoother the DC current, also limits a short circuit current during faults. These main advantages that keeps the high interest in the LCC HVDC technology up to this day.

In addition to regular point-to-point configuration HVDC system, a multi-terminal HVDC connection can be used when high power transmission to several different areas is needed. In general, multi-terminal LCC HVDC consist of at least three converter stations. Such configuration has several advantages over typical two terminal HVDC system. First of all, the number of converter stations is reduced to transmit the same power what results in reduced losses and installation cost. Furthermore, multi-terminal HVDC increases redundancy of the system during various disturbances. Moreover, increased expansion possibilities. As a result of these advantages, the multi-terminal LCC HVDC can be assumed as one of the solutions for high power transmission.

However, the line commutated converters have some disadvantages. Firstly, a DC voltage has to be reversed if power reversal is needed. Secondly, the LCC HVDC is sensitive to AC faults during which a commutation failure can occur. Thirdly, as only firing of the valves is controlled, the converter stations consume reactive power and compensation is needed. This also leads to the requirement of a strong AC network, otherwise the LCC HVDC can experience commutation failures even during small disturbances what can lead to unstable operation. Finally, a continuous communication between terminals is needed, especially when the system is operating in a constant beta control mode, which is explained later in the project. This becomes even more important in the multi-terminal HVDC systems which are more complex than regular point-to-point HVDC. The loss of telecommunication can lead to instabilities in the system, overcurrents, increased stress for the components or even collapse of the entire HVDC system. For this reason, all the HVDC systems require a control logic in which the system would be able to operate without the telecommunication [9][10][11].

1.2 Aim

The aim of this thesis is to develop, implement and evaluate the control methods for a stable operation of multi-terminal LCC-HVDC system operating with lost telecommunication during various transient events, disturbances and even loss of a station based on local measurements.

1.3 Problem

All HVDC systems are designed to withstand various disturbances and be able to recover to a stable operating point. One of the problems for the system can be the operation with loss of telecommunication between the stations. Even if a parallel back-up communication system is used, the requirement for operation without telecom for the HVDC system remains. As the multi-terminal HVDC systems are more complex in many different aspects in comparison with regular point-to-point interconnections, it requires new control strategies to deal with telecommunication problems.

In order to fully investigate the problem and propose proper solutions, the project is divided into different parts. First of all, operation with telecommunication is investigated, a control logic for the stable operation is implemented, which is confirmed by applying and analyzing various disturbances. Secondly, operation with loss of communication is analyzed, control methods are introduced to maintain stable operation in the steady state. Furthermore, different transient events are applied to the system and according to the results improvements for the control are done. The case is investigated, when one of the stations is lost and final improvements are done.

1.4 Scope

The multi-terminal LCC HVDC systems can be very complex in their structure and its controls. A lot of different parameters can be changed which have various impacts for the operation of the system. In order to limit the scope of the work and achieve more accurate results some assumptions are made:

- In this project, the multi-terminal HVDC system consists of one rectifier station and two inverter stations which are connected in parallel, monopole configuration.
- The stations are connected using overhead lines and a case with cable connection is not investigated.

- Re-connection of a station without the telecom is also not studied as if the station was disconnected completely, the most likely it experienced mechanical damage which requires physical investigation and during which the telecommunication would be fixed as well.
- The AC network parameters and a Short Circuit Ratio (SCR) for each station remains unchanged during all investigated cases.
- Two types of AC faults were applied during simulations, single phase to ground and three phase to ground. As the first type of the faults are the most common and the second type are the most severe [12].
- A normal recovery of the system is assumed to be when 90% of the pre-fault power flow is reached in about $250 - 300ms$.
- Longer faults than $200ms$ are not investigated as today's protection system should not react slower than this time.
- The fault angle was kept constant for all introduced faults and it is equal to 75^o.
- Due to software limitations, which was used for the simulations, the lowest remaining voltage during a fault is set to 10%. The lower voltage can give inaccurate results.
- The parameters of the control system (gains, time constants, etc.) are kept constant for all the simulations unless stated.
- The telecommunication system, which is used in the simulation model, is designed such that real communication between stations is achieved where the data is not transmitted instantaneously.

The results presented in this project were obtained by using power system transient simulation software "PSCAD". The changes in the controls were done in using internal ABB's software HiDraw. Furthermore, before dynamic simulations, every system configuration was tested with continues operation in steady state for two minutes in simulation time. All dynamic simulations were done from snapshots which were created at twentieth simulation second for each case and all the disturbances or transient events were applied at $0.1s$ of simulation time.

2

Principle Operation and Controls of the HVDC System

2.1 Components of the LCC HVDC

The main difference of the HVDC system in comparison with the traditional HVAC is that direct current and voltage is used to transmit the power instead of alternating. However, the system itself is more complex than only two converters which are required to change AC to DC and DC to AC in the sending and receiving ends respectively. To achieve all the benefits of the LCC HVDC, different components described below are needed.

In general, the essential element of the HVDC system are converters. The converter located at the sending end changes AC to DC and the converter at the receiving end does the opposite. The converters consist of the valves connected in series in order to withstand high voltages. In 1954 when the first HVDC transmission system was commissioned, mercury - arc valves were used. Nowadays, thyristors and IGBT's are used for different HVDC technologies[13][14].

The second most important component is the converter transformer. The transformer steps up the AC voltage before it is converted to the DC voltage and at the receiving end steps it back. Furthermore, using 3-winding transformers for two six pulse converters a 12-pulse configuration is done, which reduces harmonics, thus, more even direct and more sinusoidal alternating currents are achieved. Additionally, tap-changer is used to keep the DC voltage within a certain range. Finally, converter transformer creates galvanic separation between AC and DC systems [13][14].

The AC filters, breakers and capacitors are another group of the components. AC filters consist of shunt capacitors, rectors and resistors. Some of them are specifically tuned for specific harmonics (11th or 13th) and others for several higher frequency harmonics (less effective). The capacitors provide reactive power compensation as the LCC HVDC system always consumes reactive power which can account for about 60% of the active power. The AC circuit breakers are used to separate the AC system from the HVDC system if needed. Additionally, AC breakers can be used to switch filters or capacitors [13][14].

As the LCC consumes reactive power, a network to which the system is connected should have a certain SCR. In case when an AC network is weak, a Capacitor Commutated Converter (CCC) can be used. Such configuration HVDC system is achieved by adding capacitors in series between the valves and the converter transformer for the LCC. The capacitors improve the stability of the system when it is connected to weak AC networks, reduce the risk to have a commutation failure, compensate reactive power and limit overvoltages [11][14]-[15].

The DC filters and smoothing reactors are also used in the LCC HVDC. The DC filters reduce DC harmonics while the smoothing reactors connected in series make the DC current more even [13][14][16].

Finally, the controls of the LCC HVDC. All the hardware of the controls is located in a separated place in a station. The two identical control units are used for the same station, one operates as main unit and the second works as a back-up system. The master controller, which can be located somewhere in regional control center, provides power order. Using this power order, locally measured parameters and operation mode the controls generate firing impulses for the valves which are sent through using optical-fiber cables [16].

However, all this complexity of the HVDC system increases its initial price and as a result, implementation of such transmissions is economically beneficial only for projects with a certain distance or cable transmission [13].

2.2 Point-to-point configurations of HVDC

HVDC systems can be arranged in different configurations depending on transmitting power, customer requirements, location and other variables. The most common are represented in figure 2.1 [17].

Asymmetrical Monopole

This configuration consists of only one conductor (figure 2.1a). In such a case, the earth is used as a return path for the current. To reduce the corona effect, typically, the conductor has negative polarity [4]. However, this configuration has one main disadvantage. In the ground, there are a lot of metallic objects like pipelines, various communications, structures, etc. and return current flowing through the ground will flow through these objects as well. This can lead to higher corrosion and leakage currents. As a result, the asymmetrical configuration HVDC is used only for temporary operation [16].

Symmetrical Monopole

In this configuration, two conductors are used with different polarities and there is no earth current (figure 2.1b). This way monopole HVDC is operating with metallic return and grounded neutral [4][16].

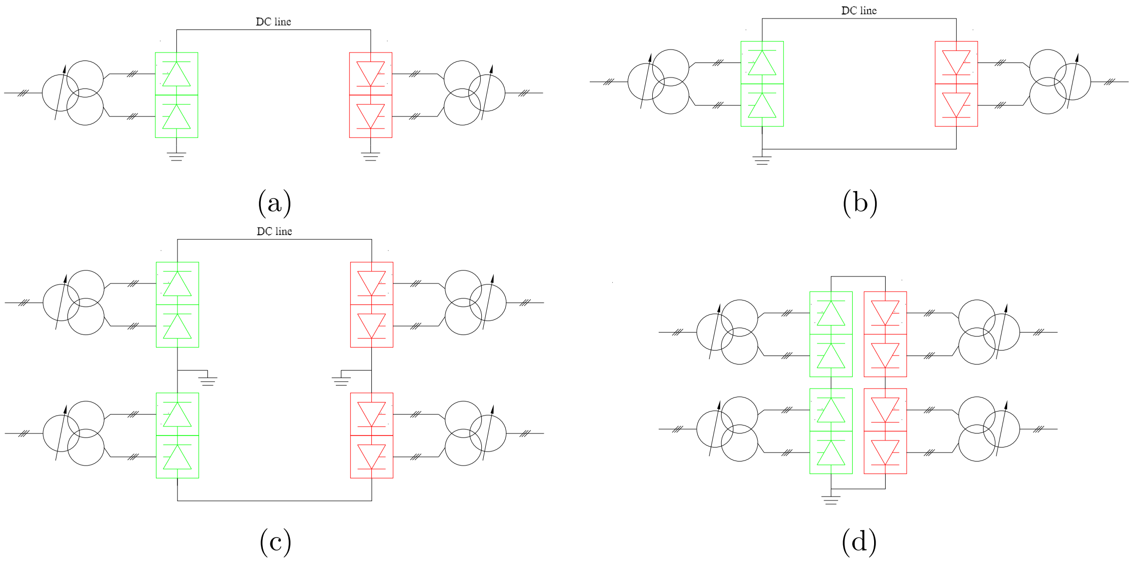


Figure 2.1: The most common configurations of the HVDC: (a) Asymmetrical Monopole (b) Symmetrical Monopole (c) Bipole (d) Back to Back

Bipole

This configuration consists of two monopoles and two conductors (figure 2.1c). One pole operates with positive voltage and current while another with negative voltage and current. This way, both poles are able to transmit power to the same direction. Furthermore, as only half of the current is flowing through one conductor, the bipole HVDC system is able to transmit more power. Moreover, both stations are grounded what gives a possibility to continue the operation even when there is a fault in one of the lines. In such a case, the system operates as monopole with a single conductor and return current through the earth. Consequently, HVDC system is able to transmit only half of its nominal power, but total losses during the fault is reduced in comparison with monopole system, where there is no power transmission for the period of a fault on the conductor. During the normal operation, equal currents are flowing through the lines and because of this there is no ground current. All these advantages made bipole configuration the most popular nowadays [4][16][18].

Back-to-Back

Back-to-back configurations are mostly used to interconnect two areas with different or not synchronized frequencies. In such an arrangement, both converters of the HVDC system are located in one station. It can be designed for monopole or bipole operation (figure 2.1d). A small distance between the inverter and the rectifier gives a possibility to increase the DC current in the system. As a result of this change in DC current and voltage, the thyristors are better utilized. This leads to a reduction in the number of thyristors and the size of the valves [14]. Furthermore, due to reduced voltage, smaller transformers and other equipment are used, lower requirements for insulation. Moreover, there is no long cable or overhead line between the terminal. All this leads to reduced the total price of a back-to-back HVDC system [16][18].

2.3 Multi-terminal HVDC

In general, multi-terminal HVDC systems consist of at least three converter stations interconnected through DC lines. Both, monopole and bipole configurations are available as for two terminal HVDC [4]. Similarly to AC networks, the MTDC can have different topologies like radial, meshed or star and can be connected in parallel or series [13][5].

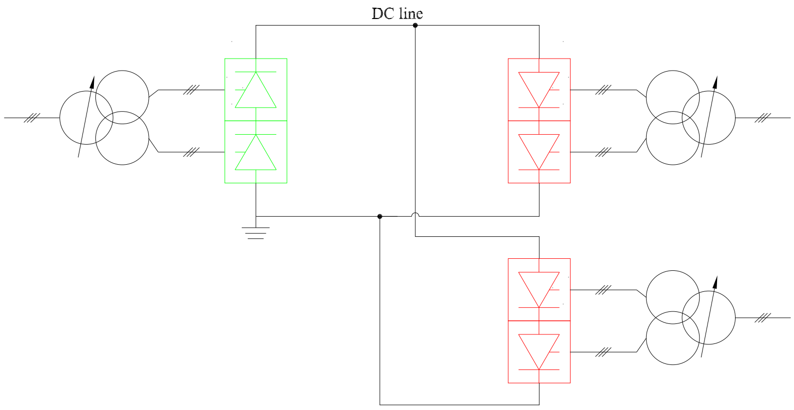


Figure 2.2: Parallel connected multi-terminal HVDC

Both connection types have different advantages depending on the situation. In the series arrangement of the MTDC, one converter station sets the current, which is flowing through all the terminals and other converters are operating in a DC voltage control or in a minimum extinction angle control. Such operation leads to independent voltage control in each station what can be very beneficial during AC faults at the inverter side if all the stations are connected to separate AC networks. For example, if a fault occurred at one of the inverter's AC side, a commutation failure can appear and the DC voltage will drop to zero. However, if the AC side, to which the remaining inverters are connected, is strong enough and the rectifier current controller is properly designed, the remaining inverters will not be affected or the disturbance will be minimal [19]. Moreover, in comparison with parallel, the MTDC connected in series has a lower installation cost up to a specific distance [16][1][4].

Contrary to the series MTDC, in parallel connection, one terminal is controlling voltage, which is the same for the entire system and other terminals are operating in a current control mode. As a result, during disturbances in the AC side, all the terminals will experience a DC voltage sag which will considerably affect transmitting power over the disturbance and will prolong the recovery of the system [20]. Despite this property, parallel configuration has many advantages. First of all, it is redundant and is able to continue the operation even after loss of one of the terminals or DC lines. Furthermore, such MTDC system has lower operational losses in comparison with series connected MTDC and it is easier to expand [16][21][19]. As a consequence of these advantages, only parallel connected MTDC has been implemented and commissioned up to this day [22].

In comparison with point-to-point configuration, multi-terminal HVDC has these main advantages [13][8]:

- Less converter stations are needed to transmit the same power. This means lower losses and the lower installation cost of a project.
- Redundancy of the system. During the faults, unaffected terminal can continue to operate without significant disturbances in the power flow.
- Ability to operate converter stations with different power and current orders. One terminal will set the voltage and other converter stations will set its own current to have ordered power flow.

However, in order to maintain the stability of the MTDC system, fast telecommunication is needed between the terminal. This is extremely important during the loss of the converter stations. For instance, when the MTDC system has several inverters and one of them is lost, others will be overloaded as rectifiers will continue to supply the same current. In the case of lost rectifier, the current margin will become negative and this would lead to DC voltage collapse in the system [13][23][24]. For these reasons, during disturbances when one of the terminals is lost, new current orders should be set to the remaining converter stations to maintain the current balance between rectifiers and inverters (2.1).

$$\sum I_{rectifiers} = \sum I_{inverters} \tag{2.1}$$

2.4 The Commutation of the LCC HVDC

Before explaining the control of the HVDC systems, a commutation between the valves have to be described. For this purpose, a simplified 6-pulse converter bridge is used, which is represented in figure 2.3. This simplified converter consists of six thyristors which are connected to an AC network through three legs. The total commutation inductance for each phase are represented as L_C, the DC current and voltage are assumed to be constant and each of the thyristors conducts for 60^o in one period. The thyristor can start to conduct when the voltage difference between the two legs, to which it is connected, becomes positive. For instance, the thyristor T1 can start to conduct when a voltage difference between U_A and U_C becomes positive.

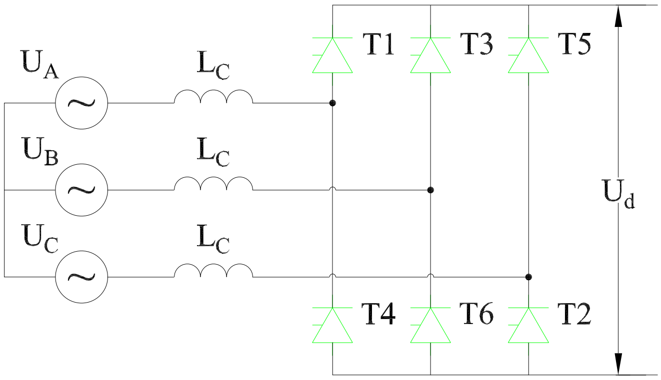


Figure 2.3: Six pulse converter bridge

As thyristors are semiconductors with ability to control only a firing instance, the control of the converters of the LCC HVDC system is done by changing the firing angle α. In some literature this firing angle is named as delay angle and it represents a time difference between a moment when the valve was able to start and it actually started to conduct (a delay time).

The time instance expressed as an angle when current over the thyristor becomes zero and the voltage across it again becomes positive is named as extinction angle γ. Furthermore, after a thyristor has finished to conduct and current is extinguished, a certain time is required when a negative voltage is applied over the thyristor before the forward voltage can be applied. This time is needed to remove the remaining charge in a thyristor so that it would not start to conduct without a triggering pulse. This is referred to as the minimum extinction angle [12].

Moreover, as figure 2.3 represents, the converter transformer has a certain leakage inductance L_C. As a result, the current between two valves cannot change instantaneously and for a certain time two valves are conducting simultaneously. The time expressed as an angle is called the overlap angle μ. The overlap is directly proportional to the DC current I_d, transformer inductance and inversely proportional to the AC voltage. The relationship between these three angles is as follows [12]:

$$\alpha + \mu + \gamma = 180^o \tag{2.2}$$

The extinction angle γ represents the minimum extinction angle for the successful commutation plus a certain margin. In a rectifier, which operates with the firing angle about 15^o (the rectifier operation is assumed for α range of $0^o - 90^o$), this margin is large what leads to low risk of unsuccessful commutations. However, in an inverter, the firing angle is considerably larger as inverter operation is assumed to be between 90^o and 180^o of α. Typically, the extinction angle during the normal operation for the inverter is about 18^o and this leads to the small commutation margin and high risk of unsuccessful commutation, especially during disturbances [16][12].

In practice, it is preferred to operate an inverter at the smallest possible extinction angle as it reduces the losses, reactive power consumption, etc. (further described later in the text). However, in such operation, the commutation margin is already small and during disturbances it is reduced even more. This reduction can lead to a commutation failure.

For example, if a commutation failure occurs during commutation between T1 and T3 (figure 2.3), the thyristor T1 cannot block the forward voltage and it starts to conduct again, the DC current goes up. Additionally, current over thyristor T3 drops back to zero. The following commutation is between thyristors T2 and T4 and when the T4 starts to commutate, T1 and T4 creates a short circuit. The DC current in the system goes up while the DC voltage down, the system is discharged because of the short circuit on the DC side. At this point, the control system interacts which limits the current and eventually restores the system to a normal operation [12].

2.5 Current - Voltage Characteristics

In order to explain LCC HVDC system controls and dynamics, the basic current-voltage characteristics for the rectifier and inverter will be used.

2.5.1 Rectifier current - voltage characteristic

The main I_d/U_d characteristic for the rectifier is shown in figure 2.4. It is based on a simplified expression for the direct voltage over the rectifier:

$$U_d = U_{di0} \cdot \cos\alpha - (d_{xN} + d_{rN}) \cdot \frac{U_{di0N}}{I_{dcN}} \cdot I_d \tag{2.3}$$

where U_{di0} is an ideal no load direct voltage, d_{xN} and d_{rN} are relative inductive and resistive DC voltage drops in p.u. referred to U_{di0} or in other words the impedance of a converter transformer, U_{di0N} and I_{dcN} - the nominal direct voltage and current.

As impedance of the converter transformer in the 2.3 depends on its design and is constant during the operation as well as nominal voltage and current, the U_d expression can be simplified to:

$$U_d = U_{di0} \cdot \cos\alpha - KI_d \tag{2.4}$$

where K represents the impedance of the transformer multiplied by the relationship between the nominal DC voltage and current.

Based on 2.4, it can be stated that the direct voltage over the rectifier basically depends on U_{di0}, α and I_d. Furthermore, the variable U_{di0} is proportional to the voltage at the AC side of the rectifier which can be assumed constant during the normal operation. As the result, at a minimum value of α and no current flowing,

U_d will be at the maximum value as the point A represents in figure 2.4. The minimum value of the firing angle is usually limited to 5^o. This limit is set by the requirement that the voltage across have to reach a specific minimum value before successful firing can be achieved [16]. By increasing current order and keeping α at its minimum value, the direct voltage of the rectifier goes down (the negative slope line A-B). However, during the normal operation the rectifier is working in a constant current mode, which is represented by the vertical line B-C in figure 2.4. In this case, I_d is equal to I_{ord} and voltage across the rectifier is controlled by changing firing angle α.

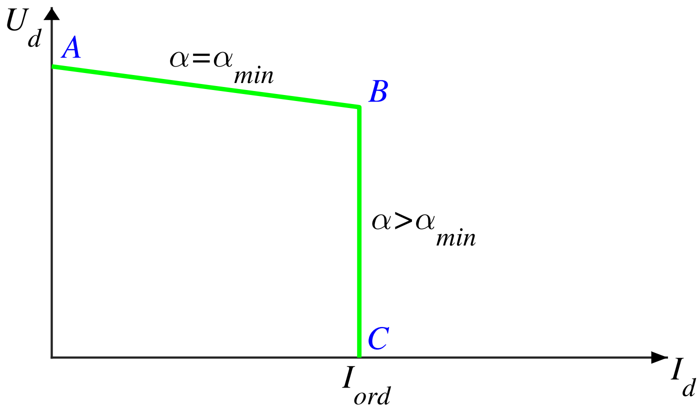


Figure 2.4: Rectifier direct current - voltage characteristic

2.5.2 Inverter current - voltage characteristic

The inverter I_d/U_d characteristic, which is shown in figure 2.5, is based on 2.5. As the inverter operating with firing angle above 90^o it is better to express U_d using extinction angle γ.

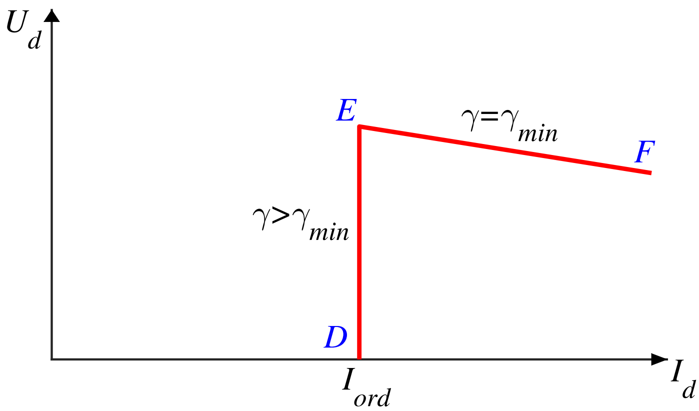


Figure 2.5: Inverter direct current - voltage characteristic

$$U_d = U_{di0} \cdot \cos\gamma - (d_{xN} + d_{rN}) \cdot \frac{U_{di0N}}{I_{dcN}} \cdot I_d \tag{2.5}$$

Applying the same assumptions as for rectifier, the simplified expression for the inverter direct voltage can be written as:

$$U_d = U_{di0} \cdot \cos\gamma - KI_d \tag{2.6}$$

As can be seen from 2.6, the highest value of U_d in the inverter will be when γ is at its minimum value. The vertical line D-E in figure 2.5 represents the constant current operation. In this mode, by changing the extinction angle, the DC voltage will be controlled to keep the ordered current. However, in the steady state operation, it is preferred to operate inverter at γ_{min} control (negative slope line E-F in figure 2.5) due to several advantages. First of all, the minimum amount of reactive power consumed by the inverter is at the minimum value of γ. Furthermore, less stress for the valves, transformers and other equipment what means higher reliability. Moreover, the lower amplitude of the harmonics at minimum γ what leads to smaller filters and lower losses [14][16]. In practice, the minimum value of the extinction angle γ is limited to about 12^o. However, this is not the minimal physical extinction angle as some safety margin is added. The period of time, which is expressed in degrees as γ_{min} is required to ensure the forward blocking of the thyristors before the next firing is done. The lower value of extinction angle γ can lead to commutation failure caused by unsuccessful forward blocking [25][13]. The angle of negative slope E-F in figure 2.6 changes depending on the strength of an AC network to which an inverter is connected. The weaker the network, the more negative the slop is.

After combining current - voltage characteristics for the rectifier and inverter, the main I_d/U_d characteristic for the system is represented in figure 2.6. Nevertheless, it should be noted that this combined characteristic does not include some of the control functions which influence its shape and operation of the system. These functions are explained in following chapters.

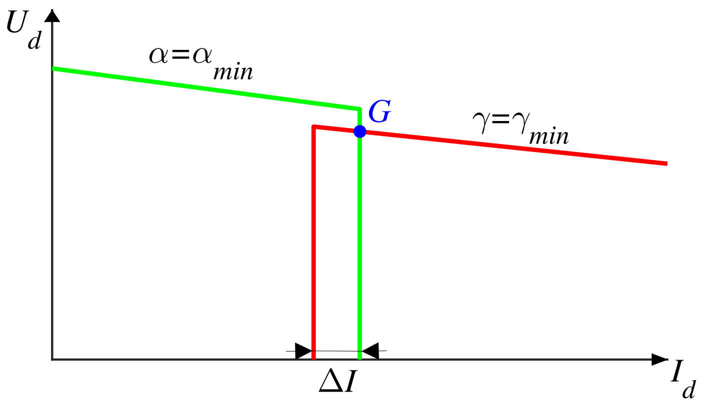


Figure 2.6: Rectifier and inverter direct current - voltage characteristics

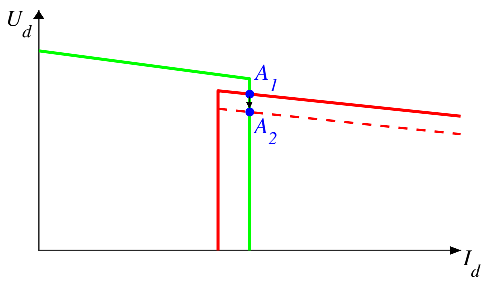
As it was mentioned before, during the normal operation, it is preferred to operate rectifier in the current control mode and inverter in γ_{min} control mode. For this reason, current margin is introduced by setting 10 % lower current order for the inverter than for the rectifier [26]. In such a case, the inverter tries to reduce the current by lowering its extinction angle γ thereby voltage, until the minimum value of γ is reached. This way the inverter is forced to operate at γ_{min} control and it sets the DC voltage while rectifier operates in a current control mode where firing angle α is controlled according to the DC voltage to keep the current reference. In such way, a stable operating point is achieved 2.6).

Co-operation of the converters during disturbances

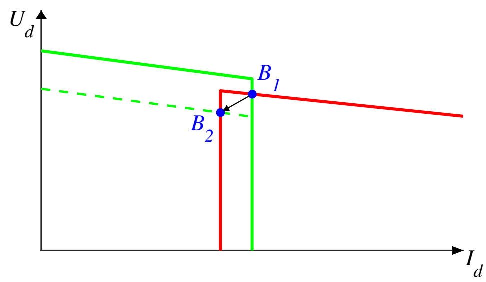
Similarly to the co-operation in the steady state, during a disturbance in the AC side converter stations will try to adjust itself to reach a new stable operating point.

In the case of reduced voltage on the inverter side, the DC voltage U_d will decrease according to 2.5 as U_{di0} is directly proportional to the AC voltage and γ is at its limit. The rectifier, which operating in the current control mode, will react to the change in U_d by increasing firing angle α to maintain direct current at ordered value. This way the system will be shifted from operation in point A_1 to a new stable point A_2 as it is shown in figure 2.7a.

If AC voltage drop appears at the rectifier side, the inverter will respond. During the disturbance, the rectifier I_d/U_d characteristic will shift down as it is shown in figure 2.7b with the dotted line. As direct current is reduced, the inverter will increase its extinction angle γ to bring down the voltage U_d at the inverter side. As a result, DC current I_d will become equal to the ordered current for the inverter and it will take over the current control. The operating point will move from point B_1 to B_2 in figure 2.7b.



(a)



(b)

Figure 2.7: AC voltage drop at the (a) inverter side and (b) rectifier side

2.6 The control system of HVDC

As it was mentioned before, one of the main HVDC advantages over the HVAC is fast and accurate power transfer regulation. However, to achieve this a complex control system is required with many sub and main functions operating in the prioritized sequential order. Overall, the main requirements for the HVDC control system are [18][13]:

- Symmetrical firing of the valves during steady state operation
- Fast control response to various disturbances and changes in the power order
- Stable operation during transient events on AC or DC side
- Reduced number of commutation failure during disturbances
- Ability to operate without telecommunication
- Minimum consumption of reactive power

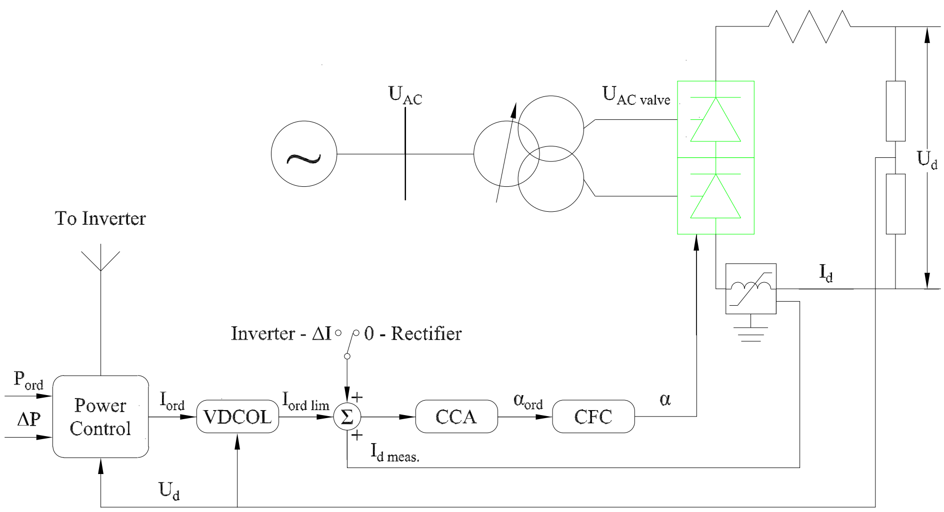


Figure 2.8: The basic overview of control system in the rectifier

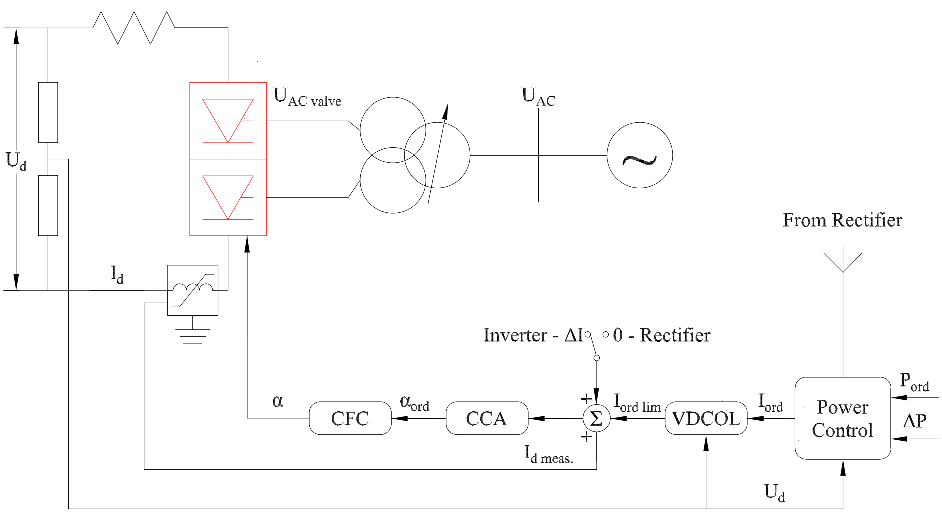


Figure 2.9: The basic overview of control system in the inverter

Generally, all converters are controlled by changing thyristor firing/delay angle α as it is mentioned in section 2.4. The simplified structure of the controls for rectifier and inverter are represented in figures 2.8 and 2.9, respectively.

In the steady state, the HVDC system is operating in power control where the operator of the system sets a power order P_{ord}. The control sequence starts in the power controller, which calculates the current order I_{ord} according to P_{ord} and measured voltage U_d. The calculated value of I_{ord} is sent to the Voltage Dependent Current Order Limiter (VDCOL) and into the Current Control Amplifier (CCA). During the normal operation, the VDCOL function is not active as operating voltage is around nominal value and the current order is not affected. The CCA is a regular Proportional-Integral (PI) regulator which compares ordered current from the power controller with measured and according to the error a firing angle α is calculated. Finally, calculated value α_{ord} goes to converter firing controller, which generates firing pulses for the converter.

Typically, all the converter stations are equipped with the same control systems, but depending on the operation (rectifier or inverter) some of sub-functions are deactivated or work differently. In such way, the HVDC is able to transmit power in both directions as the converters can be operated as rectifier or inverter. During the normal operation, rectifier operates in constant current mode, while the inverter operates in constant voltage or constant extinction angle control mode [27].

In general, the firing angle and firing instants are calculated in Converter Firing Control (CFC) which can be divided into three main groups:

1. Current control
2. Voltage control
3. Firing control

These three groups include different sub functions (VDCOL, CCA, Constant Beta Control), which are needed to achieve proper dynamics of the HVDC for the stable operation and during various disturbances.

2.7 Current Control

2.7.1 Voltage Dependent Current Order Limiter (VDCOL)

The voltage dependent current order limiter is one of the main sub-functions of the converter controls during transient events. The objective of VDCOL is to reduce the current order, thus lower the demand of reactive power on the AC side when DC voltage drops below a certain value and help the system to recover [25]. For example, if the HVDC system is operating in the control mode of constant power, it will try to keep the power order. During DC or severe AC faults, the DC voltage will go down, therefore the control system will try to compensate this drop by increasing current. However, these changes in current and voltage will lead to increased consumption of reactive power what will make the AC voltage to go down even more. All these actions can lead to [28]:

- Instabilities in the AC voltage
- Commutation failure
- Long recoveries after disturbances
- Increased stress for the thyristors during commutation failure

Depending on the DC voltage, the current order from the CCA will be limited according to the VDCOL characteristics which are represented in figure 2.10. As can be seen in figure 2.10a, there are minimum and maximum limitations for the current order, I_dMIN and I_dMAX respectively. The minimum limit is set to about 0.08 - 0.1 p.u. in order to prevent converter operation in a discontinuous current mode and the maximum limit is set according to overloading limitations for the valves [28] [29]. When the DC voltage reduces below a certain value of U_dHigh, the maximum current order decreases. This dropping slope continues until the point of U_dLow is reached and the steepness of this slop depends on the gain in the current control loop of the VDCOL. From there, current order is limited to 0.3 p.u. ($I_{d\ lim}$) in order to minimize the stress for the valves [29].

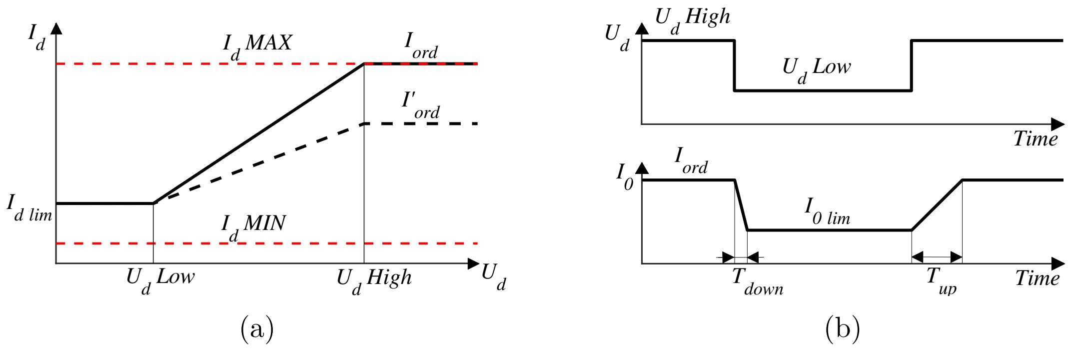


Figure 2.10: VDCOL characteristics: (a) Steady-state (b) Dynamic

The value of U_dHigh is limited by the AC network. If the AC network is strong, the U_dHigh limit can be lower and vice versa. Furthermore, the limit of I_dMIN can be reduced below 0.1 p.u. for the special cases [28]. However, this will lead to longer recovery time as the current order in the current control amplifier will be low.

Additionally, a low pass filter is included in the VDCOL function which has different settings for specific situation (figure 2.10b). In a case when a fault occurs and the DC voltage drops, the time constant of the filter is set to a low value in order to have a fast response of the system and prevent commutation failures. Additionally, the inverter should have the same or faster down time in comparison with the rectifier to maintain the current margin. After a fault is cleared and DC voltage is recovered, the current order should be reset to the pre-fault value. In this case, rectifier has to restore its order faster than inverter to keep the current margin. Moreover, up time T_{up} for the current order during recovery no need to be as fast as down time T_{down} so time constants for both stations are higher. This gives smooth recovery of the system [18][25][29].

The time constants T_{up} and T_{down}, the limits $U_d High$ and $U_d Low$, the current limit $I_{0\ lim}$ have to be tuned specifically for each project as these variables directly affect the VDCOL interaction, recovery time and system dynamics. A bigger difference of T_{up} times between the stations will create a higher voltage difference thus higher current and this would lead to faster recovery. However, increased current will increase the reactive power consumption and if an AC network is not strong enough the system can collapse. Similarly, if $U_d High$ value, according to which the VDCOL is activated will be too low or $I_{d\ lim}$ too high, the network can collapse as well.

2.7.2 Current Control Amplifier (CCA)

After current order passes the VDCOL, it is fed into the current control amplifier as it can be seen in figures 2.8 and 2.9. In general, CCA is a close loop Proportional - Integral (PI) regulator. The main block diagram of the CCA is shown in figure 2.11.

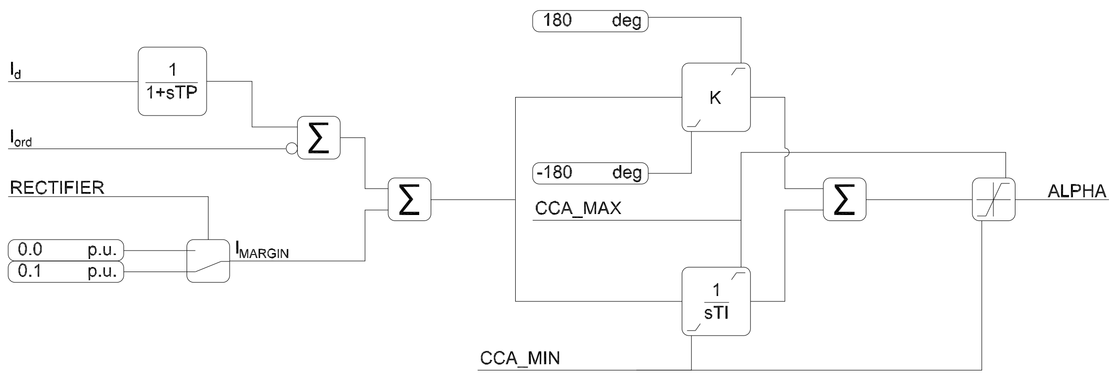


Figure 2.11: Block diagram of the CCA

As the inputs, ordered current reference I_{ord} from the power controller and measured direct current I_d are used. The CCA compares both inputs to calculate the error, which is used in PI regulator to generate a firing angle α. So that a proper dynamics of the system would be achieved, the CCA must fulfill these main requirements [28]:

- Quick reaction to transient events with a step response
- Stable current regulation with minimum overshoots
- During normal operation, keep zero error between I_{ord} and I_d (for the rectifier)
- Be able to quickly reduce the increased current during faults
- Ability to operate as rectifier and inverter

To do this, proper design and tuning for CCA is needed. The fast response is achieved by proportional part of the PI regulator. The gain value K of the regulator must be such that the regulator would be fast, but at the same time remain stable. Too high gain would result in a large change in output for a small error and instabilities, while too small gain would lead to a slow system response. During the normal operation, the zero error of the CCA is accomplished by the integral part of the PI regulator, which is slow. However, it also has to be tuned properly as an inappropriate gain of integral part can lead to unstable operation.

Additionally, the minimum and maximum limits are included for the CCA regulator. Figures 2.12 and 2.13 represent how these limits are determined for each station. The upper limit in the rectifier is set by the constant beta control function which is described in section 2.9.1 and the lower limit by the Voltage Regulator (VCAREG), which is described in the next section. Typically, as the rectifier operates in the current control, none of the CCA limits are reached in the steady state. However, during some disturbances, the lower limit can be increased by a Rectifier ALPHA Minumum Limiter (RAML) which is described further in the project [28].

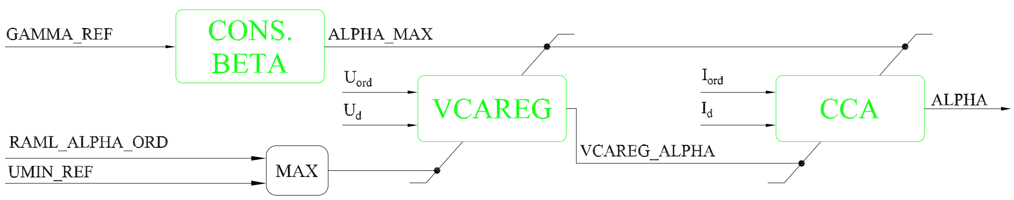


Figure 2.12: Rectifier control sequence

In the inverter, the upper limit for the CCA is determined by the VCAREG which itself is limited by the constant beta controller. The reason for such structure is to have a secondary control of the VCAREG, but in the steady state operate at the constant beta control by adding the current margin and forcing the CCA to its maximum value. The lower limit in the inverter is set to 110^o. Moreover, the CCA is also equipped with a low pass filter for the measured current I_d in order to reduce harmonics on the AC side [28].

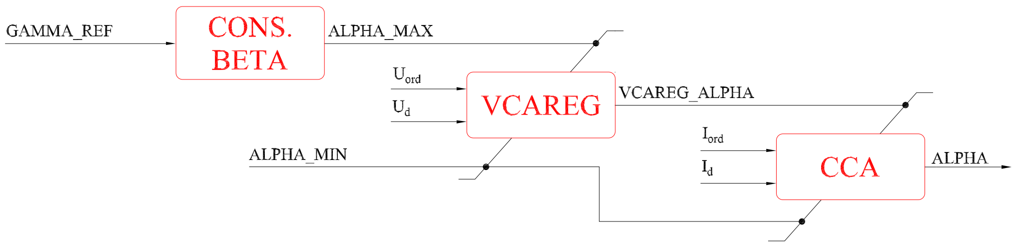


Figure 2.13: Inverter control sequence

2.8 Voltage Control

2.8.1 Voltage Regulator (VCAREG)

The voltage regulator, as all other regulators, is implemented in both rectifier and inverter controls, but depending on the station, its logic and output differs. The controller itself consists of a PI-regulator and a limiter with variable limits depending on the mode of operation.

The main inputs of the VCAREG are measured and ordered voltages, U_d and $U_{d\ ord}$ respectively. The difference of these inputs goes to the PI-regulator whose proportional and integral gains have to be tuned accordingly in order to achieve proper dynamics of the regulator. Depending on the terminal, the voltage difference changes its sign to get a correct response of the controls.

In the normal operation of the system, the ordered value of voltage is set above the operating voltage in order to prevent the VCAREG and tap changer control interaction with each other. Typically, this difference is approximately equal to one step of the tap changer. Keeping the ordered value of the voltage close to the measured, VCAREG is able to quickly react to the rapid increases in DC voltage. Furthermore, in most of the cases the ordered value of the DC voltage in the rectifier is higher than in inverter. In such a case, the voltage control is kept in the inverter. However, for the particular events, the voltage control could be shifted from the inverter to the rectifier. This particular control mode was implemented in the analyzed system and its detail description is represented in sections 3.4.

The output of the PI-regulator then has to pass the limiter. During the normal operation, the output of the constant beta regulator, which is discussed in section 2.9.1, set the upper limit and the lower limit is the minimum firing angle. For the inverter it is 110^o and for the rectifier 5^o. In the case of low or no current flowing in the system, an overvoltage limiter will be activated which will set new limits for the VCAREG output in order to limit the DC voltage in the system. The DC voltage calculation, when no current is flowing, is done according to the 2.7. By rearranging it, new upper and lower limits for the limiter are calculated using 2.8. Without this sub-function a high overshoot of voltage will occur. A block diagram of the VCAREG function is represented in figure 2.14 [28].

$$U_d = U_{di0} \cdot \cos\alpha \tag{2.7}$$

$$\alpha = acos\left(\frac{U_d}{U_{di0}}\right) \tag{2.8}$$

The VCAREG output is expressed in degrees and it is used as the upper limit in the rectifier controls or lower limit in the inverter controls for the CCA. The general view of the VCAREG in HVDC controls can be seen in figures 2.12 and 2.13.

In general, the DC voltage reference in the rectifier station is set to a value which is approximately by $0.1p.u.$ higher than nominal voltage in the system. This way, no contribution from the VCAREG is done to the CCA controller and the rectifier operates in the current control. In the inverter, the voltage reference is lower than in rectifier, but still higher than nominal value (approximately $1.03p.u.$). As a result, the VCAREG works as the secondary control during disturbances and otherwise it do not affect the operation of the CCA [28].

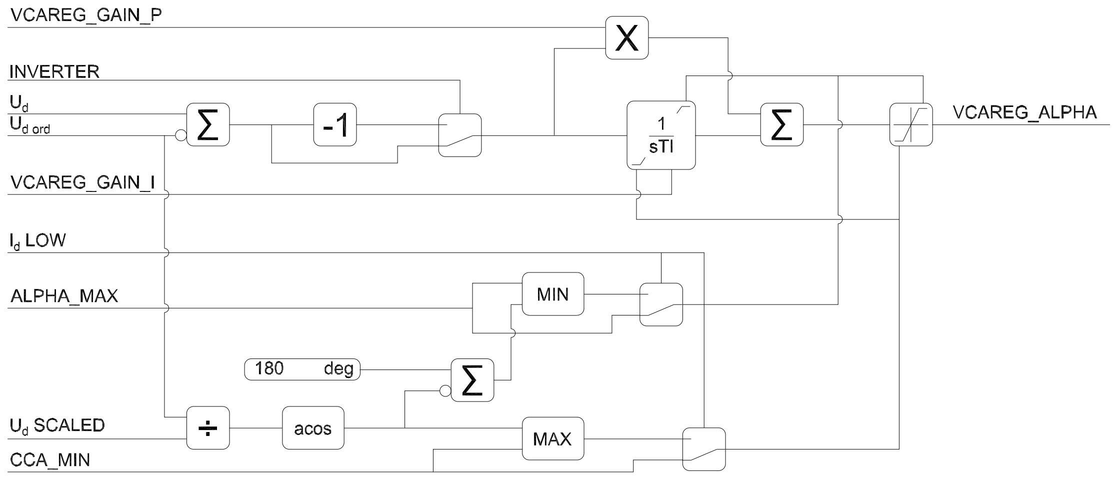


Figure 2.14: Block diagram of the VCAREG

2.9 Firing Control

2.9.1 Constant Beta Control

According to 2.9 and figure 2.6, it can be seen that by increasing direct current in the system, DC voltage will drop when γ is kept constant. In other words, an inverter acts as a negative resistance. With increased direct current, the consumption of reactive power rises and if the AC network at the inverter side is weak, the change in reactive power is seen as a reduction in the U_{di0} term. As a consequence, the counter voltage of the inverter goes down even more and a potentially unstable situation may develop [28].

$$U_d = U_{di0}\cos\gamma - (d_x - d_r)\left(\frac{I_0}{I_{dN}}\frac{U_{di0N}}{I_{dN}}\right) \tag{2.9}$$

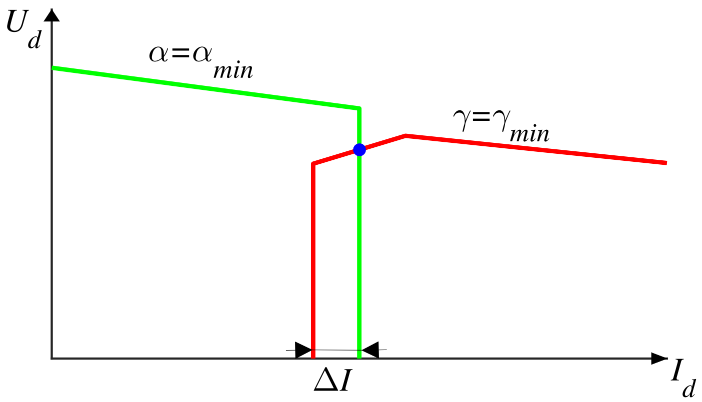


Figure 2.15: Rectifier and inverter direct current - voltage characteristics with constant β angle control

In order to increase the stability of the system, a positive slope of the constant beta control is introduced to the I_d/U_d characteristic of the inverter as it is shown in figure 2.15. This is done by operating the inverter at a constant value of firing angle α and because of that the dynamic resistance instead of being negative becomes positive. In such a case, the direct voltage of the inverter can be calculated as follows:

$$U_d = \frac{1}{2}U_{di0}(\cos\gamma + \cos(\gamma+\mu)) \tag{2.10}$$

As the inverter DC voltage is expressed using γ, a new term of angle β is introduced which represents a constant sum of the extinction and the overlap angles.

$$\beta = \gamma + \mu \tag{2.11}$$

$$\beta = \cos^{-1}\left(\cos\gamma - 2d_x\frac{I_0}{I_{dN}}\frac{U_{di0N}}{U_{di0}}\right) \tag{2.12}$$

To achieve a stable operation of the system with a proper response, an extra input of the difference between ordered and measured current is added to the final equation of the value of constant angle β:

$$\beta = \cos^{-1}\left(\cos\gamma - 2d_x\frac{I_0}{I_{dN}}\frac{U_{di0N}}{U_{di0}} - K(I_0 - I_d)\right) \tag{2.13}$$

The final inverter firing angle α_{inv} , which is sent into converter firing controls, is calculated as follows:

$$\alpha_{inv} = 180^o - \beta \tag{2.14}$$

The figure 2.15 also shows that the positive slope of the constant beta control is limited at the point where the current is equal to the ordered value minus current margin. At this point, the control mode of the inverter is shifted from the constant beta to the current control in the inverter.

The simplified block diagram of the constant beta inverter control is represented in figure 2.16. The gain factor K and a time constant in the controls are tuned accordingly for different systems to achieve the best performances.

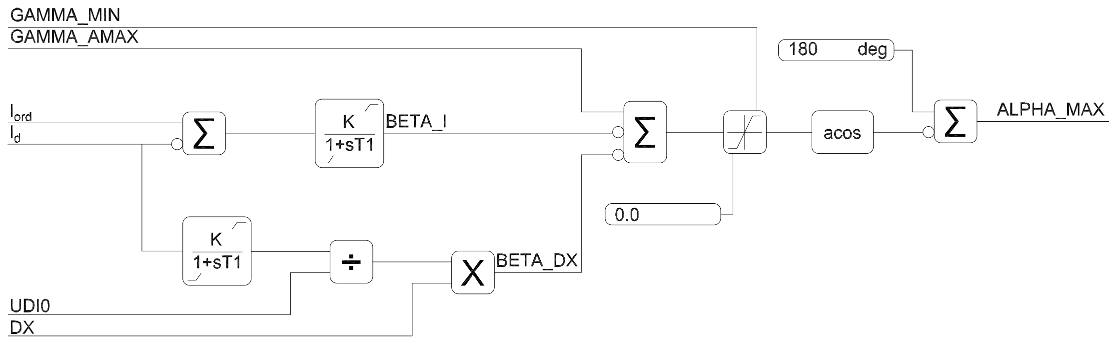


Figure 2.16: Block diagram of the constant beta inverter control

The direct current - voltage characteristic for the multi-terminal HVDC with one rectifier and two inverters is shown in figure 2.17. In this figure, two blue dotted lines represent I_d/U_d characteristics for each inverter separately and the red curve shows the combined characteristic for both inverters. The operation point of the system is marked with the blue dot.

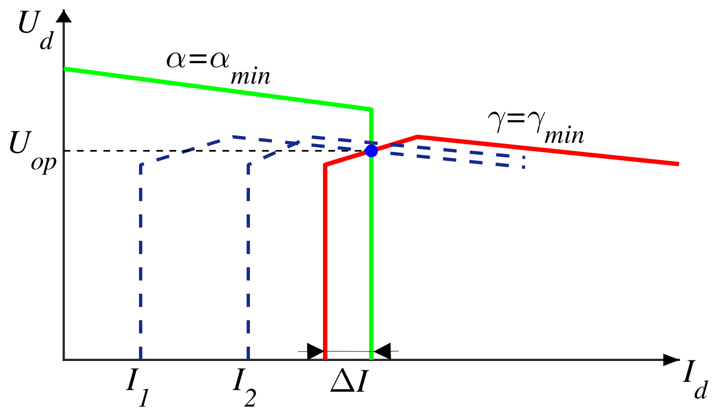


Figure 2.17: Multi-terminal HVDC with one rectifier and two inverters direct current - voltage characteristics

2.9.2 Rectifier Alpha Min Limiter (RAML)

The rectifier alpha min limiter is one of sub-function in the converter firing controls. Its task is to increase the firing angle α for the rectifier during AC faults at the rectifier side.

When the system experiences an AC fault on the rectifier side, the AC voltage will decline and as a result of this the rectifier controls will drop the firing angle to its minimum value α_{min}. However, after the fault ends and the AC voltage recovers, the low value of alpha will result in highly increased DC voltage. Therefore, the RAML function is implemented in the controls which tracks the AC voltage and if a reduction in voltage below a certain value is detected, the minimum limit of alpha for the CCA is increased [28].

The contribution of the RAML is illustrated in figure 2.12. The function has two parallel detection systems for single phase and three faults and according to a fault type a different minimum limit of α is activated.

2.10 Tap Changer Control

In HVDC systems, all the converter transformers are equipped with tap changers. The main function of the tap changers is to keep the firing angle, extinction angle and DC voltage close to the default values by tapping and changing U_{di0} (2.4 and 2.6).

As it was mentioned in section 2.5.2, the minimum reactive power consumption of the system is achieved when converter stations are operating at the minimum firing angle α or extinction angle γ (rectifier and inverter respectively). However, during the disturbances in the AC system or varying the amount of transmitted power, the values of these angles will change. For example, if the AC voltage in the rectifier increases, the DC voltage will increase as well. The rectifier control system will react to this change by increasing the firing angle α and thus the consumption of reactive power will increase. Similarly, if the voltage on the AC side decreases, the controls of the system will decrease the firing angle. As a result, the operation at minimum α without any margin can be reached therefore the rectifier capabilities in response to the specific disturbances will be limited as there will not be possible to reduce the firing angle any further. Moreover, the system might shift from the constant beta control to the voltage control mode, which is not optimal for continues operation. Using the tap changers, the firing angle, extinction angle, thus direct voltage can be brought back close to the default values depending on changes in transmitted power or during the disturbances in the AC system.

However, during the normal operation the AC voltage is not stable and continuously slightly deviates. In order to make the tap changers insensitive to such fluctuations and avoid hunting, a dead band in tap changer range and specific step have to be designed. Typically, the range of the tap changer is about ±15 % of nominal voltage with a step between 1% and 1.3% or ±2.5 degrees for α and ±1.5 degrees for γ depending on the control mode [16].

As tap changer is a mechanical device, the speed of it is considerably slower than the converter firing controls. This means that both systems can be operated without unsuitable interactions [16].

2.11 Telecommunication

In order to maintain HVDC system stable and responsive to any kind of transient events, fast telecommunication between converter stations is needed. In the case of back-to-back HVDC links, this is not a problem as terminals are located very close to each other, usually several meters. However, in most of the cases, converter stations are situated in different areas and distance between them can be more than 2000 km (Rio Madeira transmission link, Brazil [30]). Consequently, not only fast communication system is required, but also redundant as the probability of mechanical damage and telecommunication failures increase with distance.

As it was mentioned before, the actions of HVDC system are coordinated between converter stations. In such way safe margins of current for the constant beta control and proper response during transient events is achieved.

For example, simultaneous changes in converter stations should be made by the system control depending on a new current order. In the case of a reduced current order, inverter controls should be activated before rectifier and if current order is increased vice versa. This is done in order to maintain the current margin. If the new order of reduced current is set in the rectifier station, firstly, this command is transmitted to the inverter station. There, current order is reduced and at the same time signal of completed control action is sent back to the rectifier, which consequently changes its current order. Similarly, in the situation when current order has to be increased, rectifier takes action first and the same time, signal to inverter is sent. After a certain time delay, inverter control system sets a new current order. With such simultaneous interaction between converter stations, current margin never drops below a certain value. During a change in the current order, it is even temporary increased and after it, the margin gets back to the original value. This way, HVDC system stability is improved [13].

As the HVDC system developed, extra features for power transferring were introduced. For instance, frequency control, oscillation damping, etc. For all this extra functionality, the importance of fast and reliable telecommunication increased even more.

In the multi-terminal HVDC system continues communication is even more important. As it was mentioned in section 2.3, the total sum of current orders at all rectifiers should be equal to the sum of current orders at the inverters plus the current margin. If, for some reason, one of the inverters will be lost and rectifiers will continue to operate with the same current order, other inverters will be overloaded. In the case of rectifier loss, all the system might collapse [23].

In general, these are the main advantages of telecommunication in HVDC systems [13]:

- Fast and accurate power control
- Automated control strategy from one control center
- Availability of new features like frequency control of an AC network or oscillation damping
- Fast response to transient events
- Quick response to converter loss in multi-terminal HVDC system

In addition, all converter stations have a local memory where transmitted values are stored. In such way, during telecommunication interruptions the last stored values are used by converter controls to keep the stable operation of the system [13].

During development of HVDC systems, different methods for telecommunication were used. In early projects microwave or HF radio links, different types of wires, rendered telephone lines, etc. were used for commutation between terminal [31]. However, some of them were too slow for simultaneous operation while others had frequent failures or was interfered by external influence (electromagnetic fields, atmospheric noise, etc.) [14][31].

Nowadays, optical-fiber cables are mainly used in HVDC systems due to several reasons. First of all, information in optical-fiber cables are transmitted using light in digital format. This gives a very high speed over long distances (two thirds of the speed of light in vacuum or 2 Mbit/s). Secondly, such cables have higher bandwidth what means that the same size cable can transmit considerably more information in comparison with other cables. Thirdly, the signal is not affected by electromagnetic fields because of the method how information is transmitted. As a result, optical-fiber cables can be integrated into energy cable, ground wire or overhead line depending on specific project [13][32].

In order to make a telecommunication system of HVDC more reliable back-up communication links are used. Both systems are physically independent in order to minimize the risk of telecom failures. Nevertheless, one of the requirements for the HVDC is that the system would be able to operate without telecommunication [14].

3

Improvements of the MTDC Controls

3.1 The Main Parameters of the System

The simulations were carried out using the monopole multi-terminal LCC HVDC system with one rectifier and two inverters connected in parallel. The basic structure of the model used in the simulations is represented in figure 3.1 and the main parameters are shown in table 3.1.

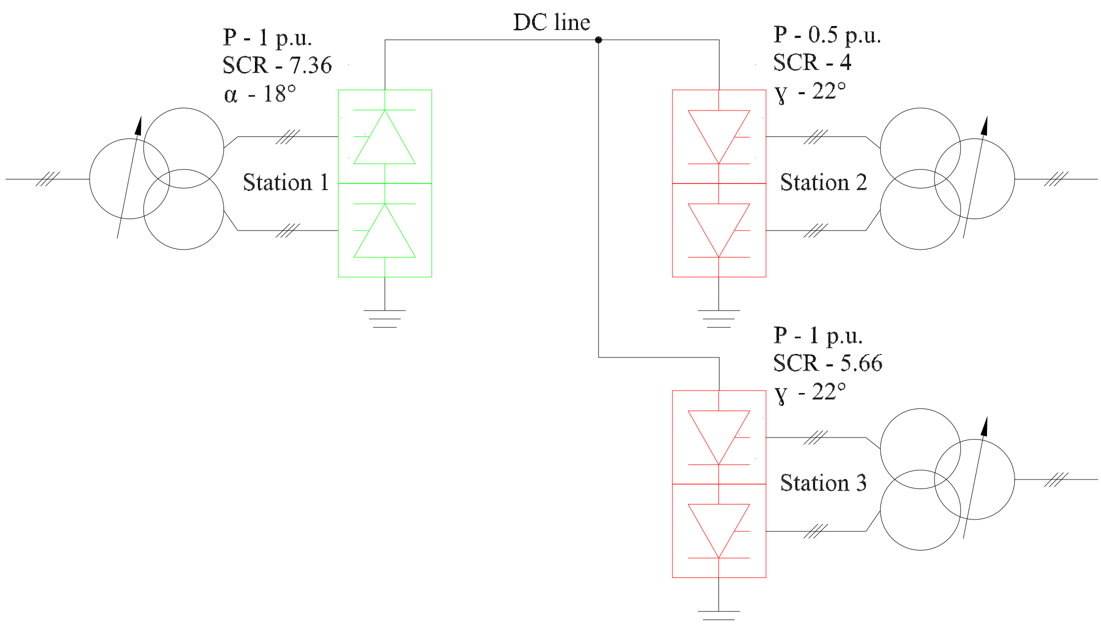


Figure 3.1: Basic structure of the simulation model

Table 3.1: Parameters of the system

Parameter	**Station 1**	**Station 2**	**Station 3**
Operation mode	Rectifier	Inverter	Inverter
Configuration		Monopole	
DC transmission link		Overhead line	
DC resistance from S1 to S2 [p.u.]		0.0402	
DC resistance from S2 to S3 [p.u.]			0.0435
Rated power [p.u.]	1	0.5	1
Rated current [p.u.]	1	0.5	1
Nominal firing angle α	15^o	-	-
Minimum firing angle α	5^o	110^o	110^o
Nominal extinction angle γ	18^o	22^o	18^o
Minimum extinction angle γ	12^o	12^o	12^o
d_x [p.u.]	0.078	0.0685	0.078
SCR of the AC network	7.36	4	5.66

3.2 Operation with Telecommunication

The operation of the multi-terminal HVDC system in the constant beta control requires an extra control strategy in comparison with a regular two terminal system, in order to maintain the current margin stability of the system. For this purpose, a current sharing control for ordered current re-calculation is introduced whose block diagram is shown in figure 3.2.

First of all, the nominal current IdN of each station is divided by the nominal current of the leading rectifier. After this, the current order I_ORD of the each station is multiplied by the calculated scale factors of that converter.

Lastly, the final scaling factors $I0\_SCALE$ for each station are calculated. For two converter station, which are not leading, it is done by dividing their current proportion by the leading rectifier current proportion, while for the main rectifier the factor is set to one.

Similar to a case of a point-to-point HVDC, the inverters get the current order from the leading rectifier using telecommunication. Consequently, in the controls of each inverter, this current order is multiplied by the scale factor of the station to calculate the final current order used in the inverter controls. Such way, the current supplied by the rectifier is shared between two inverters.

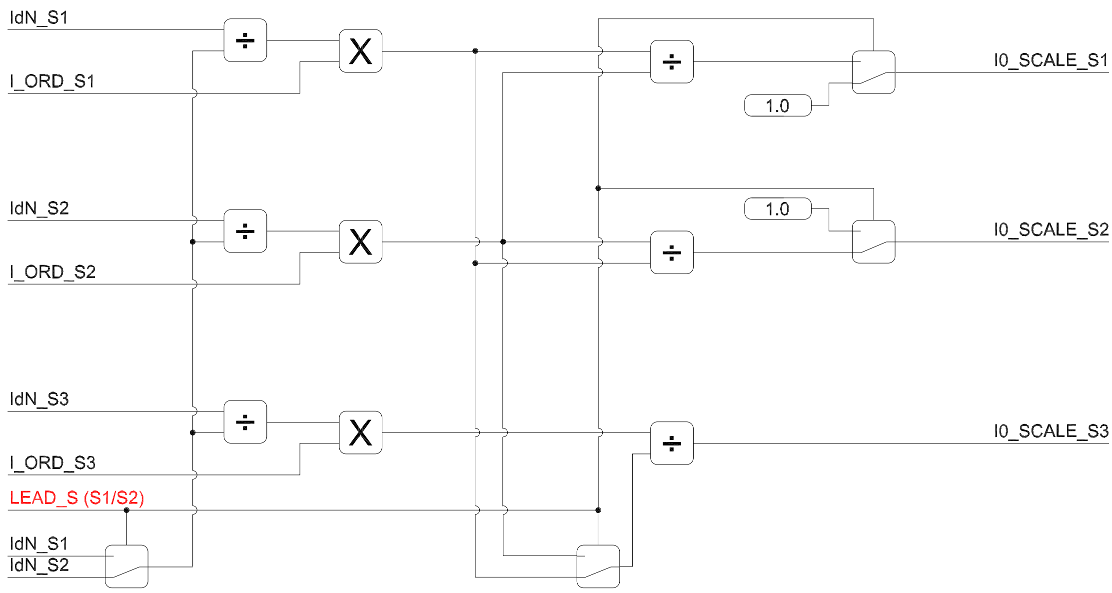


Figure 3.2: A block diagram for the current sharing control of the system

With such current sharing control strategy implemented, the system is able to operate in the constant beta angle control, keep the margin and withstand different types of disturbances. However, this current sharing control requires continuous communication between the stations.

3.3 Operation without Telecommunication

The loss of the telecommunication for the multi-terminal HVDC can lead to instabilities or even the system collapse, especially during transient events. In a case of point-to-point HVDC, the inverter, which is operating in the constant beta control using the current order from the rectifier, can measure locally the actual current sent by the rectifier. Using this locally measured current, the inverter can continue to operate in the constant beta control even without telecommunication.

Contrary, in the parallel MTDC HVDC system, each inverter can only measure its own DC current, but not the total current sent by the rectifier. If a malfunction of the telecommunication occurs, the system can continue to operate using the current orders stored in the memory since the time when the telecom was available. However, such operation is very limited and can lead to stability problems. For instance, as expression 2.1 shows, the sum of currents should be equal to zero. Since the rectifier is operating in current control, the inverters have to take all the DC current sent by the rectifier. If a change in the rectifier current order is done, the total current in the system will change and as a result, the current in each inverter decrease or increase depending on the change. Consequently, the controls in the inverters will react and try to keep its current order, but as the stations can only control the proportion of the total current they are getting, the inverters will start to fight with each other and unstable situation can develop. Furthermore, in a case when one of the inverters is lost, the remaining inverter can be overloaded. For example, a fault occurs at one of the inverters, which is eventually disconnected. Since the rectifier is operating in current control, it cannot detect the loss of the station. Consequently, it recovers with pre-fault current order what leads to the overload of the remaining inverter which can damage the equipment in the station or cause a system collapse. Therefore, a different control strategy is needed to achieve a stable operation for operation without telecommunication.

The idea proposed by this project is that the rectifier would shift from current control to voltage control and the inverters would move from the constant beta control to current control when telecommunication is lost. In such a way, each inverter would be able to control its current, while the rectifier would keep the voltage at nominal value. If one of the stations would be disconnected, the rectifier, based on changes in locally measured current, will be able to detect the loss of a station and if needed update its current order. The operation of rectifier in voltage control and inverters in current control will be active until the telecommunication will be restored. The changes for the controls, which are needed to change the control modes in the stations, are described in the next section. Additionally, the possibilities to use a RETARD function during disturbances, which restarts an HVDC system, are investigated and discussed further in the project.

3.4 Rectifier Voltage Control (RVC)

As mentioned in section 2.8.1, during the normal operation, the rectifier is controlling the current and the VCAREG does not have any contribution. In order to shift the rectifier to voltage control, two main changes have to be done in the controls:

1. Reduce the voltage reference in the rectifier to $1p.u.$
2. Shift the current margin from inverters to the rectifier

By reducing the voltage reference in the VCAREG, the output from the regulator is no longer forced to its minimum value, contrary, VCAREG tries to keep the voltage at 1 p.u. by setting the firing angle accordingly.

In order to fully activate the voltage control in the rectifier, the final firing angle of the valves should be equal to the value from the VCAREG. To achieve this, the CCA should be forced to operate at its minimum limit (VCAREG output) and this is done by introducing the margin to the rectifier similarly as it is done for the inverters when CCA is forced to operate at its maximum limit for the constant beta operation. This way, the output from the VCAREG will bypass the CCA and rectifier will operate in the voltage control mode.

Furthermore, the same time as margin is added to the rectifier it should be taken out from the inverters as now they are controlling the current. Additionally, the VCAREG, which is used in the controls, are tuned to operate more like a slow limiter than like a real voltage regulator. As a result, it is needed to increase the gain in the VCAREG to get faster and more accurate response from the regulator. Based on simulation results, the gain in the VCAREG was increased by four times during the operation without telecommunication. The I_d/U_d characteristic for the multi-terminal HVDC system is represented in figure 3.3.

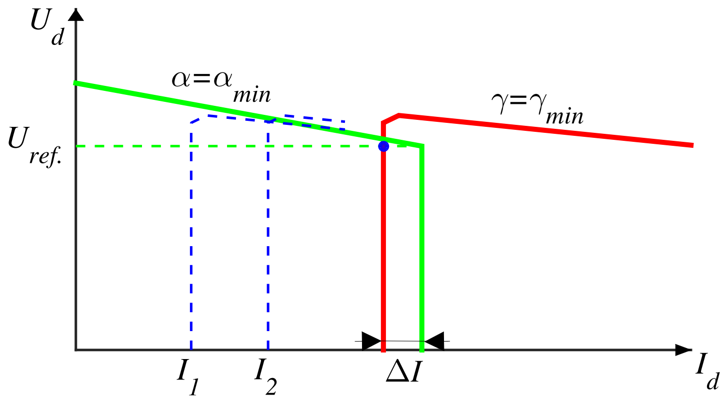


Figure 3.3: Direct current - voltage characteristics of rectifier operating in voltage control and inverters in current control.

The I_1 and I_2 in figure 3.3 represents different current references for the inverters. By adding I_d/U_d characteristics of two inverters (the dotted blue lines), the combined characteristic is represented by the red curve. The rectifier current - voltage characteristic is represented by the green curve. Changing the current in the system, the operating point will move along the horizontal dotted line, which represents the constant voltage control mode in the rectifier.

The main advantage of such mode during loss of telecom is that inverters are able to control their current depending on the power reference, while the rectifier is controlling the DC voltage. If one of the inverters is tripped, the total current becomes equal to the current of the remaining inverter.

However, an operation mode when current control is done in the inverters has one main disadvantage, a limited control margin. As table 3.1 shows, The minimum firing angle for the rectifier is 5^o, the maximum is 100^o and α during the normal operation is around 15^o. The control range if the rectifier is operating in the current control, then is: $5^o \leq 15^o \leq 100^o$. Meanwhile, the minimum extinction angle for the inverters is 12^o and their nominal operating angles are 22^o and 18^o, respectively. The maximum extinction angles are 90^o minus the overlap so the total control range for the current is: $12^o \leq 18^o/22^o \leq 90^o - \mu$. From this relationship, it is visible that the lower limit for the second inverter is only 6^o, while the lower limit for the rectifier is 10^o. For this reason, the current control during the normal operation with telecommunication is done in the inverters.

In addition to the changes for the current margin and the voltage reference, a few other improvements were done for the controls to get a proper dynamic response of the system during the disturbances or transient events. These improvements are discussed in the following sections.

3.4.1 Operation with Reduced Nominal Extinction Angle

As it was mentioned in the previous section, the inverters have the smaller margin of the current control, especially the second inverter which can reduce its extinction angle only by 6^o. During the simulations it was noticed that for specific cases, the second inverter was reaching its upper limit of the CCA. That means that the converter station was no longer in the current control. As it is shown in figure 2.13, the reference value of γ has a direct effect to the constant beta calculations and this leads to the smaller range for the CCA operation. In order to keep the inverter in the current control, the upper limit of the CCA should be increased by decreasing the nominal value of the extinction angle γ in the inverters.

The control logic of this function consists of two blocks: "&" and a switch. The block "&" has two inputs and it is generating a positive signal when station operates as an inverter and it is in the current control mode. When the triggering signal is activated, the reference value of γ is reduced to 12^o. The effect of this change is represented in section 4.2.7.

3.4.2 Reduced Voltage Recovery

Depending on the strength of AC network to which the stations are connected, the reduced voltage recovery can be needed in order to avoid repetitive commutation failures. During the simulations of the system when the rectifier was operating in voltage control and both inverters in current control, it was noticed that if an AC fault was applied at the second station, often, the second commutation failure appeared. As the system was operating without the telecom, the rectifier is not able to identify the faulted station. Consequently, the recovery with reduced voltage is activated for all the cases when a voltage drop is detected.

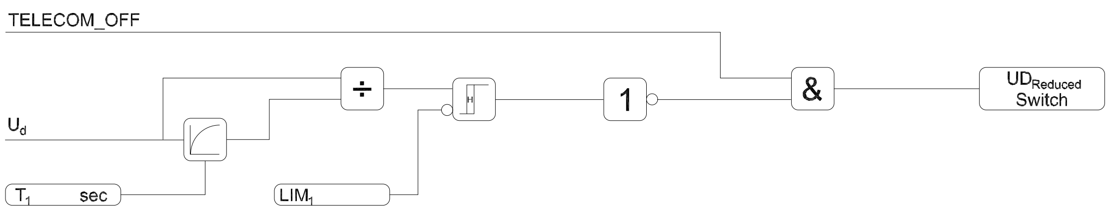


Figure 3.4: A block diagram for the reduced voltage recovery activation

The main block diagram of the function is represented in figure 3.4. The logic consists of three main parts: detection, triggering and changer of the voltage reference.

The basic principle of the detector is to notice a voltage drop in the system as in the parallel connected MTDC, the DC voltage should be the same in all situations if voltage drop over the overhead lines is neglected. In the detector, the measured direct voltage is passed through a low pass filter with slow gain T_1 to limit its sensitivity for small voltage fluctuations. The filtered voltage then is compared with not filtered DC voltage and the ratio is sent to a comparator. If the first input of the comparator drops below the limit LIM_1, an activation signal is generated. By tuning the time constant of low pass filter and the detection limit, different sensitivity and activation times for the reduced voltage recovery can be achieved. In this project, the time constant T_1 was set to one second and the limit LIM_1 to $0.8p.u.$ based on the system dynamics during different disturbances.

The triggering part consists of control block "&" with two inputs. To get a positive output the "&" should get the positive signal from the comparator and a signal that telecom is not available.

Finally, if a positive signal from the "& block is generated", the voltage reference is changed from $1p.u.$ to $0.9p.u.$ and it is done instantaneously. When the voltage in the system recovers to a certain value and triggering signal becomes negative, the voltage reference is set back to $1p.u.$. However, as some of the results showed (section 4.2.8), instant or too fast change in the voltage reference from reduced to nominal value can lead to repetitive commutation failures. In order to avoid such effects and smoothen the transition, a low pass filter is introduced, which is active only when voltage reference shifts back from $0.9p.u.$ to $1p.u.$. The time constant for this low pass filter is set to $0.2s$ based on different simulations. The lower constant can lead to repetitive commutation failures, while the slower gives unnecessary long operation with reduced voltage as it is further represented in the project.

3.4.3 Current Order Limiter

The third sub-function which was implemented consists of two parts, a current order limiter and a logic which switches the current order from the power controller to locally measured current. The function can be activated only in the rectifier. The main purpose of these sub-functions is to limit the current order in the rectifier if one of the inverters is tripped.

For instance, even when the rectifier is controlling the DC voltage of the system, its current order is still calculated by the power controller, which cannot detect that one of the inverters is disconnected and the total power of the system is reduced. After a disturbance, during which VDCOL or other functions were active and current order was reduced, the rectifier will recover with the same current order, but the actual direct current will be lower. In some cases this difference can be up to $0.5p.u.$. If the telecommunication is restored, the rectifier will shift back from voltage control to current control. In such a case, it will try to keep the current according to the reference and if the reference will be higher than actual current in the system, the remaining inverter can be overloaded or unstable operation can develop.

The basic structure of the sub-function is represented in figure 3.5. A certain margin $Margin_{up}$ is added to the measured current ID and this value becomes the upper limit for the current order from the power controller. In this project, the margin of $0.016p.u.$ was used which was selected based on various simulations. The limiter is activated when telecommunication is not available and reduced voltage recovery described in section 3.4.2 is switched off. After the activation signal becomes positive, a limited current order becomes the output of this control logic. In order to get a smoother transition from not limited to limited current order a low pass filter is added, which is not active until the current order limiter is not activated.

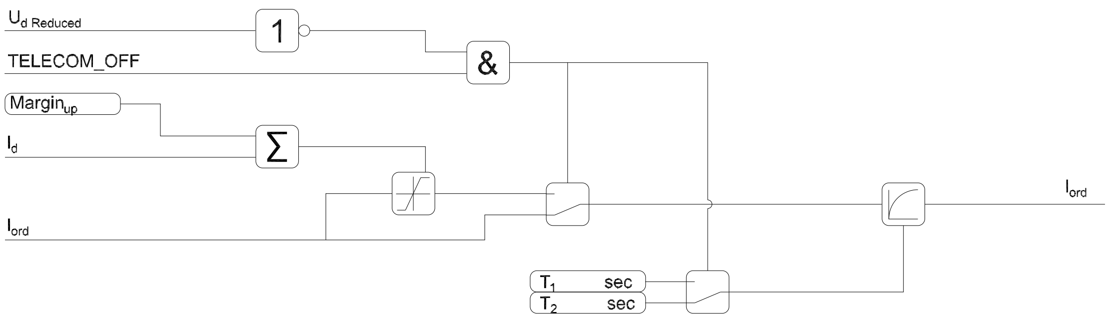


Figure 3.5: Block diagram for the current order limiter

The second part of the current order limiter is designed to switch the current order from the power controller to a locally measured current ID which is used as the current order. It is done when telecom between the terminals is not available, the reduced voltage recovery are not active, and the current limiter is activated for a certain time (in this project the delay time is set to $50ms$). A transition between these two current orders are ramped down so that no step changes would be introduced.

It should be noted that all these gains, time constants, and limits for all the functions should be tuned accordingly in order to achieve proper dynamics of the system. Some of the impacts of these settings are investigated deeper and results are represented in section 4.2.9. In the same section, a simulation results are shown when recovery is done without the current order limiter and ID is set as current order.

3.4.4 RETARD

The RETARD is one of the protective sub-functions in the converter firing control used to extinguish DC line faults. The principle of the RETARD is to force the rectifier station into the full inverter operation by pushing the firing angle to the maximum possible value. This is done through the limits of the CCA, which are set to 164^o (theoretically 180^o) for a predefined time. By forcing the rectifier to operate as an inverter, the DC line is discharged and the system shuts down since all the stations are operating as inverters.

After the defined time, which is typically $200ms$, passes, the system restarts. Firstly, the DC line is energized by setting the rectifier firing angle α to 70^o for $30ms$. After this time, the α value in the rectifier is reduced back to the nominal value and the DC current starts to flow. The sequence of the changes in firing angle alpha over the time is represented in following figure.

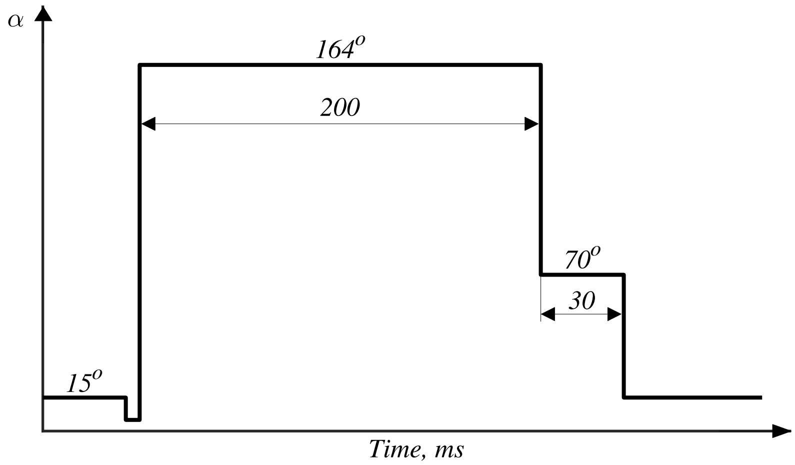


Figure 3.6: Changes in the firing angle α during the RETARD

3.5 Chronology of events for operation without telecommunication

Figure 3.7 represents a chronology of events when the loss of telecommunication occurs. The sequence starts when telecommunication between the terminals is lost. After it happened, the RVC mode is activated after a certain delay (Delay 1). This delay is needed in order to avoid unnecessary actions in the system when telecom is lost only for a very short time. Once the RVC is activated, the HVDC remains in this mode until telecommunication is not recovered.

During a disturbance, the voltage in the system drops and after a few milliseconds this voltage drop is detected by the controls, the reduced voltage recovery is activated. After the disturbance ends and voltage recovers, the current order limiter is turned ON. Finally, if the current order $I_{ord.}$ from the power controller is higher than measured current $I_{meas.}$ for a time set in the controls, the measured current is taken as current order.

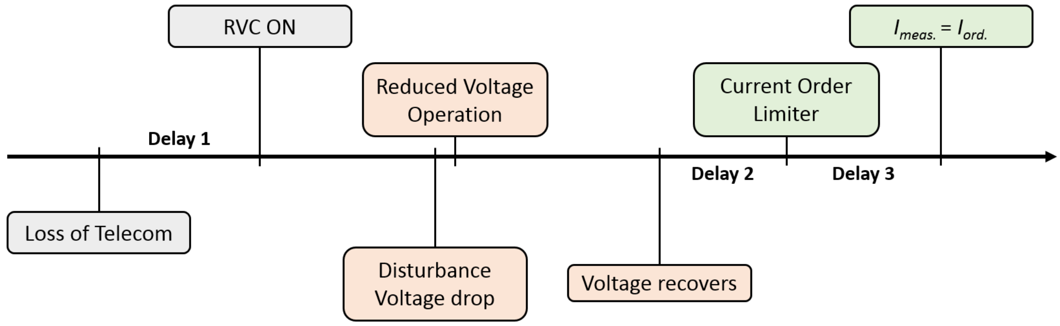


Figure 3.7: Sequence of events. Approach 1

As mentioned in section 3.3, the possibility to restart the system using the RETARD function is investigated and the chronology of this approach is represented in the figure 3.8.

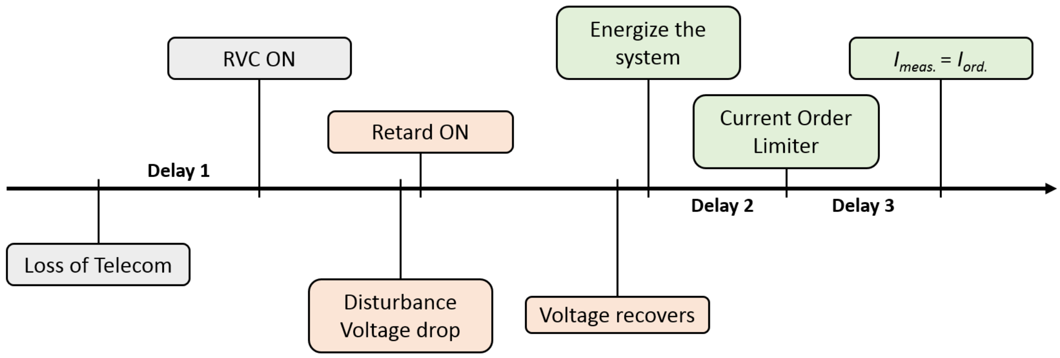


Figure 3.8: Sequence of events. Approach 2

Similarly to the case before, while the telecommunication is lost the system operates in the RVC mode. However, when a disturbance is detected the RETARD function is activated, which is described in section 3.4.4. After the RETARD ends, the system recovers with activated current limited and the same as in the case before, the measured current can be used as current order if one of the stations is lost or the system recovered to a different operation point. A sequence of events for the second case is represented in the following figure.

4

Results and Discussions

This chapter contains the results of simulations. Most of them are represented using the same templates with such parameters: the first sub-plot represents all three phases for the AC voltage at the station, the second shows measured current ID and ordered current I_ORD. The third sub-plot displays the DC voltage in the system while the fourth, the power order P and measured power Pdc. The fifth sub-plot for the rectifier shows the measured, ordered and minimum firing angles, while in the inverter the measured, ordered and the maximum angles, $ALPHA\_MEAS$, $ALPHA\_ORD$, $ALPHA\_MAX$ and $ALPHA\_MEAS$, $ALPHA\_ORD$, $ALPHA\_MIN$ respectively. The figures with results for an inverter have a sixth sub-plot where extinction angle gamma is represented. Moreover, in this chapter, all the results are discussed.

4.1 Operation with Telecommunication

In this section, the results of simulations when the system is operating with telecommunication are presented. The single phase and three phase to ground AC faults with different remaining voltages were applied at the different stations. Moreover, the basic control actions of the controls are described in each case.

4.1.1 AC Faults

4.1.1.1 Fault at Station 1

At 0.1s, an AC fault with 10% remaining voltage was applied for 200ms on the rectifier side. Almost instantly, the DC voltage in the system drops and the VDCOL function is activated which reduces the current reference to the specific value as it is seen in 4.1. Furthermore, when the AC voltage goes down, the firing angle drops to its minimum value in order to increase the DC current. However, recovering with a such small value of α can lead to a significant increase in the DC current as it is mentioned in section 2.9.2. Because of this, the RAML function is activated by the controls in the station which increases the minimum firing angle limit in the CCA to 45^o. As the fault ends and the DC voltage recovers, the VDCOL brings back the current order to the nominal value with certain speed, which is defined by the time constant in the controls.

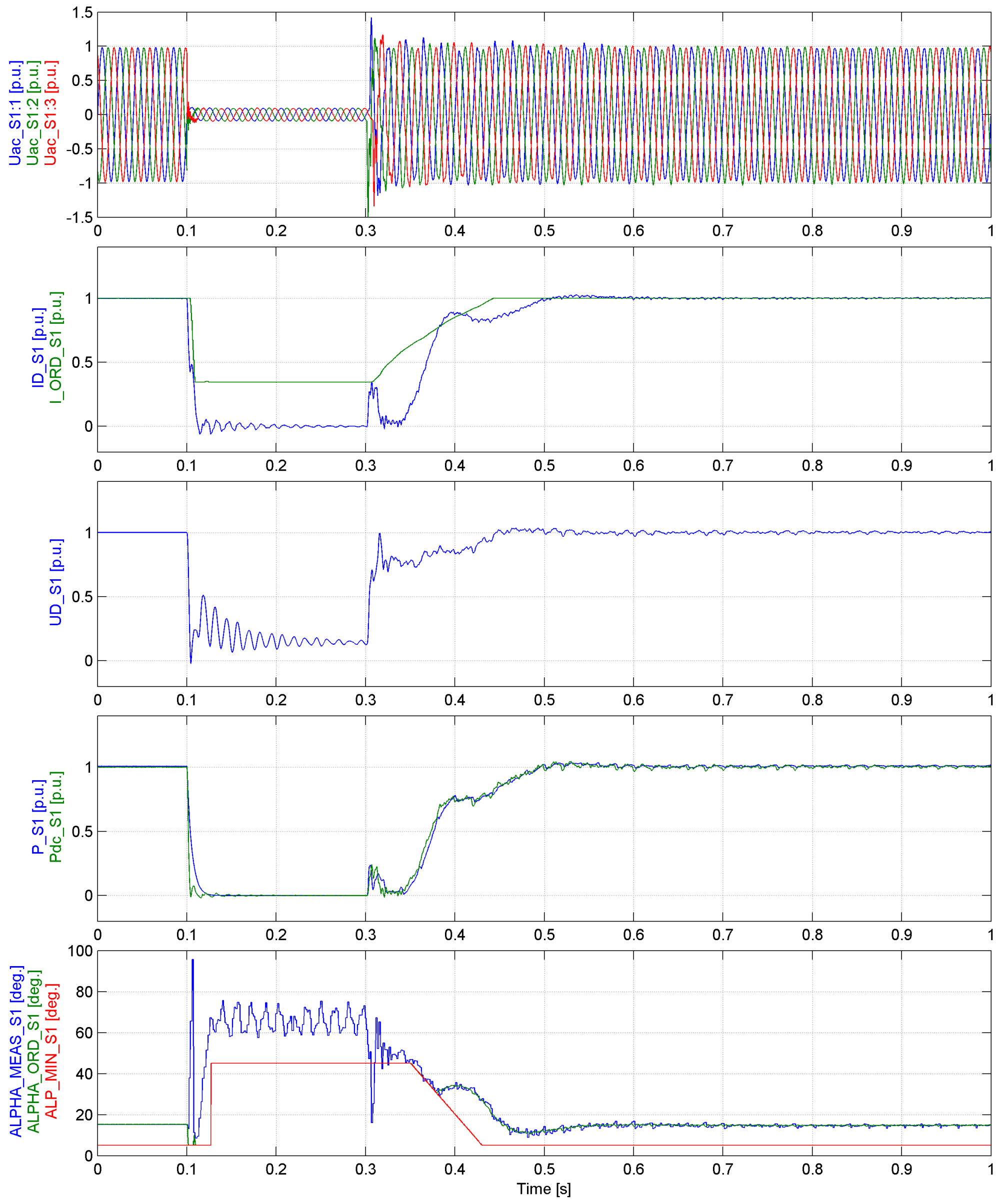


Figure 4.1: 200ms three phase to ground fault with 10% remaining voltage. Station 1

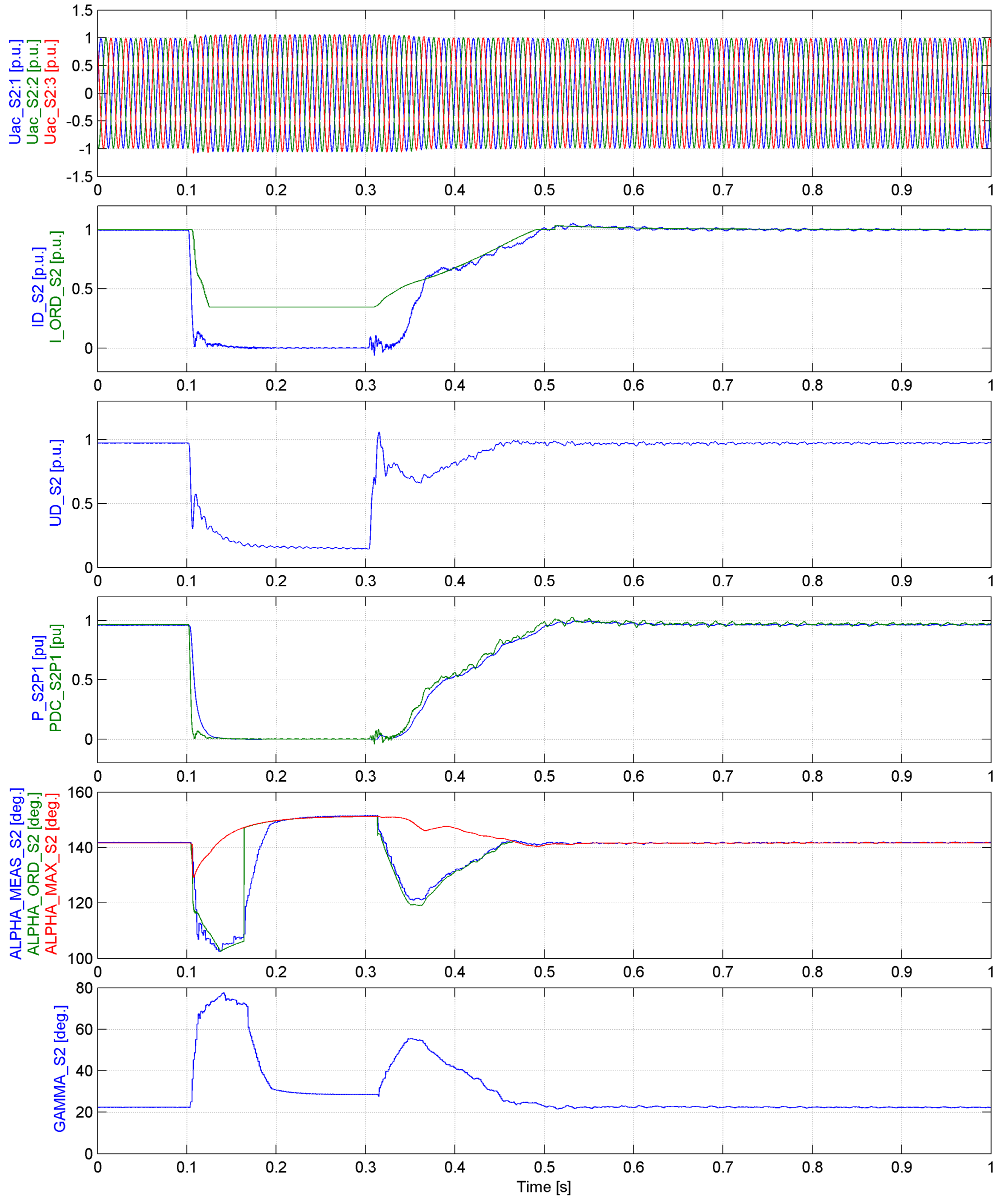


Figure 4.2: 200ms three phase to ground fault with 10% remaining voltage. Station 2

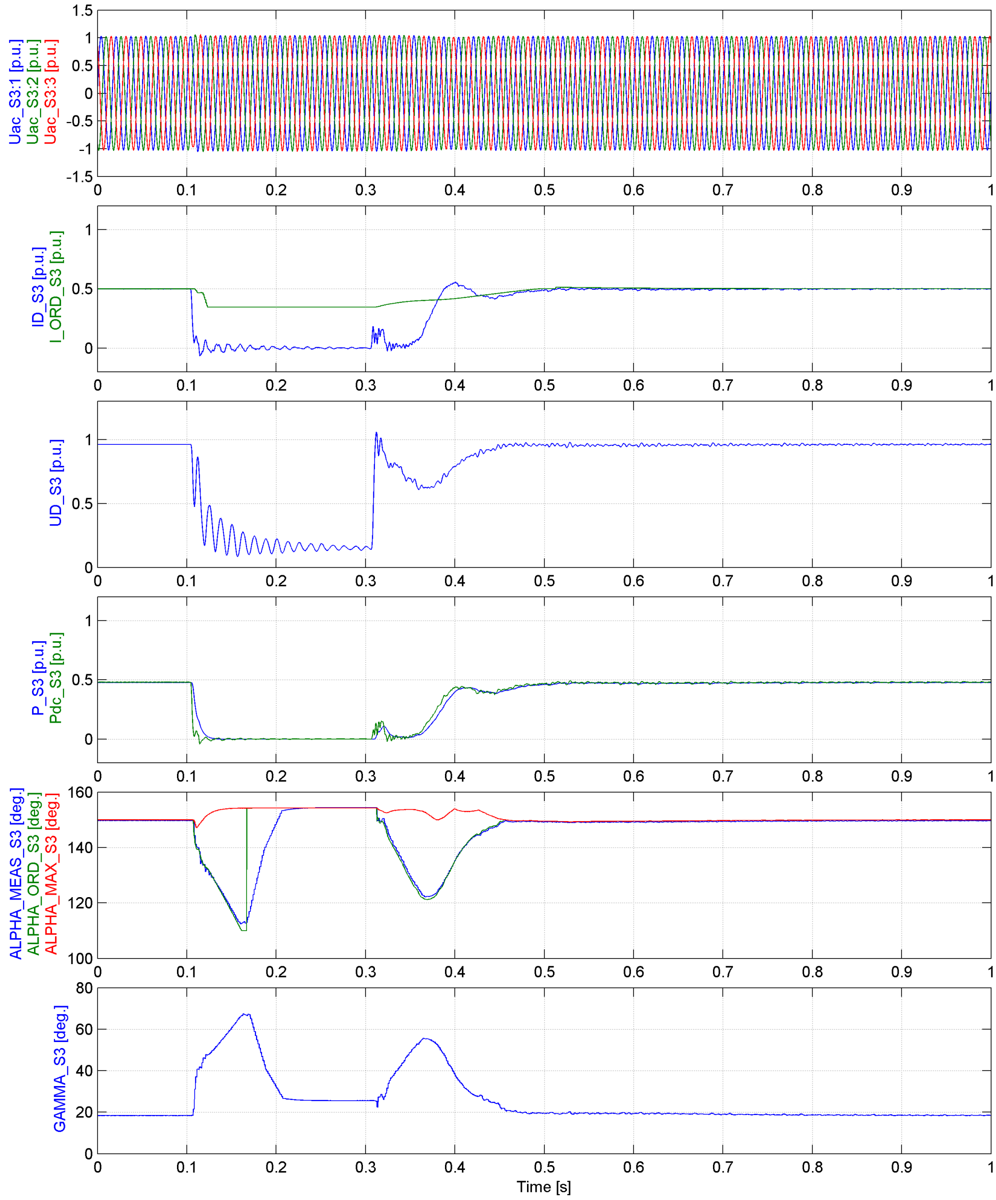


Figure 4.3: 200ms three phase to ground fault with 10% remaining voltage. Station 3

During the fault, the VDCOL function was activated in the inverters as well, as the DC voltage went down in the entire system. Responding to reduced voltage, gamma has increased, but as only firing angle alpha is actually controlled, it was a consequence of decreased α. At about time of 0.17s the commutation failure prevention system was activated which increased the minimum angle of alpha as it is seen in figures 4.2 and 4.3. When the prevention system stops interacting, the firing angle drops again since the DC voltage is not fully recovered yet. Moreover, the recovery of the current order in the inverters is noticeably slower in comparison with rectifier in order to keep the current margin. The system recovered in about 160ms after the fault.

4.1.1.2 Fault at Station 2

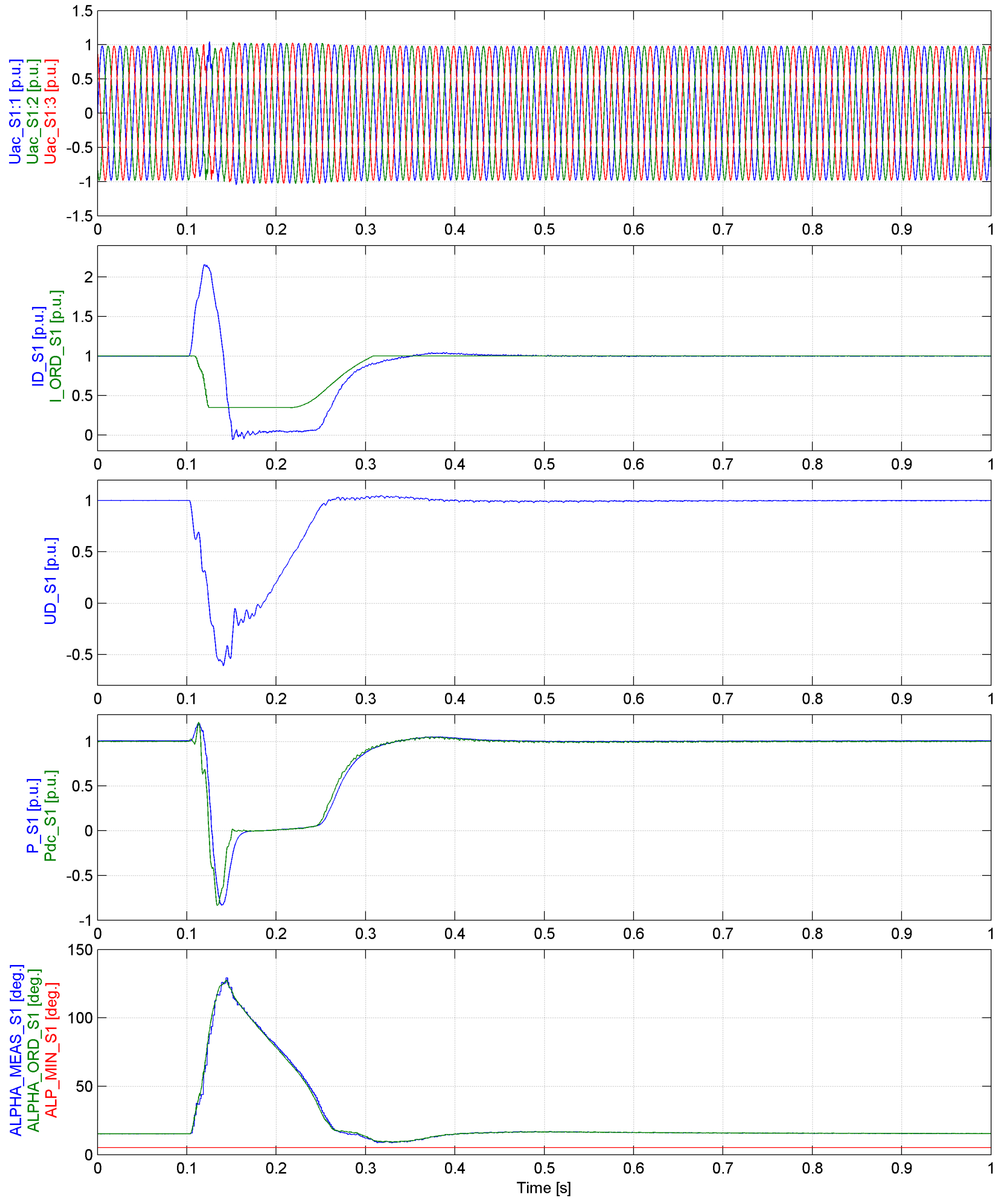


Figure 4.4: $50ms$ single phase to ground fault with 10% remaining voltage. Station 1

A single phase to ground AC fault was applied with 10% remaining voltage for $50ms$ at the second station. During the disturbance, a commutation failure occurred and the DC voltage dropped. As a result, the VDCOL was activated in all three stations. Furthermore, the DC current went up significantly as it is seen in figure 4.4 (approximately to $2.2p.u.$ in the rectifier and $2.4p.u.$ in the first inverter). In order to extinguish the failure, the firing angle alpha was increased above 90^o what means that the rectifier started to operate as an inverter. For this reason, in the fourth sub-plot (figure 4.5), a short power reversal can be seen. After the fault ended, the rectifier recovered.

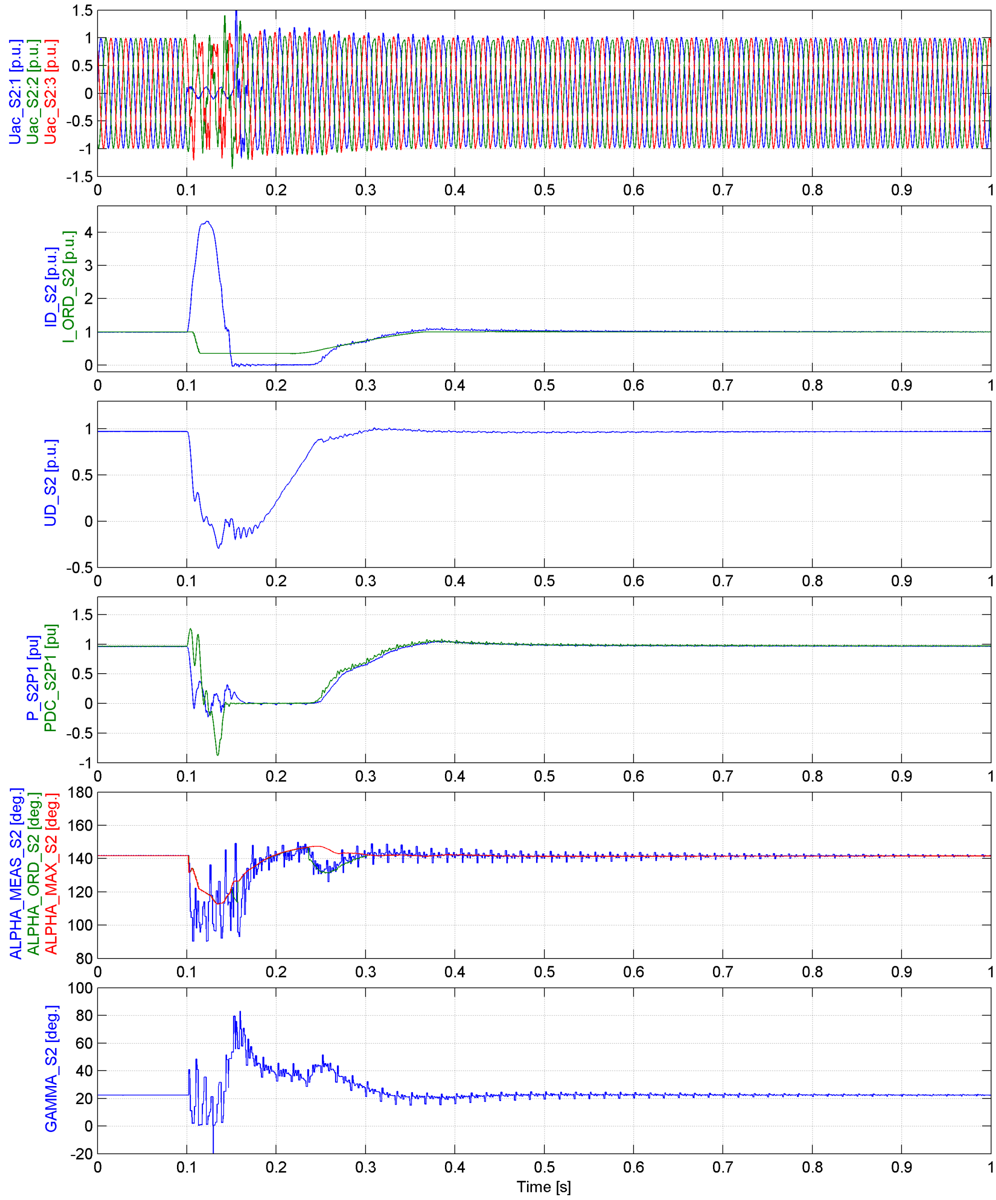


Figure 4.5: 50ms single phase to ground fault with 10% remaining voltage. Station 2

As it has been mentioned before, the commutation failure occurred in the inverter during the fault. When the DC current increased, the overlap angle increased as well as it is directly proportional to the current and because the inverter is operating in the constant beta control, extinction angle drops. Typically, the firing angle is inversely proportional to the extinction angle, but this is true, when the overlap is not changing much. During the commutation failure when the DC current went up, the increase of μ was higher than the decrease of γ so according to 2.2, α dropped. Once the commutation failure was extinguished, the inverter recovered.

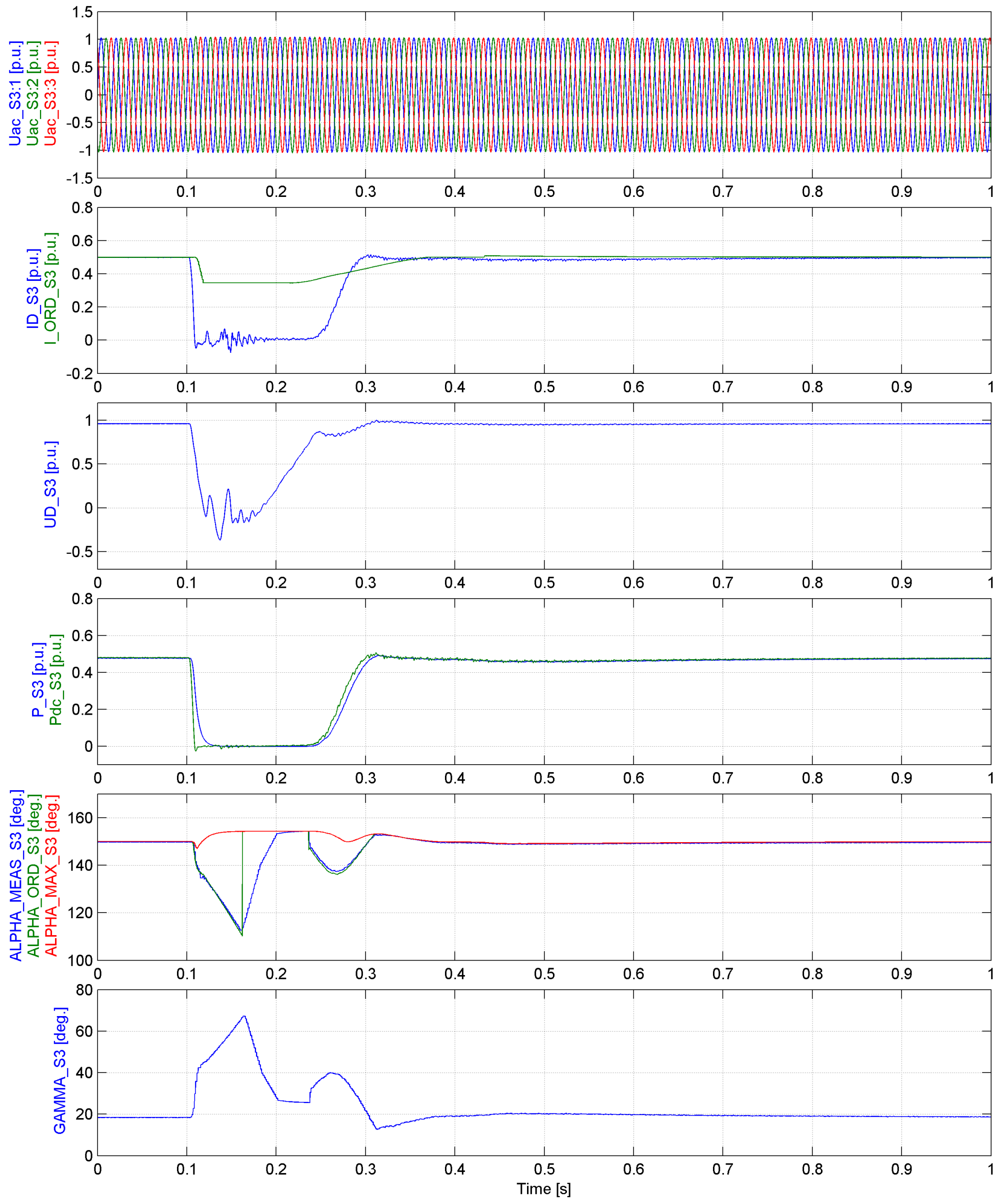


Figure 4.6: 50ms single phase to ground fault with 10% remaining voltage. Station 3

The third station did not experience any overshoots in the DC current as all the current from the rectifier went to the fault through the second station. As a result, when the fault was applied, the current just dropped to zero. In general, all the actions of the controls and dynamic behavior of this inverter is the same as in the case when the fault was applied on the rectifier side (figure 4.3).

4.1.1.3 Fault at Station 3

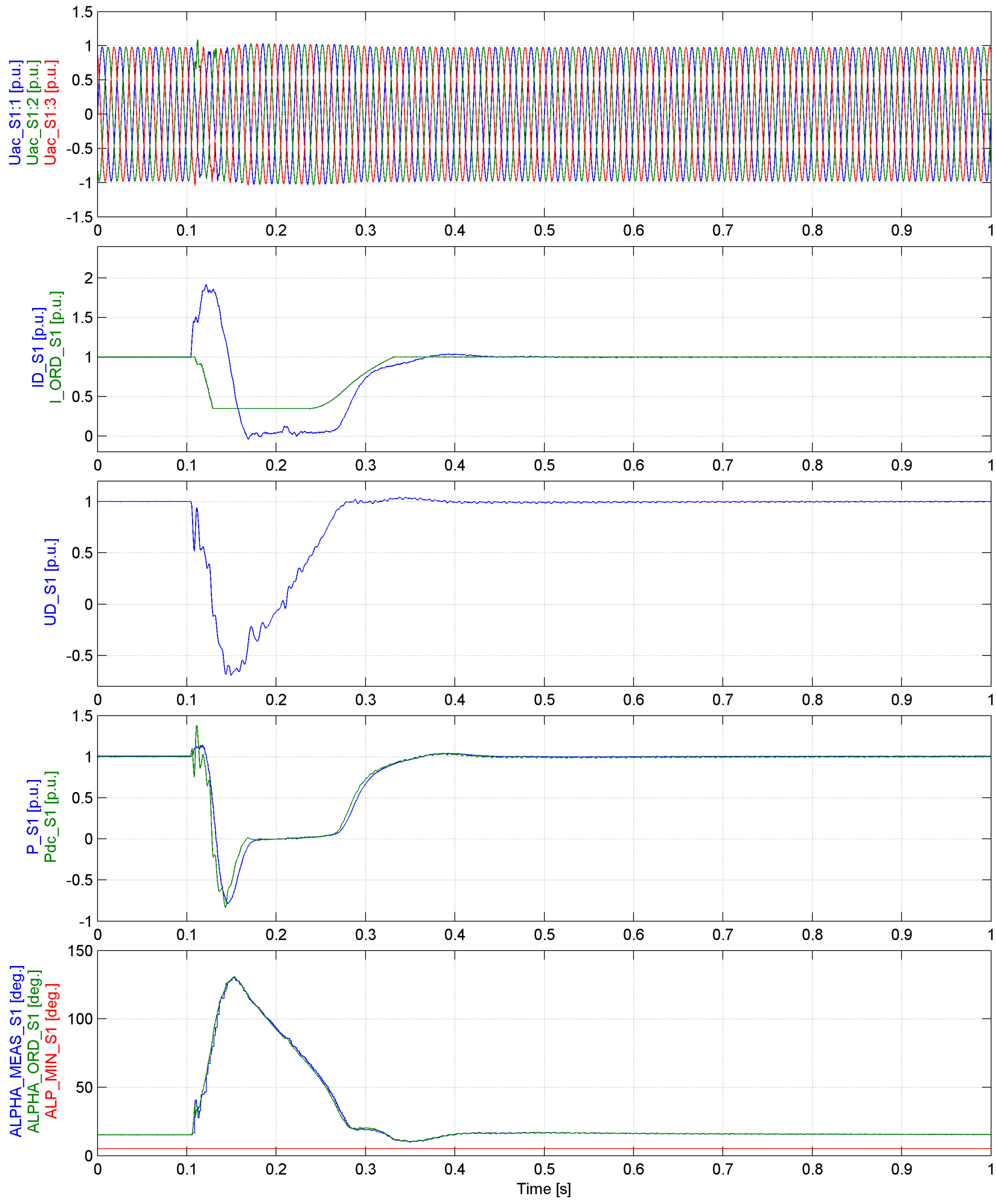


Figure 4.7: 100ms three phase to ground fault with 10% remaining voltage. Station 1

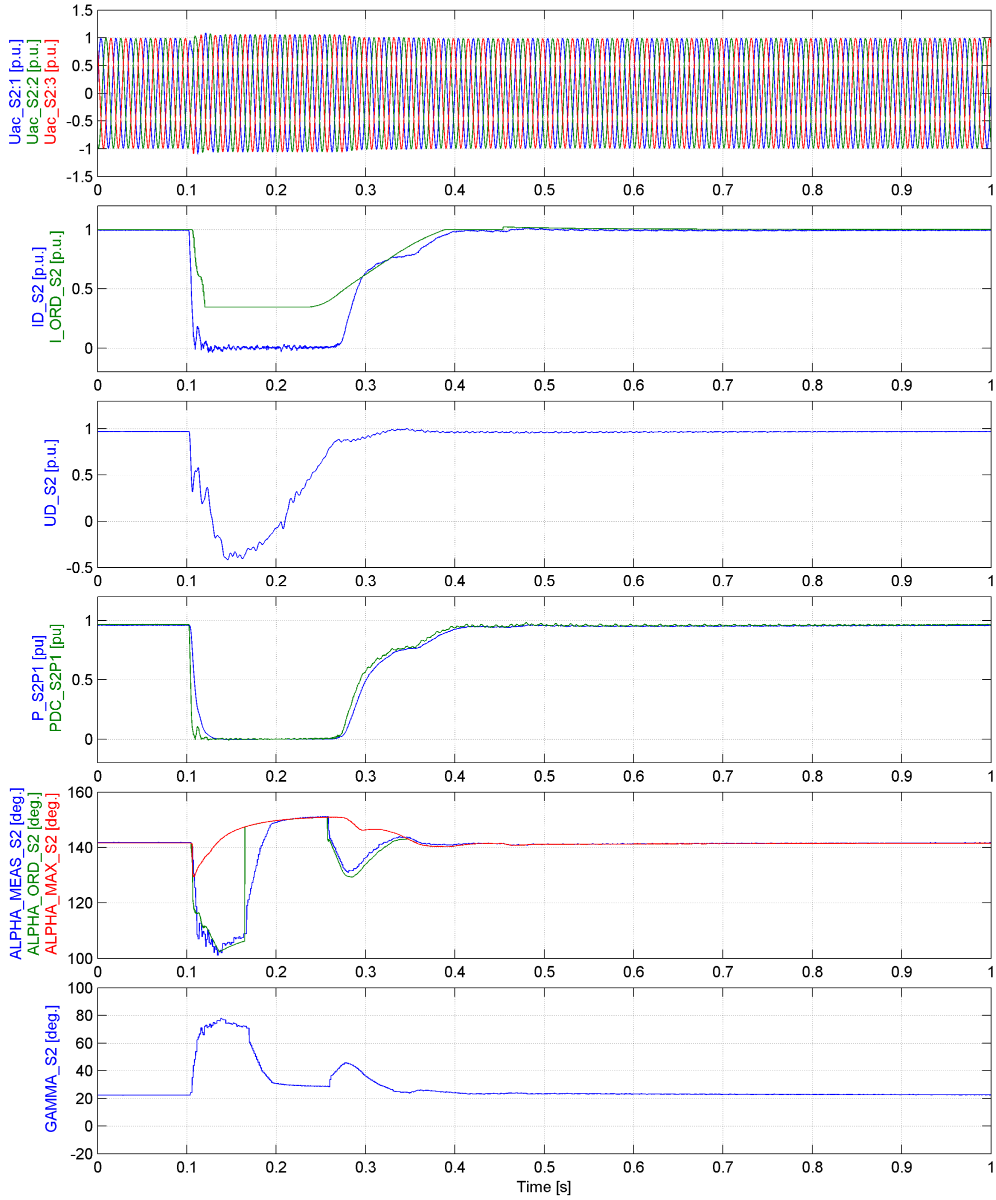


Figure 4.8: 100ms three phase to ground fault with 10% remaining voltage. Station 2

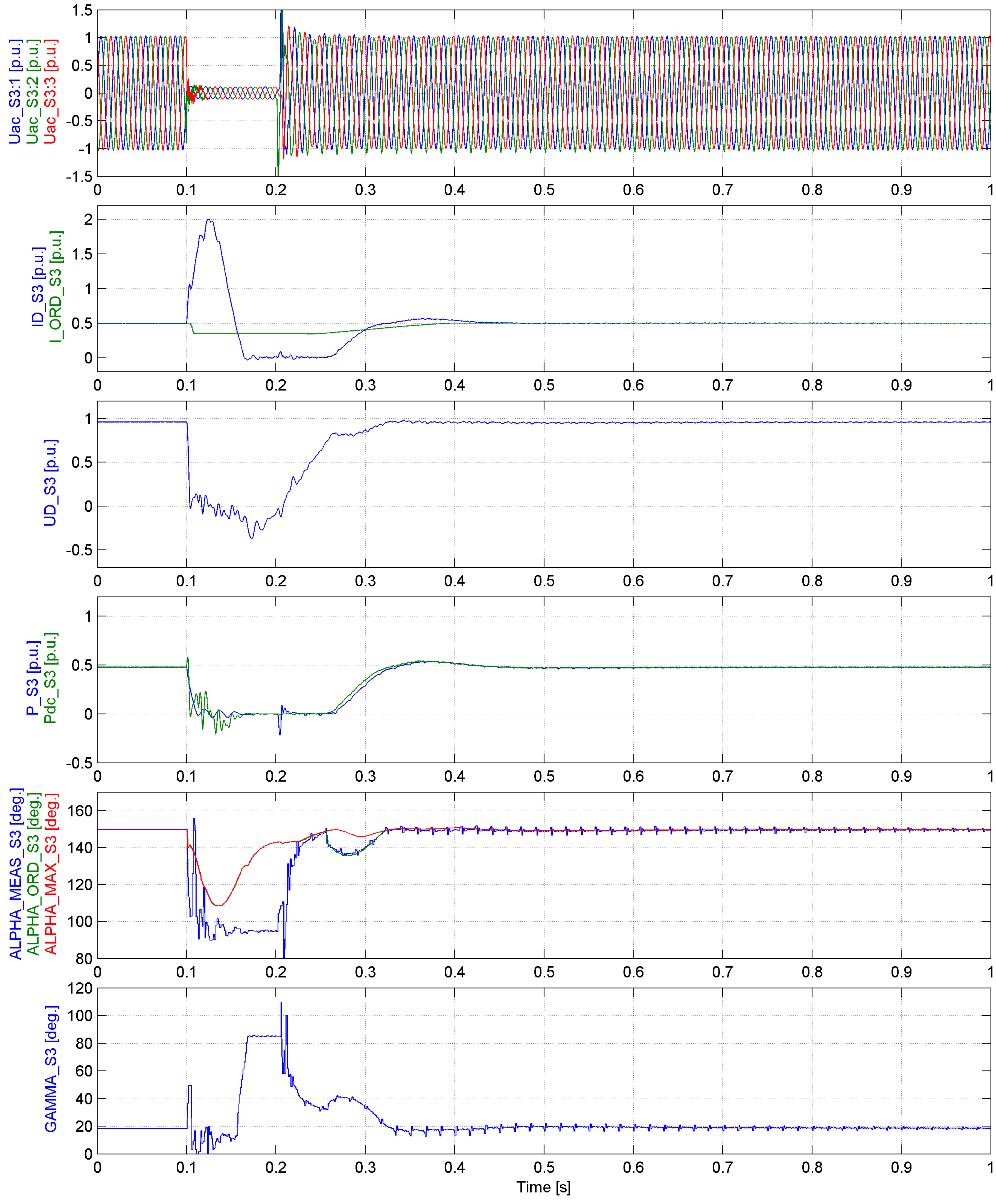


Figure 4.9: 100ms three phase to ground fault with 10% remaining voltage. Station 3

When the three phase to ground AC fault was applied on the third station's AC network, the dynamic response of the system is similar to the case where the single phase to ground fault was applied on the second station's side (section 4.1.1.2). This is expected as both stations operate as inverters and in both commutation failure occurred. Since, the parameters of the AC networks (SCR) to which both stations are connected are not the same, a commutation failure for each inverter may occur at different values of the remaining voltage. However, the influence of different AC network parameters for the system is not included in the scope of this work and was not investigated.

4.2 Operation without Telecommunication

4.2.1 Transition

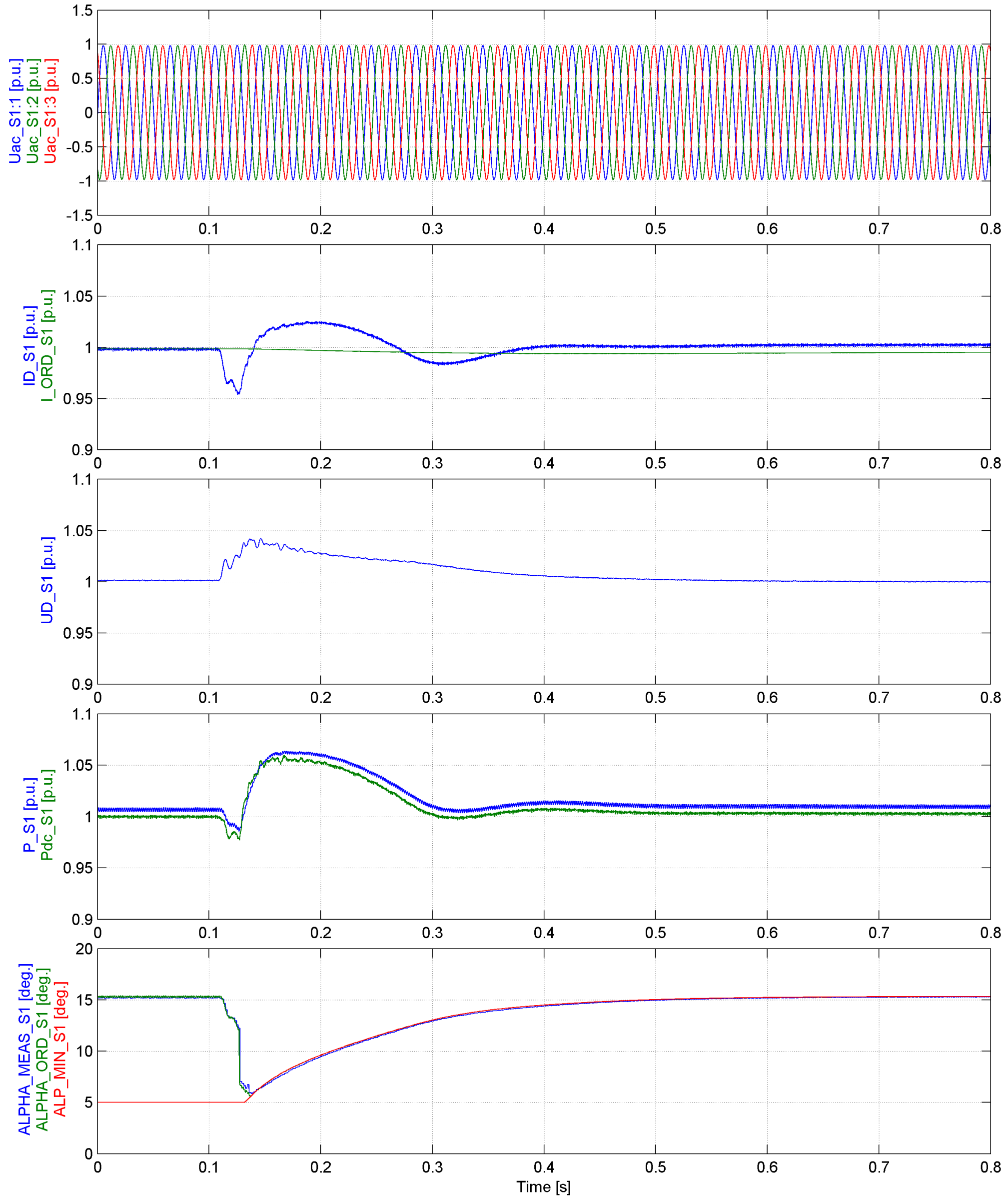


Figure 4.10: Transition to voltage control in the rectifier and current control in the inverters. Station 1

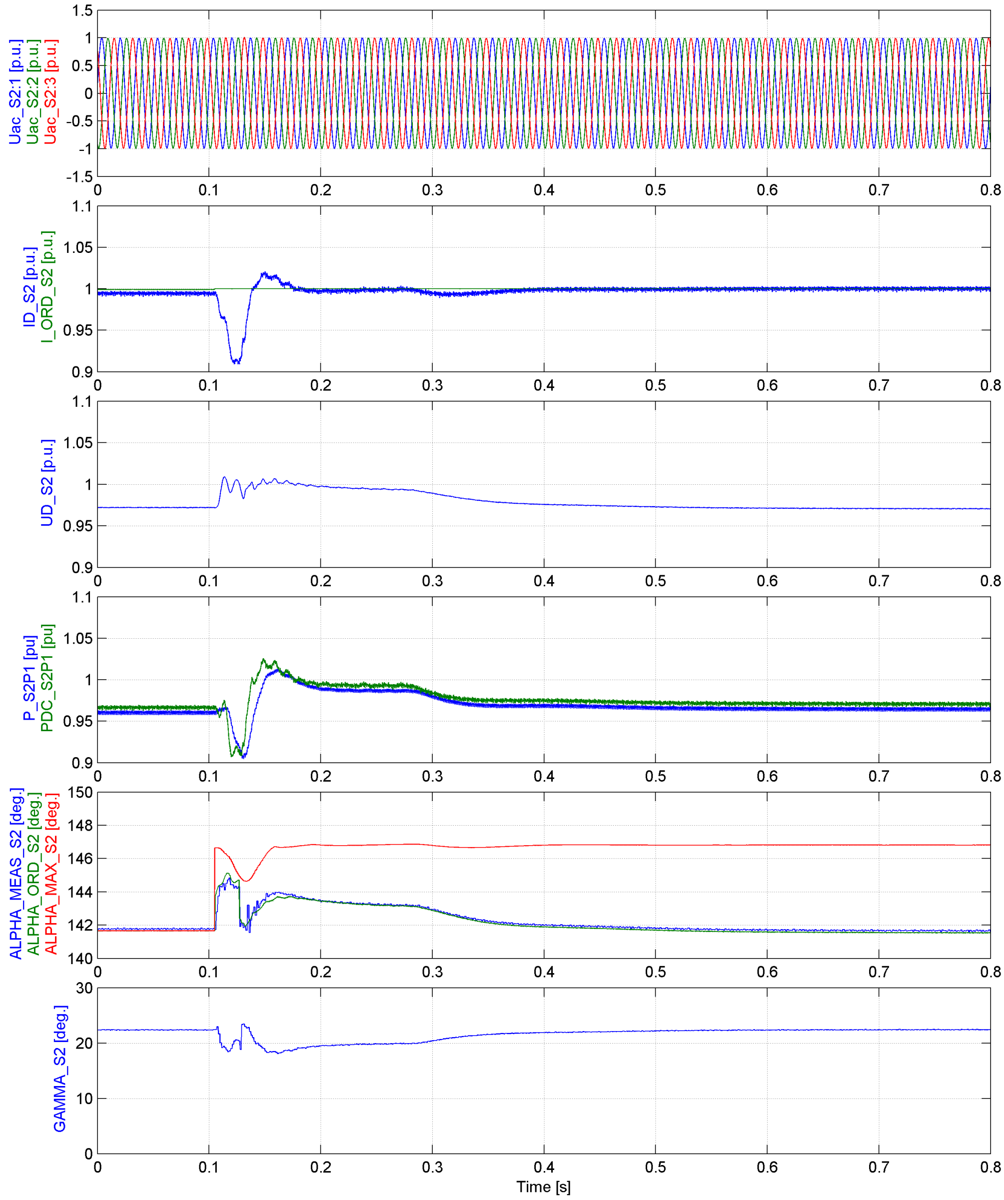


Figure 4.11: Transition to voltage control in the rectifier and current control in the inverters. Station 2

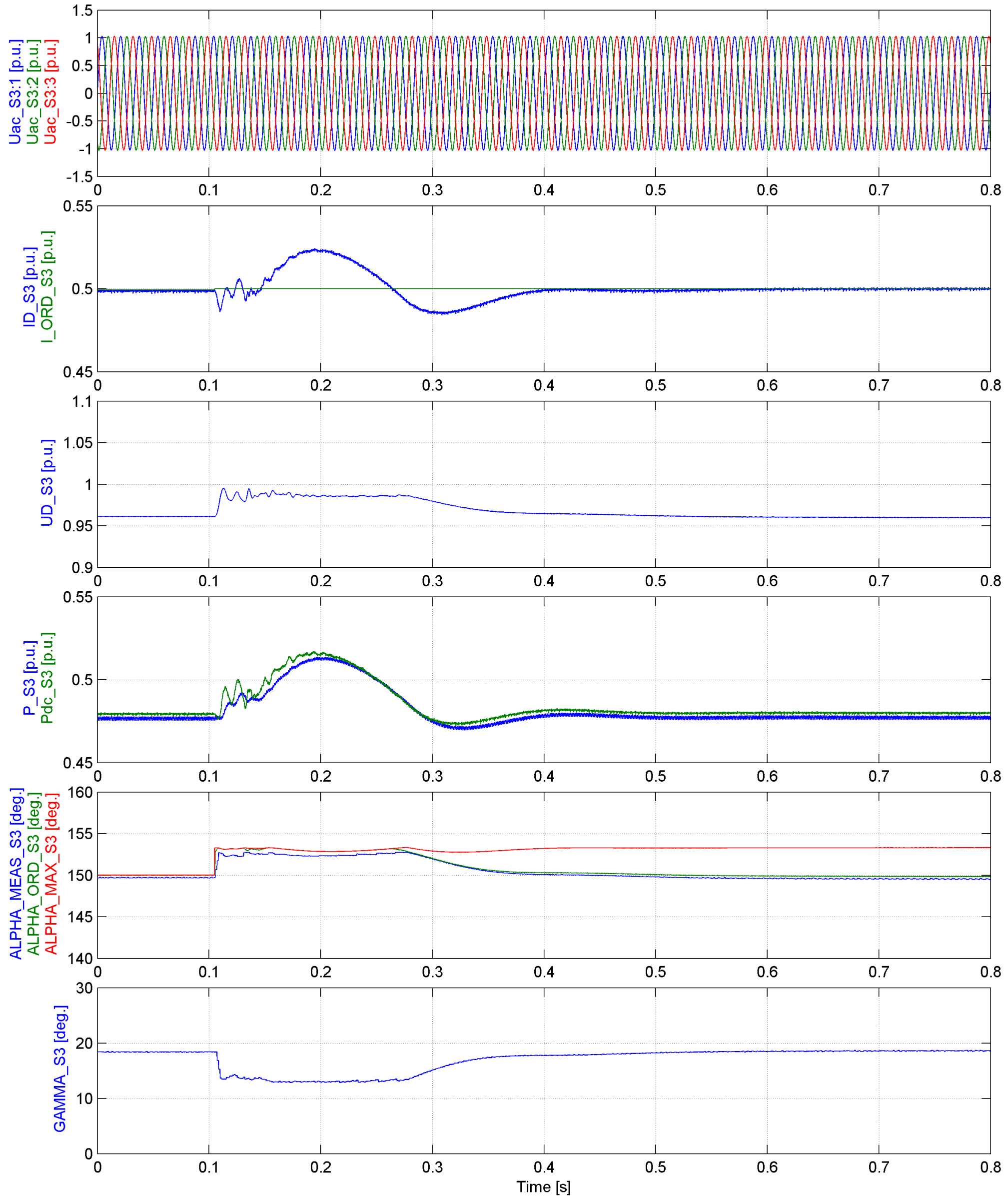


Figure 4.12: Transition to voltage control in the rectifier and current control in the inverters. Station 3

As figures 4.10, 4.11 and 4.12 show, at $0.1s$ the telecommunication is turned off and the system is shifted from current control to voltage control in the rectifier and from constant beta control to current control in the inverters. During this event, the system experienced a small transition, which is expected due to the shift of margin from inverters to the rectifier. As figure 4.10 represents, after the margin is introduced in the rectifier, the ordered firing angle in the CCA is moved to the lower limit what means that rectifier has started to operate in voltage control. Similarly, both inverters are no longer operating at the maximum firing angle α what means that both stations are in current control. The transition itself lasted approximately $300ms$ after which the steady state is reached again.

4.2.2 Current Step of +5%

A current step of +5% was applied in station 3 at 0.1s. The following three figures represent the response of the system to this change in current order. A short delay between the current step, which was applied at 0.1s, and the change of the current order is seen. However, this is expected since controls used for the simulations represents a real control system where all the signals and calculations are processed not instantaneously.

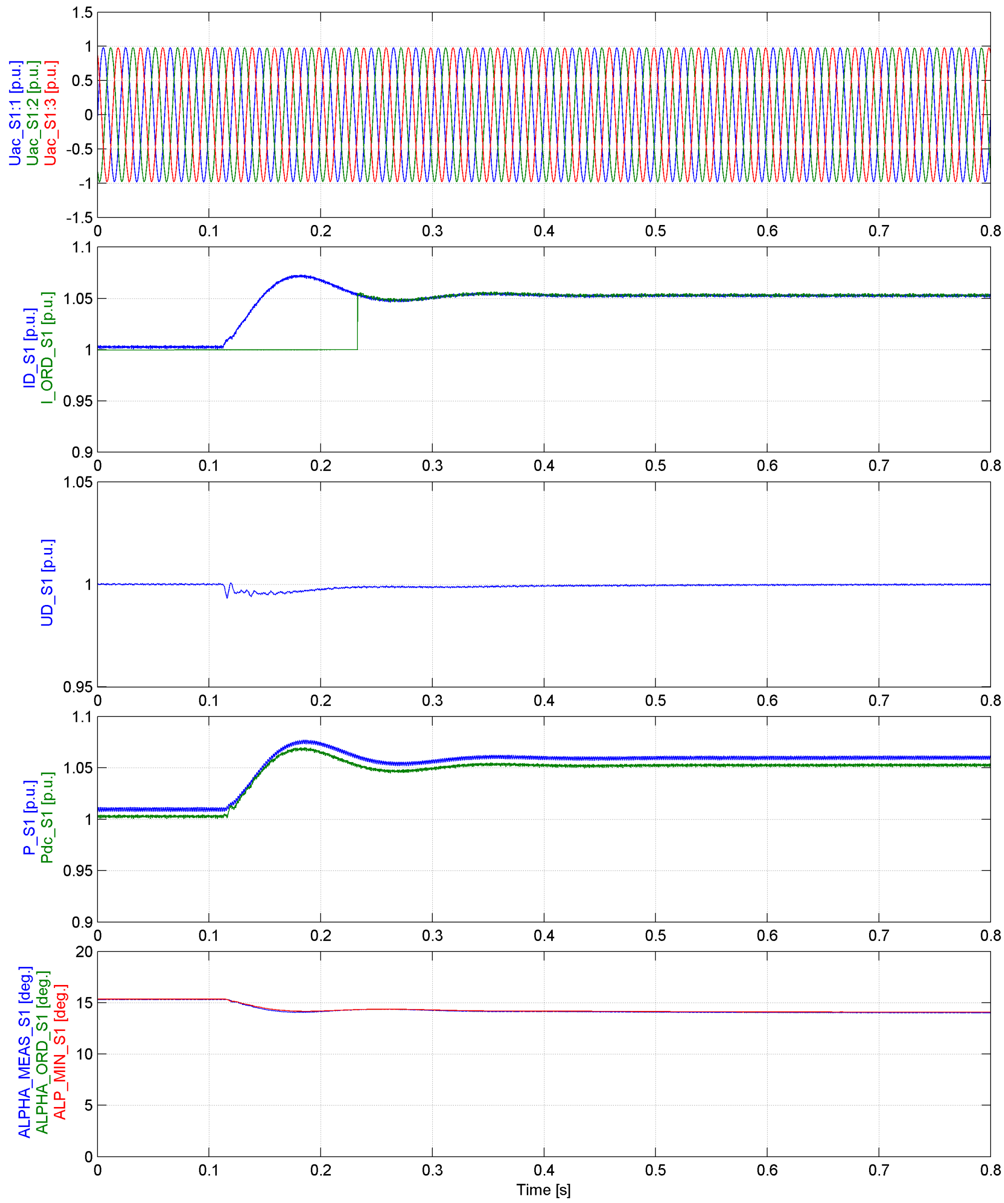


Figure 4.13: Positive current step of 5% in station 3. Station 1

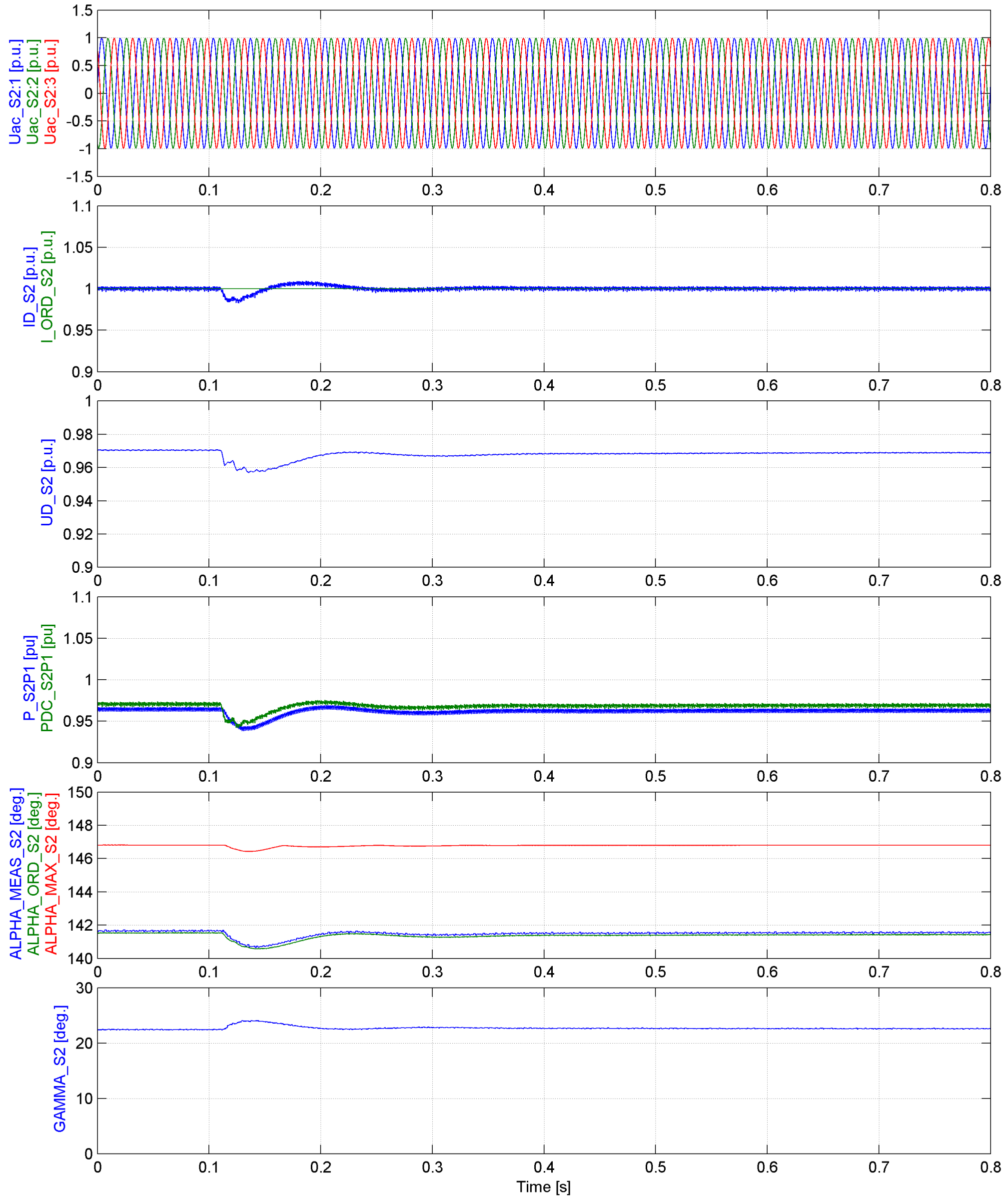


Figure 4.14: Positive current step of 5% in station 3. Station 2

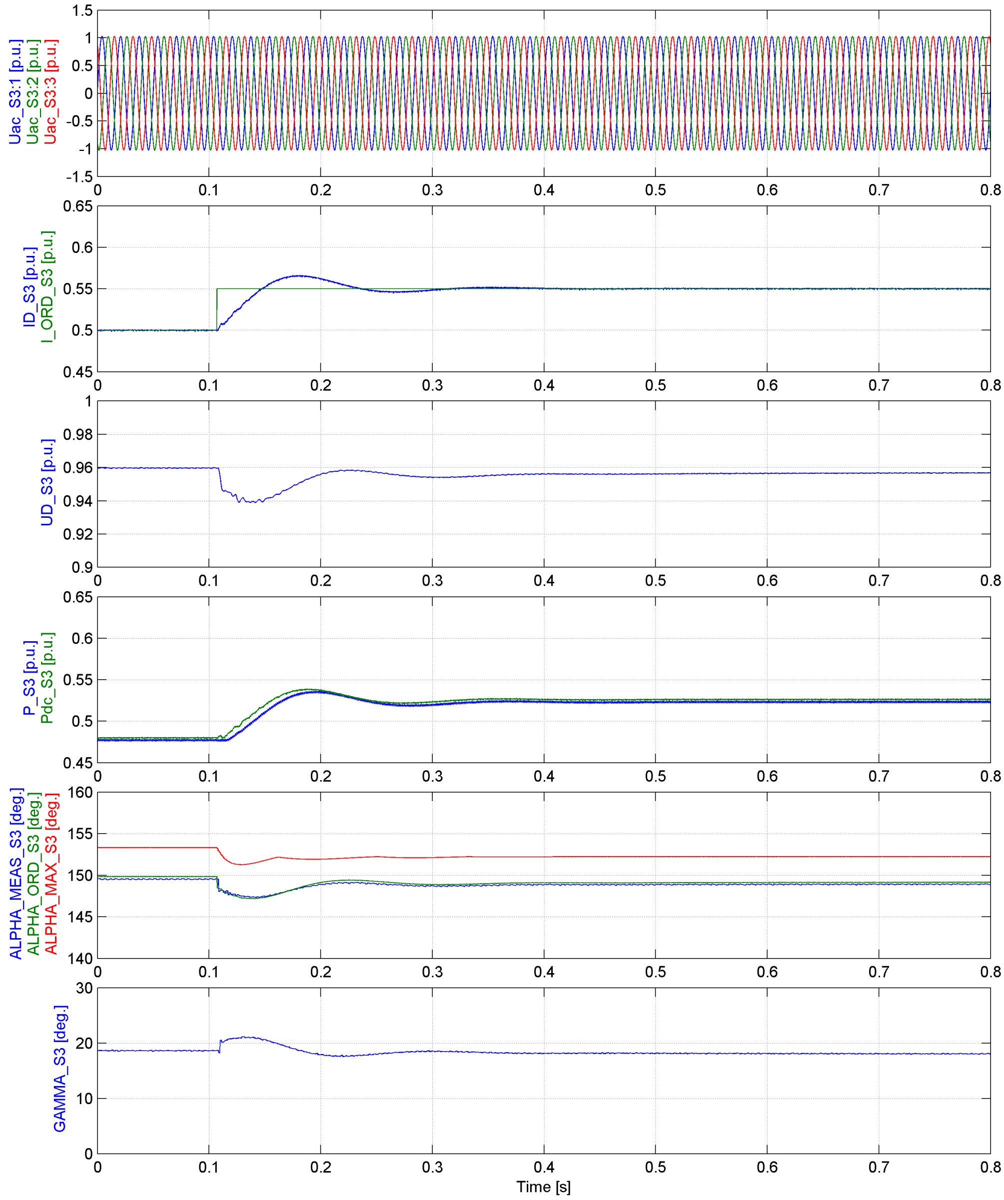


Figure 4.15: Positive current step of 5% in station 3. Station 3

After the current step was applied, the DC current in the inverter as well as in the rectifier started to increase. Furthermore, after a certain delay, the current order in the rectifier was updated according to the new measured current. Moreover, during the transition to a new operating point, the system experienced a temporary decrease in the DC voltage according to 2.5. As a result, the controls of the rectifier dropped the firing angle to keep the DC voltage at $1 p.u.$. The system response to a negative current step can be seen in the appendix (section A.1).

4.2.3 AC Faults

In this subsection, the results of different faults when telecommunication was not available are presented. In order to compare the cases with and without the telecom, the parameters of the applied faults in each station are the same as in subsection 4.1.1. Since the dynamic behavior and control actions of the system are explained in subsection 4.1.1, only main differences between operations with and without the telecommunication are discussed.

4.2.3.1 Fault at station 1

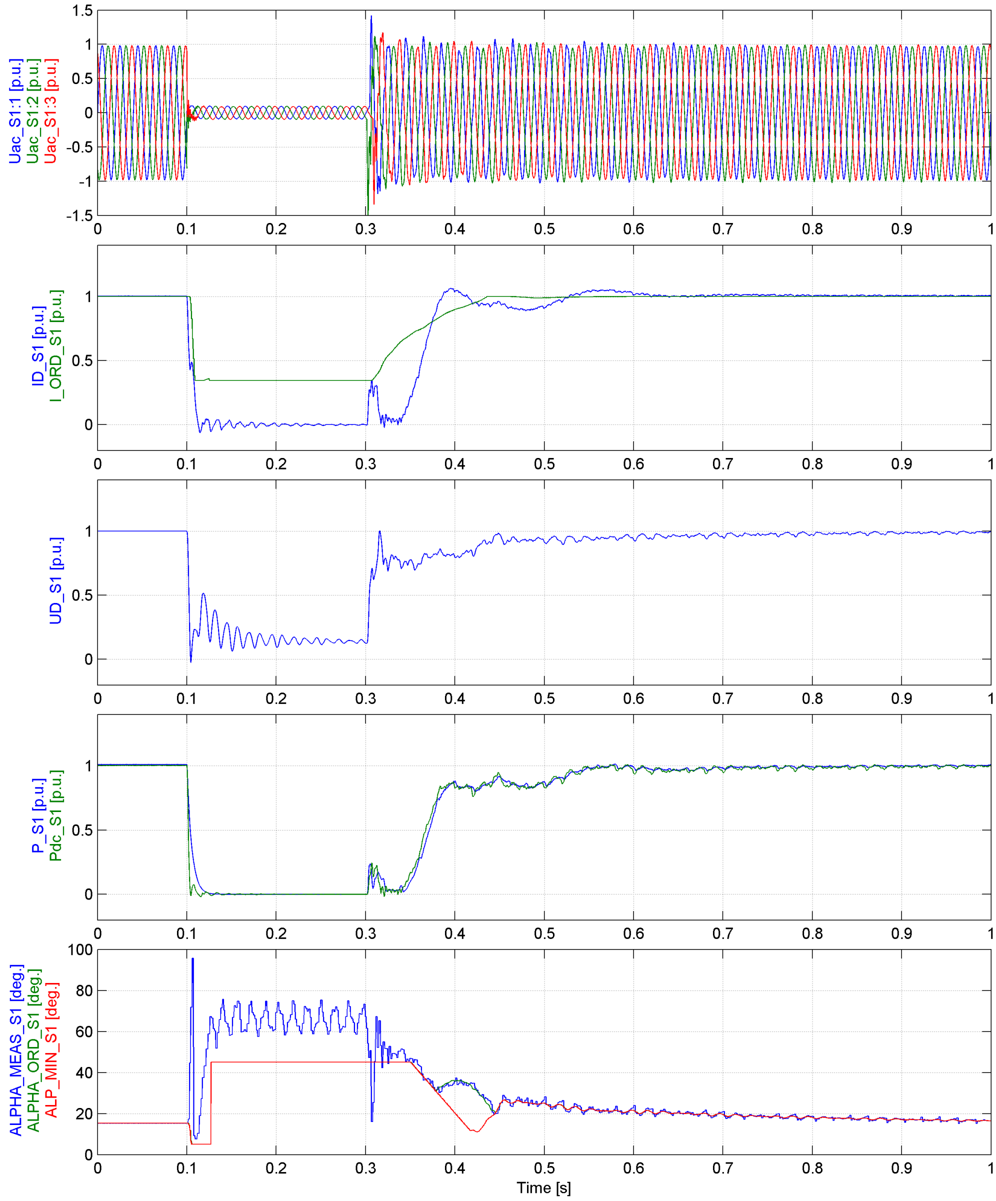


Figure 4.16: 200ms three phase to ground fault with 10% remaining voltage. Station 1

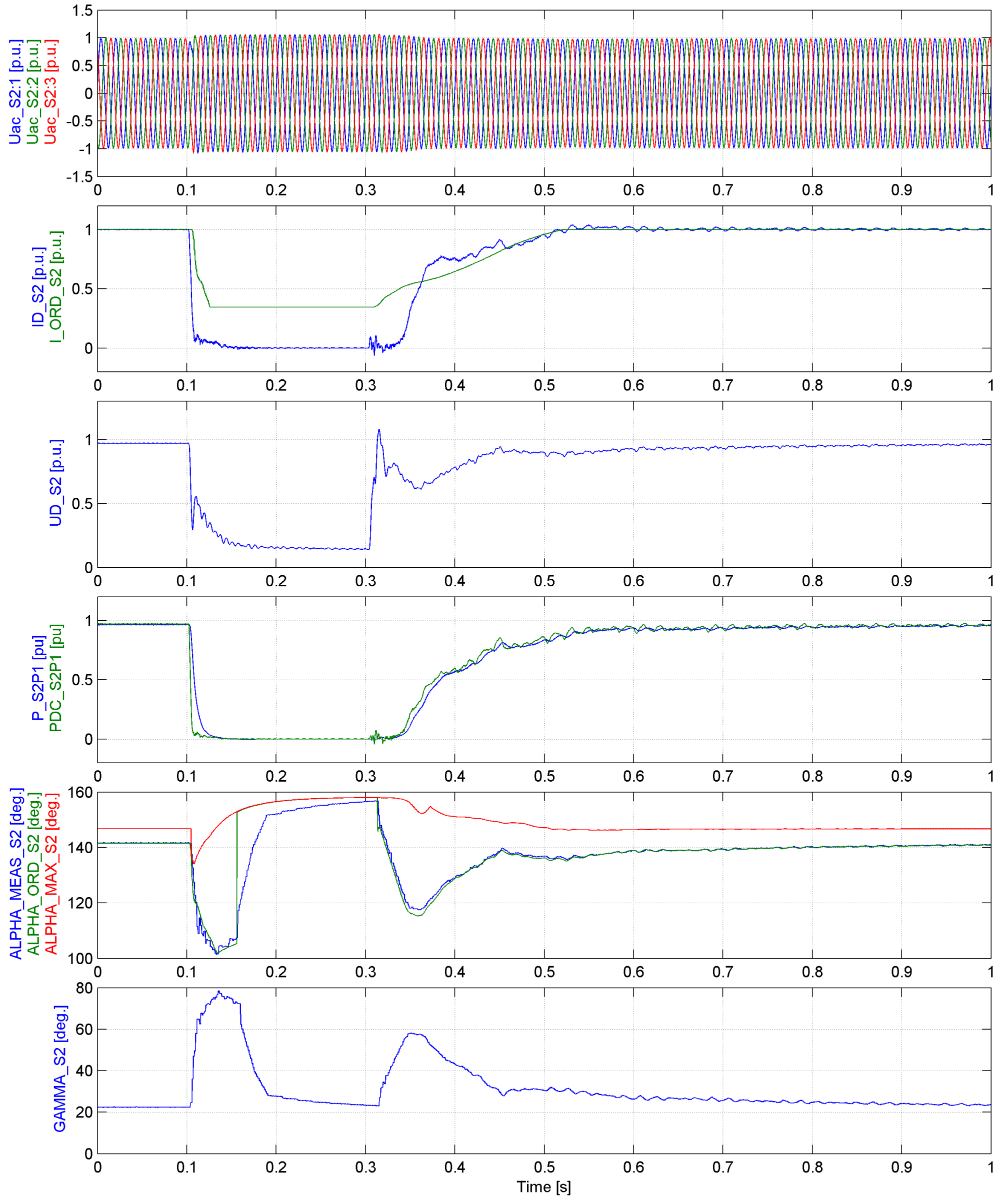


Figure 4.17: $200ms$ three phase to ground fault with 10% remaining voltage. Station 2

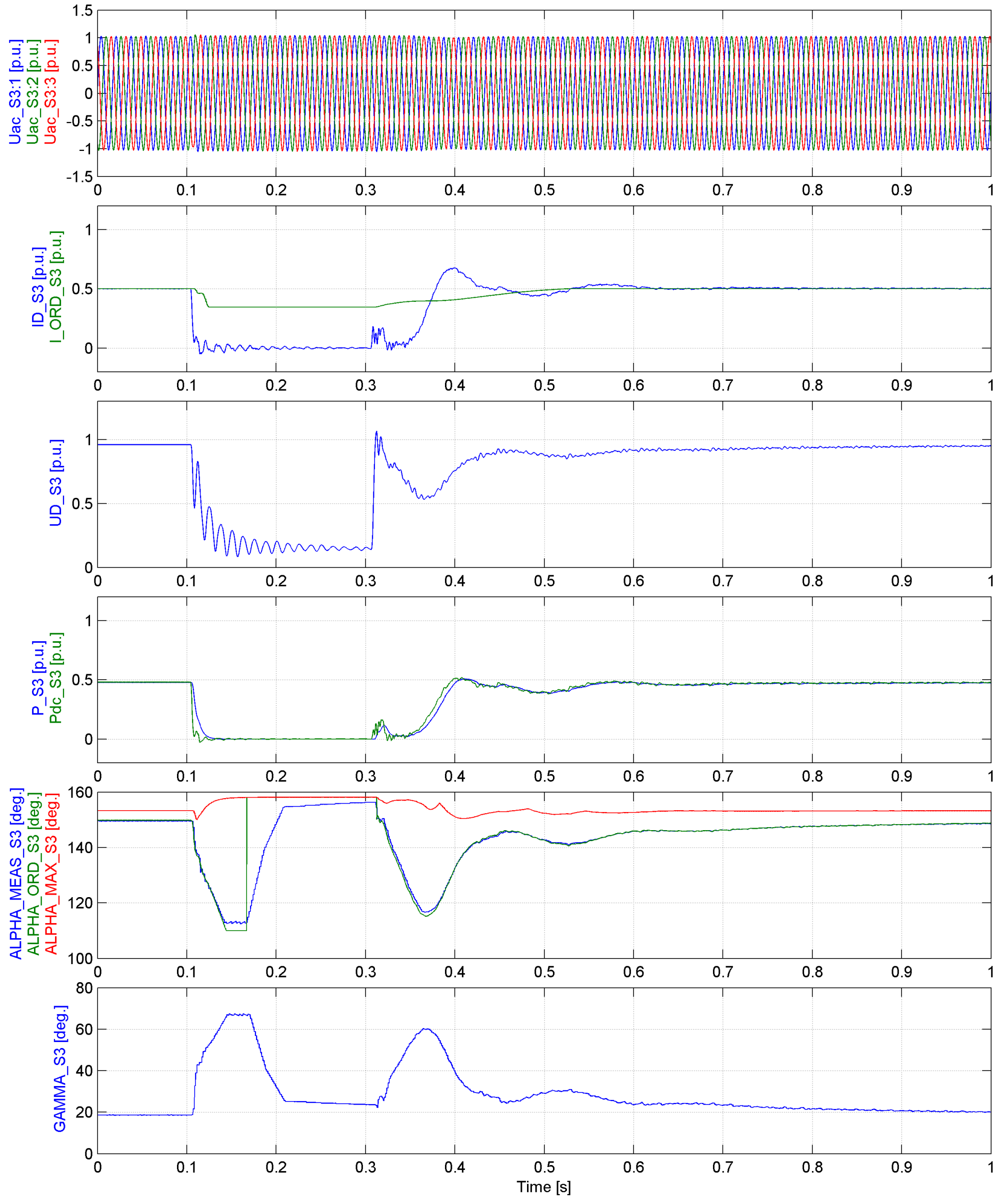


Figure 4.18: 200ms three phase to ground fault with 10% remaining voltage. Station 3

The three phase to ground AC fault with 10% remaining voltage was applied at the first station's side for 200ms. As figures 4.16, 4.17 and 4.18 show, the system without the telecommunication and in the RVC mode reacted to the fault almost identical as when the telecomom was available (figures 4.1, 4.2 and 4.3). The VD-COL and RAML functions were activated and deactivated at the same time and in both cases the system recovered in about 150ms. However, the system without the telecommunication recovered with reduced voltage as the reduced voltage recovery was activated and in addition to that, the rectifier and the second inverter experienced a small overcurrent.

4.2.3.2 Faults at station 2

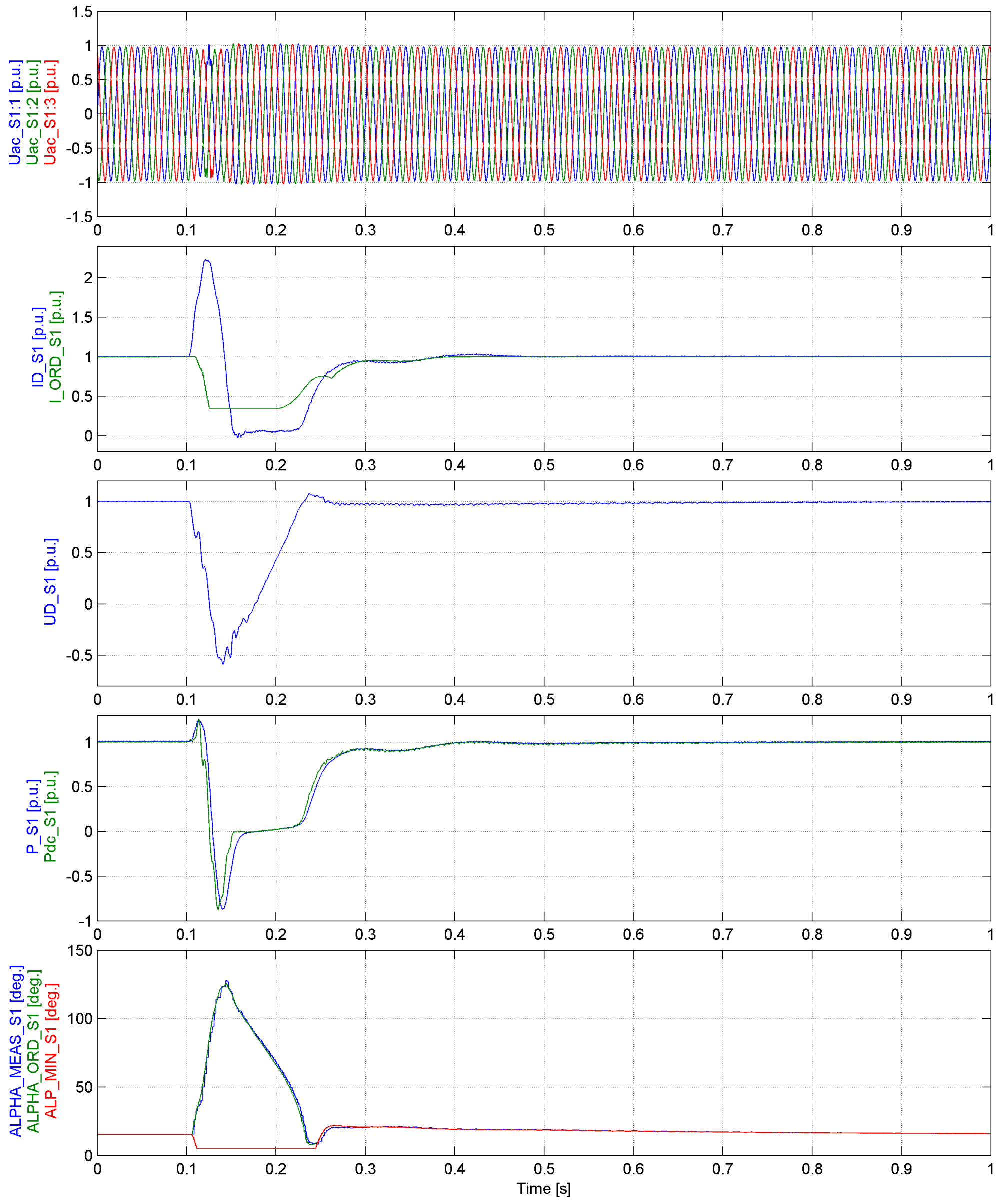


Figure 4.19: $50ms$ single phase to ground fault with 10% remaining voltage. Station 1

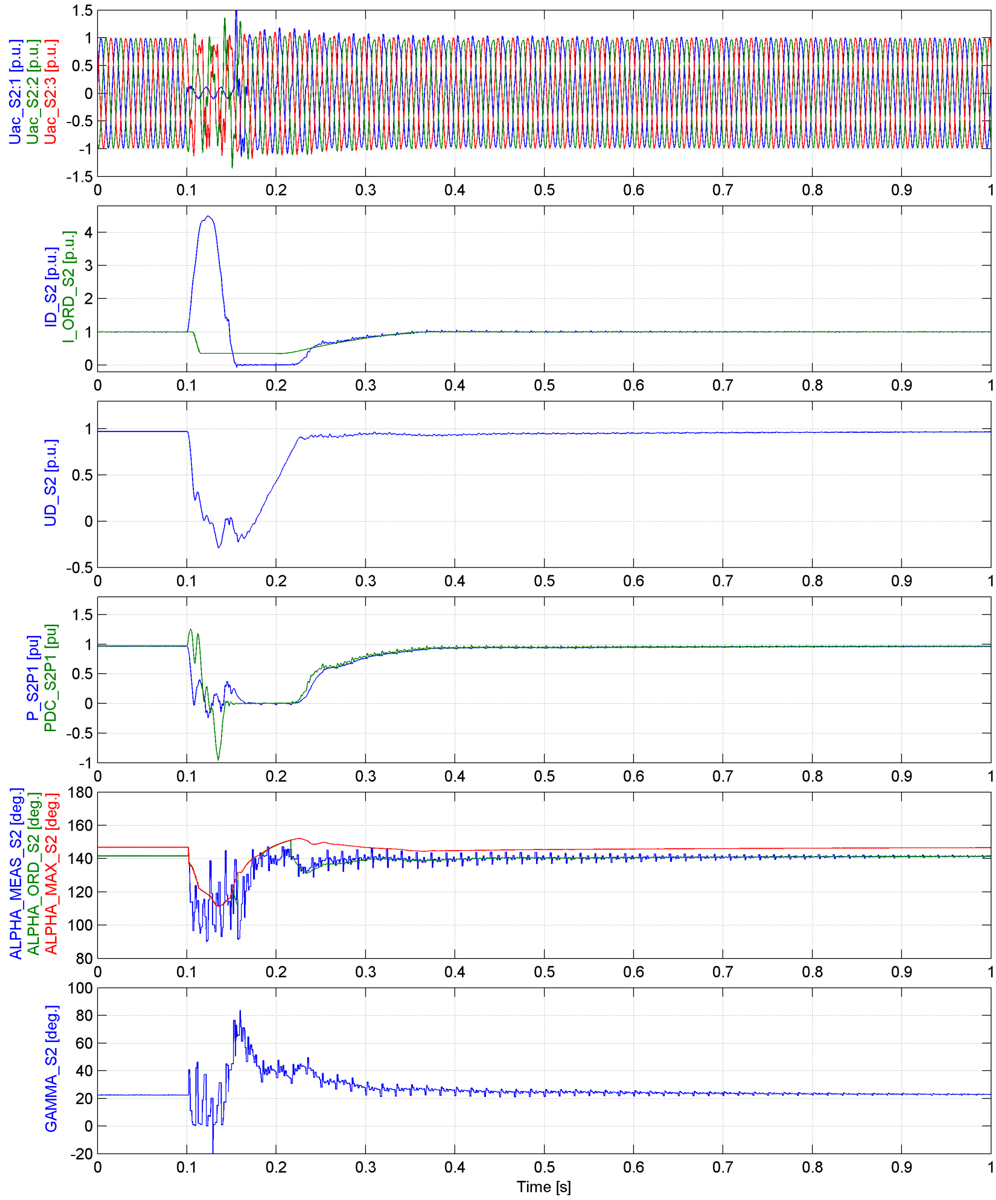


Figure 4.20: 50ms single phase to ground fault with 10% remaining voltage. Station 2

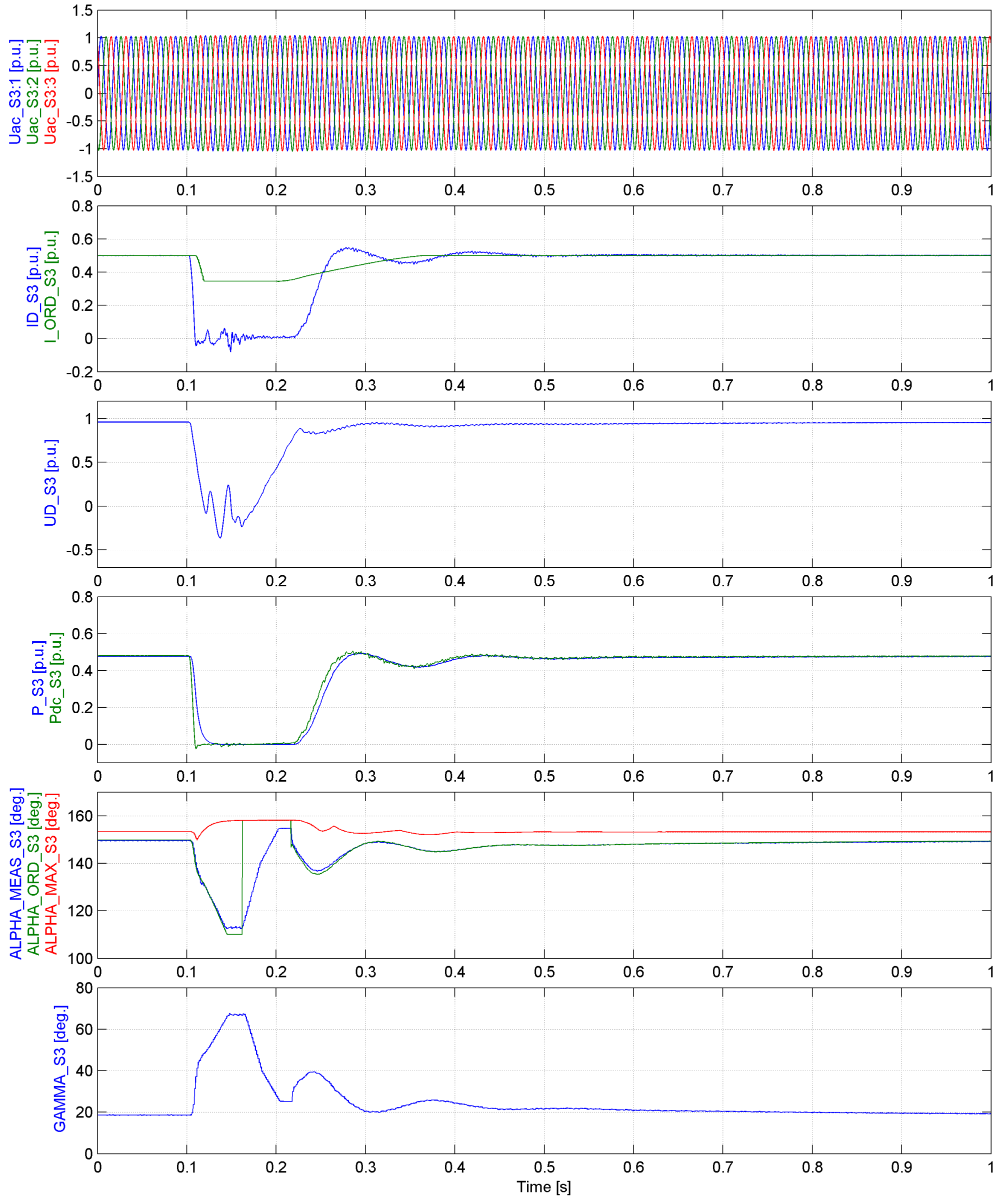


Figure 4.21: 50ms single phase to ground fault with 10% remaining voltage. Station 3

Similar to section 4.2.3.2, there was only a small difference between the cases with and without the telecommunication. Again, the system with no telecom recovered with reduced voltage and the third station experienced a small overcurrent. However, due to increased gain in the VCA when the system operating in the RVC mode, the voltage recovered faster what led to approximately 20ms faster recovery. Besides, in the rectifier, the current order limiter was activated which interaction can be seen in the second sub-plot in figure 4.19.

Additionally, the following three figures show the results when a three phase to ground fault with 10% remaining time was applied at station two for 50ms. Based on these figures and previous results, it can be concluded that if a fault was applied on the inverter side and a commutation failure occurred, the dynamic behavior and control actions of the system may be similar irrespective of whether was a single phase or a three phase fault.

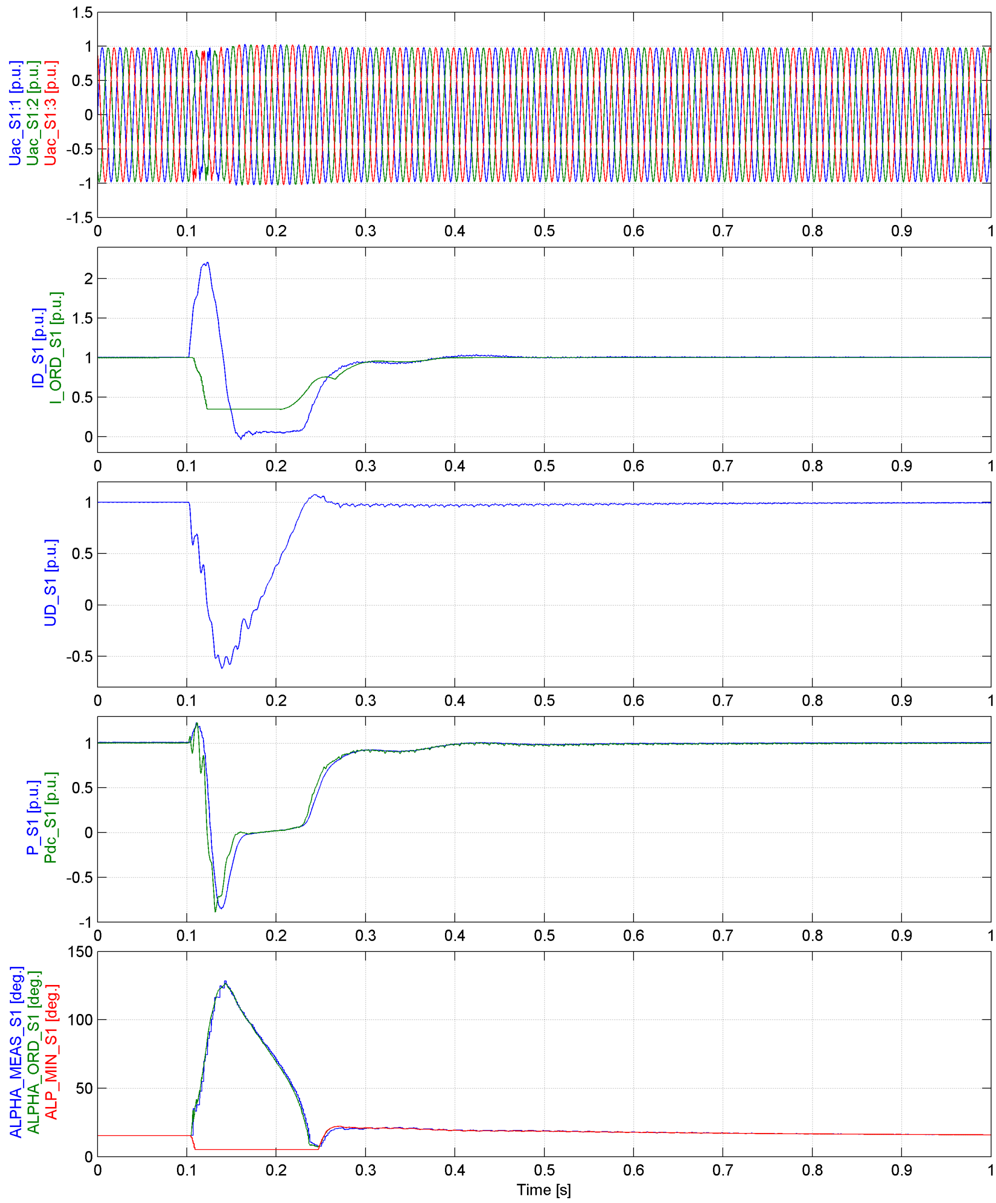


Figure 4.22: 50ms three phase to ground fault with 10% remaining voltage. Station 1

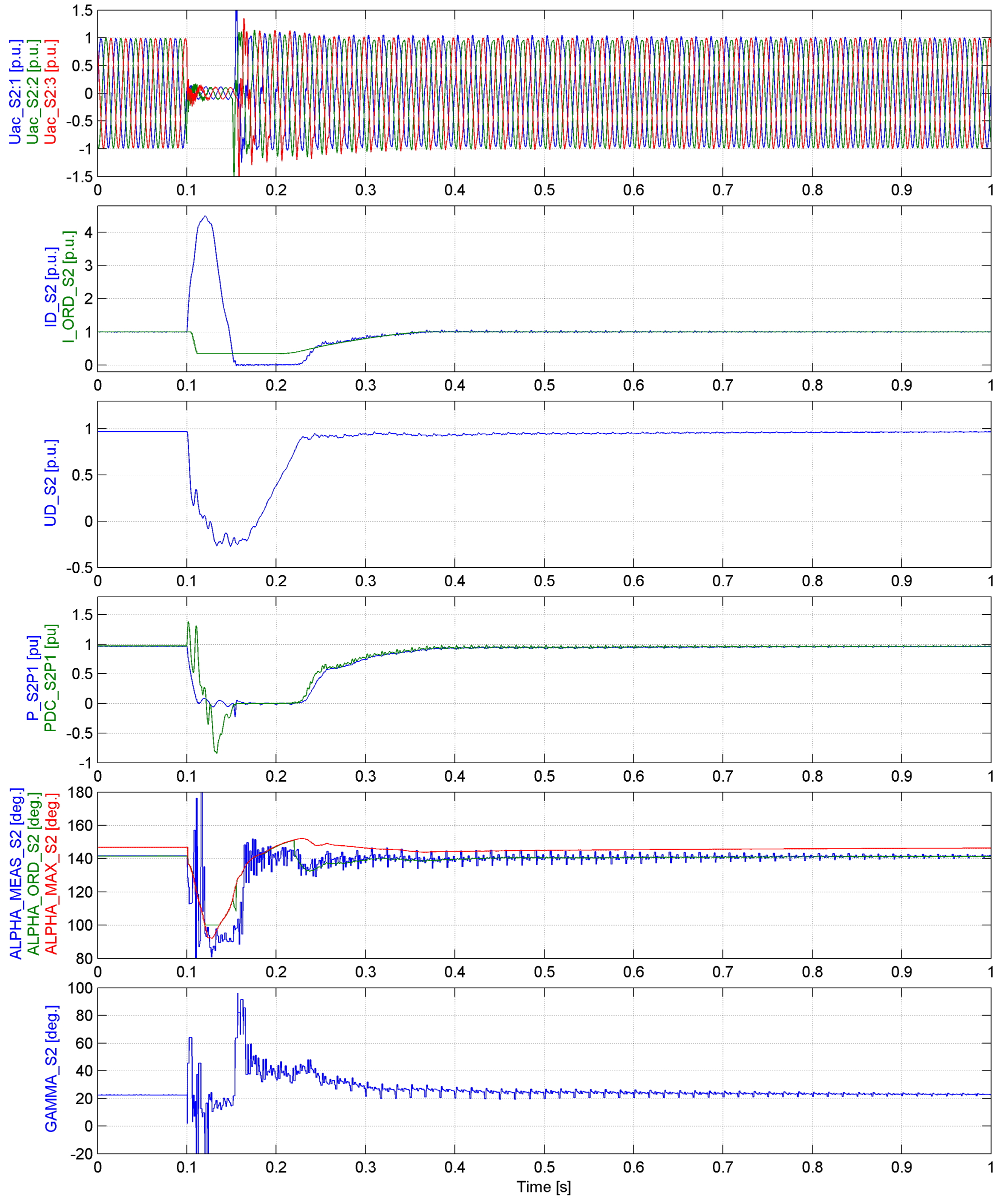


Figure 4.23: 50ms three phase to ground fault with 10% remaining voltage. Station 2

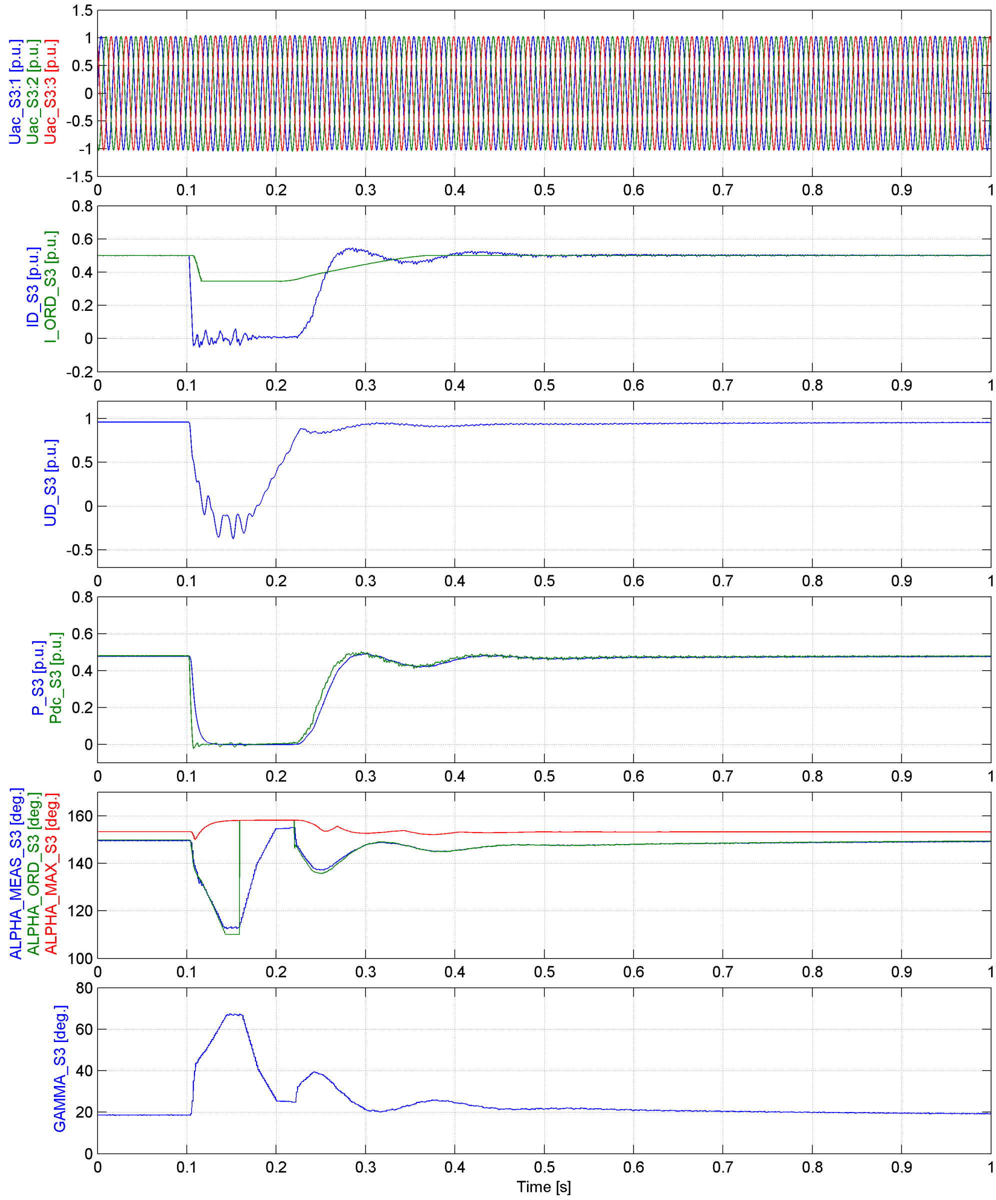


Figure 4.24: 50ms three phase to ground fault with 10% remaining voltage. Station 3

4.2.3.3 Fault at station 3

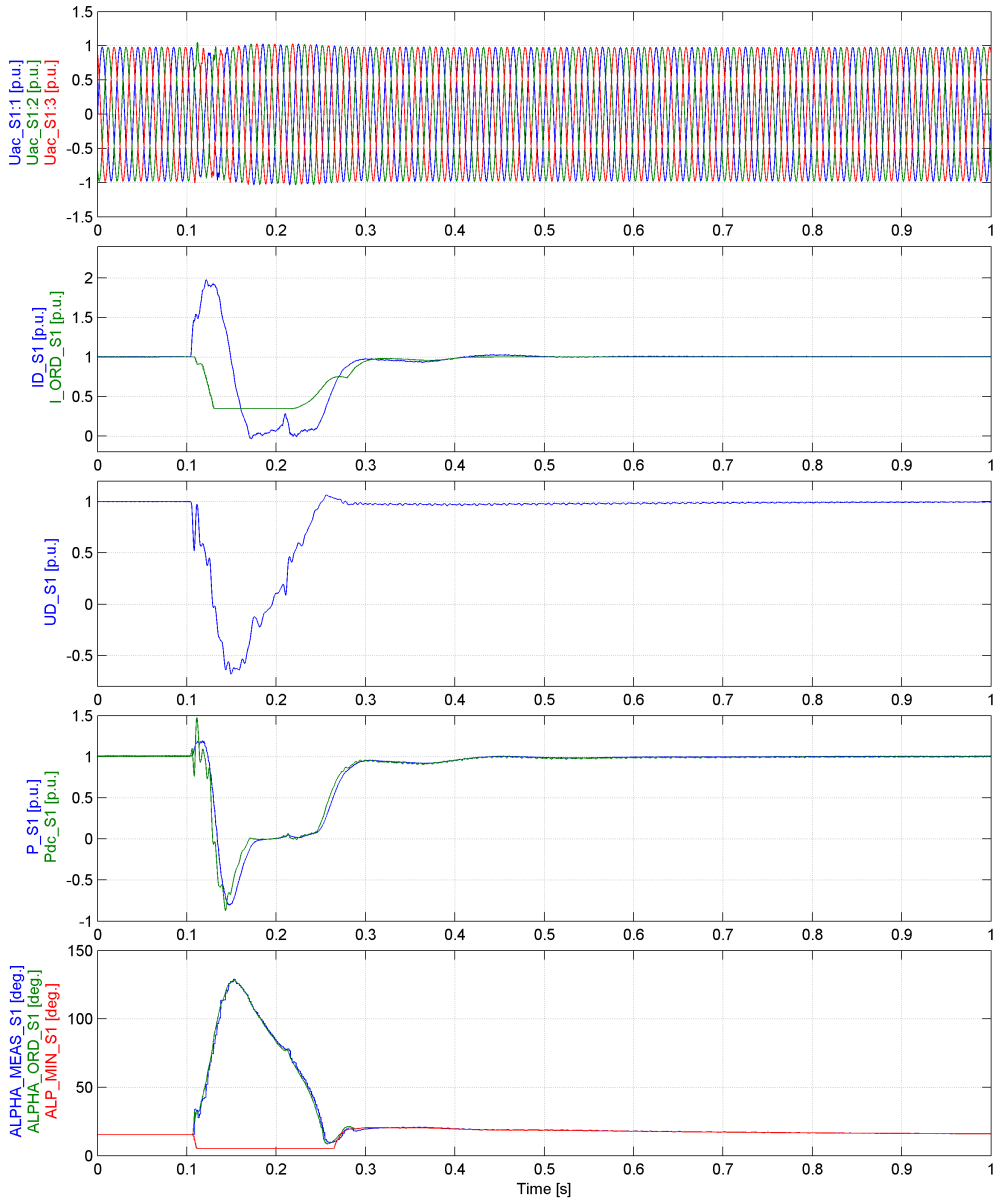


Figure 4.25: $100ms$ three phase to ground fault with 10% remaining voltage. Station 1

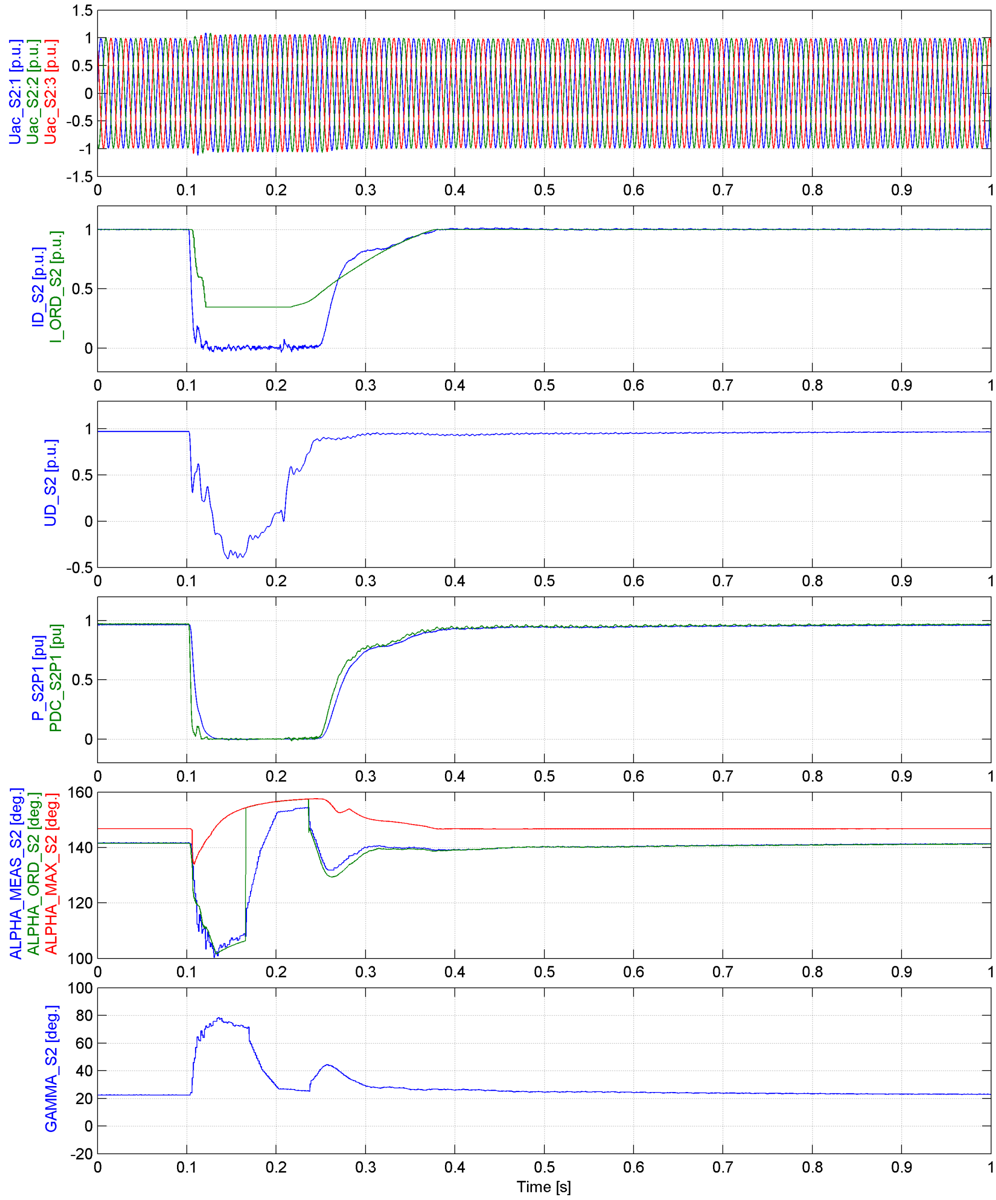


Figure 4.26: 100ms three phase to ground fault with 10% remaining voltage. Station 2

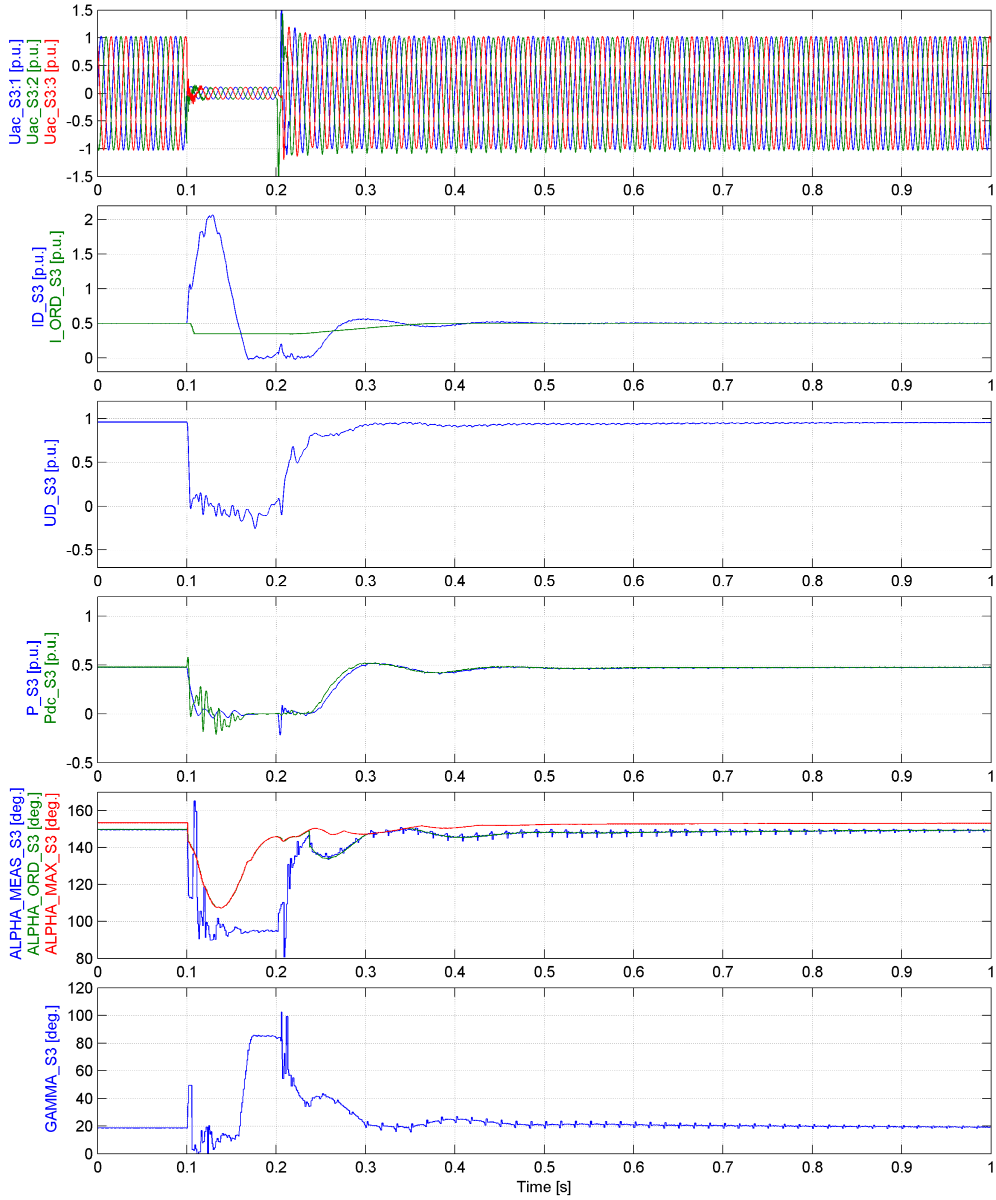


Figure 4.27: 100ms three phase to ground fault with 10% remaining voltage. Station 3

Similarly, in the case when the fault was applied on the third station, the system with no telecommunication recovered faster than with telecom by about 50ms. The reason of this difference can be that the network strength of the AC network to which the third station is connected is higher than the second station's AC network what led to faster DC voltage recovery. Similarly to the previous case, the current order limiter was activated (figure 4.25), but besides that all the dynamic behavior of the system is similar to the case with telecommunication.

Additionally, more simulations were done when different faults were applied for the system which was operating at different operating points. Some of the results are represented in the appendix (sections A.2, A.3 and A.4).

4.2.4 DC Fault

A DC fault was applied on the overhead line between stations one and two for $100ms$. The simulation results are represented in following figures.

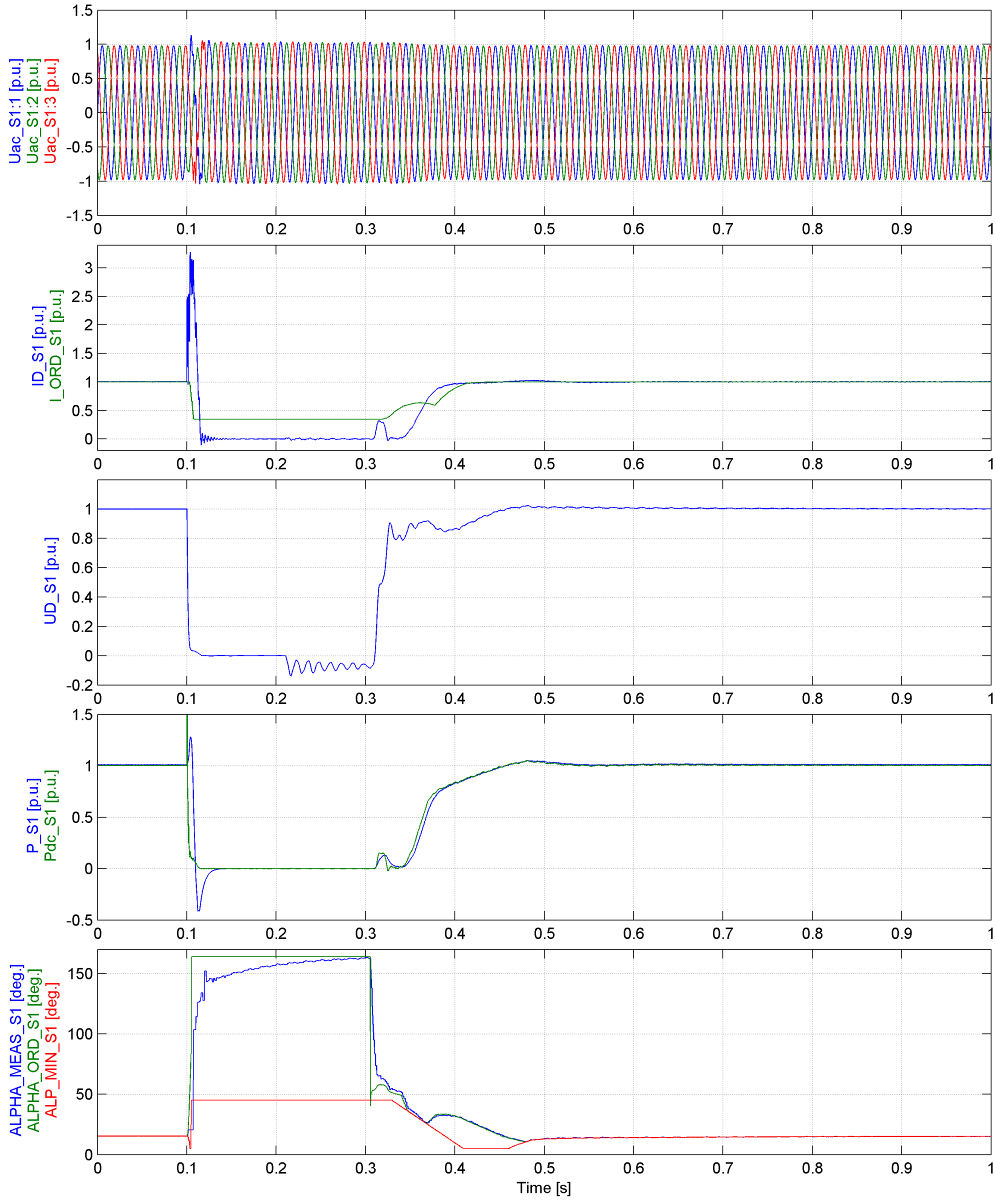


Figure 4.28: $100ms$ DC fault between stations one and two. Station 1

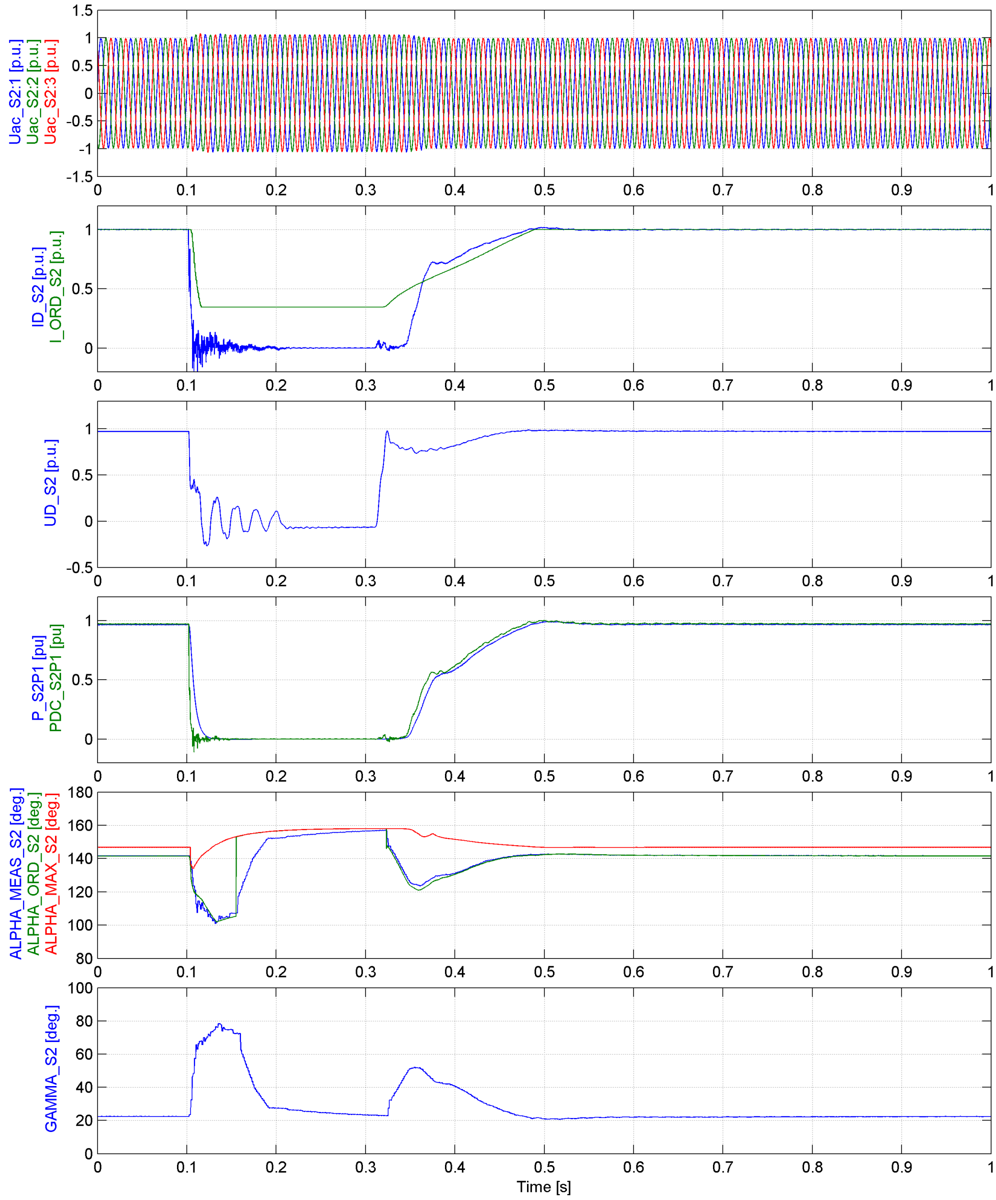


Figure 4.29: 100ms DC fault between stations one and two. Station 2

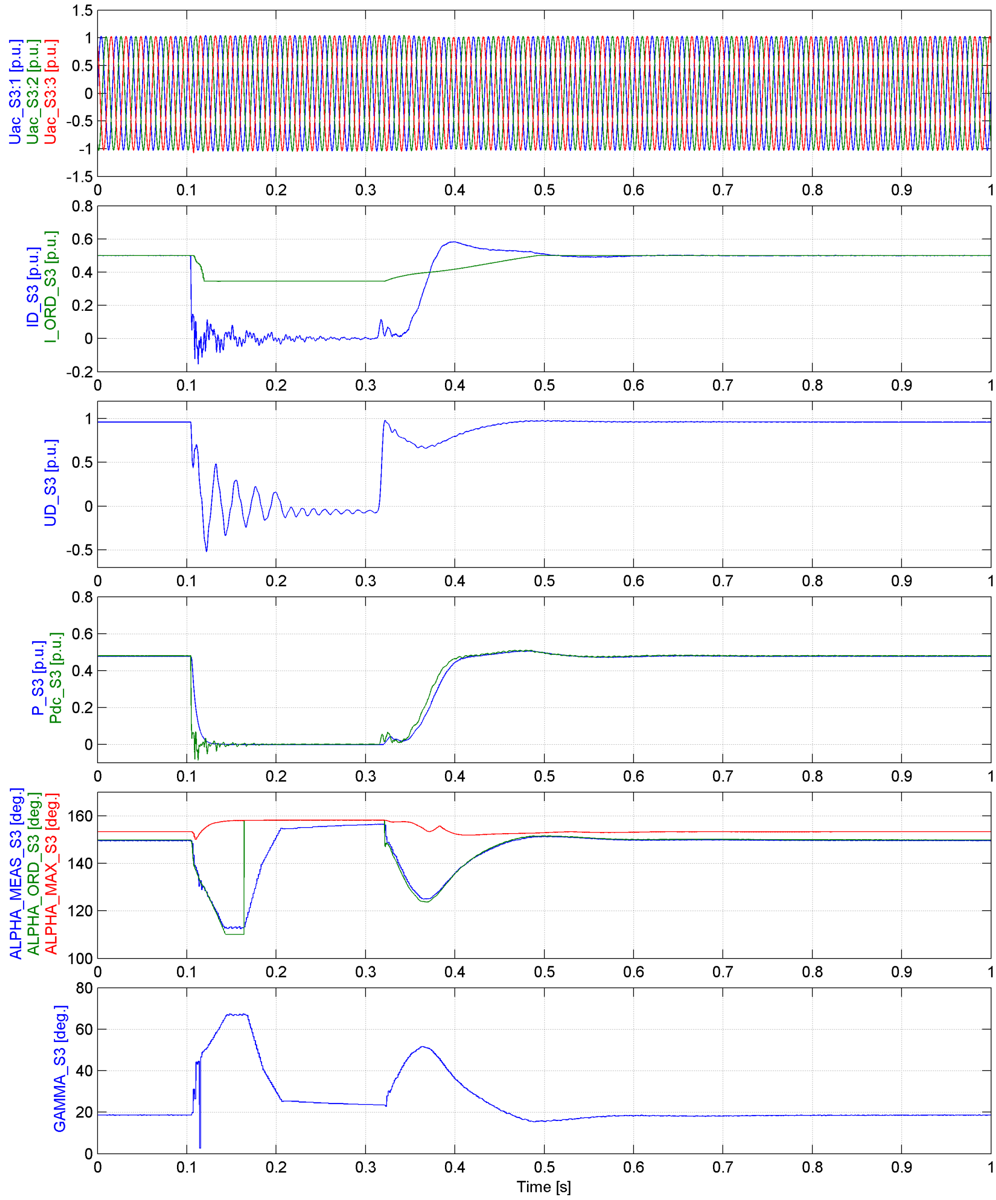


Figure 4.30: 100ms DC fault between stations one and two. Station 3

When the DC fault was applied, the RETARD function was activated in the rectifier as it is seen in figure 4.28. The firing angle alpha increased to its maximum value for 200ms and the station started to operate as an inverter, consequently, the system discharged. After the time of RETARD function past, the system had to be energized and this period can be seen in the figures between 0.31s and 0.34s when the DC voltage starts to increase, but there is no any current flowing in the system. When the system is energized, it is recovering similarly as after any other fault. Moreover, as the RETARD function is activated only in the rectifier, the control actions in both inverters are similar to the case when an AC fault appears at the rectifier side (section 4.1.1.1).

4.2.5 The Loss of One of the Stations

In this project, the multi-terminal HVDC system consists of one rectifier and two inverters and because of this, only the loss of one of the inverters is investigated. The rectifier tripping would lead to the collapse of the entire system.

In both cases, at $0.1s$ three phase to ground AC fault were introduced with 10% remaining voltage for $100ms$. At the time equal to $0.15s$, firing impulses for the valves were blocked and at $0.18s$ a station was disconnected.

The loss of station 2

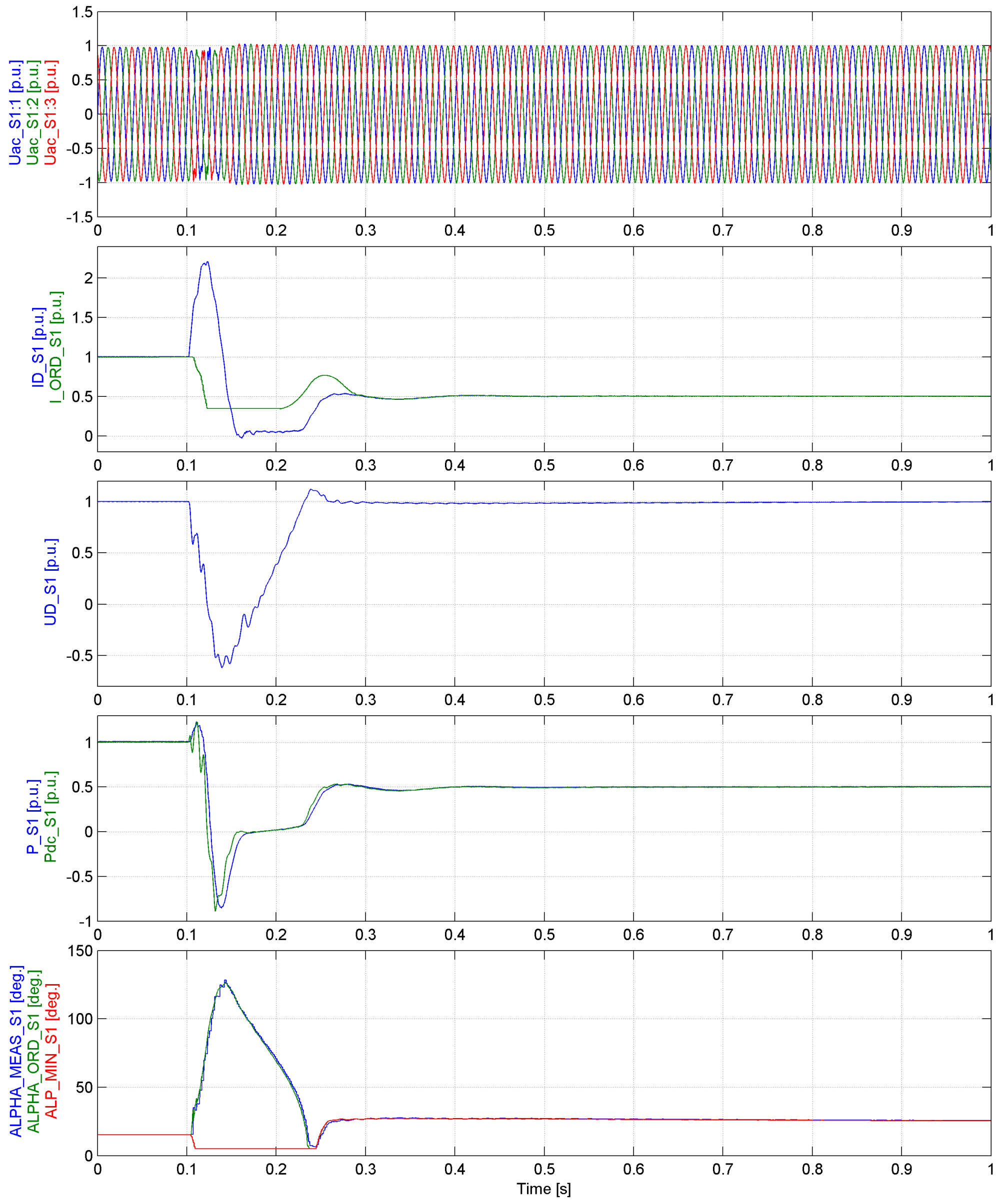


Figure 4.31: The loss of station 2. Station 1

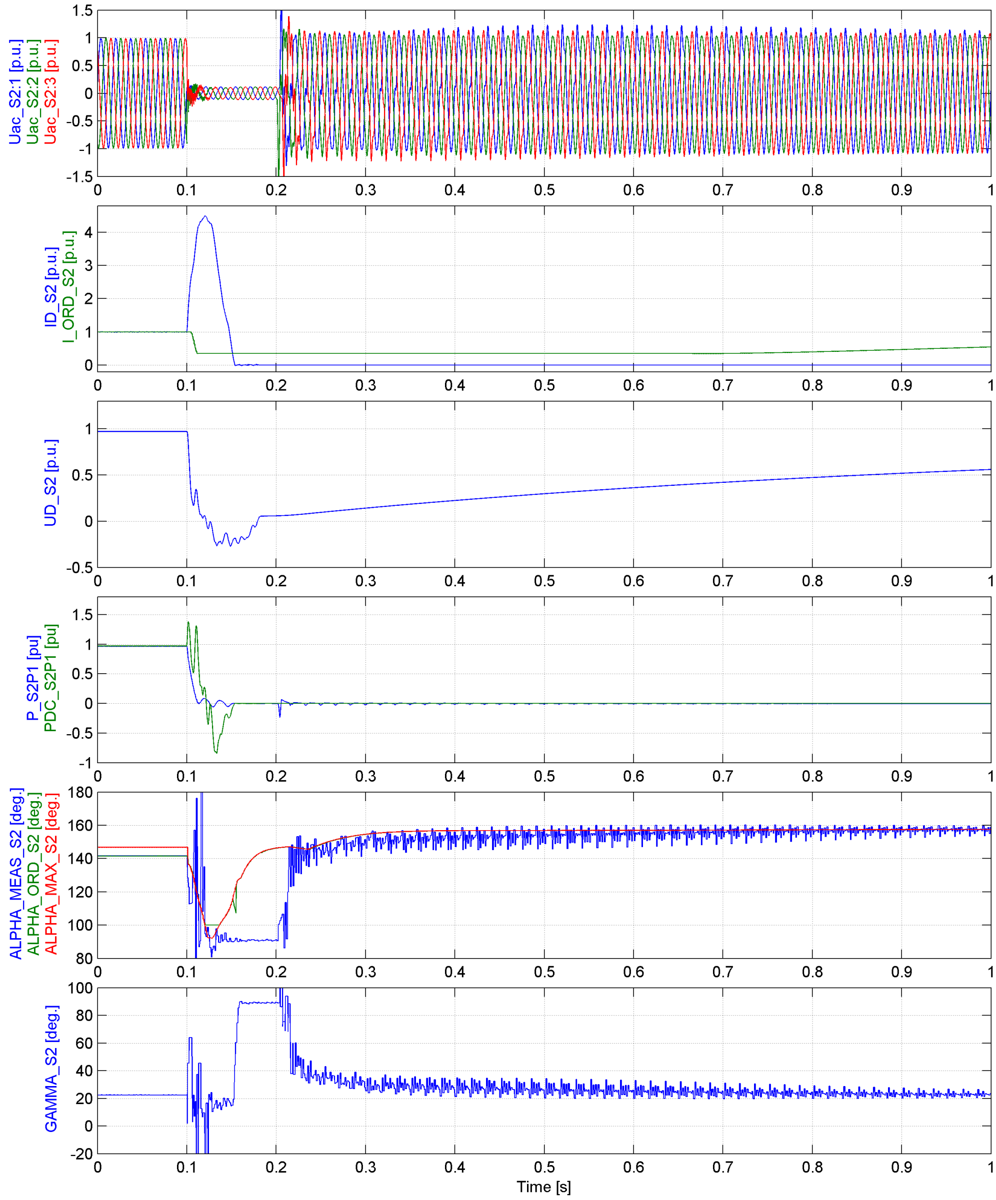


Figure 4.32: The loss of station 2. Station 2

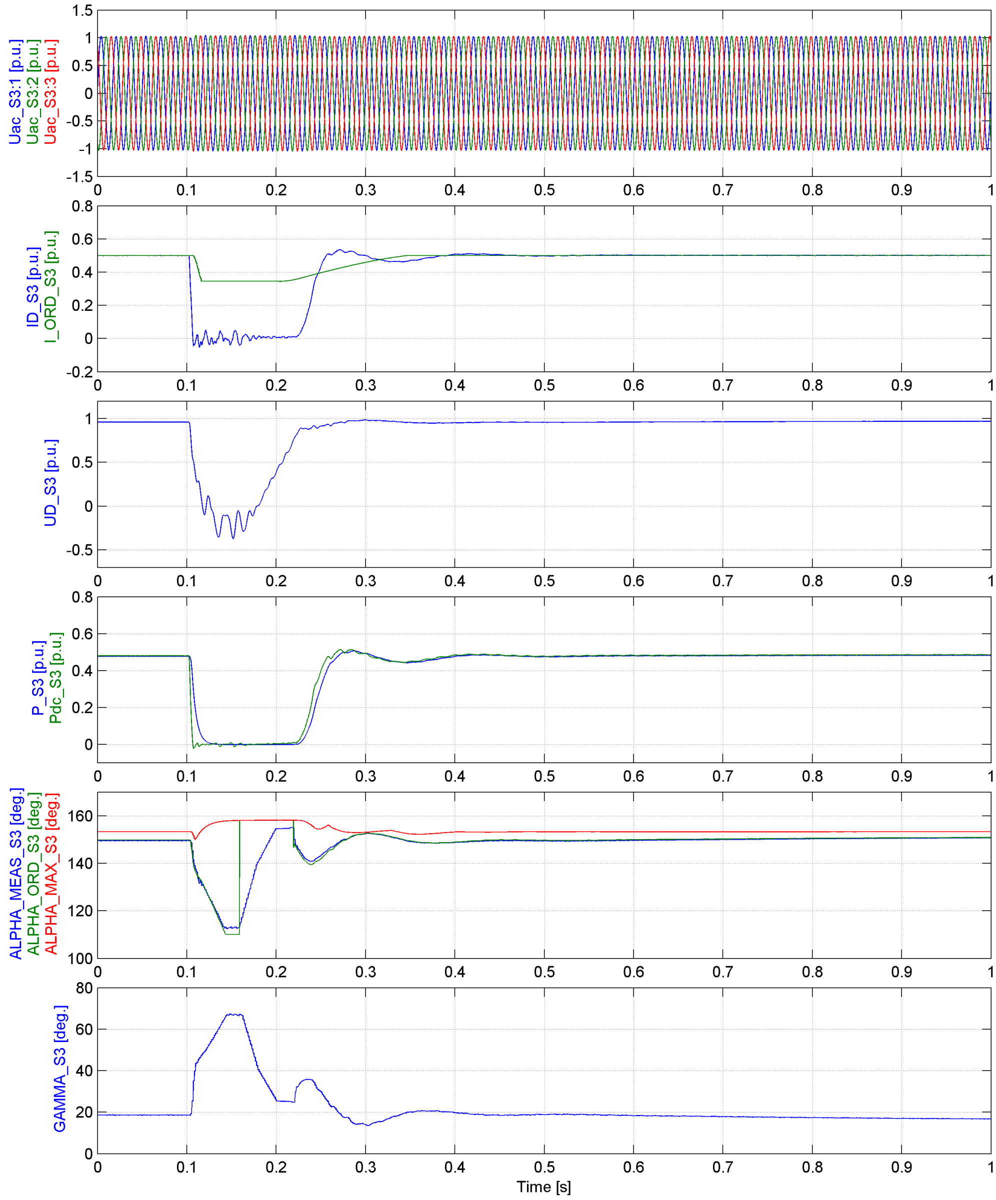


Figure 4.33: The loss of station 2. Station 3

The loss of station 2

As the figures below show, the system was able to recover and reach a new steady state in both cases. Furthermore, the behavior of the system and control actions during the recovery was as in the case with available telecommunication (section 4.1).

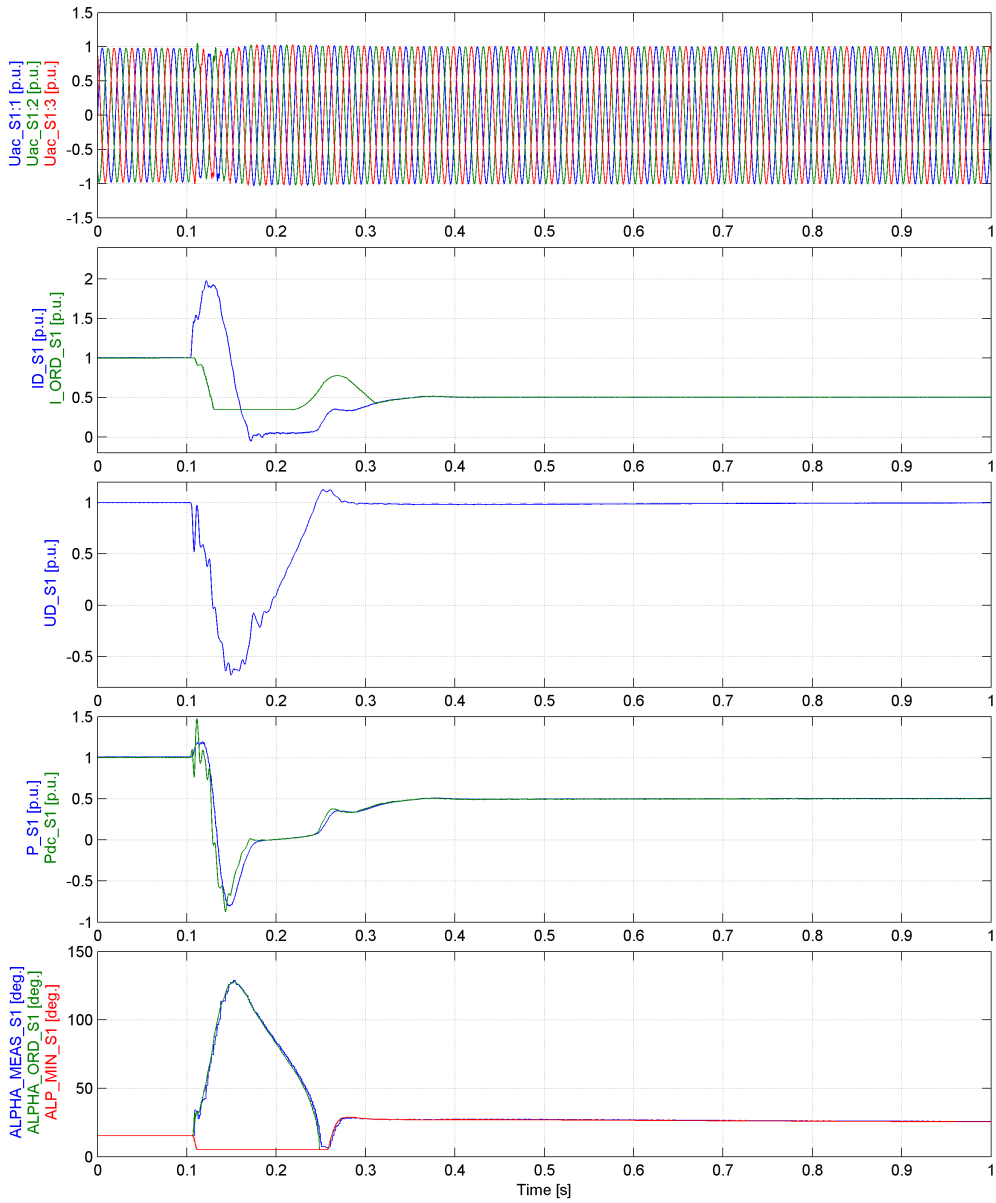


Figure 4.34: The loss of station 3. Station 1

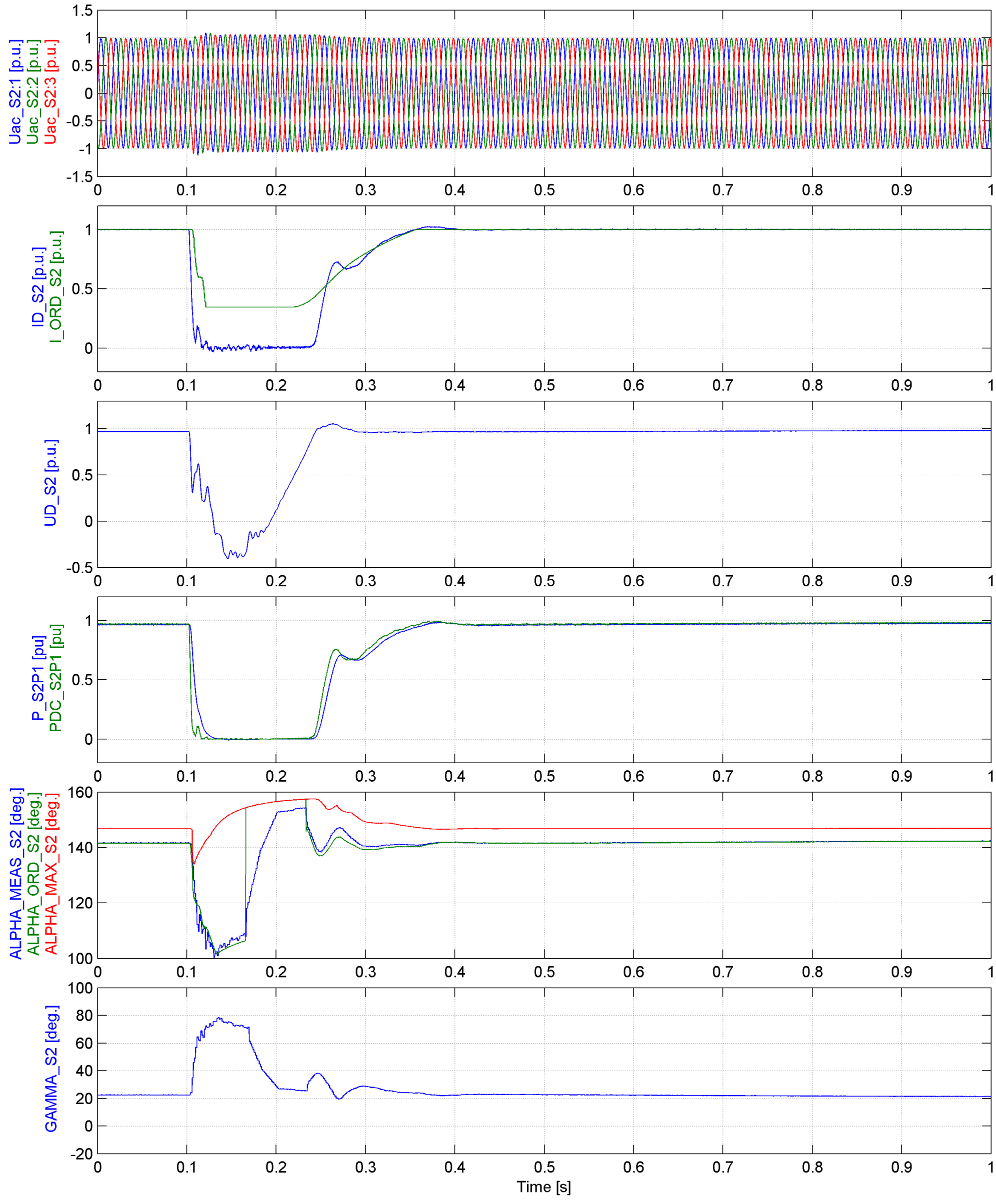


Figure 4.35: The loss of station 3. Station 2

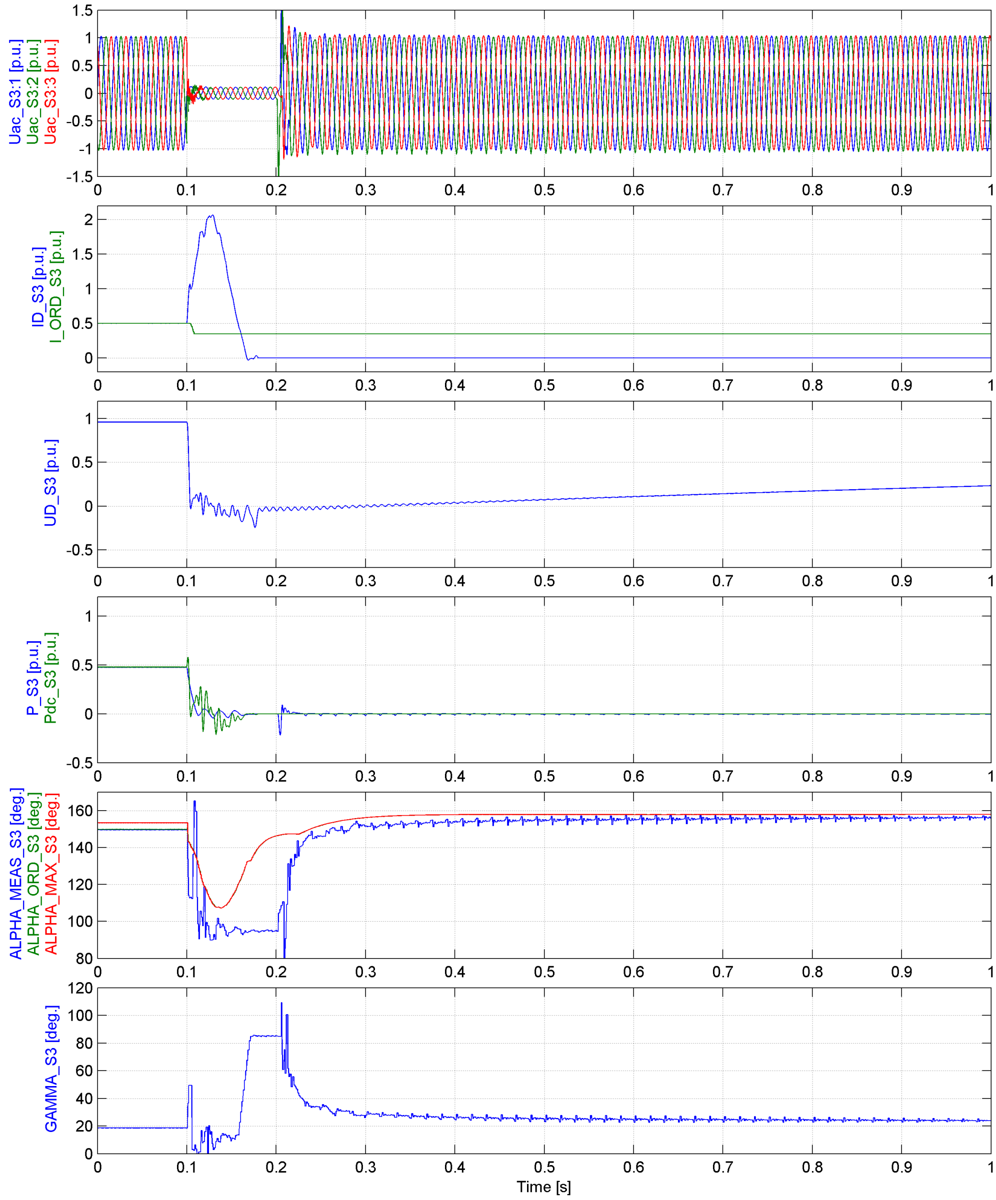


Figure 4.36: The loss of station 3. Station 3

However, in both cases a temporary mismatch between current order and actual current in the rectifier after the VDCOL stopped interacting are observed. The reason of this mismatch is that the current order, which is normally calculated by the power controller, is replaced by the measured current at the station, but only after the DC voltage is recovered. The reasons of such control sequence are discussed in section 4.2.9. However, this mismatch does not have any contribution to the recovery of the system until telecommunication is not available as the rectifier gets back to operation into the voltage control when the DC voltage is recovered. In both cases, the 90% of pre-fault transmitted power in the remaining inverter was reached in less than 200ms after the fault and this is assumed as normal recovery (approximately 60ms for station two and 130ms for station three).

4.2.6 Effect of the Gain in the VCAREG

In section 3.4, it was mentioned that the VCAREG is designed to be slow regulator and operate as a secondary control. Consequently, for the operation without the telecommunication, the gain of the VCAREG in the rectifier was increased by four times. For the comparison, figures 4.37 and 4.38 represent the case, when the gain was kept default in the rectifier and three phase to ground fault was applied on the second station's AC side after which the station was disconnected.

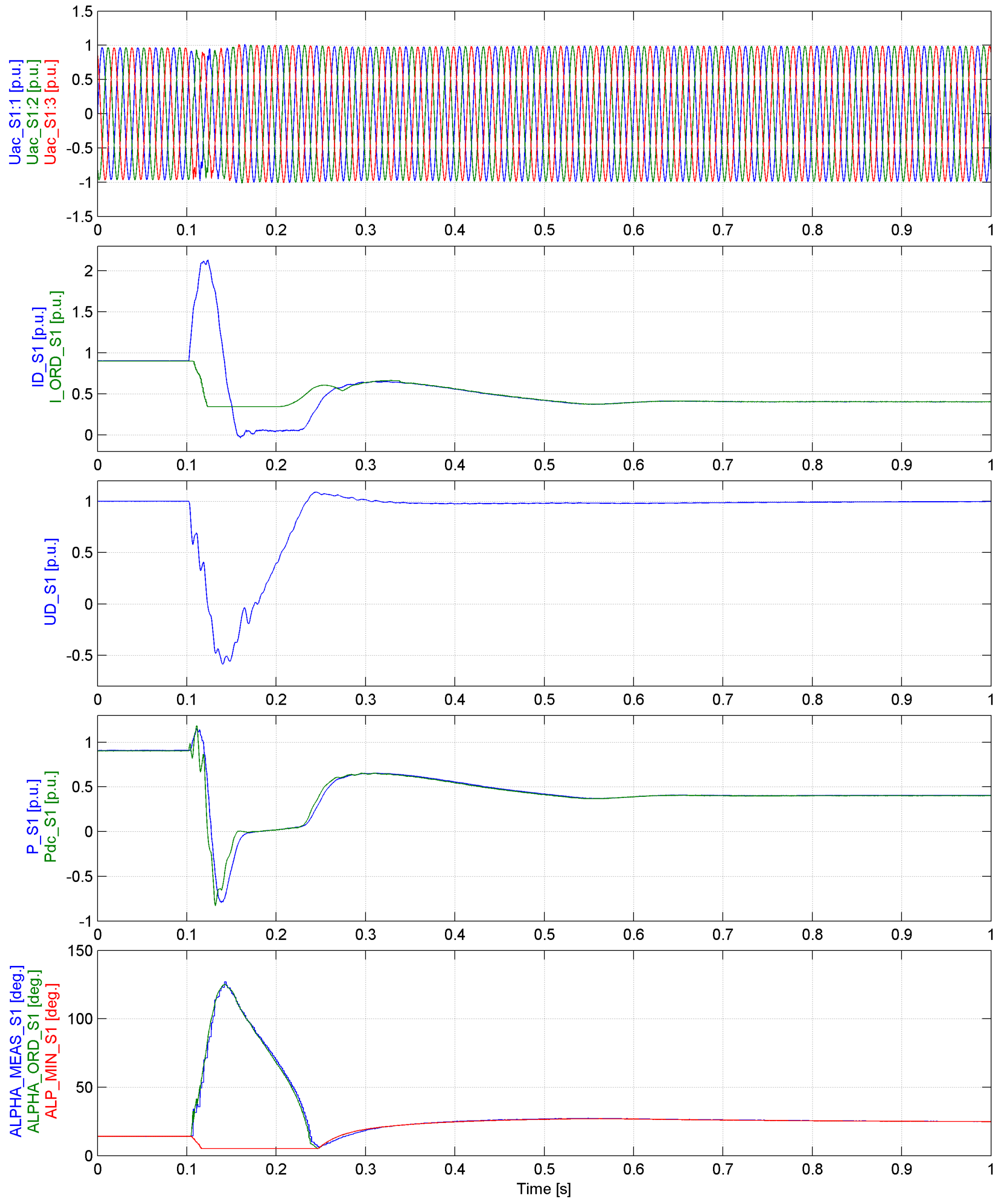


Figure 4.37: The loss if station 2, the gain of the VCAREG unchanged. Station 1

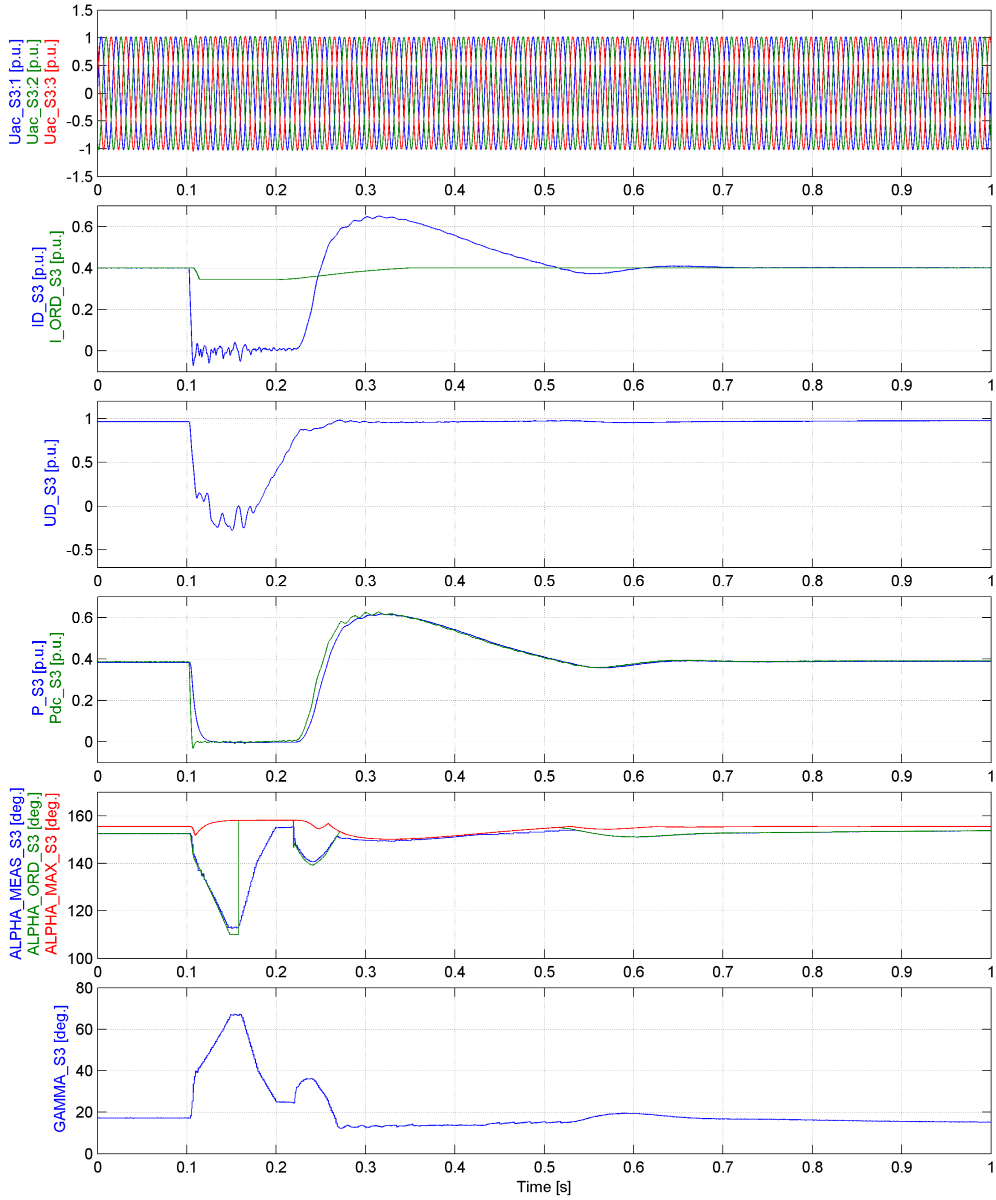


Figure 4.38: The loss if station 2, the gain of the VCAREG unchanged. Station 3

The general actions of the controls during the disturbance are similar to other cases when the same fault was applied. However, the main difference can be seen after the DC voltage recovered. The remaining inverter experienced a huge overcurrent of approximately $0.25 p.u.$. Depending on the system, such high overcurrent can lead to the severe damage to the equipment in the system. Furthermore, increased current resulted in the increased reactive power consumption and if the AC network at the station is weak, an unstable operation can develop. For these reasons, the gain of the VCAREG in the rectifier when it is operating in the voltage control mode should be increased to keep the proper dynamics of the system.

4.2.7 Reduced Nominal Extinction Angle

As it was mentioned before, in some cases, the upper limit of the CCA in the inverter can be reached. For instance, an AC fault with 10% remaining voltage on the second station's side was applied at the time equal to $0.1s$. At $0.15s$, firing impulses for the inverter at station two were blocked and at $0.18s$ it was disconnected.

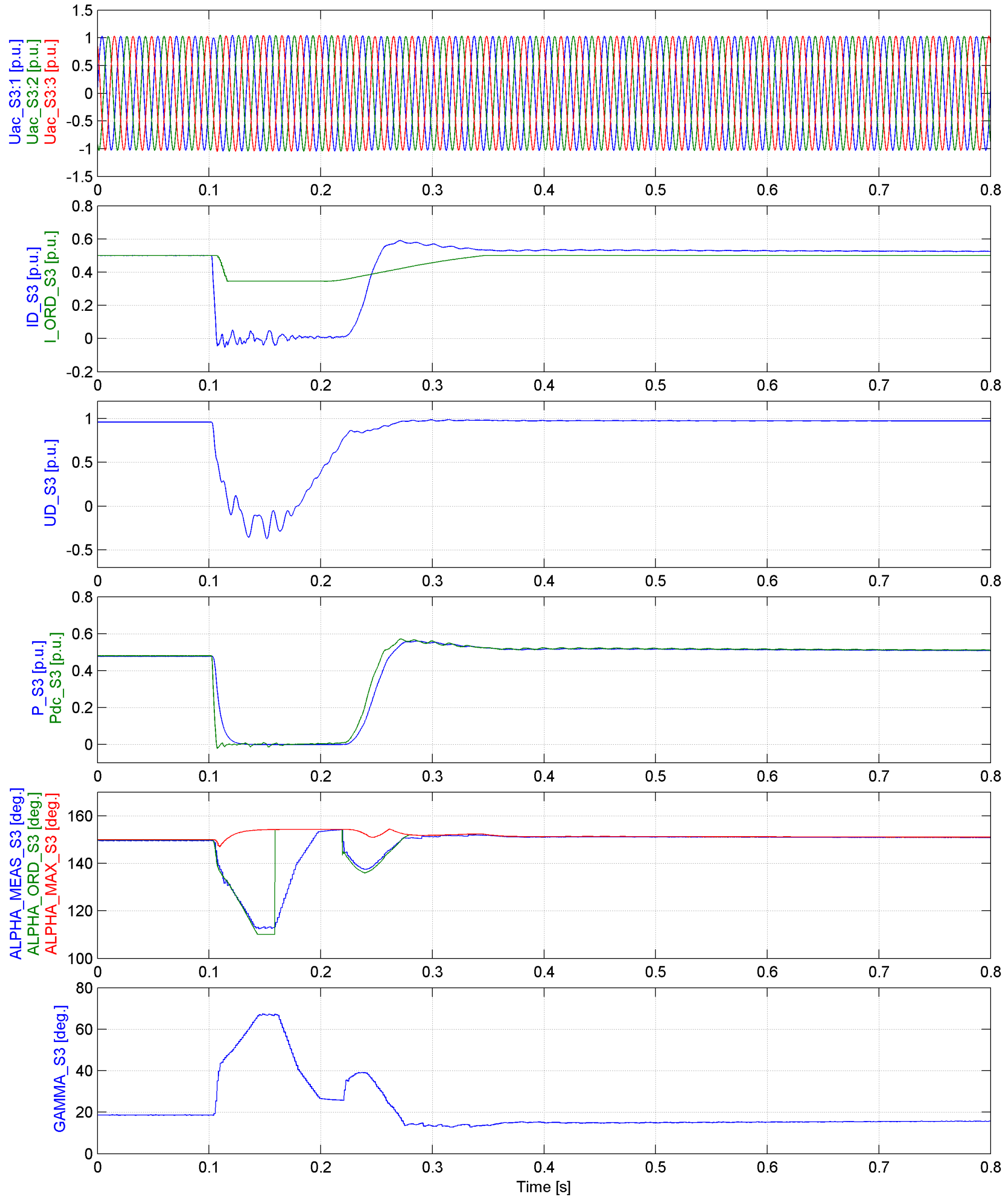


Figure 4.39: Operation with reduced nominal extinction angle. Station 3

Figure 4.39 represents plots for the third station during the disturbance and when the nominal γ value was not decreased. As this figure shows, even before the fault was applied, the inverter operates almost at the maximum firing angle. After station two was disconnected, the remaining inverter tried to reduce its current to ordered value, but the maximum limit of α was reached and a new steady state, with actual current higher than the ordered, was reached. The inverter is no longer in the current control.

To avoid such situations, the upper limit of the CCA in the inverters is increased by reducing the nominal extinction angle for the inverters when they are operating in the current control mode. The effect of this function can be seen in figure 4.33. After the same disturbance, the remaining inverter did not reach the maximum limit in the CCA and was able to control its current.

4.2.8 Reduced Voltage Recovery

This section shows the effect of the reduced nominal voltage to the system during recoveries. In the first case, a three phase to ground AC fault with 10% remaining voltage was applied on the second station's side and at $0.18s$ the station was disconnected. In this case, no reduced voltage recovery was used.

As it is seen in figures 4.40 and 4.41, the system recovered, but the remaining inverter was overloaded with two times higher current than ordered. The reason of this overloading is that the CCA in the inverter reached its maximum limit during the recovery and was not able to control the current. Consequently that the inverter is no longer operating in the current control, the firing angle in the rectifier is no longer forced to the lower limit of the CCA, therefore, the station is operating not in voltage control anymore, even though the DC voltage is $1p.u.$.

Without the reduced voltage recovery, the DC current in the remaining inverter firstly increased above the ordered value and this led to increased overlap angle. As a result, extinction angle gamma dropped to its minimum value and the firing angle reached its maximum. However, as both limits are reached, the inverter no longer can control its current which increased even more as well as the overlap. Consequently, the maximum limit of α started to go down to keep the relationship 2.2 valid.

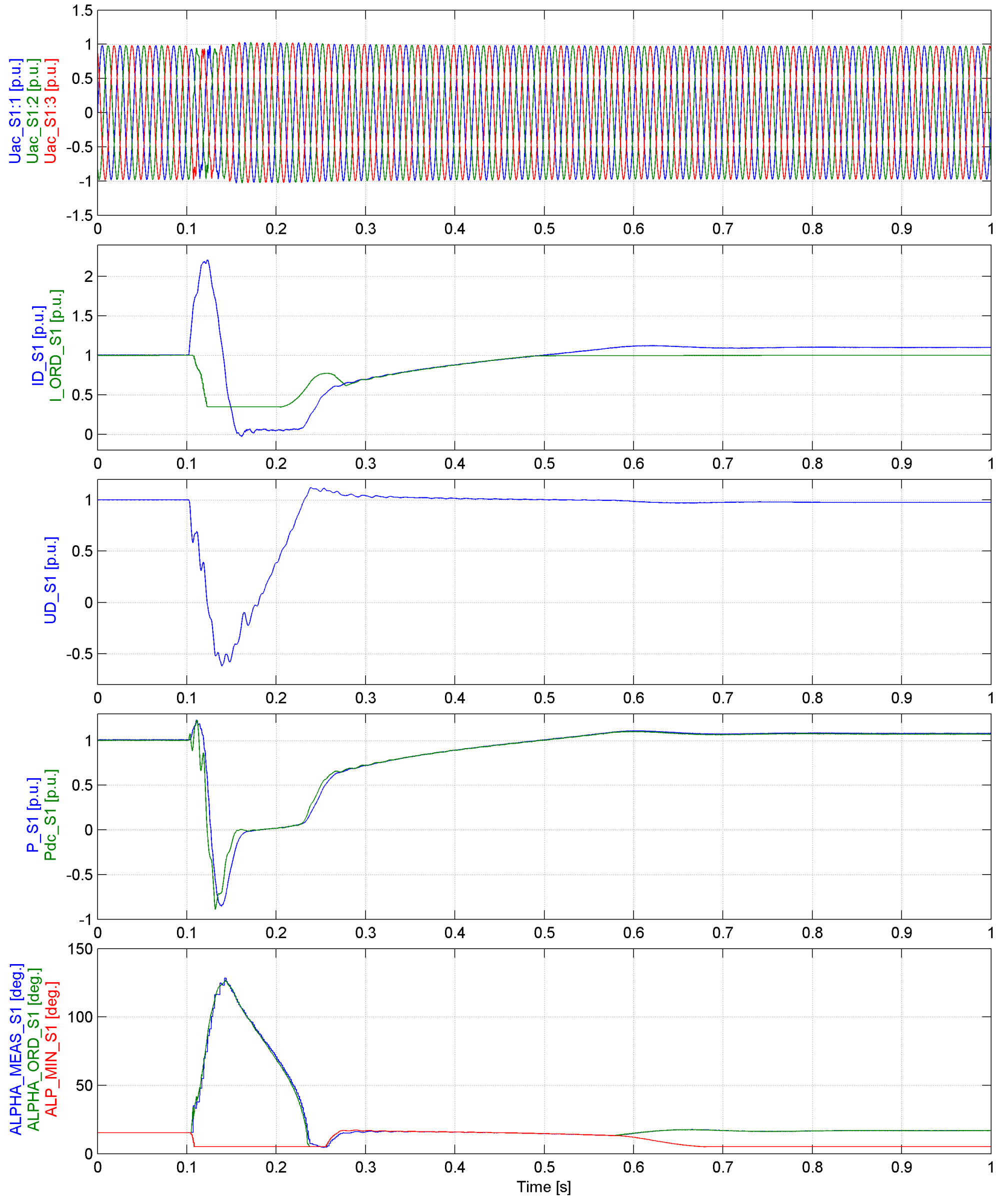


Figure 4.40: The loss of station 3, the reduced voltage recovery is not activated. Station 1

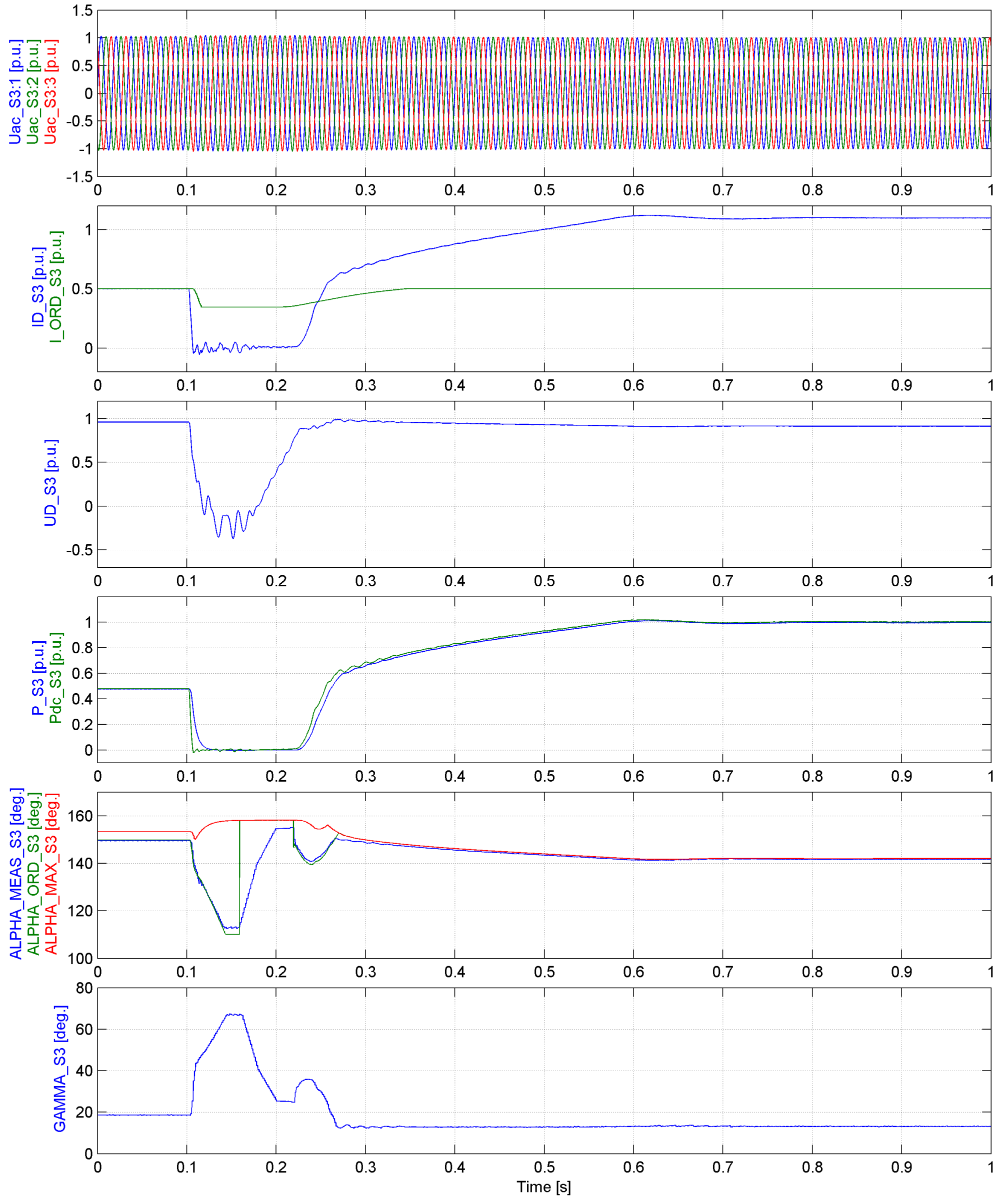


Figure 4.41: The loss of station 3, the reduced voltage recovery is not activated. Station 3

In the second case, the time constant of the low pass filter in the function controls was reduced to $0.1s$ and a three phase to ground AC fault with 10% remaining voltage was applied on the second station's side for $100ms$. It should be noted that all other results represented in other sections were obtained using the time constant of $0.2s$.

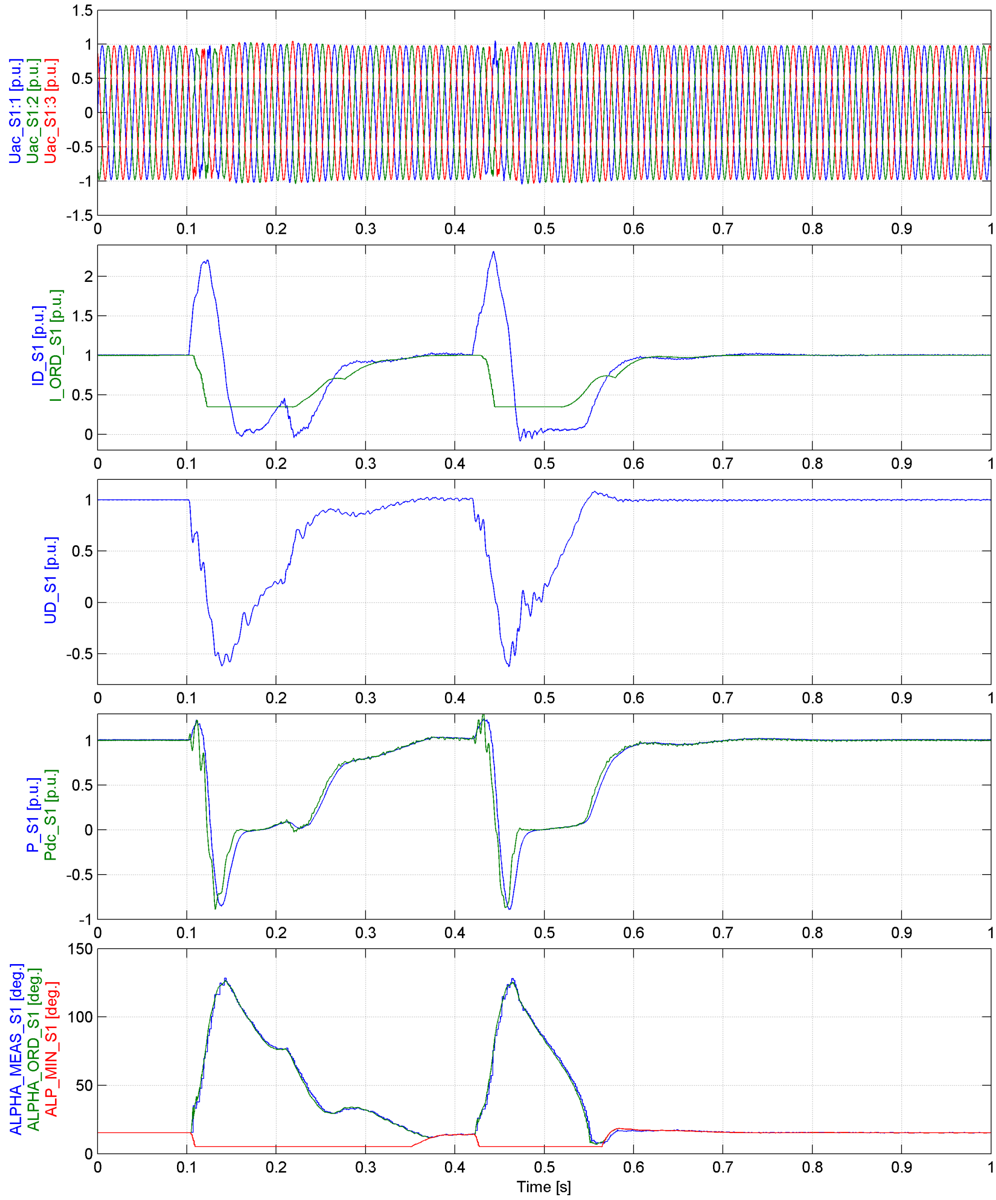


Figure 4.42: 100ms three phase to ground fault with 10% remaining voltage, the time constant of 0.1s. Station 1

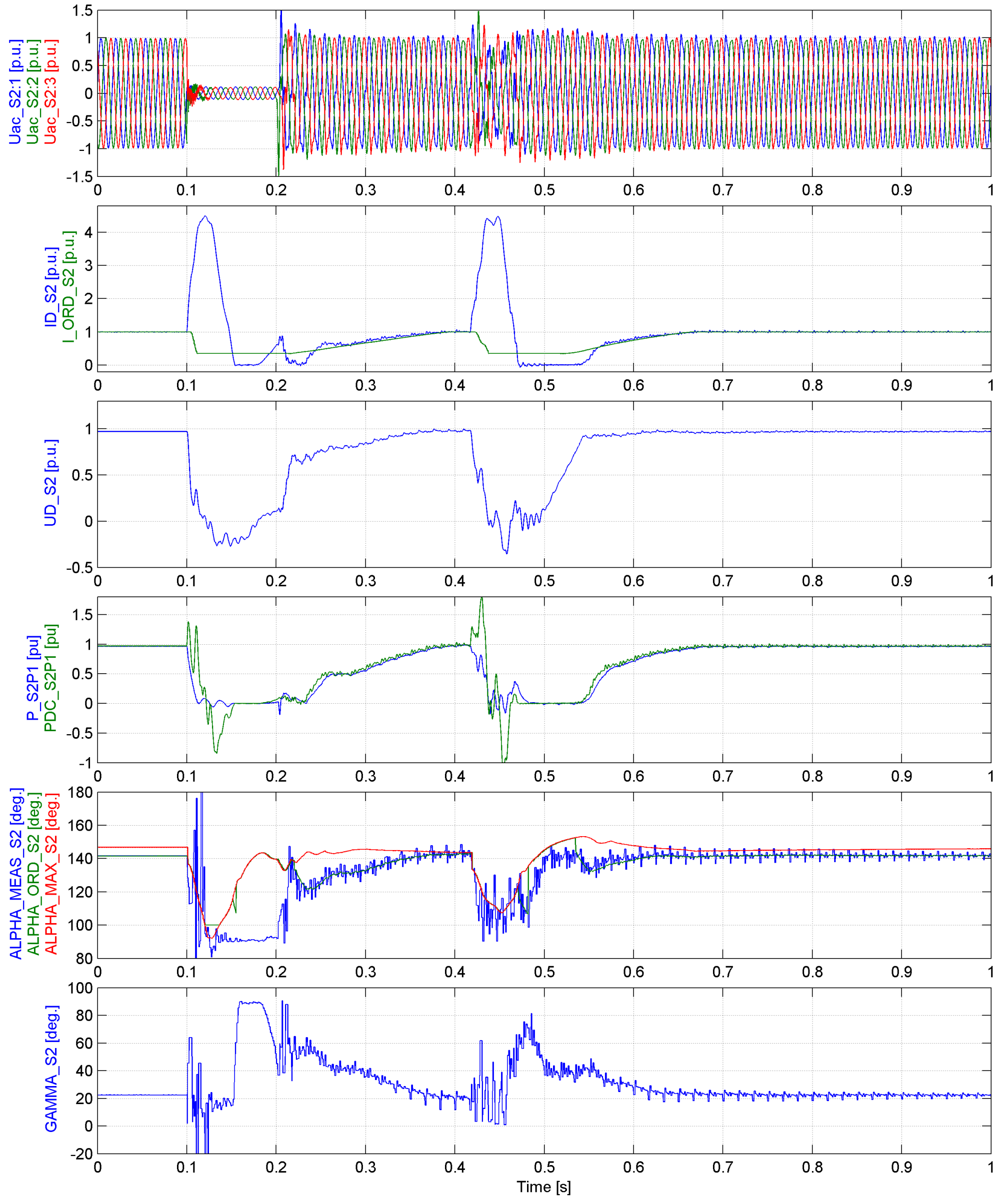


Figure 4.43: 100ms three phase to ground fault with 10% remaining voltage, the time constant of 0.1s. Station 2

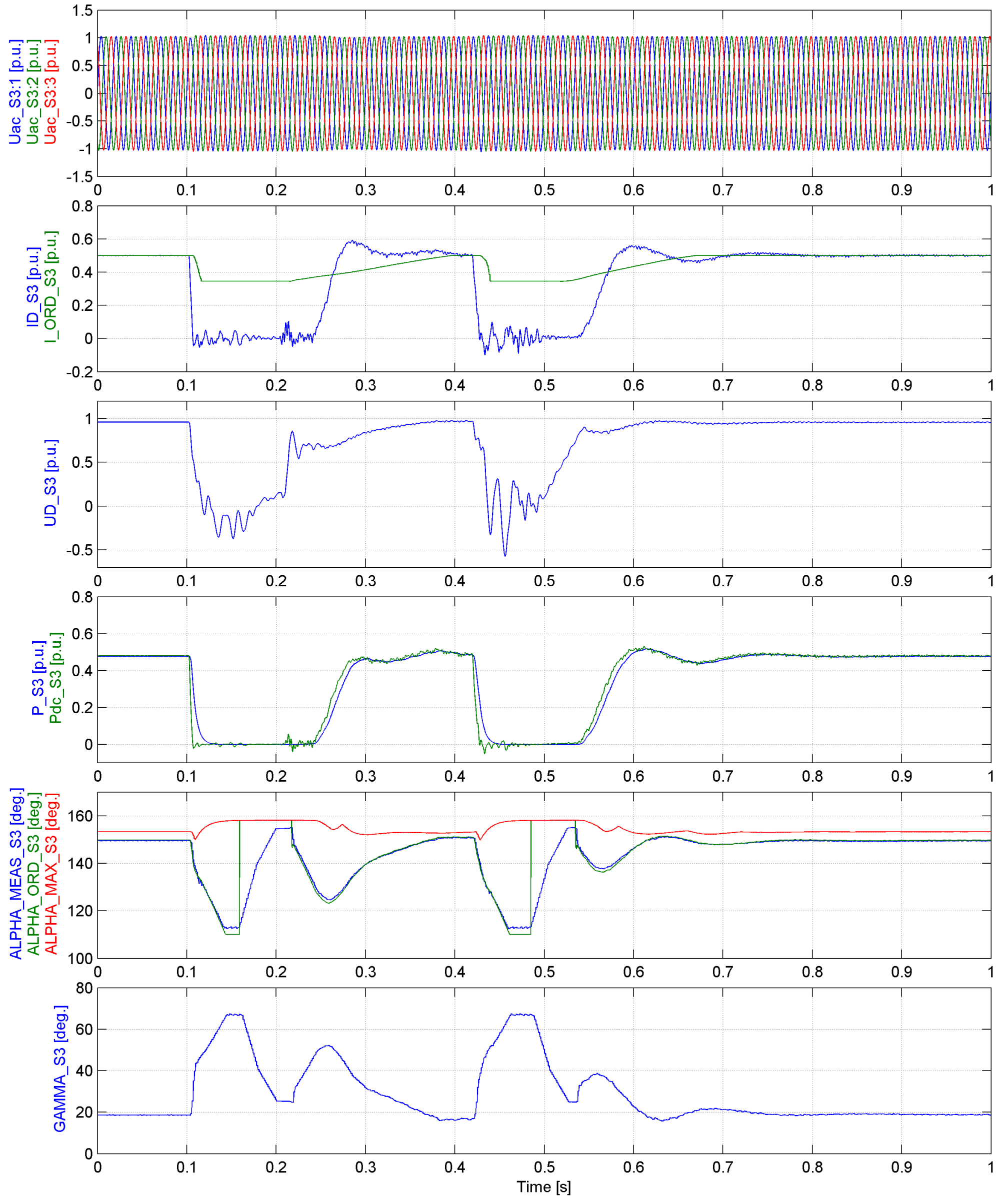


Figure 4.44: 100ms three phase to ground fault with 10% remaining voltage, the time constant of 0.1s. Station 3

As figures 4.42, 4.43 and 4.44 represent, the inverter in station two experienced the second commutation failure during the recovery. This was a consequence of reduced the time constant of the low pass filter, what led into a faster recovery of the voltage thus increased reactive power consumption. When the AC network, to which the station is connected, is weak and cannot satisfy the increased reactive power consumption can, the system can experience instabilities or commutation failures as it happened in this case.

The last figure displays the effect for the system recovery when the time constant for the low pass filter is higher. The green curve represents the case when the constant is equal to $0.2s$ and the blue curve - $0.5s$. A 70% remaining voltage, three phase to ground fault was applied at the second inverter for $50ms$. According to this figure, a conclusion can be made that for smaller faults, especially when commutation failure is avoided, the higher time constant gives too slow voltage recovery and reduced power transmission. In general, the detection limit and the time constant for the low pass filter should be tuned depending on the system parameters (SCR) to achieve the best recovery. Additionally, a detector of zero voltage crossing can be added to this function. In such way that if a commutation failure is not detected, the reduced voltage recovery would not be activated.

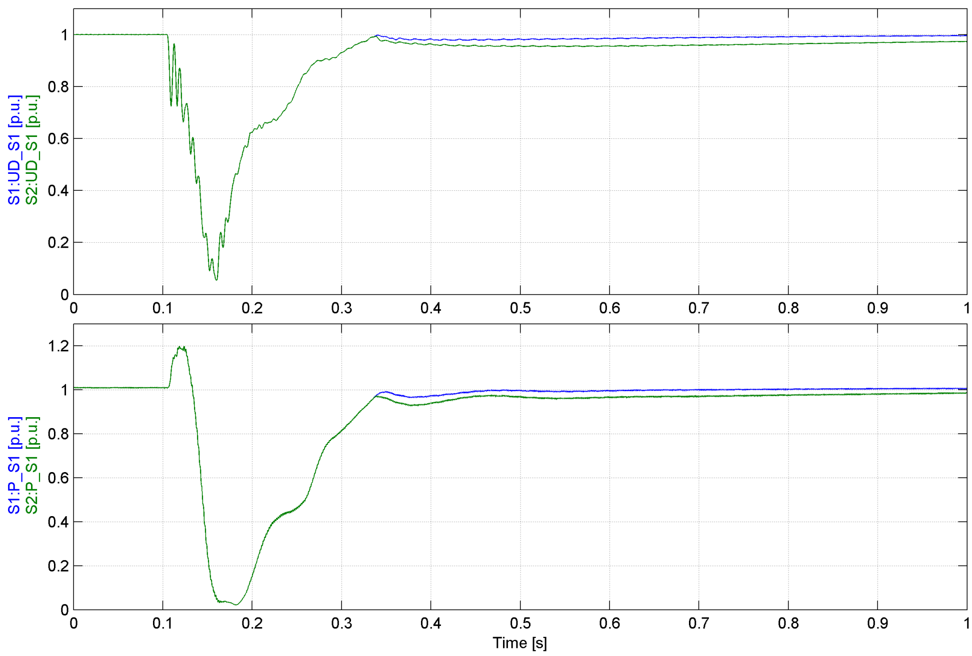


Figure 4.45: $50ms$ three phase to ground fault with 70% remaining voltage, the time constants of $0.2s$ (blue curve) and $0.5s$ (green curve). Station 1

4.2.9 The Change of Current Order

This section shows the effect of the change in current order. In the first case, the current order in the rectifier, which typically is calculated in the power controller, is switched to measured current ID when a voltage drop is detected. To represent a contribution of this change a three phase to ground AC fault at the second station was applied at $0.1s$ with 10% remaining voltage and at $0.18s$ the station was disconnected.

After the DC voltage drops, the VDCOL reduces the current order as it has a priority. When the voltage recovered and contribution from VDCOL ends, current order is ramped down until it becomes equal to the measured current. After that, the system reaches a new steady state. No overshoot in current order appeared during the recovery and the system recovered in about 150ms.

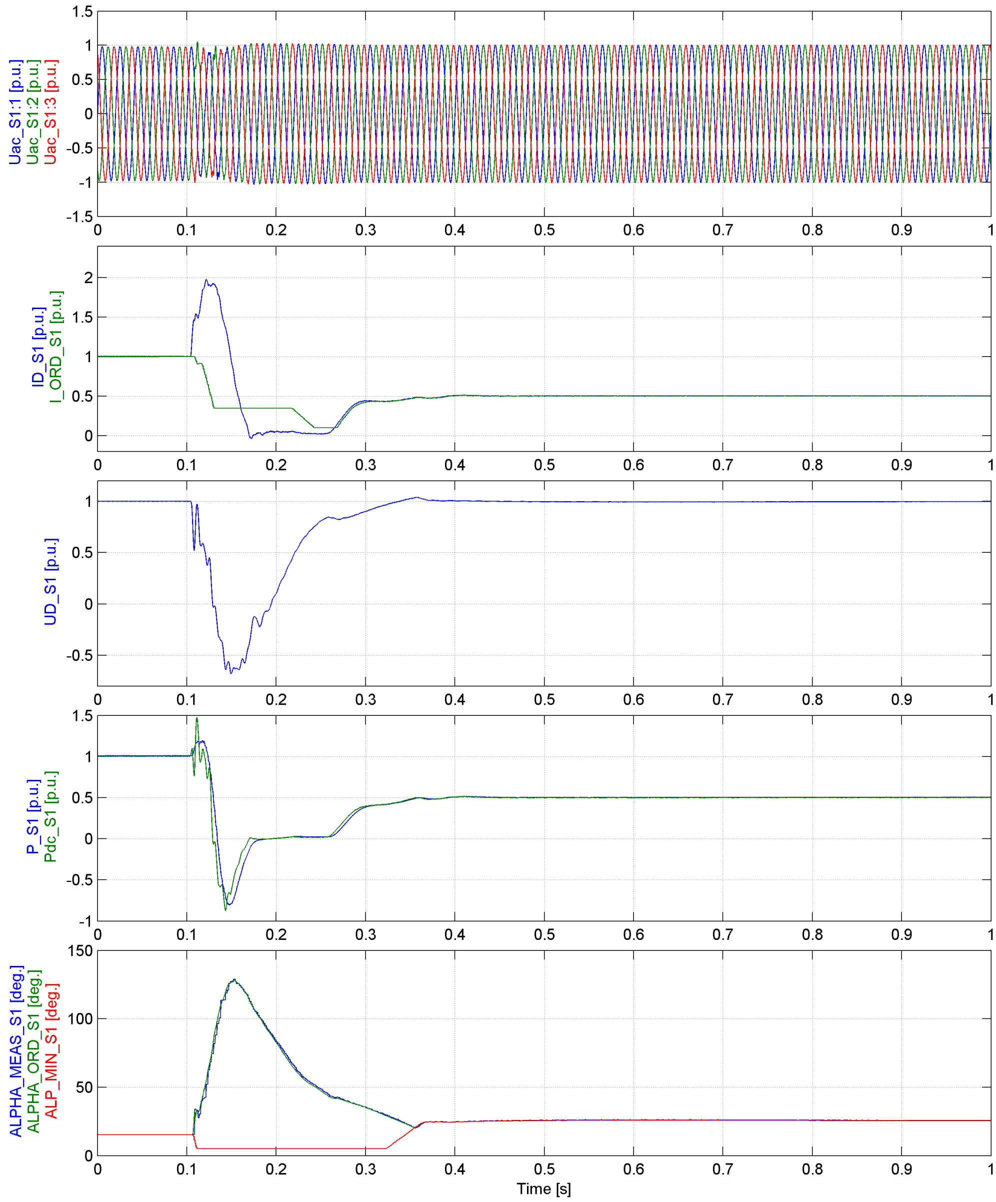


Figure 4.46: The loss of station 3, the change in current order. Station 1

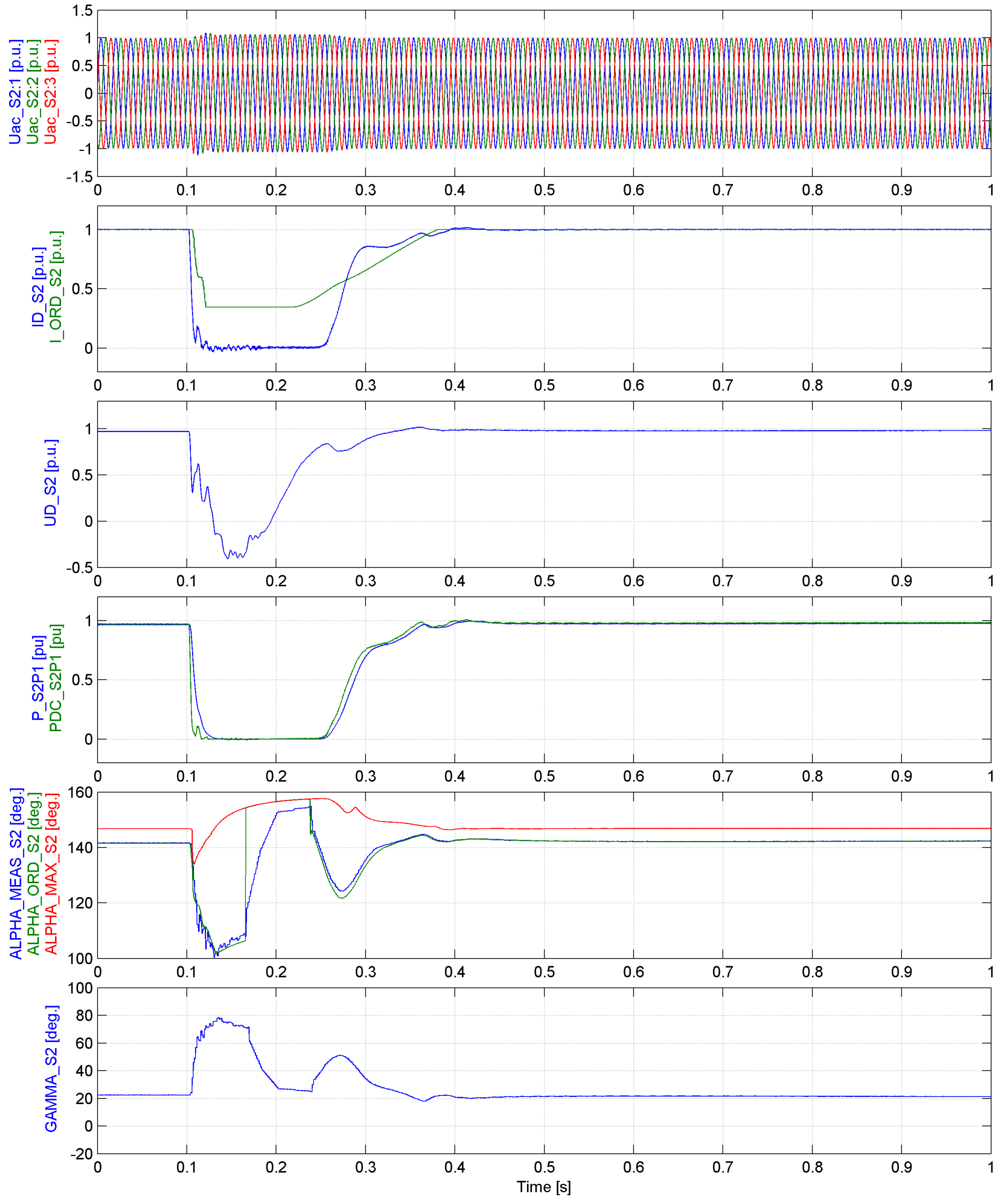


Figure 4.47: The loss of station 3, the change in current order. Station 2

However, in the second case, when 10% remaining voltage, three phase to ground AC fault at the second station was applied, the system failed to recover with ID used as current order. Comparing both cases, a difference in the DC voltage is seen after the VDCOL stopped interacting. In the case when the system recovered successfully, the DC voltage was at a higher value than in the case of unsuccessful recovery. Based on this fact, the current limiter and the change of current order are only activated after the DC voltages is recovered.

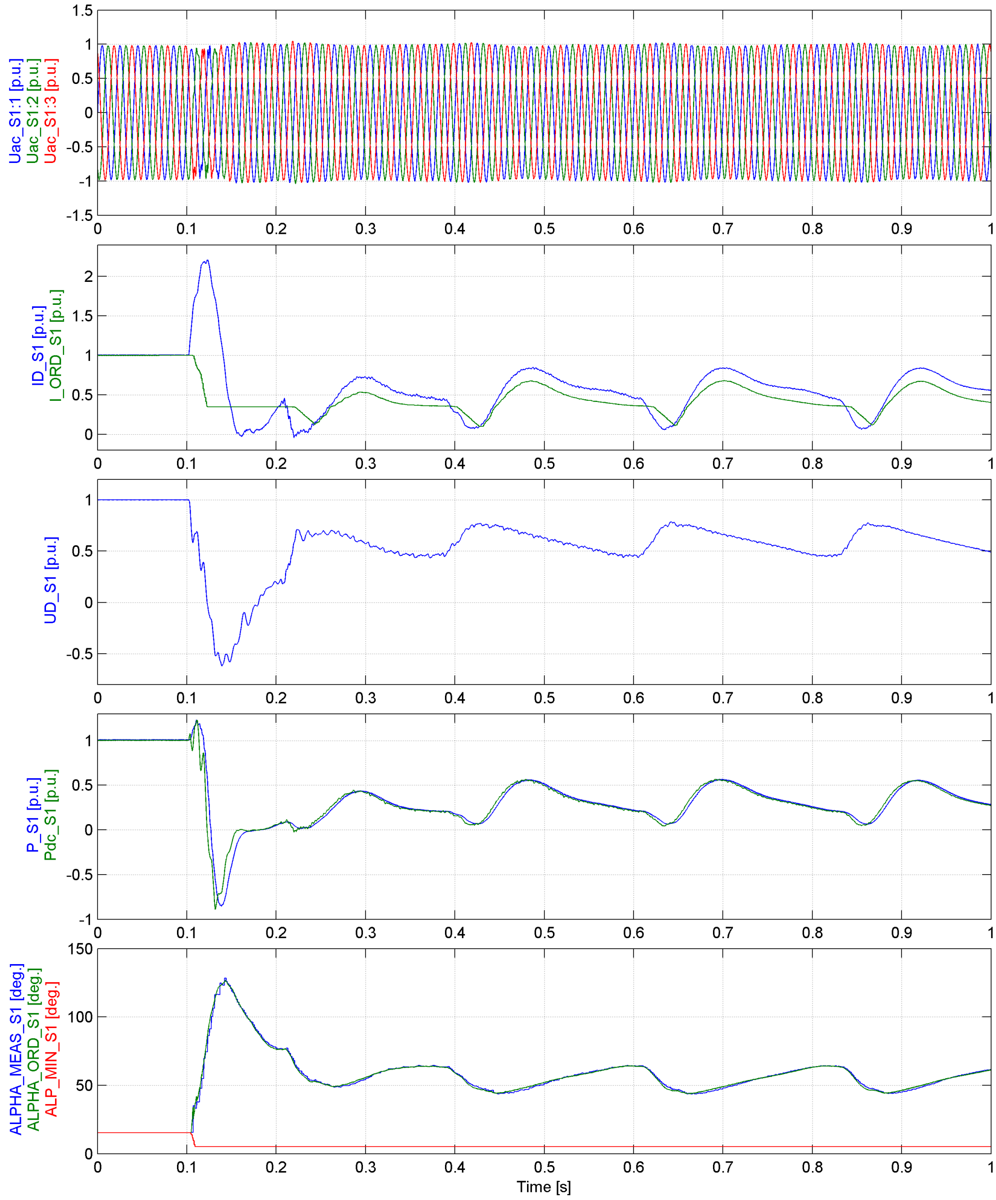


Figure 4.48: 100ms three phase to ground fault with 10% remaining voltage, the change in current order. Station 1

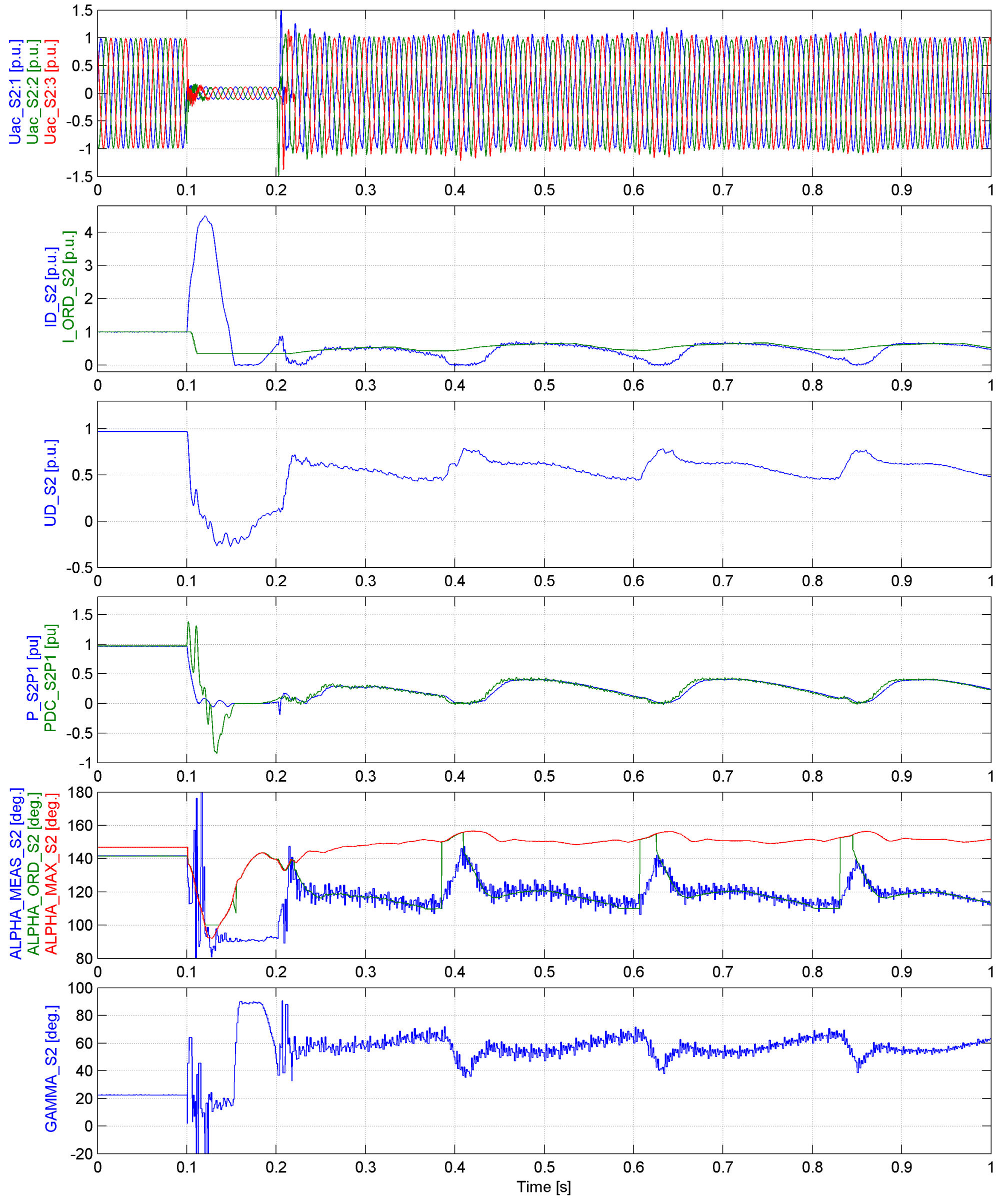


Figure 4.49: 100ms three phase to ground fault with 10% remaining voltage, the change in current order. Station 2

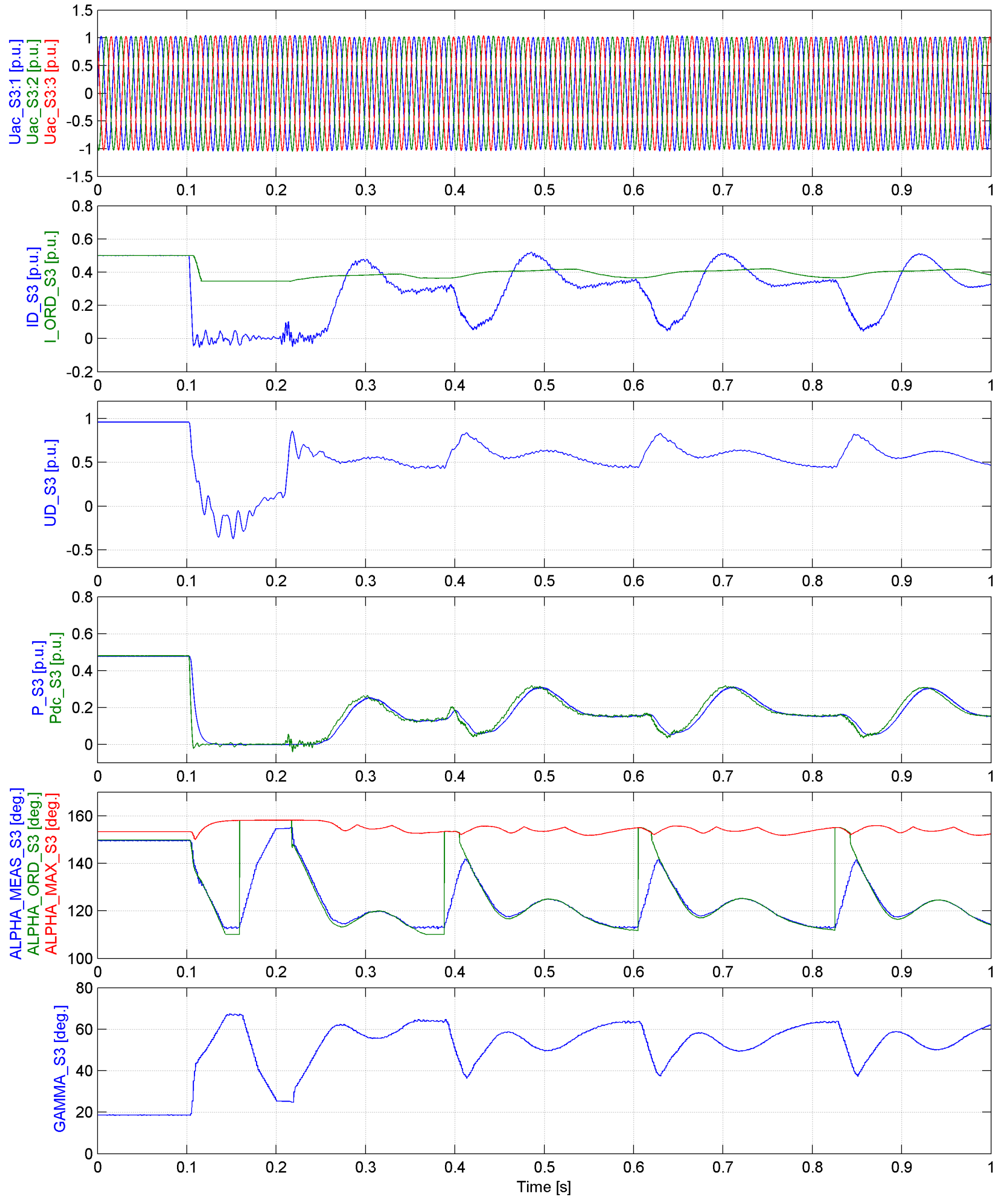


Figure 4.50: 100ms three phase to ground fault with 10% remaining voltage, the change in current order. Station 3

4.2.10 RETARD

As it was described in section 3.4.4 one of the possibilities to recover the system even after loss of one of the terminals is to use the RETARD function and start the system again. The figures below represent two different disturbances, three phase AC fault at the second station with 10% remaining voltage and the same fault at station three, which was disconnected at 0.18s (4.51, 4.52, 4.53 and 4.54, 4.55, respectively). It should be noted that reduced voltage recovery was not activated in these cases.

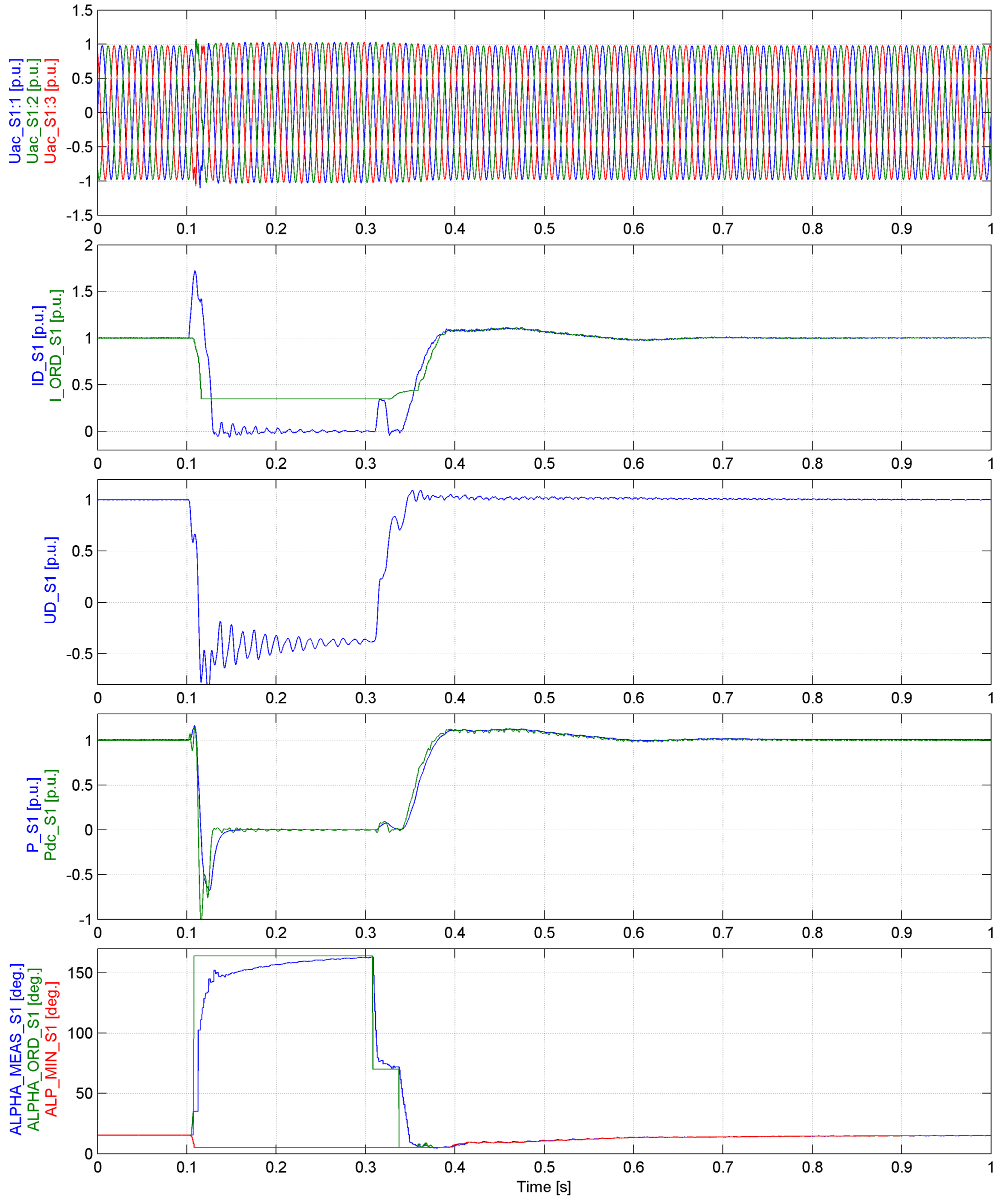


Figure 4.51: 100ms three phase to ground fault with 10% remaining voltage. Station 1

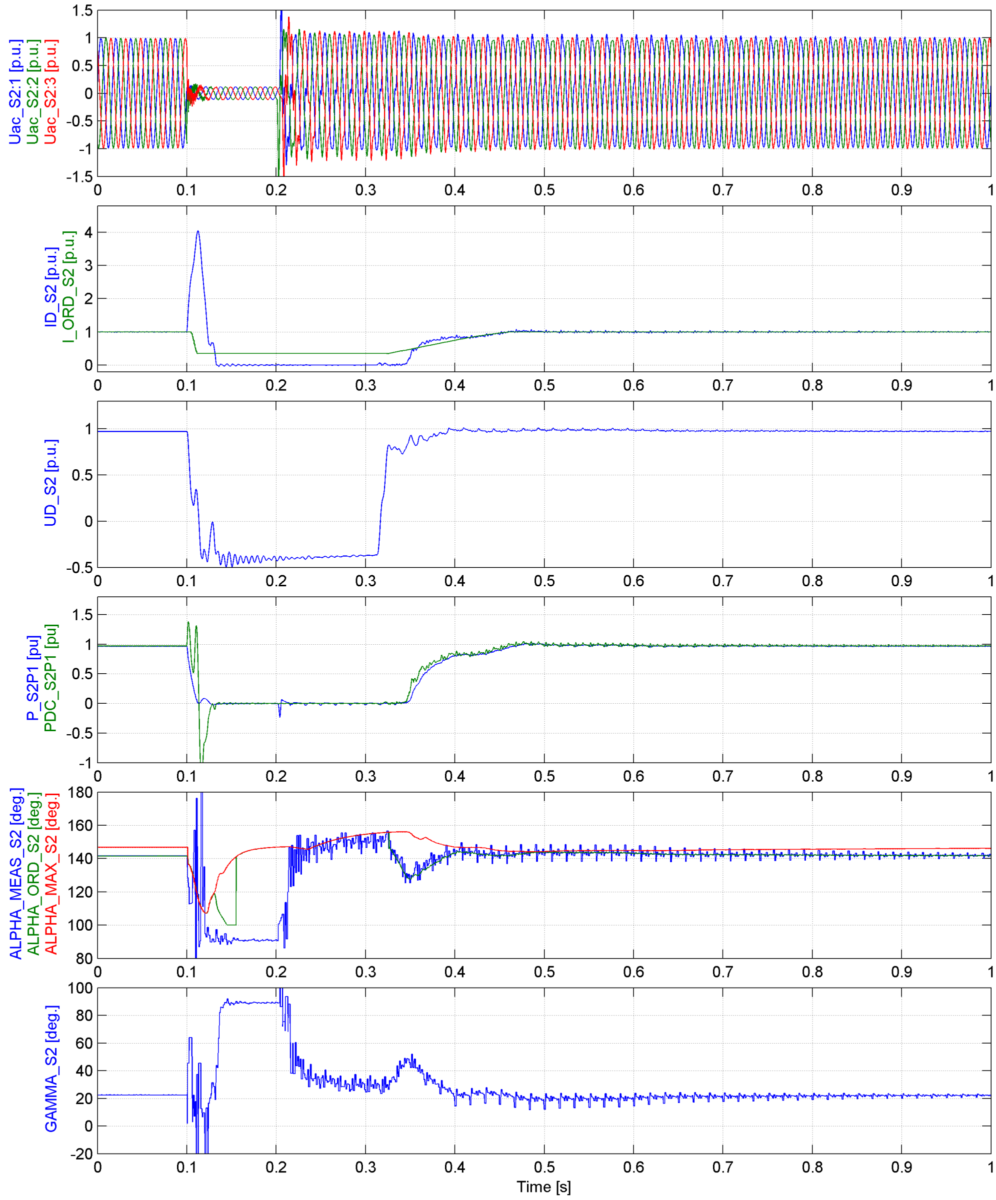


Figure 4.52: 100ms three phase to ground fault with 10% remaining voltage. Station 2

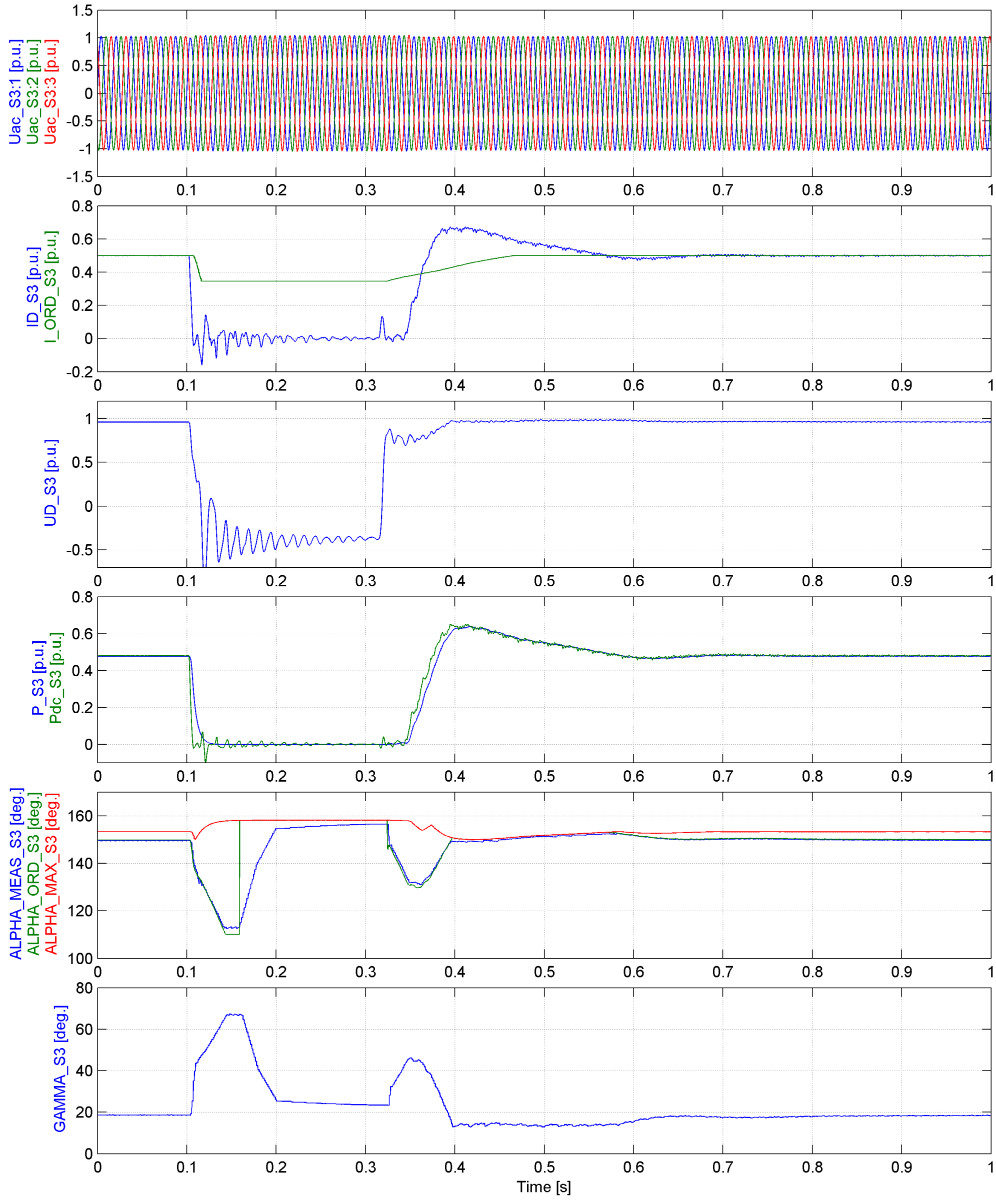


Figure 4.53: 100ms three phase to ground fault with 10% remaining voltage. Station 3

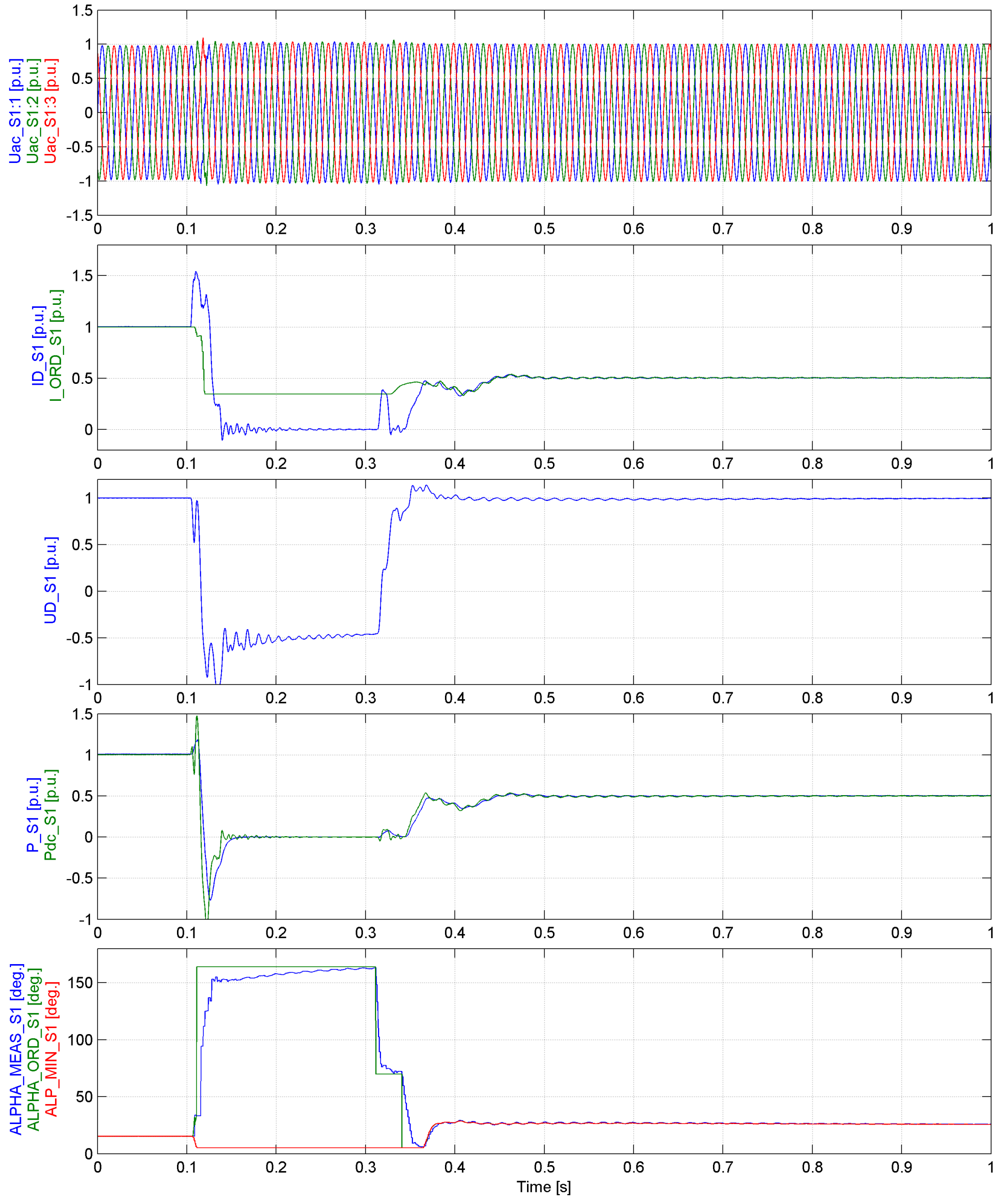


Figure 4.54: 100ms three phase to ground fault with 10% remaining voltage, the loss of station 3. Station 1

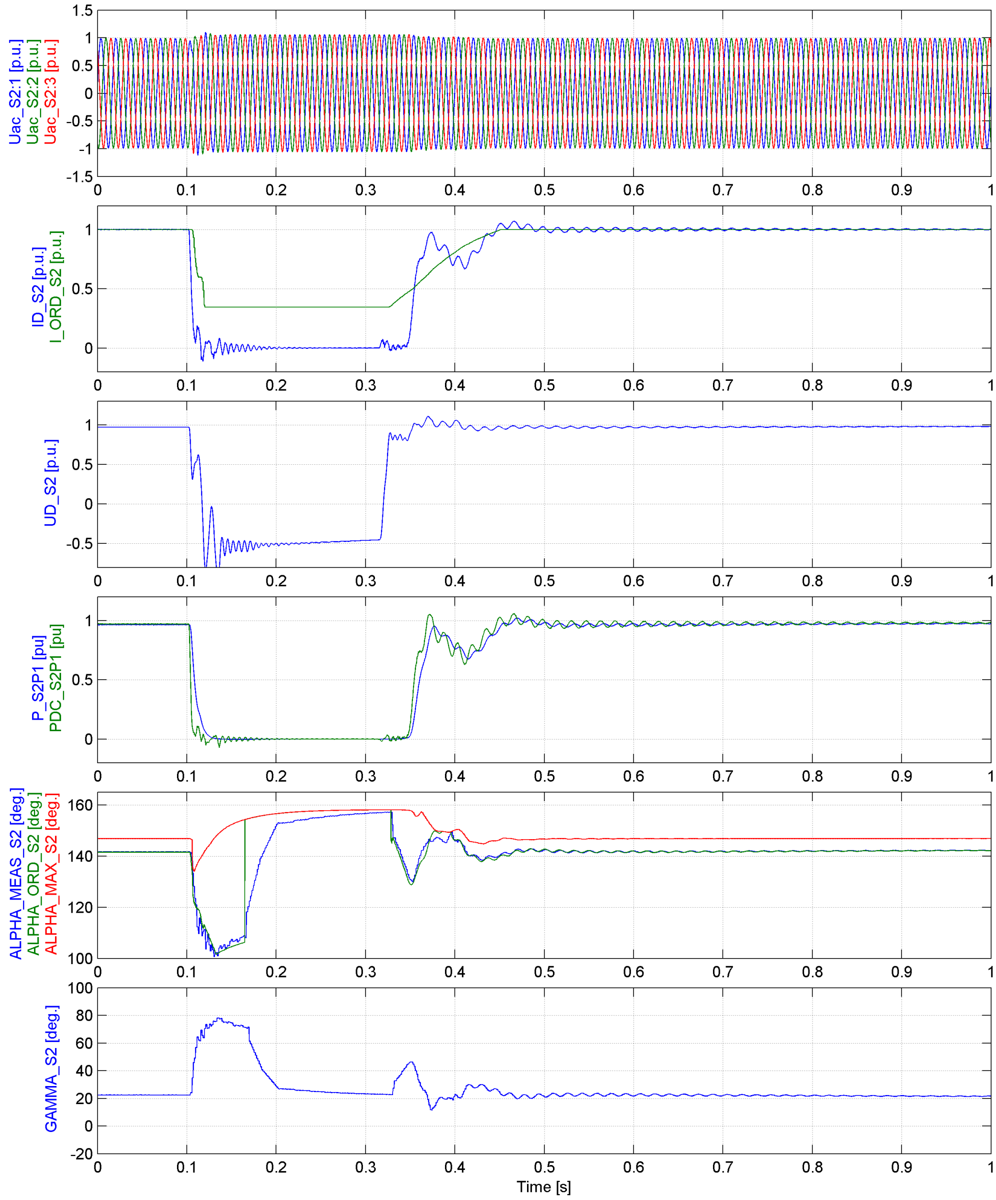


Figure 4.55: 100ms three phase to ground fault with 10% remaining voltage, the loss of station 3. Station 2

In both cases, the system recovered successfully even without reducing the DC voltage during the restart. However, the time when the system is not in operation accounts for at least 230ms even for the smallest faults and for larger disturbances it takes approximately 350ms to reach 90% of pre-fault power transmission.

Additionally, a three phase to ground AC fault at the second station was applied with 10% remaining voltage when the system was operating at a different operating point. As figures 4.56, 4.57 and 4.58 represent, several commutation failures at station two occurred and the system failed to recover. The reasons of this unsuccessful recovery is that the AC network at the second station is not strong enough to support the increased reactive power consumption during the recovery. Consequently, this leads to unbalance AC voltage and repetitive commutation failures. Similarly to the case when the system remains in the RVC operation during a disturbance, the rectifier cannot detect in which station a fault occurred, and as a result, it is recommended to use the reduced voltage recovery during all disturbances.

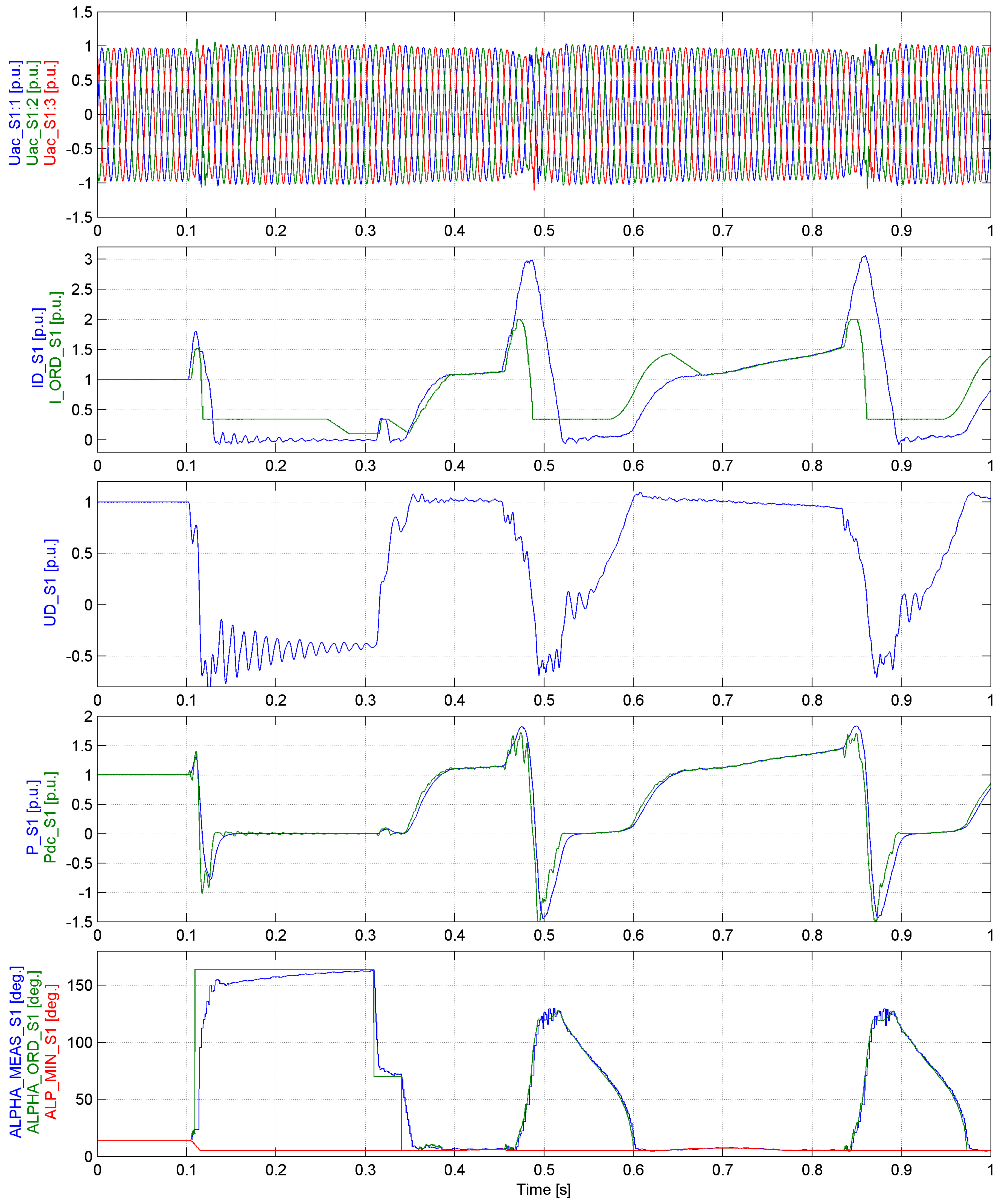


Figure 4.56: 100ms three phase to ground fault with 10% remaining voltage. Station 1

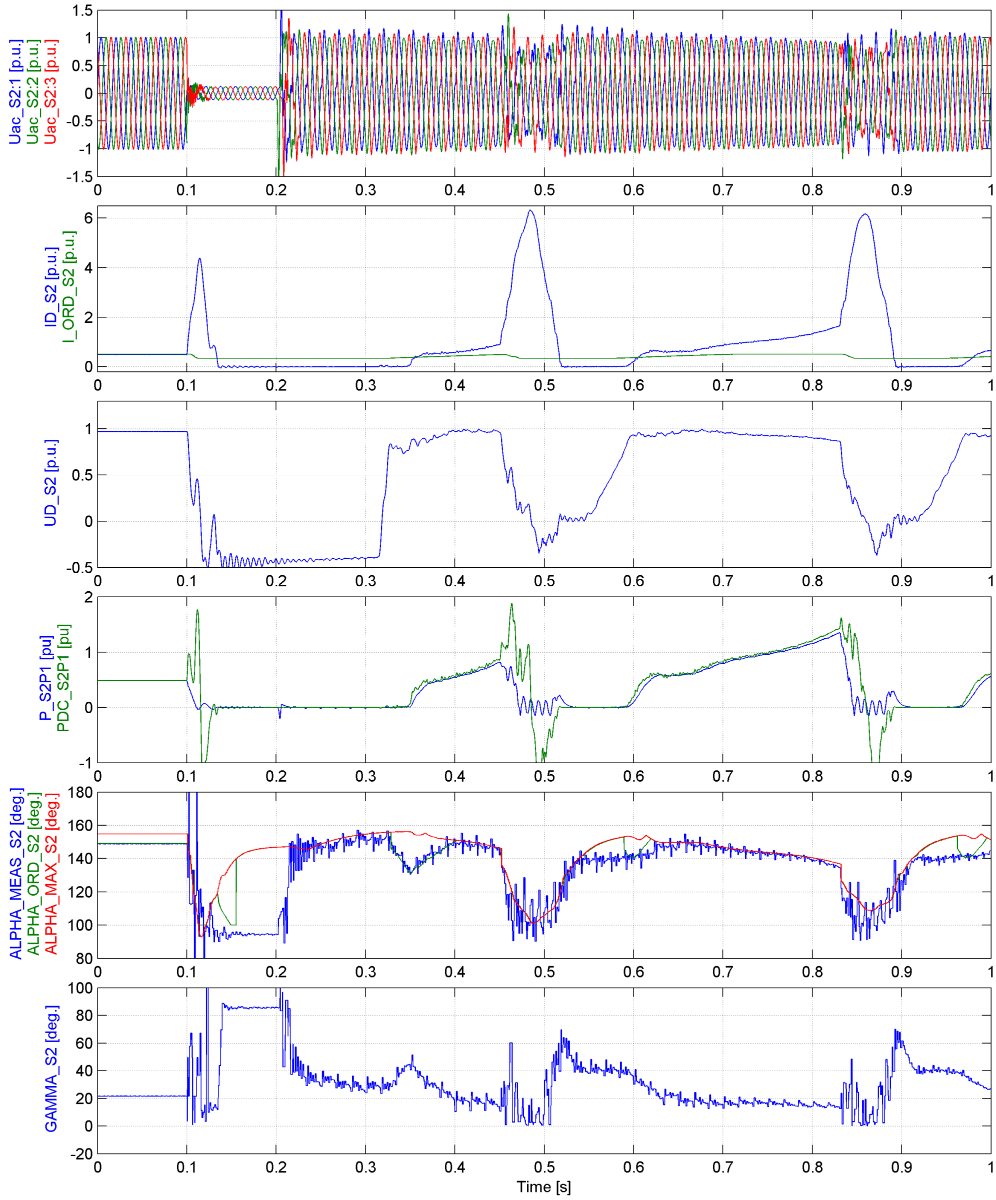


Figure 4.57: 100ms three phase to ground fault with 10% remaining voltage. Station 2

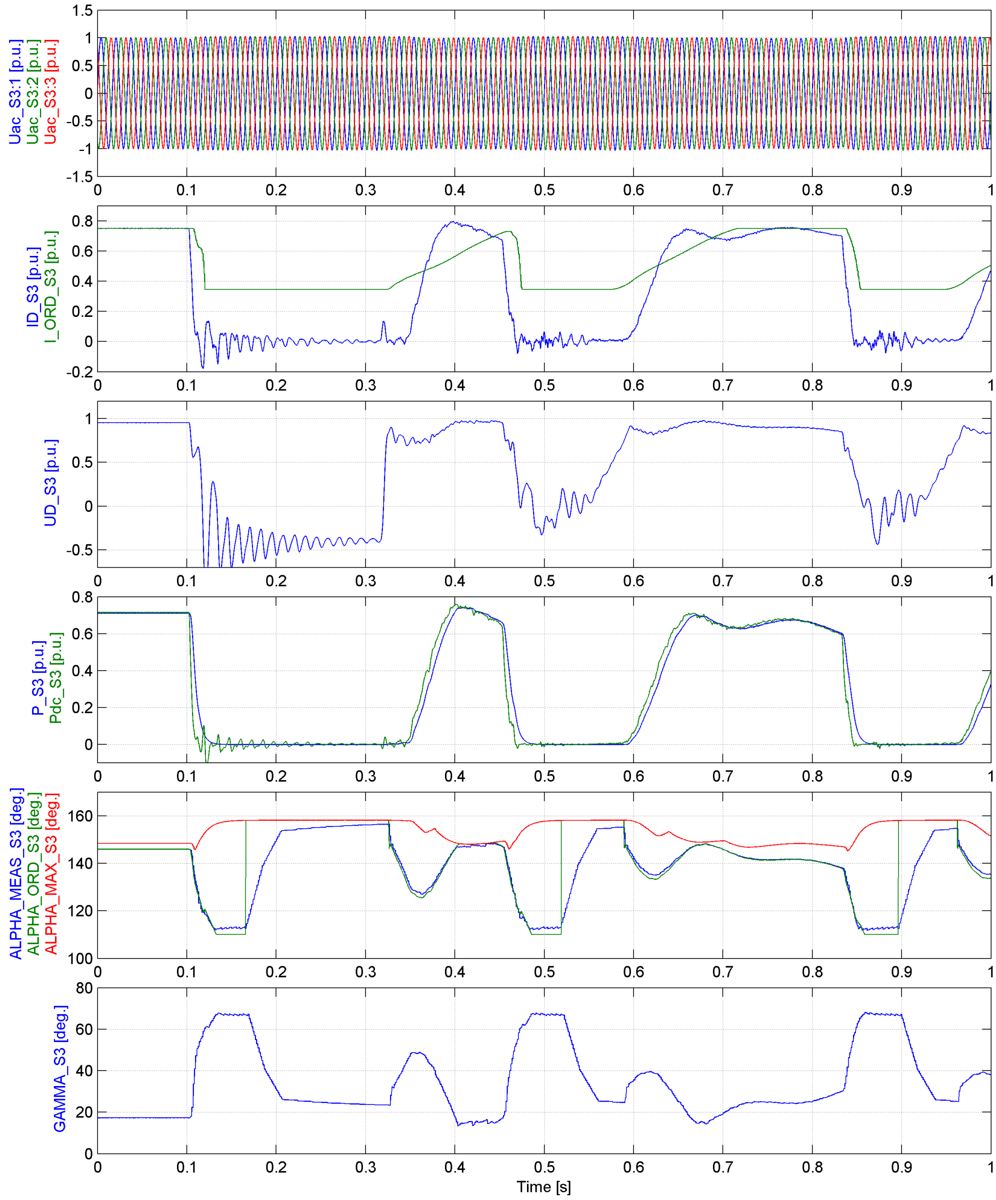


Figure 4.58: 100ms three phase to ground fault with 10% remaining voltage. Station 3

To conclude, the RETARD function can be one of the possible solutions to survive different disturbances. Additionally, a zero voltage crossing detector can be introduced to limit the activation of the RETARD function during small disturbances when commutation failure has not occurred. However, due to fixed time of the function (230ms) which results in prolonged the total recovery time, it is more economically beneficial use the RVC mode during disturbances.

5

Conclusions and Future Work

The main task of the project was to design and implement a control logic, which would allow the operation of the multi-terminal LCC HVDC system in the case when telecommunication is lost. Furthermore, the system has to withstand different disturbances such as AC and DC faults as well as the loss of one of the stations and be able to recover a stable operation.

The main idea of the proposed improvements of the controls is to change the operating modes in the stations during disturbances. The rectifier, which typically operates in the current control mode, is switched to control the DC voltage while the inverters are switched from the constant beta angle control to the current control. As the results proved, such control logic allowed the system to attain the stable operation when the telecommunication was lost. Furthermore, the system was able to withstand different disturbances and transient events and reach a new steady state, even when one of the stations was disconnected. Some of the results were compared with the simulations when the telecommunication between the stations was available. In both cases, the control actions and the dynamic behavior of the system was similar. The reason of this is that the same sub-functions were activated during the disturbances, which resulted in a very similar dynamic response with and without the telecommunication. Finally, in some cases the system without the telecom was able to recover slightly faster due to increased gain in the VCAREG.

However, to achieve such results, several sub-functions were implemented which allow to keep the HVDC system stable during different transient events. For instance, the reduced nominal extinction angle increases the control range of the CCA in the inverters. Furthermore, recoveries after faults when one of the inverter stations is connected to weak AC networks can lead to repetitive commutation failures or even unstable operations so the reduced voltage recovery was introduced. Additionally, the current order limiter was implemented which is needed to reduce the current order in the rectifier when one of the stations is lost. Moreover, as simulations showed, all these functions can have a great impact on the system performances. For this reason, the parameters of the sub-functions have to be tuned properly for the specific project in order to achieve the best performances.

Additionally, the possibility to restart the HVDC system using the RETARD function was investigated if a disturbance is detected. The simulations showed that such approach can be one of the possible solutions to withstand different transient events. However, due to long power transfer interruption, it is not economically beneficial.

To conclude, after implementation and proper tuning of proposed control logic, the multi-terminal HVDC system successfully withstood all the applied disturbances and transient events without telecommunication.

Future Work

The results of the project proved that the main idea of HVDC operation in the RVC mode can be used for the operation without telecommunication. However, there are other aspects which can be investigated in the future. First of all, the case when the multi-terminal HVDC system consists of two rectifiers and one inverter can be studied. Furthermore, the stability studies with different SCR of the AC networks and its effect of the system performances can be examined as well as the case when a cable is used instead of the overhead lines. Moreover, the main idea of this project was to investigate the possibilities to operate the multi-terminal HVDC system without telecommunication, propose improvements and show how these improvements affect the system. In the future work, dynamic studies can be performed to find control parameters with which the best dynamic performances of the system can be achieved. Finally, possibilities of wind power integration using multi-terminal HVDC can be investigated.

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A
Appendix

A.1 Current Step of -5%

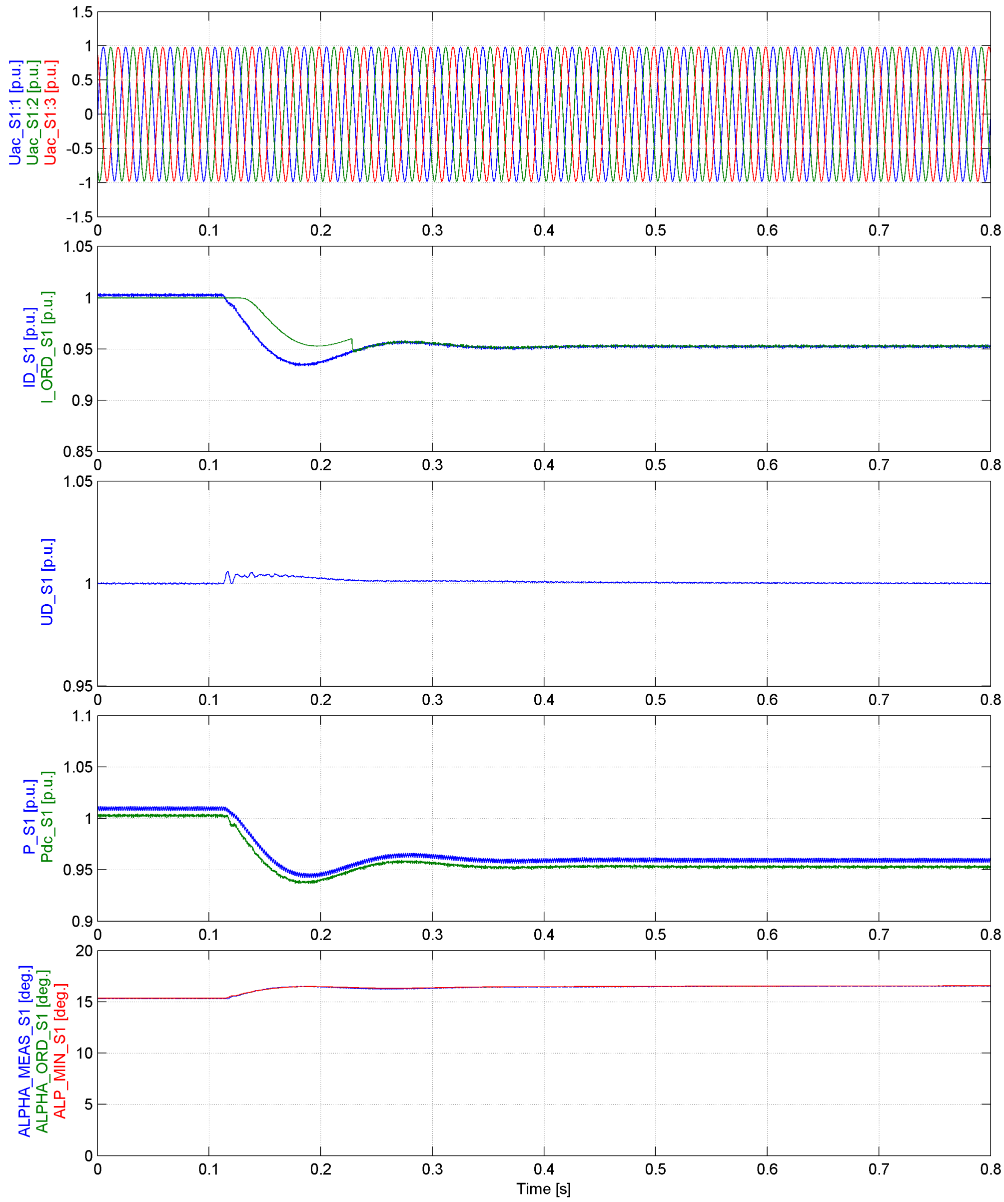

Figure A.1: Negative current step of 5% in station 3. Station 1

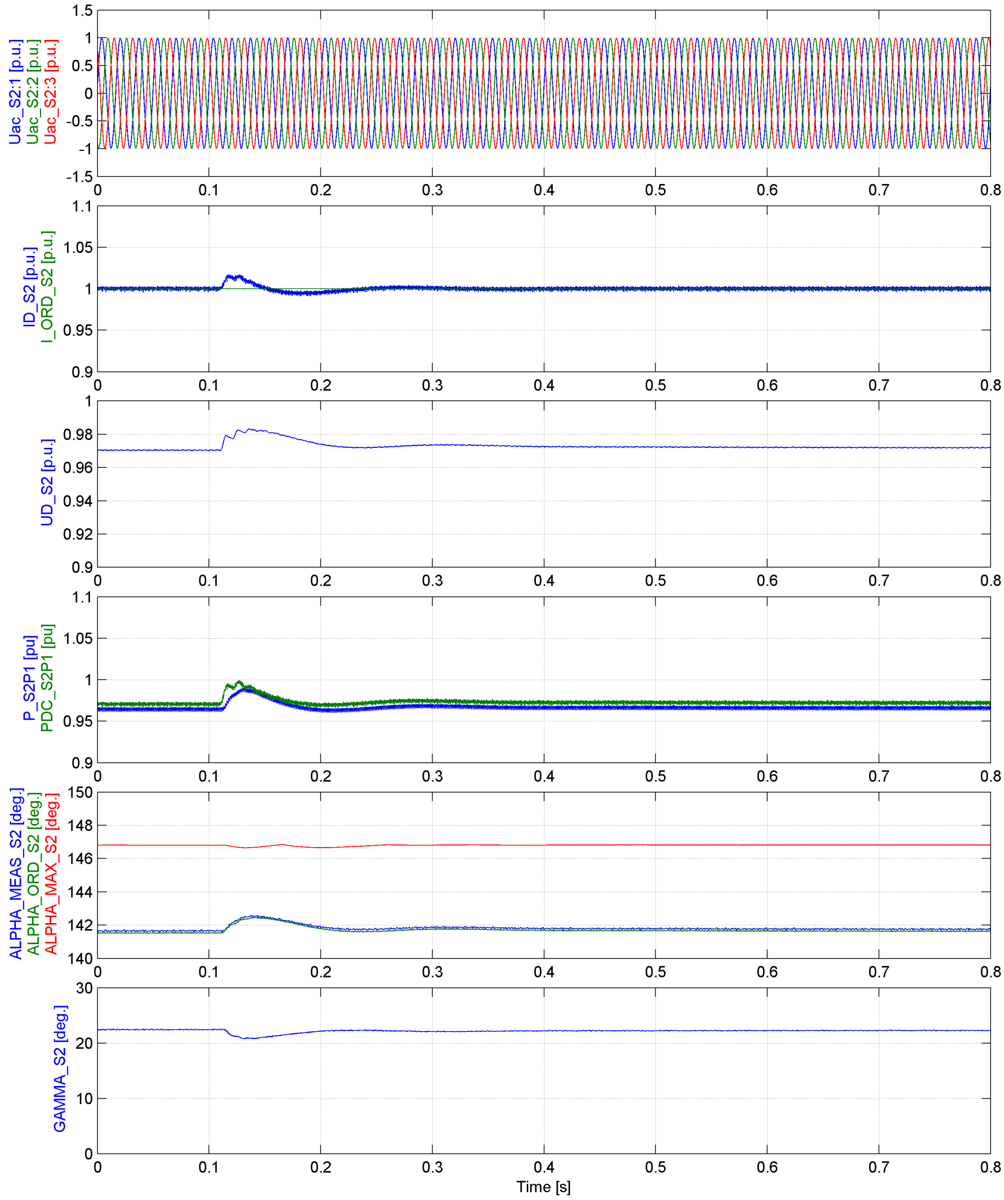

Figure A.2: Negative current step of 5% in station 3. Station 2

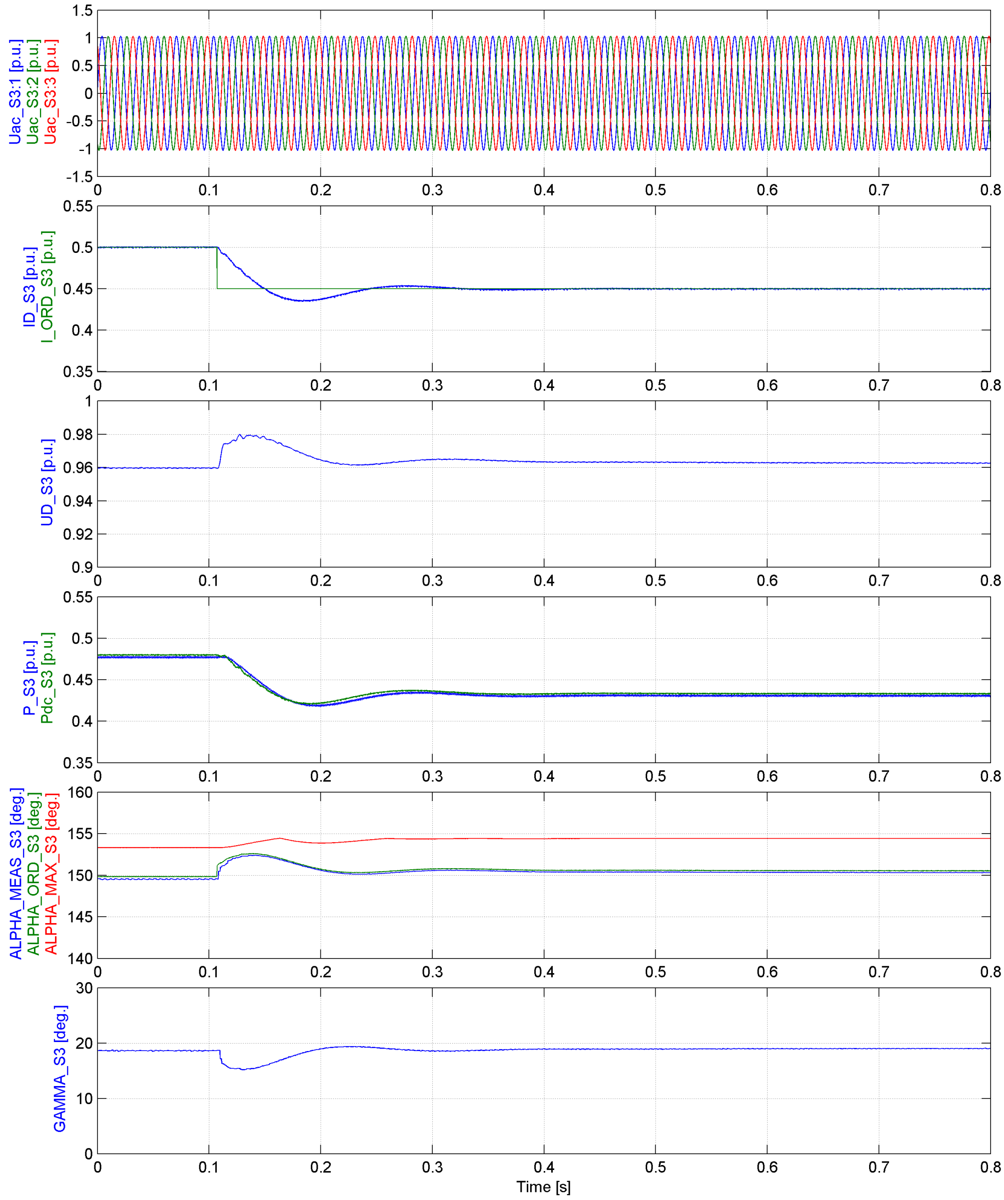

Figure A.3: Negative current step of 5% in station 3. Station 3

A.2 Faults at station 1

Single phase to ground. 1 p.u. / 0.5 p.u. / 0.75 p.u.

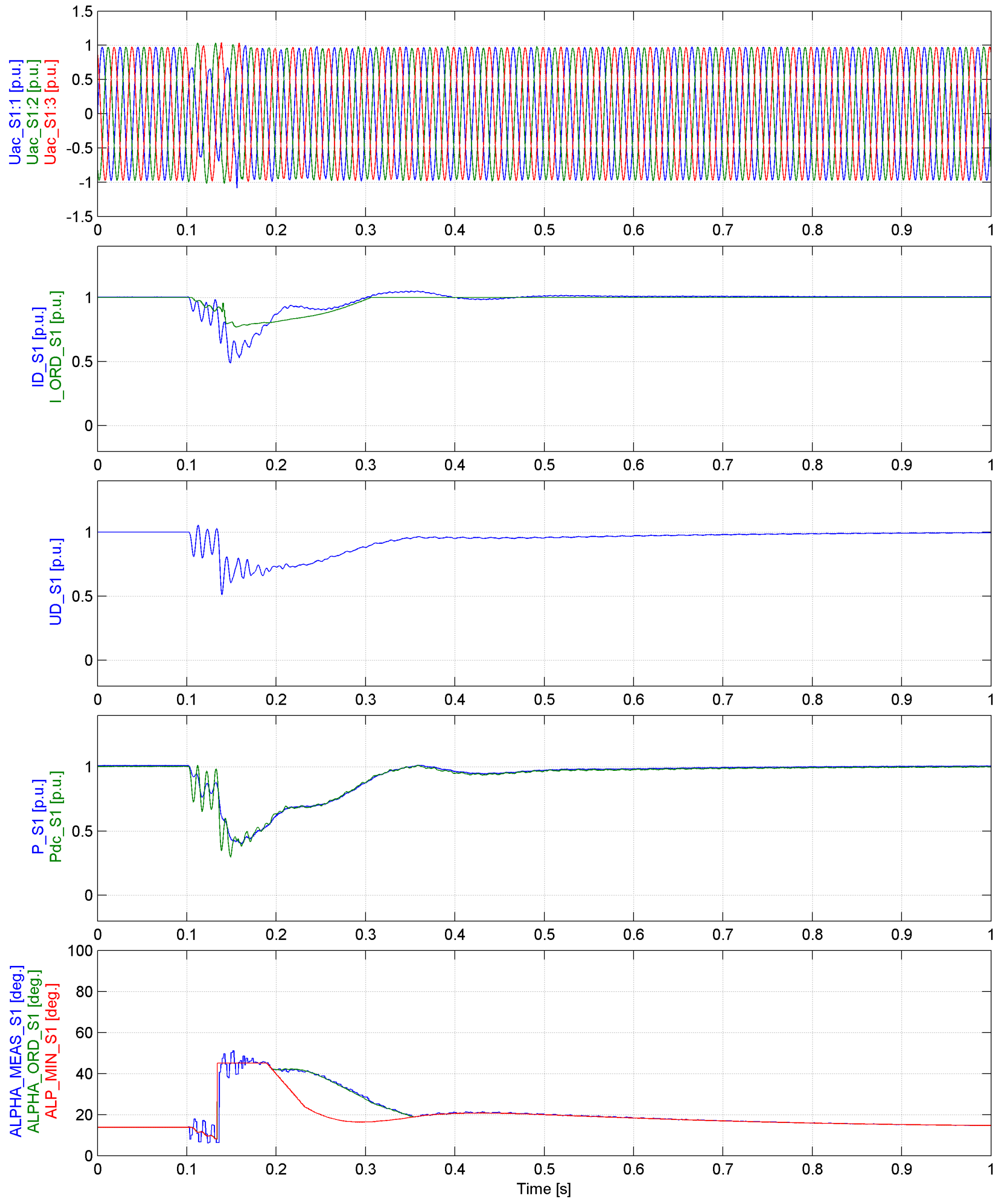

Figure A.4: $50ms$ single phase to ground fault with 70% remaining voltage. Station 1

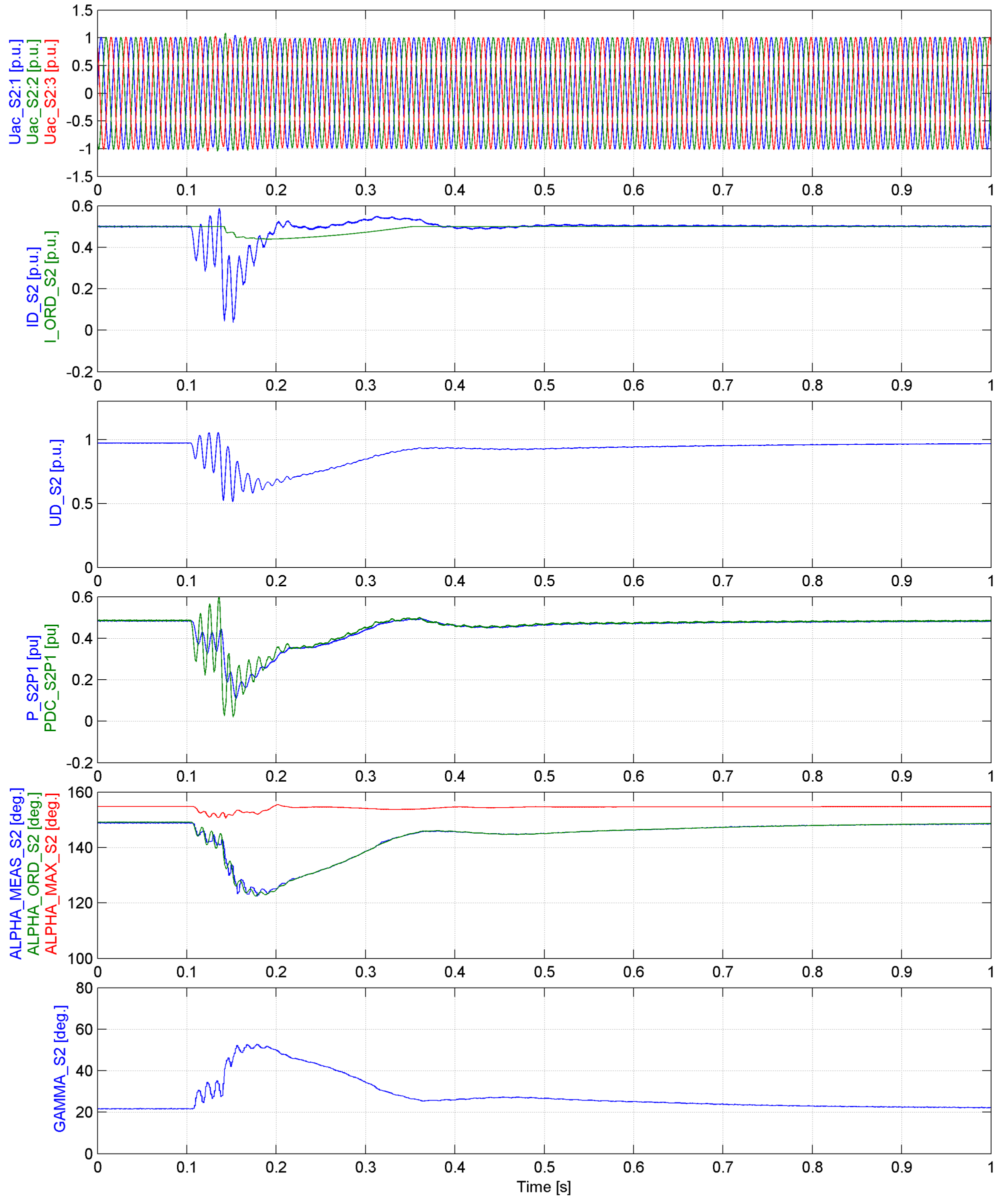

Figure A.5: 50ms single phase to ground fault with 70% remaining voltage. Station 3

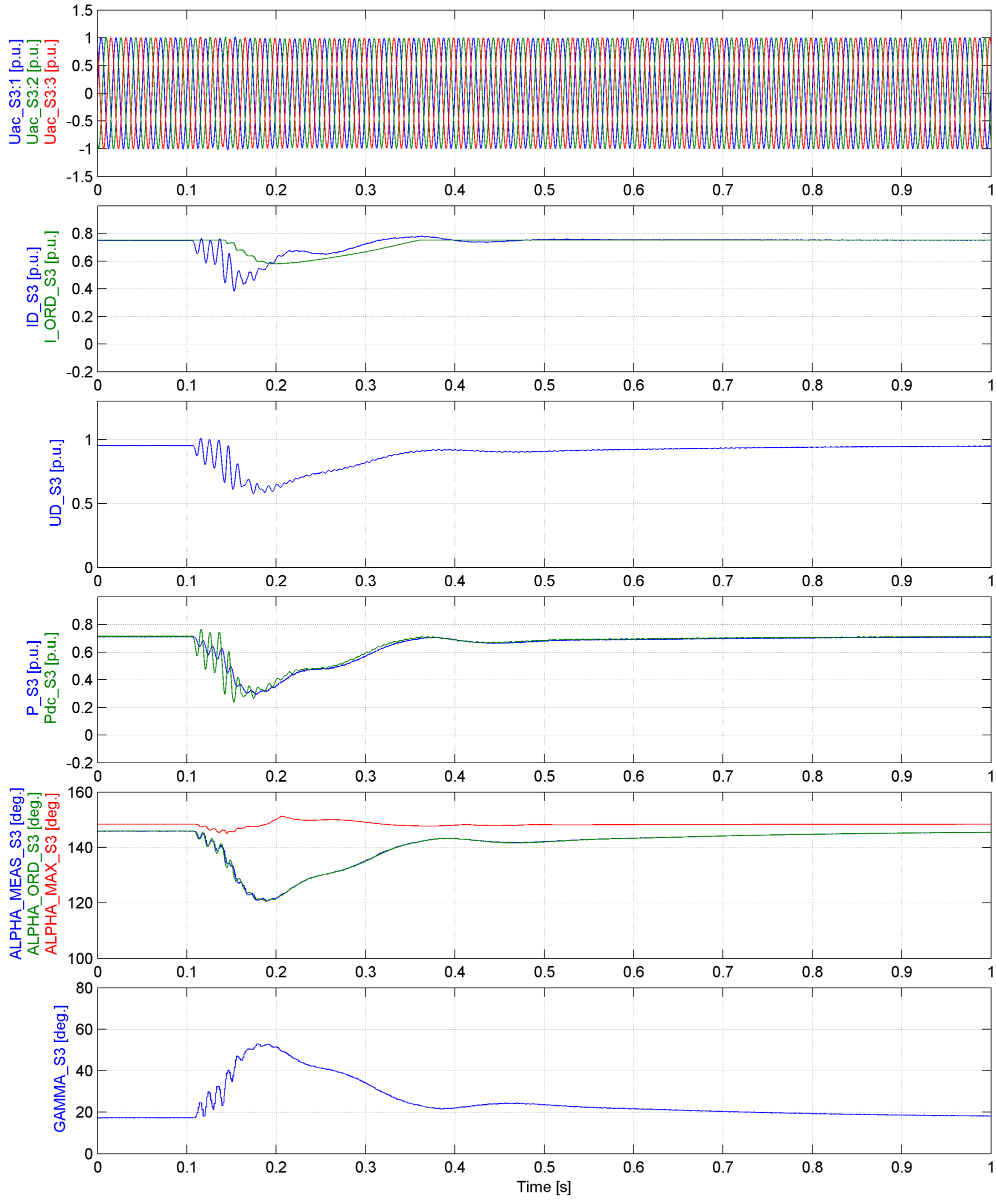

Figure A.6: 50ms single phase to ground fault with 70% remaining voltage. Station 3

Three phase to ground. 0.9 p.u. / 1 p.u. / 0.4 p.u.

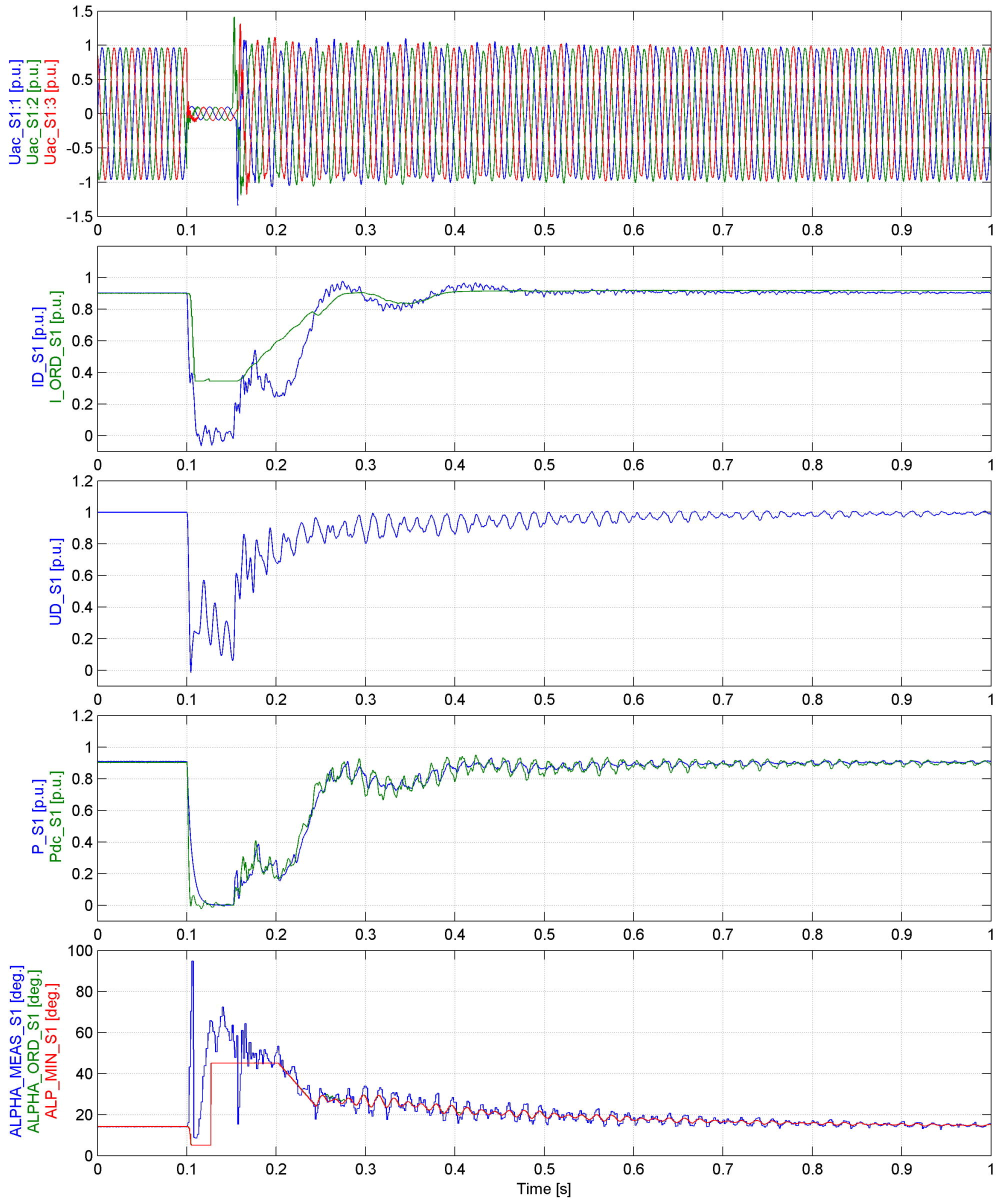

Figure A.7: 50ms three phase to ground fault with 10% remaining voltage. Station 1

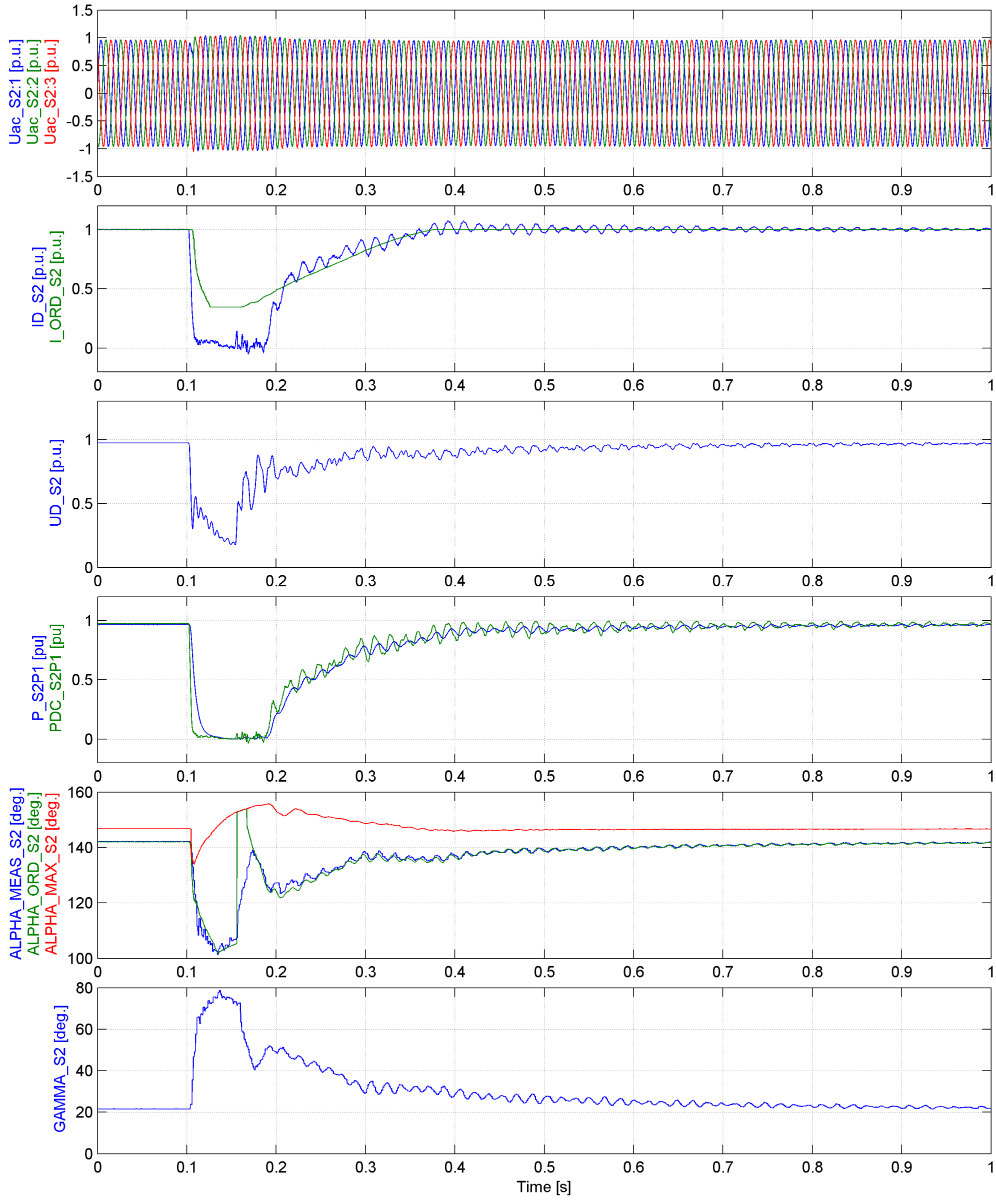

Figure A.8: 50ms three phase to ground fault with 10% remaining voltage. Station 2

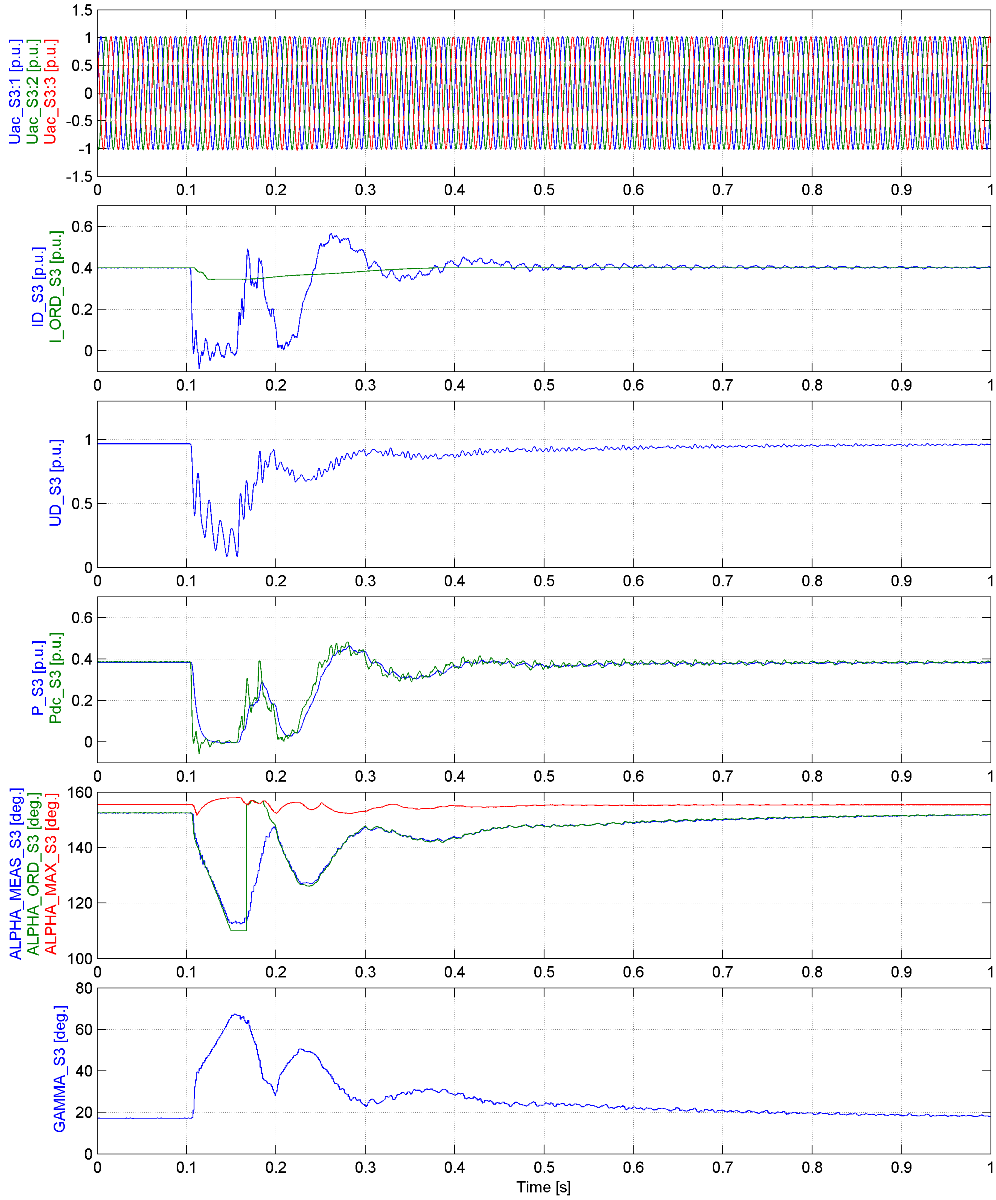

Figure A.9: 50ms three phase to ground fault with 10% remaining voltage. Station 3

A.3 Faults at station 2

Single phase to ground. 0.9 p.u. / 1 p.u. / 0.4 p.u.

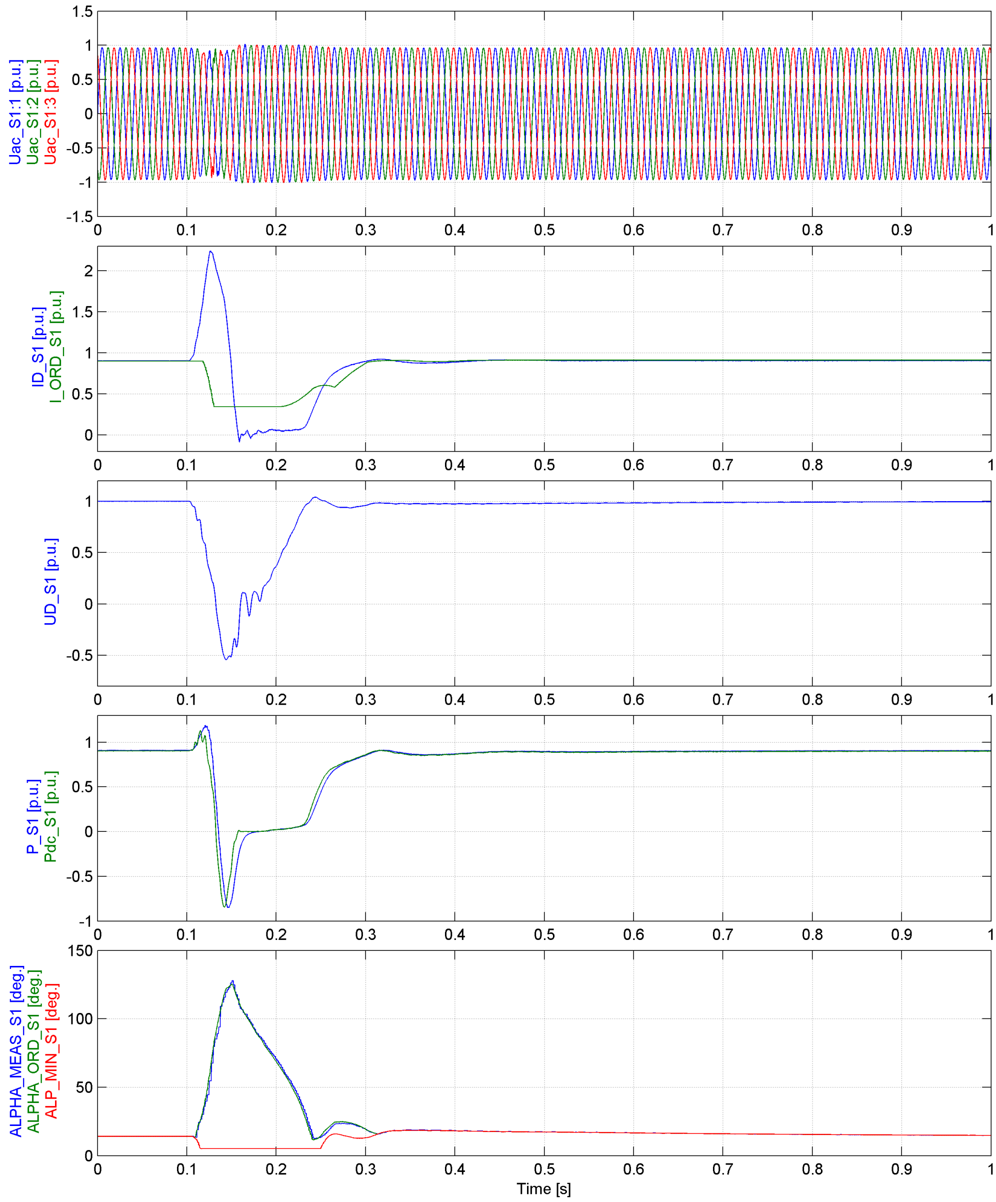

Figure A.10: 50ms single phase to ground fault with 70% remaining voltage. Station 1

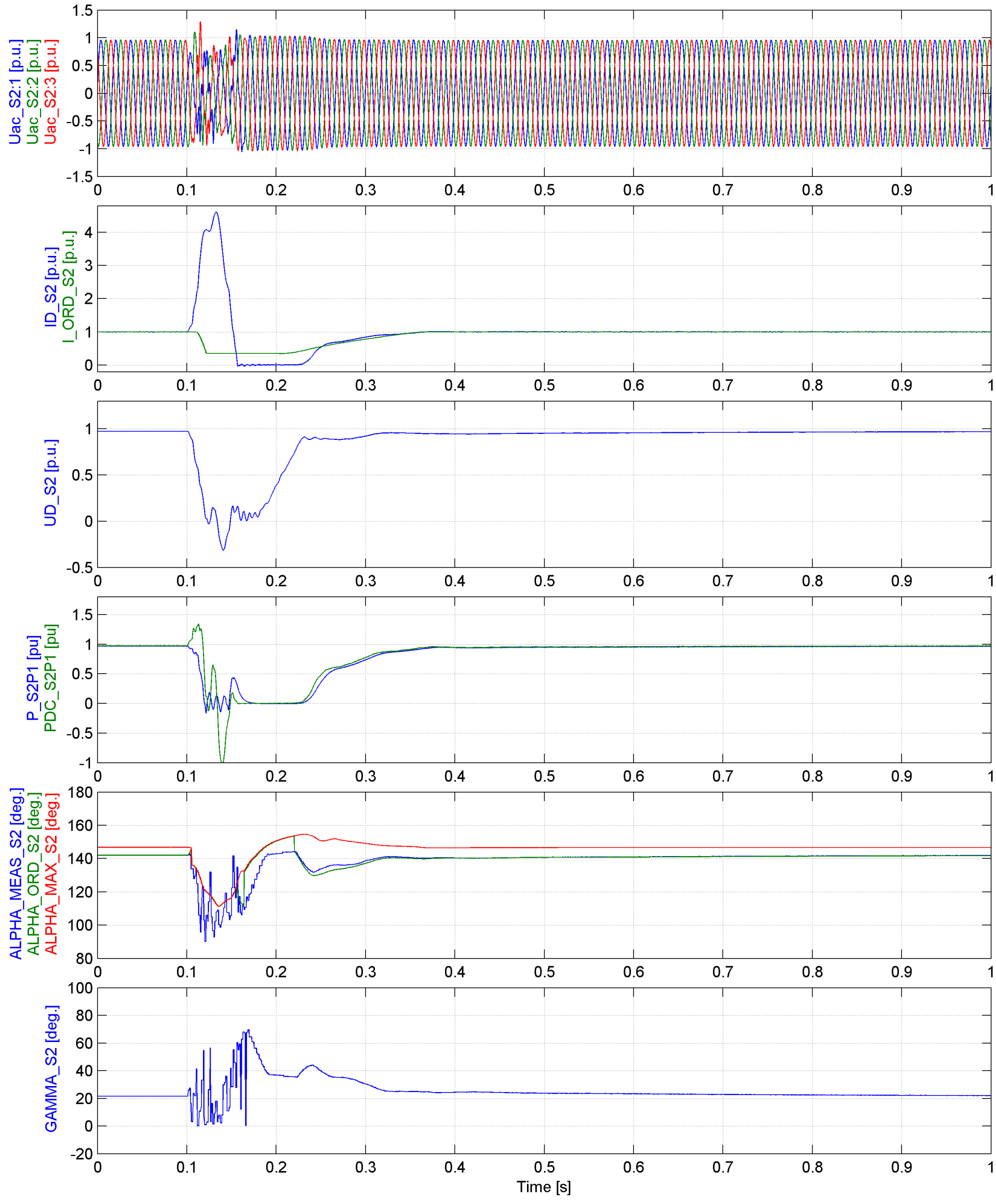

Figure A.11: 50ms single phase to ground fault with 70% remaining voltage. Station 2

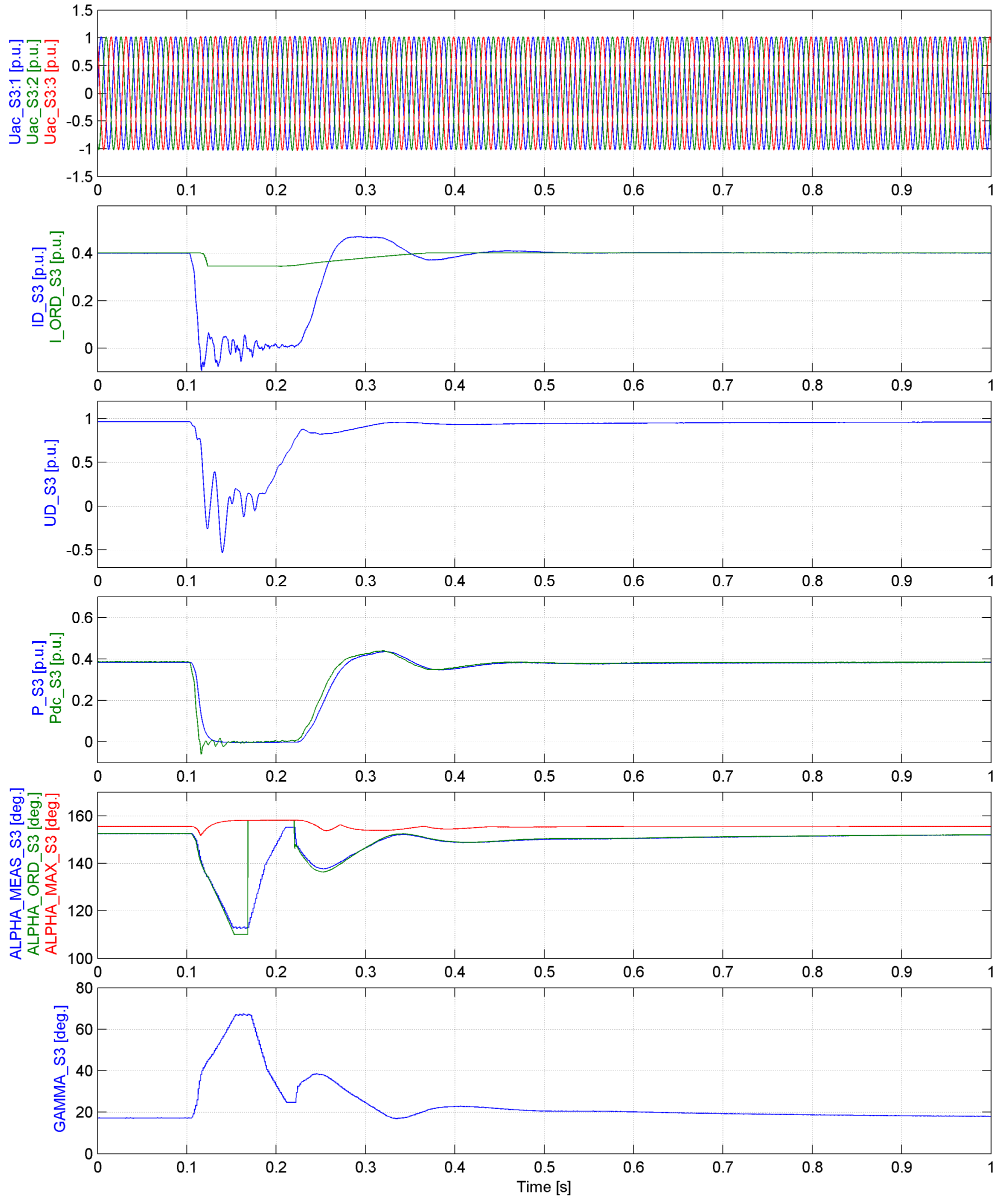

Figure A.12: 50ms single phase to ground fault with 70% remaining voltage. Station 3

Three phase to ground. 1 p.u. / 0.5 p.u. / 0.75 p.u.

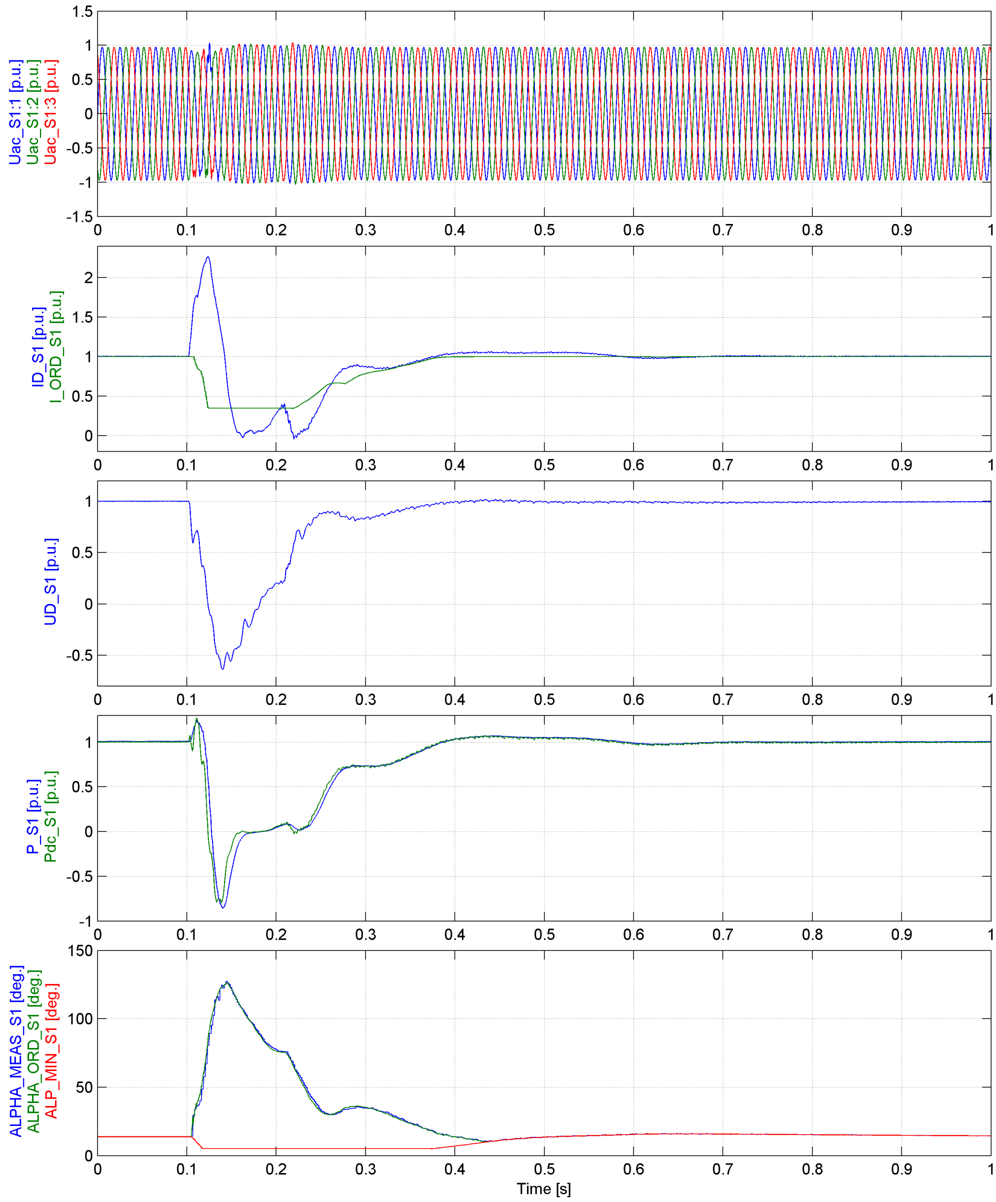

Figure A.13: 100ms three phase to ground fault with 10% remaining voltage. Station 1

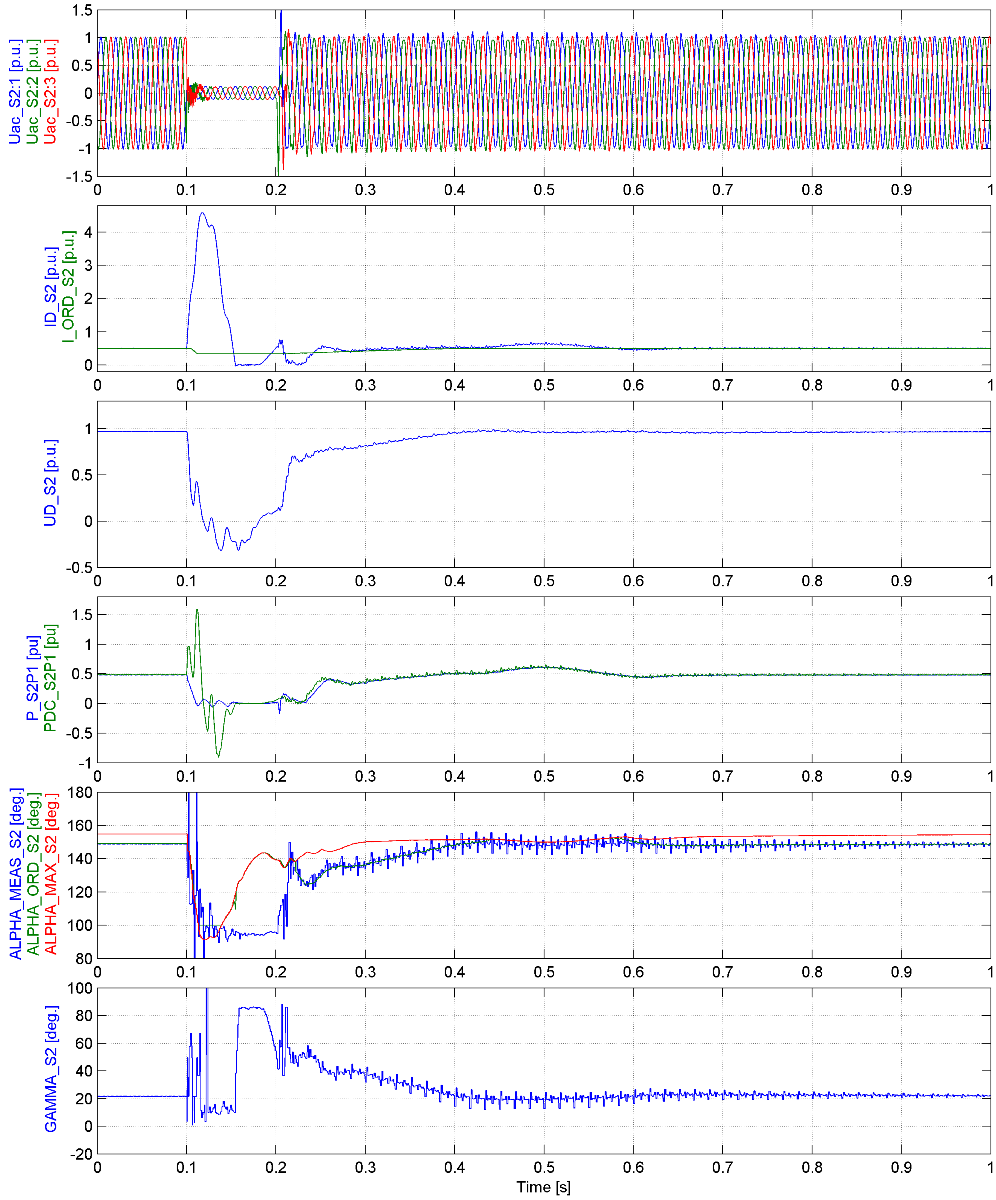

Figure A.14: 100ms three phase to ground fault with 10% remaining voltage. Station 2

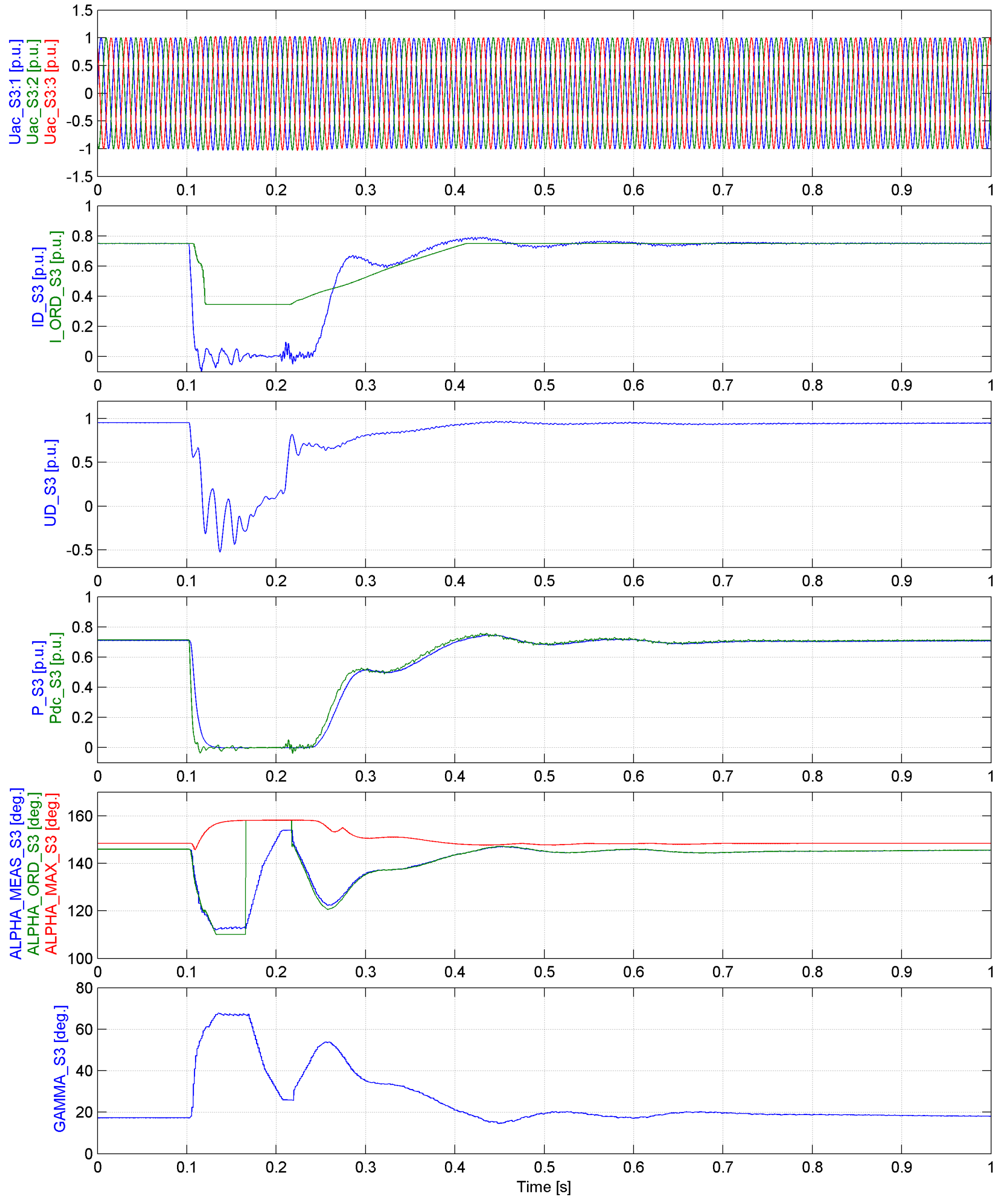

Figure A.15: 100ms three phase to ground fault with 10% remaining voltage. Station 3

A.4 Faults at station 3

Single phase to ground. 0.9 p.u. / 1 p.u. / 0.4 p.u.

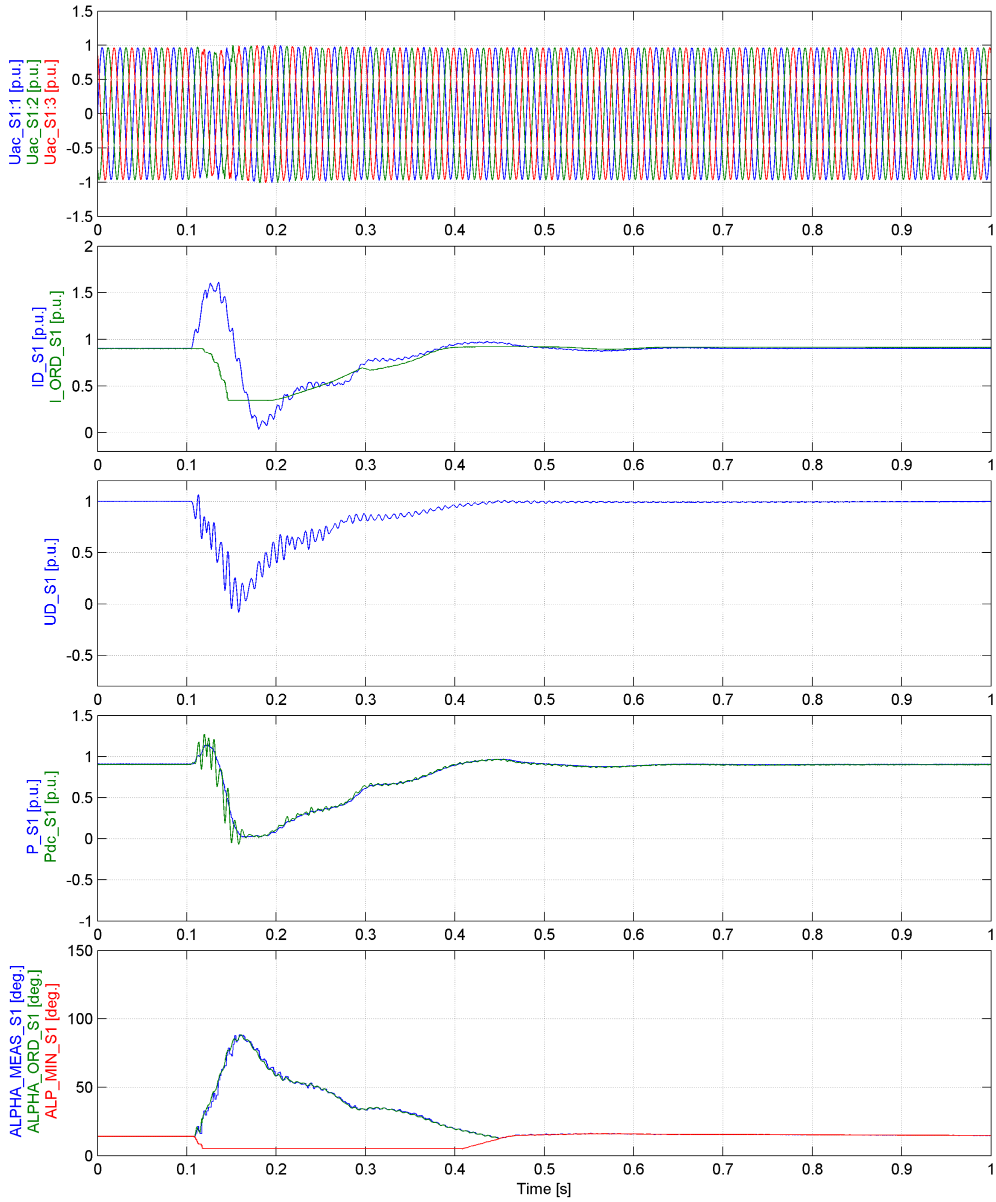

Figure A.16: 100ms single phase to ground fault with 10% remaining voltage. Station 1

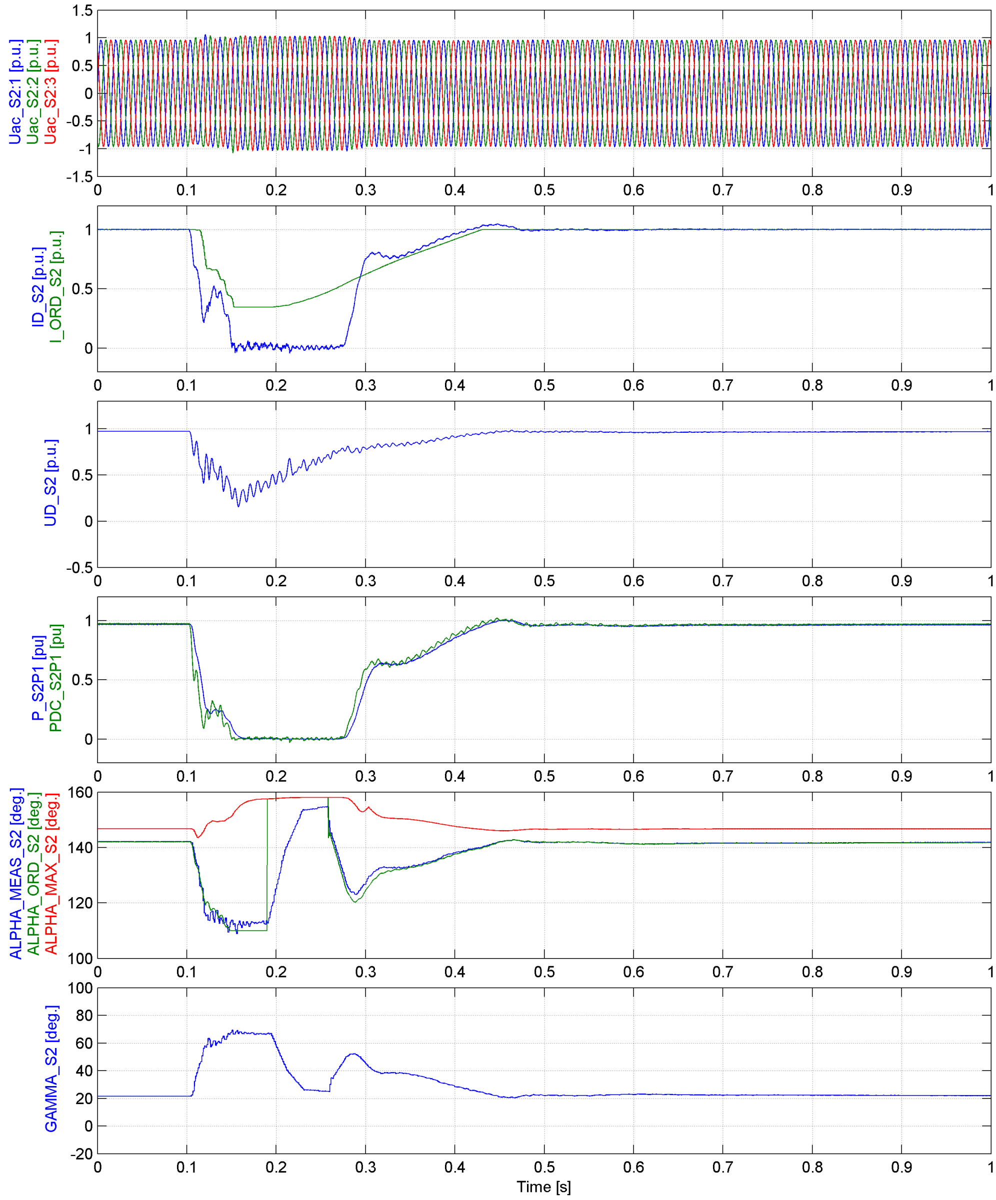

Figure A.17: 100ms single phase to ground fault with 10% remaining voltage. Station 2

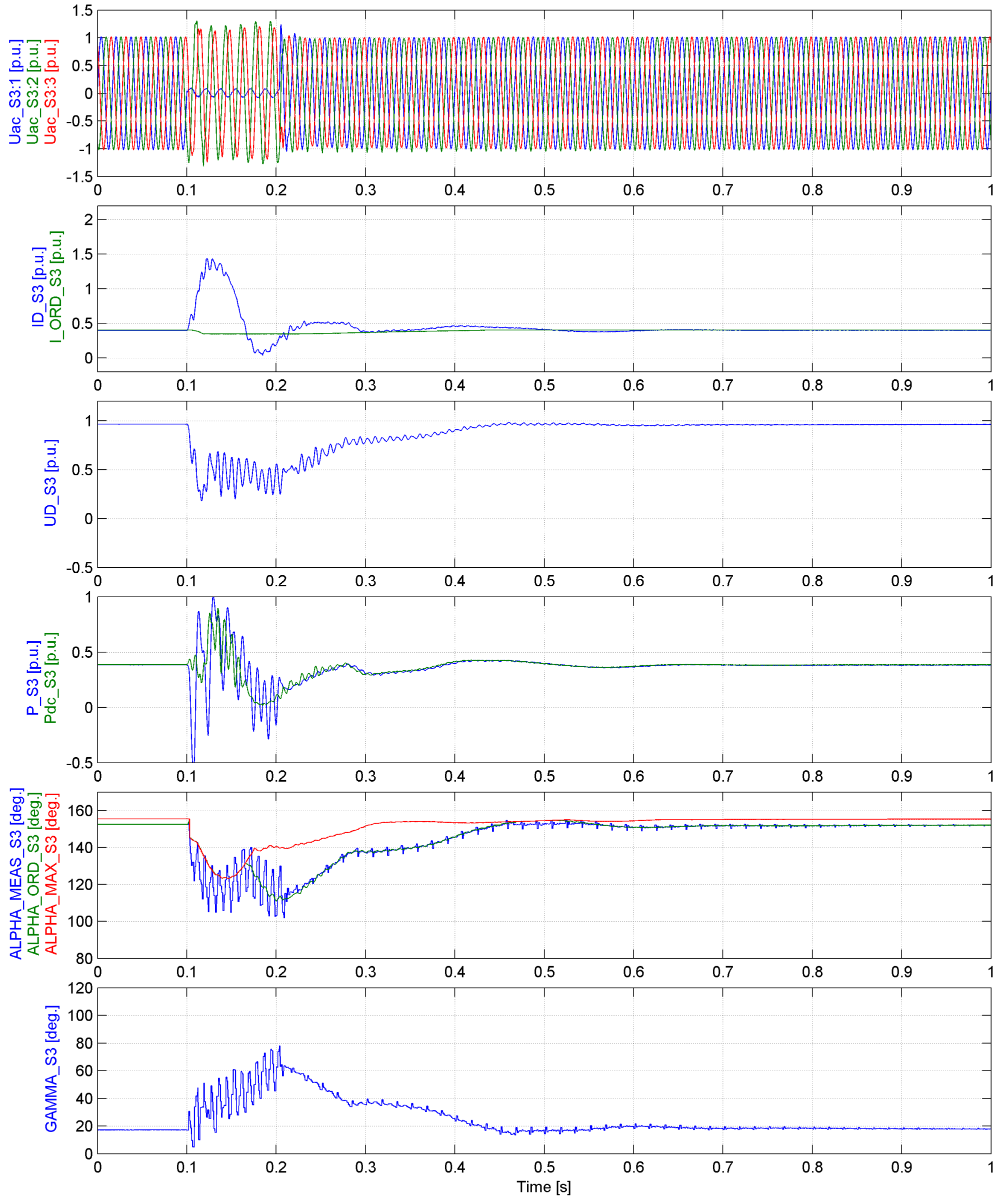

Figure A.18: 100ms single phase to ground fault with 10% remaining voltage. Station 3

Three phase to ground. 1 p.u. / 0.5 p.u. / 0.75 p.u.

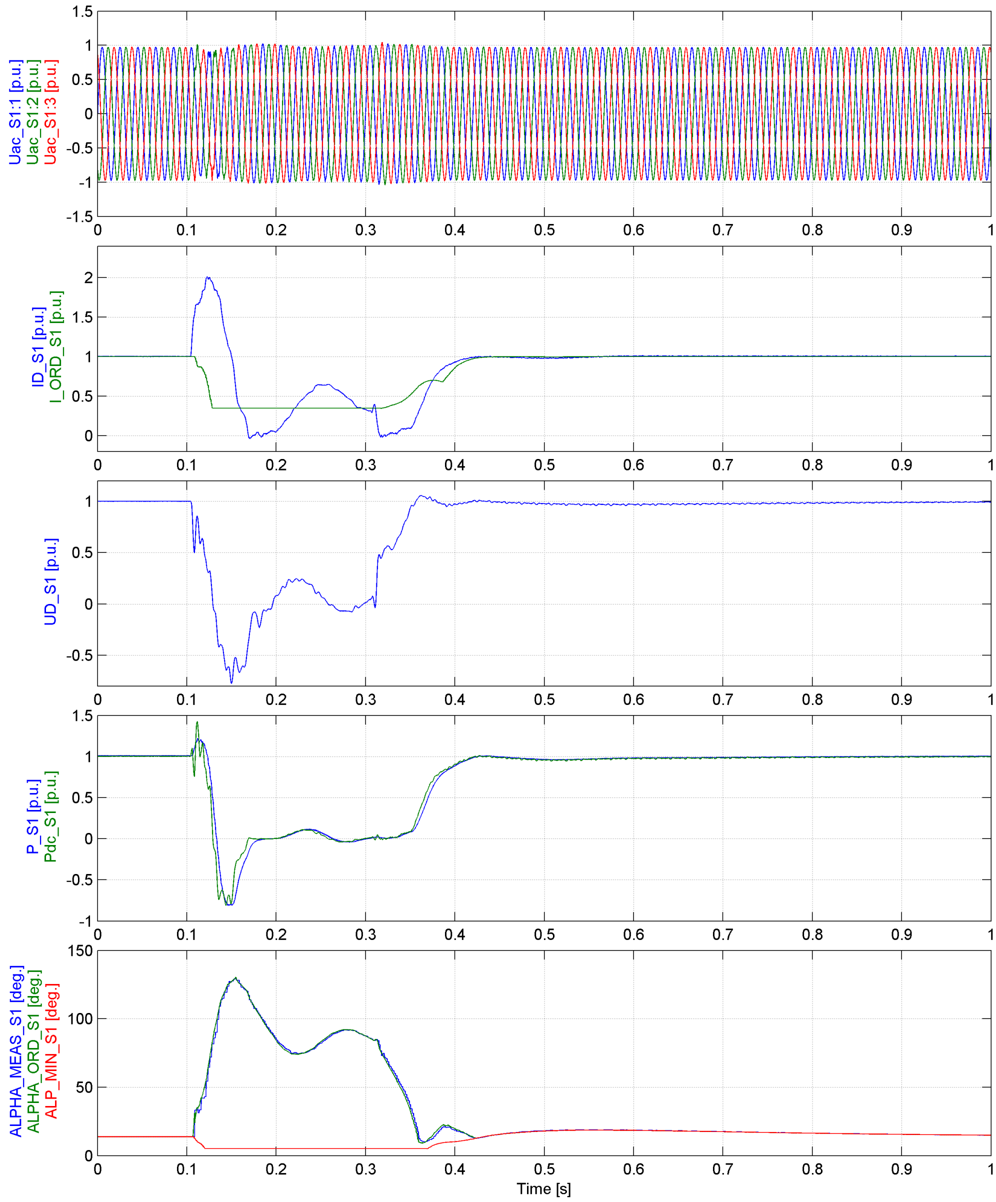

Figure A.19: 200ms three phase to ground fault with 10% remaining voltage. Station 1

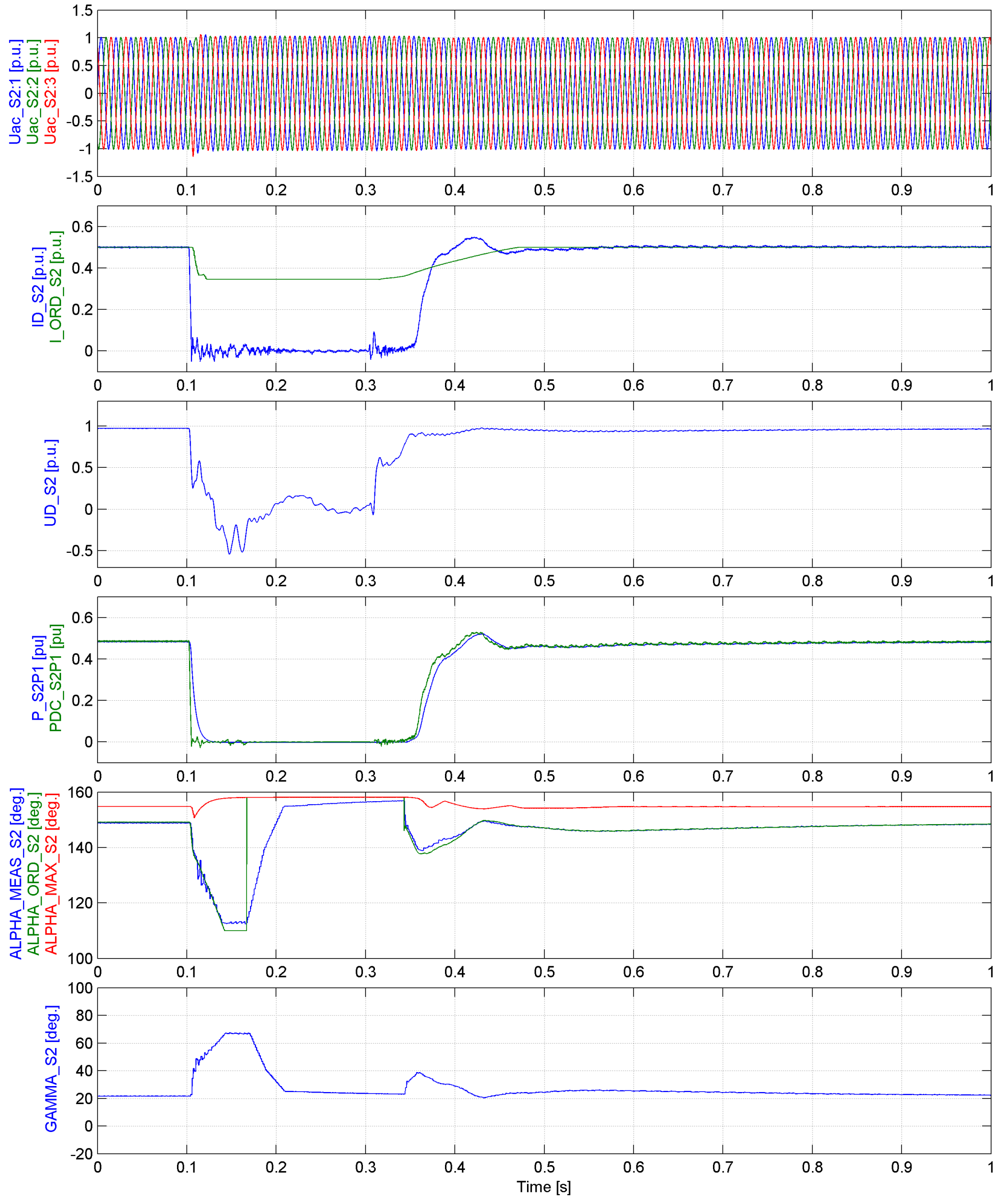

Figure A.20: 200ms three phase to ground fault with 10% remaining voltage. Station 2

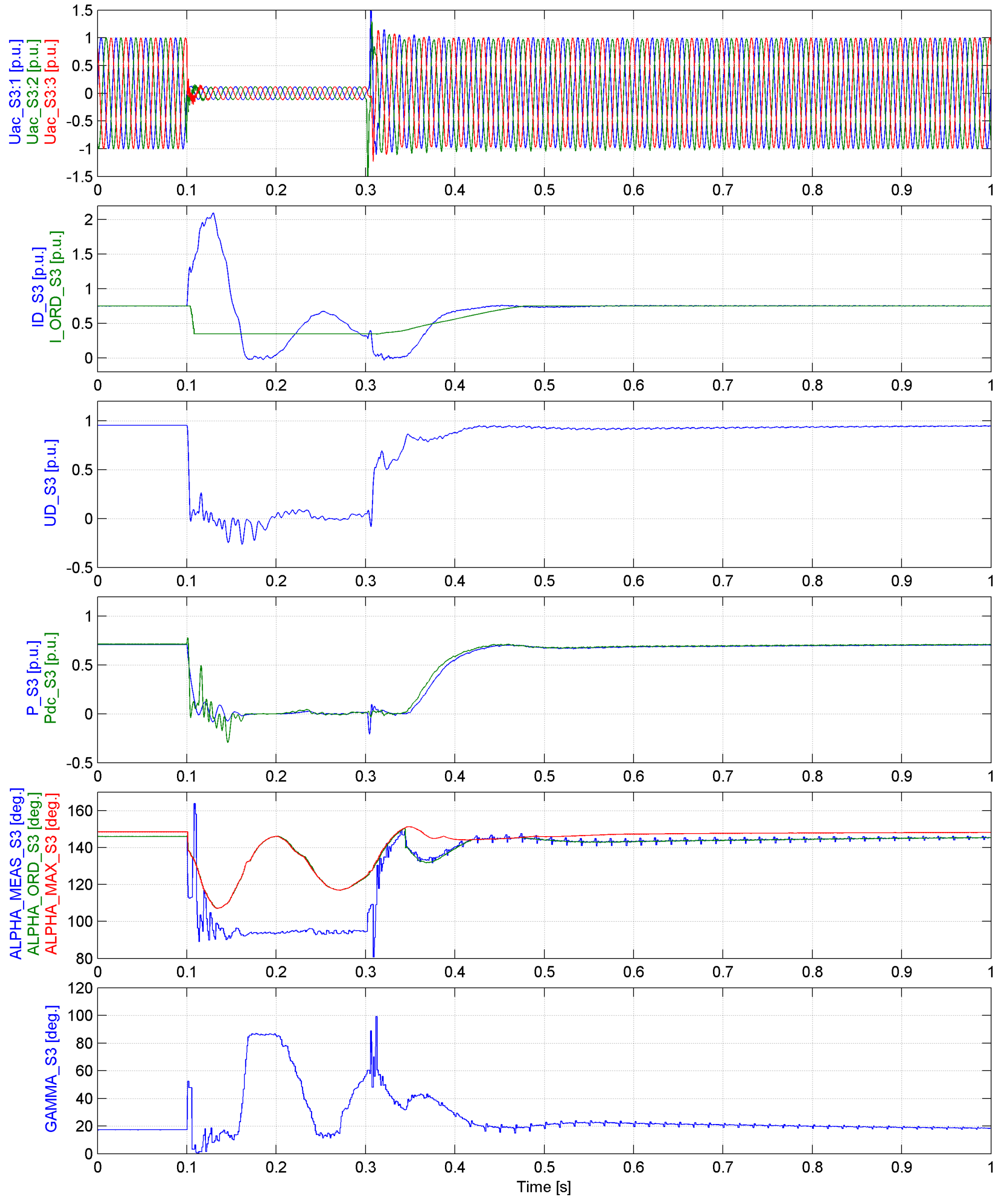

Figure A.21: 200ms three phase to ground fault with 10% remaining voltage. Station 3