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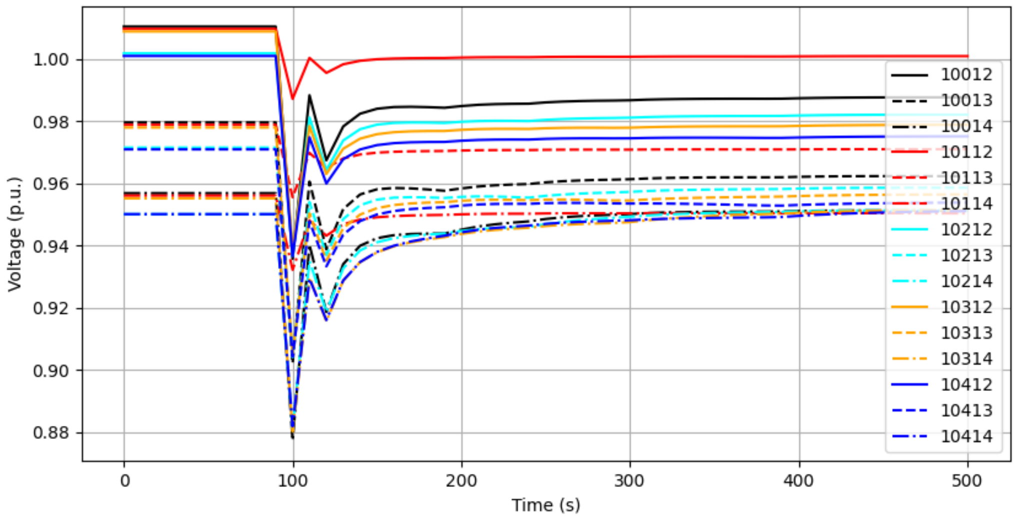

Active distribution networks and their impact on the transmission system

How local active power control in distribution networks affects the voltage stability of the transmission system

Master's thesis in Electric Power Engineering

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Ludvig Andersson

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Abstract

In order to minimize greenhouse gas emissions, fossil fuels for electric power generation are being replaced by renewable power sources in power systems across the world. Consequently, transmission network stability is projected to worsen over the coming decades partly caused by the decommission of large amounts of synchronous generation. In this thesis a local distribution network control system is studied to evaluate how it impacts the transmission network in case of contingencies. The control system is intended to allow for further integration of renewable generation in radial distribution networks, and utilizes active power control to prevent overcurrent and overvoltages in the distribution network. A radial distribution network is modelled and integrated into the IEEE Nordic transmission network model. A previously developed control system is modified to handle a greater range of contingencies, and implemented in the power system simulation software PSS/E. A number of contingencies in the transmission network are combined with different generation scenarios in the distribution network. Simulations are conducted using a semi-static simulation methodology based on load flow analysis.

The results imply that the distribution networks under local control can provide indirect mitigation of voltage deviations in the overlying network in case of contingencies. However, this mitigation is dependent on the ability to regulate the active power setpoints of the loads in the distribution network. On load tap changers of the transformers connecting distribution networks to the overlying network improve the voltage stability in the distribution networks, but reduces the amount of voltage support provided to the overlying network. The assumptions made regarding rate of change of active power setpoints and the extent to which load setpoints can be regulated have a large impact on the results.

Keywords: Voltage stability, voltage support, active power regulation, distribution network control, demand side management, PI-controller, load shifting, renewable integration.

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Ludvig Andersson, Gothenburg, January 2022

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Introduction

1.1 Background

In the current endeavour to integrate large amounts of intermittent power production in power systems around the world, steps are being taken to make full use of intermittent power when it is available. In traditional power system operation, power production is adapted to the demand at any given time. As the production of power becomes more fluctuating with the introduction of intermittent power sources, measures are being taken to ensure that the loads in the power system can be matched to the available production at any given time [1]. To enable loads to effectively use the available power at any given moment, the concept of the active distribution network (ADN) is being developed [2]. In principle, the active distribution network implements some kind of control system to be able to co-ordinate the different available loads, distributed generation units (DGUs) and possibly energy storage systems. The different available resources are coordinated to keep the system within certain current or voltage boundaries while maximizing power production, but the exact implementation often depends on the needs of the distribution network in question. The concept of the ADN is often discussed as a method that can be used to enable more distributed generation in distribution networks (DN) while ensuring that the system is operating within tolerable current and voltage boundaries.

During the shift towards renewable power production in the nordic power system, both frequency and voltage stability are projected to worsen over the coming decades unless actions are taken to improve the system stability [3] [4]. Frequency and voltage stability in a power system context can be described as the ability of the power system to keep voltage and frequency within their respective tolerable boundaries, and to recover to a tolerable state when some kind of contingency causes the frequency or voltage to deviate. In order to ensure an adequate level of stability for the power system, measures are being taken to counter the worsening stability. These measures include new ancillary services, improved monitoring systems and complementing the power system with devices such as synchronous condensers or static compensators (STATCOM).

At RISE, a number of projects related to power system stability and active distribution networks are being conducted. Methods for implementing active distribution networks are being studied in the ANM4L project, and transmission network (TN) monitoring and control is being researched in the NEWEPS project. Neither of these projects evaluate the effects that active distribution networks may have on the transmission network. As different types of active distribution networks may be implemented into the power system over the coming years, it is interesting to study the effects that the widespread use of active control systems may have on transmission system stability. In the ANM4L project, control algorithms for active distribution networks have been developed. In this particular application, focus has been on countering overvoltage and overcurrent in a radial distribution system with large amounts of distributed generation. Traditionally, distribution network voltages are managed by transformers equipped with on-load tap changers (OLTCs) that connect the distribution network to the overlying network. However, traditional OLTC control only regulates the bus voltage closest to the transformer and have no ability to compensate for voltage deviations further out in the distribution network. The control system developed in the ANM4L project is relatively simple, and does not directly consider any parameters outside of the distribution network in which it is implemented. Due to the network characteristics in the particular case considered in ANM4L, the potential for regulating voltage through reactive power control is limited. Therefore, the algorithms developed in the ANM4L project largely focus on active power control. Different ways of using active power control as a tool to support the power system is a topic that is receiving substantial attention at the moment, as a way of enabling more efficient use of the power system [5]. Reactive power is currently not traded as a commodity the way active power is, but is simply used to regulate voltage when possible with no economic gain for the owner of the resource providing the reactive power. Current developments in the power system include the emergence of the so called flexibility market, where a variability in active power demand or supply may be traded. The emergence of these markets indicate that there may be economic value to being able to shift active power usage in time to aid the stability of the power system.

In order to provide an alternative perspective to the distribution network view that is the focus in the ANM4L project, this thesis will focus on how active power control of distribution networks can impact the voltage stability of the transmission system.

1.2 Aim

This thesis intends to investigate the following questions.

- How does local active power control with the purpose of maintaining tolerable currents and voltages in radial distribution networks impact the voltages in the transmission network during contingencies?
- How does the operation of tap changers affect the impact that the active distribution system has on the transmission network during contingencies?
- How is the impact on the transmission network affected by a) the distribution network characteristics, and b) the load and generation levels in the distribution network at the time of fault?

1.3 Scope

The aim of this study is to investigate how the transmission system is affected when local active power control is used to manage the distribution network. A model of a distribution network will be developed, and integrated into a transmission network model. The control system developed in the ANM4L project will be adapted for use with the power system simulation software PSS/E. The control system will then be used to control a number of distribution networks that are integrated into the transmission network model. Once the model is complete, simulations will be used to study the impact that actively controlling the distribution networks has on the transmission network. The interaction of the active distribution network and the on-load tap changers (OLTC) of the transformer will be studied, with focus on how the OLTCs affect the voltage support ability of the actively controlled distribution networks. Voltage support can be described as a service provided by certain resources in the power system, whose primary or secondary function is to aid voltage stability. The focus will be on providing voltage support during the short-term period described in chapter 2. Both over- and undervoltage events will be studied. In order to properly evaluate the potential that active distribution systems have, different load scenarios and types of distribution networks will be evaluated. The focus of the control system will be to ensure that voltages and currents are kept within tolerable limits by utilizing active power regulation. Once the local control systems are implemented, their impact on the transmission network will be evaluated by introducing different contingencies. As the control system regulates the distribution network based on voltages and currents measured inside the distribution network itself, any effects on the transmission network are side effects stemming from voltage or current regulation within the distribution network.

1.4 Limitations

The study will mainly focus on the impact of active distribution systems on voltage stability, and will thus not examine the impact on frequency stability. The control algorithm developed in ANM4L will be developed further so that the control system can prevent overvoltage, undervoltage and overcurrent in the distribution system. The previously developed algorithm that will be used as a base in the thesis project only considers active power control, and no efforts will be made to implement reactive power control from renewable generators. The control systems will control each distribution network locally, and no centralized control system will be implemented.

The study will focus on how local control systems influence the transmission system in case they are widely implemented in distribution systems across the power system. The voltage level of the modelled distribution networks will be 20kV, and will be connected to the transmission system through the 130kV subtransmission system. The parts of the distribution system below 20kV will not be modelled, but will be implemented as loads and generation units in the model of the higher voltage level. The distribution networks will be modelled as radial networks. Primarily short-term voltage support will be considered, but no effort will be made to model any transient phenomena. The transient period and long term period as shown in figure 2.1 will thus not be considered. No estimation of the speed of a real implementation of the algorithms will be carried out, and iterative static power flow estimations will be used for the simulations. Therefore, no effort will be directed at studying the dynamic interactions of the control systems.

2
Theory

This chapter presents the theoretical concepts necessary to explain the procedure of modelling the power system, and the concepts that are key in explaining the effect that active distribution networks have on the voltage stability of the transmission network.

2.1 Transmission line parameters

When modelling transmission line impedance, both the type and the length of the conductor must be considered. Overhead lines (OHLs) and underground cables have different characteristics. The branch impedance consists of resistance, inductance and capacitance. Regardless of whether OHLs or cables are used, the resistance is dependent on the material properties and geometry of the conductor. It is often given as a value of Ω/km. The inductance describes the level of magnetic flux around the conductor that is created by a certain amount of current through the conductor, and is described with the unit of Henry (H). The total line impedance, denoted Z, is described as

$$Z = R + jX \tag{2.1}$$

where R is the total resistance of the line. The reactance X can be described as

$$X = \omega L \tag{2.2}$$

where L is the inductance and ω is the angular frequency of the power system voltage. When describing the characteristics of a certain type of conductor, either the inductance is given in mH/km or the reactance is given in Ω/km. Assuming that the electrical frequency is the same, each of these quantities can be used to compute the other.

The capacitance of transmission lines describes the amount of energy stored in the electric field created by the voltage around the conductor. It is often described as the *charging* capacitance, as it can be seen as a measure of the required charging of the transmission line. The charging capacitance depends on the geometry of the conductor and the type of conductor used. For overhead lines, charging capacitance is often neglected when considering branches of length shorter than around 80km [6]. The capacitance of a transmission line depends, among other factors, on the distance and the material between the conductor and ground. As the distance to ground is many times smaller for cables than for OHLs, the capacitance is much larger for a cable. Therefore, the charging capacitance must be considered when dealing with underground cables.

In case multiple identical conductors are used in parallel to increase the transferable power and there is no mutual inductance, both the resistance and inductance are reduced

$$Z_{eqv} = \frac{Z}{N} \tag{2.3}$$

where N is the amount of parallel conductors, Z is the impedance of one conductor and Z_{eqv} is the total equivalent impedance. However, as the charging capacitance is primarily driven by voltage the charging capacitance increases in case multiple parallel conductors are used. The capacitances of the different branches are added together, and so if N identical conductors are used the equivalent charging capacitance becomes

$$C_{eqv} = N \cdot C \tag{2.4}$$

where C is the capacitance of the individual branch and C_{eqv} is the total capacitance. The phenomena of charging capacitance is sometimes discussed by the closely related quantity of susceptance. Susceptance is the imaginary part of the admittance, which is the inverse of impedance. If the capacitance is known, susceptance can be calculated as

$$B = \omega C \tag{2.5}$$

where B denotes the susceptance. The unit of admittance, and thus also the unit of susceptance, is Siemens (S).

The voltage drop across a transmission line depends on a number of factors, but can be approximated through the following equation

$$V_S = V_R + \frac{R \cdot P_R + X \cdot Q_R}{V_R} \tag{2.6}$$

where V_S is the sending end voltage, V_R is the receiving end voltage, P_R and Q_R are the receiving end active and reactive powers. R is the resistance and X is the reactance of the transmission line. This approximation is only valid as long as the difference between V_S and V_R is relatively small. If the voltage drop is larger, this approximation will no longer be accurate. As equation (2.6) describes, the impact that the active and reactive power transfer has on the voltage drop depends on the impedance. The common case in high voltage transmission lines is that the reactance is much larger than the resistance, and in that case the reactive power transfer has a much larger impact on the voltage drop across the transmission line. In case the voltage is being actively controlled by the power transfer, a certain change in voltage requires a much larger change in active power transfer than what would be needed if the reactive power transfer was to be changed instead. In lower voltage sections of the power system the resistance is generally similar in magnitude as the reactance and may even be larger, depending on the voltage level and type of branch [7]. The so-called X/R ratio is used to describe the ratio of reactance to resistance, which can be used to discern how effectively changes in active and reactive power transfer can regulate voltage.

2.2 Voltage stability

This section presents the concept of voltage stability, and how voltage depends on network parameters and conditions. Methods for providing voltage support on different voltage levels are also presented.

During a voltage disturbance caused by some type of fault, the sequence of events can generally be divided into three periods. Immediately after the fault the transient period starts, which for the purpose of this project is estimated to last for about 10s after the start of the fault. During the transient period, the voltage may fluctuate substantially. After 10 seconds, the system has often reached a more stable state. For the purpose of this study, this period is denoted the short-term period. During this period, the short-term voltage support acts to restore the system voltage in all nodes. The range of 10-60s after the fault is denoted the short-term period. After around 60 seconds, the voltage is often restored to a level near the pre-fault value. Any events that occur more than 60 seconds after the fault are considered part of the long-term consequences. An example of a voltage disturbance sequence is illustrated in figure 2.1.

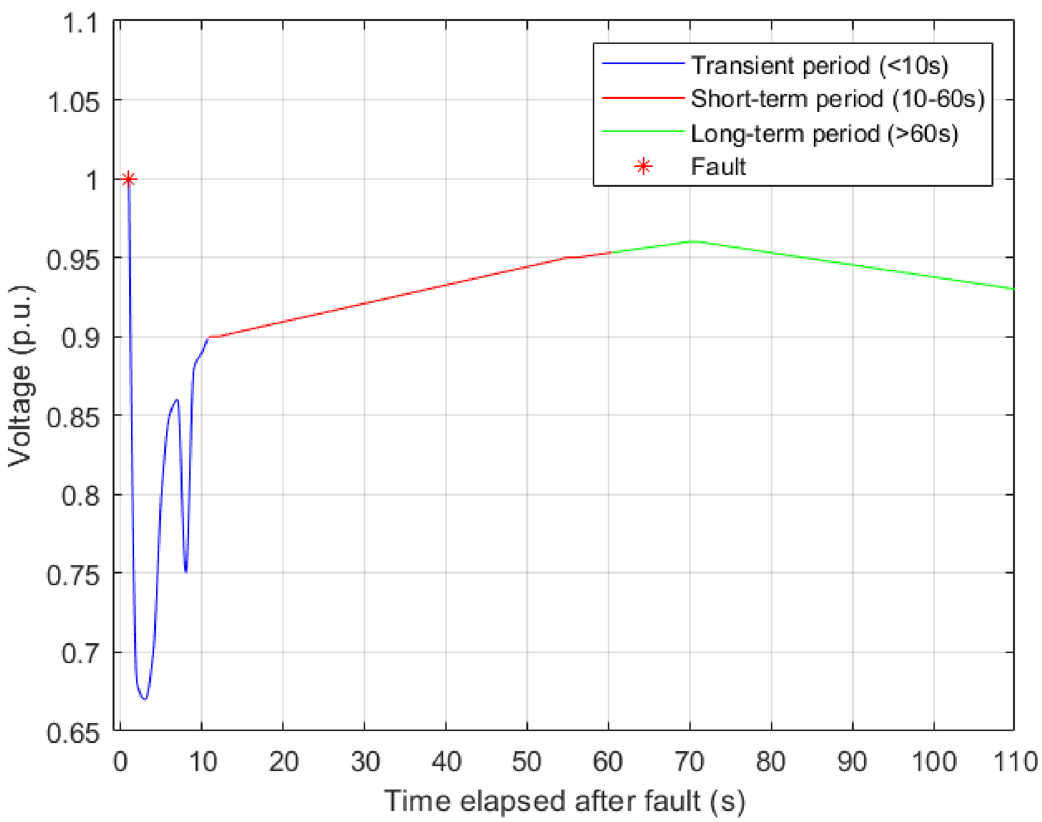

Figure 2.1: Voltage disturbance illustration.

If control systems are introduced to generation units and loads in distribution systems across the power system, they could be used to regulate the power flow. Generation units interfaced to the distribution system through power electronics are generally able to control their reactive power exchange freely as long as their current rating is sufficiently high to tolerate the resulting apparent power, and can thus often be used to provide voltage support without compromising the active power production. However, the potential for providing voltage support through reactive power control in low voltage networks depends on the X/R ratio. Regulating reactive power is generally preferable to regulating active power when possible as reactive power is not subject to trading the way active power is. Loads can generally not control their active and reactive powers separately, but the amount of power flow can often be controlled. Using generation units and loads to provide voltage support through control of power flow has the potential to increase voltage stability without investing in new infrastructure. Using active distribution systems to provide voltage support to the transmission system could therefore improve voltage stability at a relatively low cost.

2.2.1 Theory

Voltage stability can be described as the ability of the power system to keep voltage in all of its nodes within tolerable limits, and to restore it within those limits when disturbances cause deviations in voltage. The angle and magnitude of the voltage in a particular node is dependent on the voltage in neighbouring nodes and the flow of power between them. As a simplification, voltage magnitude is often considered to be strictly related to reactive power exchange while the voltage angle is considered to be related to active power exchange. Under normal operating conditions in high voltage networks this simplification is accurate, but it is not a valid simplification when the power system is in a compromised state. The simplification is also dependent on the impedance predominantly consisting of reactance. In lower voltage networks the resistance often makes up a larger portion of the total impedance than in higher voltage networks. This means that the simplification is no longer applicable for lower voltage networks.

Transmission lines in the high voltage transmission network are often simplified as lossless, due to their high X/R ratio. Using this assumption, the so-called PV-curve can be derived [8]. The PV-curve is useful for describing how the power delivered to a load depends on the voltage drop across the load. The PV-curve is actually a representation of a two-dimensional surface in the (P, Q, V) space. In order to flatten the surface so that it can be represented in the (P,V) space, multiple curves are included that describe the different levels of reactive power. In figure 2.2, which illustrates the PV-curve, Q is illustrated by the parameter tanΦ which can be described as

$$\frac{Q}{P} = tan\Phi \tag{2.7}$$

Figure 2.2 illustrates the relation between $\frac{V}{E}$, $\frac{PX}{E^2}$ and $tan\Phi$ [8].

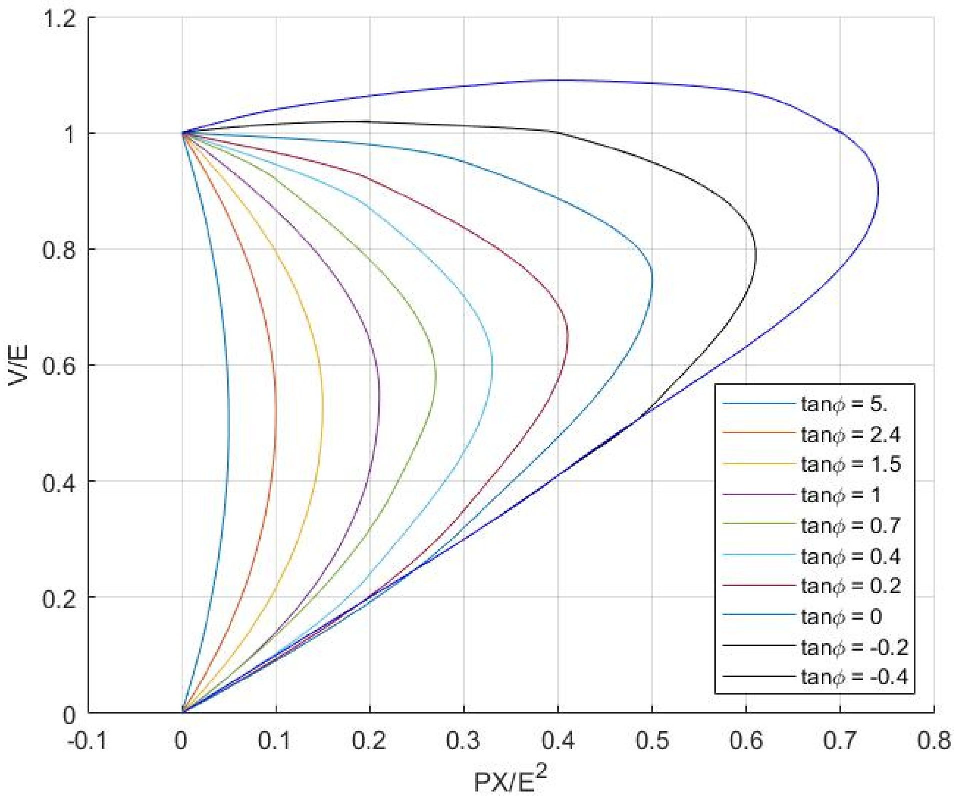

Figure 2.2: PV-curve, illustrates relation between P, Q and |V|. tanΦ describes the power factor as described in equation (2.7).

Regardless of the value of $tan\Phi$, the PV-curves illustrate the quadratic dependency of voltage in relation to active power transfer. For a certain $\frac{PX}{E^2}$ and $tan\Phi$ operating point, there are two possible corresponding voltages with exception to the operating point with the highest possible active power transfer. The operating point with the maximum value of $\frac{PX}{E^2}$ is known as the bifurcation point. For each individual curve in figure 2.2, the section of the curve above the bifurcation point is designated as the stable region, while the section beneath the bifurcation point is designated as the unstable region. In the stable region, a reduction of active power transfer results in increased voltage and an increase of active power transfer results in decreased voltage assuming that $tan\Phi$ is larger than 0. As illustrated in figure 2.2, this dependency is not strictly true for negative value of $tan\Phi$ as an increase of active power transfer in the stable region can result in a voltage increase. Power system operators often require a certain margin between the maximum tolerable power transfer and the bifurcation point. This is due to the risk of unexpected faults changing the reactance of the branch, generating a new PV-curve. In case the margin is too small, the new operating point may be in the unstable region of the new PV-curve. In the unstable region, decreasing the power transfer results in reduced voltage. Operation in this region may result in voltage collapse. If it is assumed that the system always operates in the stable region of the PV-curve with $tan\Phi$ larger than 0, the predictable dependency of voltage upon active power transfer can be used to control voltage by regulating the active power transfer.

2.2.2 On-load tap changers

Traditionally, transformers outfitted with on-load tap changers (OLTCs) have been used to regulate distribution network voltage [9]. OLTCs use a system of switches to vary the ratio of the primary and secondary windings [6]. This variable ratio is usually used to keep the lower voltage side within tolerable limits, thus allowing for safe operation of the lower voltage network even in the case of deviations in the voltage level of the higher voltage network. This decouples the distribution network voltage from the transmission network to a certain degree, as long as the voltage deviation in the transmission network is not severe enough to push the tap changer to its minimum or maximum ratio. OLTCs are common in different parts of the power system. For example, consider a 20kV distribution network connected to a 400kV transmission network through a 130kV subtransmission network. In this case, it is not uncommon that both the 20-130kV and 130-400kV transformers are equipped with OLTCs. This provides considerable ability to maintain distribution voltages within tolerable limits. OLTCs are often configured with a delay of 30-60s for the initial reaction, and a shorter delay for additional actions.

However, this system was devised at a point in time where little to no distributed generation existed in the distribution network. Due to the current increase of distributed generation in low- and medium voltage systems, distribution systems can no longer merely be considered to be loads in all scenarios. The typical implementation where OLTCs are used to regulate distribution network voltages often does not consider effects caused by distributed generation, such as overvoltages in radial networks. The current usage of OLTCs also does not consider that it may be possible to support higher voltage networks with resources in the distribution network, which may limit the potential benefits of distributed generation. The decoupling of distribution network voltage from variations in transmission network voltage may limit the ability of local control systems to contribute to voltage stability.

2.2.3 Switched shunt capacitors and reactors

As one of the methods used to regulate power system voltage within acceptable limits, switched shunt capacitors and reactors may be used. Shunt capacitors are often used to increase the voltage in a certain node, while shunt reactors are used to decrease voltage. In an effort to provide economically efficient voltage support, such resources are often kept quite simplistic in their manner of control. They are often switched manually, and have a few large discrete steps that can be switched on or off. The setpoint of a switched shunt is often changed in anticipation of a change in load or generation in the local section of the power system.

3

Distribution network control system

The following sections aim to describe why this type of active control system is developed, the different algorithms used to regulate the distribution network parameters, and the complete control system that combines the algorithms.

3.1 Control system background and goals

Traditionally, the main purpose of a distribution network is to distribute electrical energy to consumers. The electrical energy is traditionally generated relatively far away from load centers, and is supplied to the distribution network from the overlying network. In this case, the electrical characteristics of a radial distribution network are predictable with regard to voltages and power flows. The power will flow outward from the bus closest to the overlying network, to the bus furthest away from the overlying network. Assuming that the network mainly uses overhead lines, the voltage will be the highest closest to the overlying network and will be the lowest at the point furthest away.

If distributed generation (DG) is introduced to the distribution network, the predictable nature of power flow and voltage may no longer be valid. The introduction of DG may affect the direction of power flow in either the entire distribution network or certain parts of it, which may in turn affect the relative voltage of the different distribution network buses. If the amount of DG is sufficiently large in relation to the loads fed by the distribution network, the distribution network as a whole may start to feed power to the overlying network in certain operating conditions. This would not be possible in traditional distribution network operation, and gives rise to a number of side effects. Voltage may increase above the tolerable limit in certain sections of the distribution network, and the current rating of distribution branches may be exceeded.

In order to solve this issue of untolerable voltages and currents, two approaches are usually deployed. A common approach is to only allow for the introduction of DG to such a level that network parameters cannot exceed tolerable values in any operating condition. However, this approach may limit the total amount of DG that can be introduced and thus waste a potential source of energy. Another approach is to introduce a control system to the distribution network that regulates the resources in the network to ensure that voltages and currents are kept within tolerable limits. By introducing such a control system, larger amounts of DG may be introduced to the distribution network. In this particular implementation, the active power of loads and DGUs in the distribution network are regulated to keep system parameters within tolerable limits.

The distribution network is regulated solely based on measurements from inside the distribution network itself, and thus does not consider any parameters from other parts of the power system. As this type of control system does not consider any parameters from the higher voltage sections of the power system, it is interesting to study how an introduction of such control systems affect the overlying networks.

3.2 Control system algorithms

In the ANM4L project, control algorithms for managing active distribution networks have been developed. The different voltage- and current management algorithms developed are modified and combined into a complete control system used to ensure that the distribution network operates within tolerable voltage and current limits. The control system is then implemented in a distribution network model with a generator representing the 130kV network in order to verify the function of the control system.

3.2.1 PI-controller

Both the voltage and current management systems use a discrete PI-controller to control the different available resources. The discrete PI-controller can be described as

$$u = -K(e + \frac{T}{T_I} \cdot (e + e_{old})) \tag{3.1}$$

where u is the controller output, T is the sampling interval while K and T_I are design parameters. The error e is defined as

$$e = u_{set} - u_{meas} \tag{3.2}$$

where u_{set} is the setpoint of the controller and u_{meas} is the current value of the controlled parameter. The error sum e_{old} is the sum of all earlier errors, and can be described as

$$e_{old} = \sum_{n=1}^{n_s} e_n \tag{3.3}$$

where n_s is the number of previous samples. An anti wind-up scheme is implemented that limits the error sum and the controller output in case the controller output exceeds its maximum output magnitude. Figure 3.1 illustrates the PI-controller including the anti wind-up scheme.

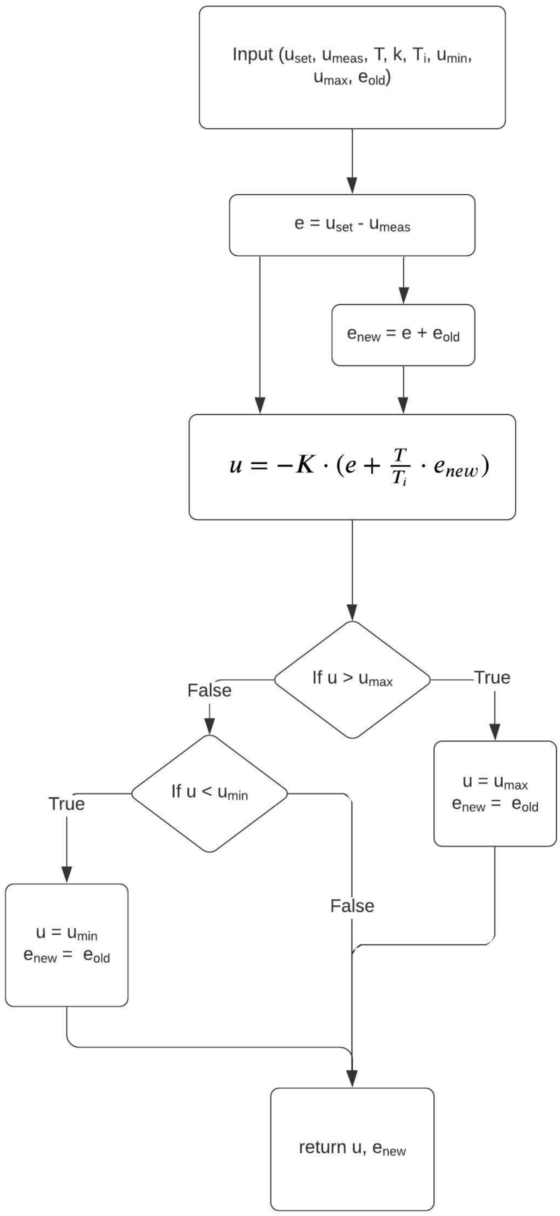

Figure 3.1: Flow chart of PI-controller with integrator anti-windup.

This type of PI-controller can be utilized for both the voltage and current management systems, albeit with different values of design parameters K and T_I. The values of those parameters determine the behaviour of the control system. Therefore, the values are to be tuned for each implementation of the controller so that it behaves as expected. The commonly used Ziegler-Nichols method is used for initial tuning of the design parameters [10]. The parameters are then tuned to avoid overshoot, to avoid fluctuations in the power system as well as unnecessary load shifting or curtailment of generation.

3.2.2 Voltage management algorithm

The voltage management algorithm is implemented locally in each bus. In case of voltage deviations, the control algorithm acts to bring the voltage within tolerable intervals. The voltage management algorithm acts as an undervoltage prevention algorithm in case the voltage is lower than its nominal value, and as an overvoltage prevention algorithm in case the voltage exceeds the nominal value. This is achieved by varying the given voltage setpoint depending on the current voltage value. In case the voltage is below its nominal value, the lower voltage threshold is sent to the PI controller. Conversely, if the voltage is above its nominal value then the higher voltage threshold is sent to the controller. The voltage is regulated to be within the tolerable interval, and the voltage regulation is deactivated within the interval in a similar manner to a deadband. If the controller output is then combined with a number of limiting conditions the system can be made to prevent voltage outside the tolerable interval by controlling the generation and flexible loads, while allowing those resources to vary according to their nominal load or generation in case the voltage is within the acceptable interval.

The algorithm is capable of prioritizing either generation curtailment or load shifting in case of overvoltage, while undervoltage can only be mitigated by load shifting. In case curtailment is prioritized, the algorithm decreases the voltage by lowering the active power setpoint of the generator. In case load shifting is prioritized, the algorithm increases the active power consumption of the load instead. In case of undervoltage, the consumption of the load is lowered in order to maintain acceptable voltage. The distributed generation units are assumed to be operating at maximum power output, thus not allowing an increase in power output to control voltage. Before updating the loads and generators with the computed setpoints, the setpoints are evaluated to check that they satisfy a number of conditions. The conditions vary depending on the type of resource and whether the controller is currently mitigating over- or undervoltage. The conditions used to limit the generator setpoints in case of curtailment prioritization are presented in Table 3.1.

Conditions 1 and 2 in Table 3.1 ensure that the generator that is being regulated is not set outside its tolerable interval of setpoints. In the most lenient case, this means that the generator can not be set to consume power and that it can not be set to produce more than its current maximum active power production. Conditions 3 and 4 ensure that the setpoint of the generator is not changed faster than the maximum tolerable rate of change.

In principle, the controller acts to regulate the voltage to its given setpoint. While prioritizing curtailment, voltage is reduced by lowering the active power setpoint of the generator at the bus. If voltage is lower than the given setpoint, the controller will signal an increase in active power to increase the voltage. However, condition 1 in table 3.1 effectively ensures that the generator operates at its current maximum power level in case voltage is below the setpoint.

Table 3.1: Conditions for generator setpoints in overvoltage mitigation mode.

Condition (Nr)	**Action if condition is false**	**Description**
$P_{setpoint} \leq P_{max}$ (1)	$P_{setpoint,lim} = P_{max}$	The generation unit cannot be set to produce more power than what is currently available.
$P_{setpoint} \geq P_{min}$ (2)	$P_{setpoint,lim} = P_{min}$	The generation unit cannot be set lower than its set minimum power production.
$P_{setpoint} \leq P_{meas} + P_{ramp}$ (3)	$P_{setpoint,lim} = P_{meas} + P_{ramp}$	The change in active power setpoint cannot exceed the ramping limit P_{ramp}.
$P_{setpoint} \geq P_{meas}$ - P_{ramp} (4)	$P_{setpoint,lim} = P_{meas}$ - P_{ramp}	The change in active power setpoint cannot exceed the ramping limit P_{ramp}.

Table 3.2: Conditions for load setpoints in overvoltage mitigation mode.

Condition (Nr)	**Action if condition is false**	**Description**
$P_{setpoint} \geq P_{nom}$ (1)	$P_{setpoint,lim} = P_{nom}$	The load cannot be regulated to a lower active power consumption in case of overvoltage.
$P_{setpoint} \leq P_{meas} + P_{ramp}$ (2)	$P_{setpoint,lim} = P_{meas} + P_{ramp}$	The change in active power setpoint cannot exceed the ramping limit P_{ramp}.
$P_{setpoint} \geq P_{meas}$ - P_{ramp} (3)	$P_{setpoint,lim} = P_{meas}$ - P_{ramp}	The change in active power setpoint cannot exceed the ramping limit P_{ramp}.

The conditions used to limit the load setpoints in case of overvoltage mitigation mode are presented in table 3.2. These are similar to the conditions applied to the generator setpoints, with a few key differences. The conditions limiting the rate of change of the resource setpoint are identical, but the conditions stipulating absolute limits are different. In overvoltage mitigation mode, the loads can not be set lower than their current nominal load. There is no upper limit to the load setpoint, as the control system allows the load to be increased to the level that is needed to mitigate the overvoltage. The level of load flexibility needed to ensure tolerable voltage in different situations can then be analyzed and discussed.

The conditions applied to the load setpoints when the controller is mitigating undervoltage are similar to the conditions set upon generator setpoints in overvoltage prevention mode. The load cannot be increased above its nominal load as stated by condition 1, as this would lead to increased voltage in normal operating conditions. The load can also not be set below a set lower limit, as stated by condition 2. The conditions regulating setpoint rate of change are the same as in the overvoltage mitigation modes.

Table 3.3: Conditions for load setpoints in undervoltage mitigation mode.

Condition (Nr)	**Action if condition is false**	**Description**
$P_{setpoint} \leq P_{nom}$ (1)	$P_{setpoint,lim} = P_{nom}$	The load cannot be set to consume more power than its current nominal load level.
$P_{setpoint} \geq P_{min}$ (2)	$P_{setpoint,lim} = P_{min}$	The load cannot be set lower than its set minimum power consumption.
$P_{setpoint} \leq P_{meas} + P_{ramp}$ (3)	$P_{setpoint,lim} = P_{meas} + P_{ramp}$	The change in active power setpoint cannot exceed the ramping limit P_{ramp}.
$P_{setpoint} \geq P_{meas}$ - P_{ramp} (4)	$P_{setpoint,lim} = P_{meas}$ - P_{ramp}	The change in active power setpoint cannot exceed the ramping limit P_{ramp}.

A flow chart of the voltage management algorithm is presented in figure 3.2. The voltage control algorithm is implemented separately at each bus in the network. New setpoints are computed in 10 second intervals, in order to allow the system to stabilize somewhat between each change in setpoint. In principle, the control system is designed in such a way that the algorithm constantly tries to regulate the voltage to the exact voltage threshold. However, the way that the setpoints are limited ensures that the loads and generators are set to their nominal load in case the voltage is within the acceptable interval.

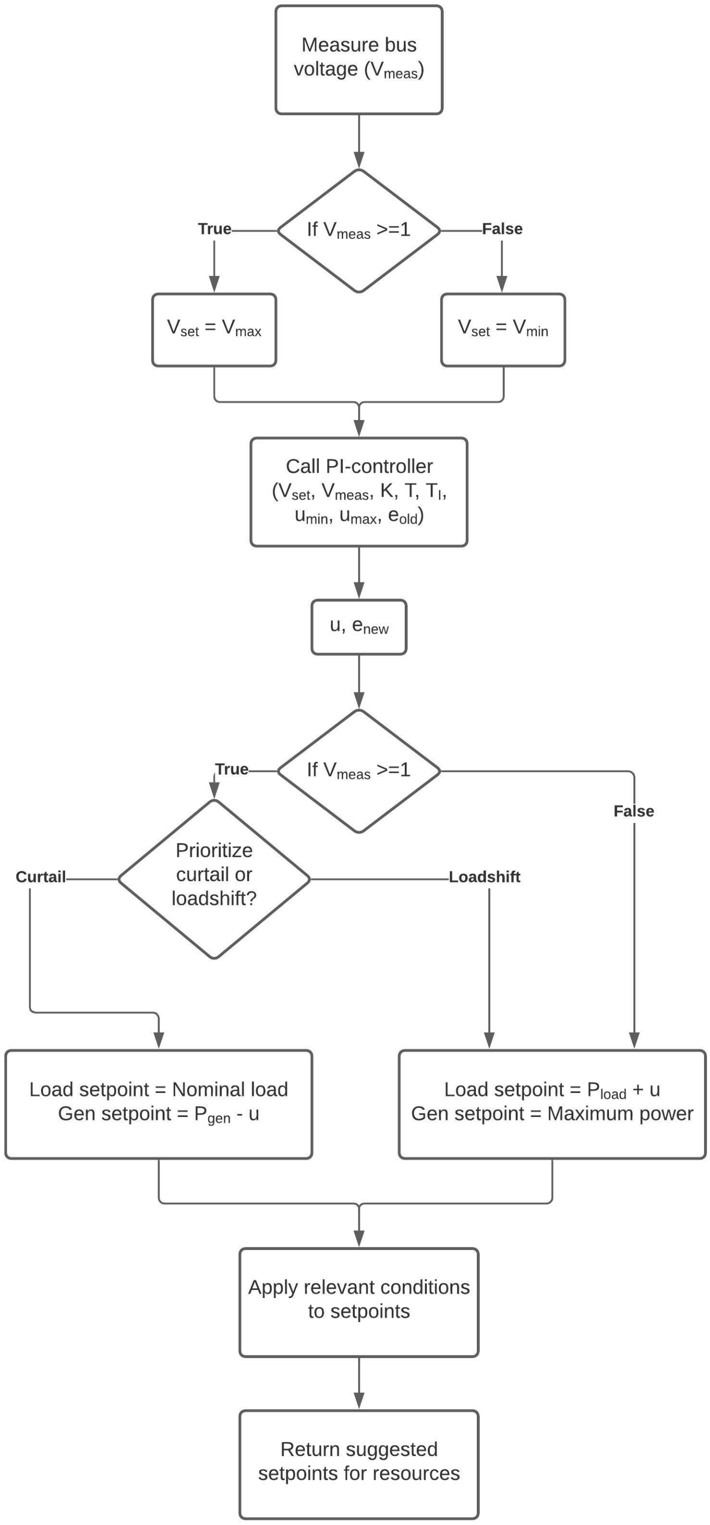

Figure 3.2: Flow chart of voltage management algorithm.

3.2.3 Current management algorithm

The overcurrent algorithm differs from the overvoltage algorithm by using a centralized control system that regulates all controllable assets in the distribution network to ensure that the current limits of the network are not exceeded. It is assumed that the distribution network is designed to supply all loads with power without any DG, but that scenarios may occur where high levels of distributed generation lead to overcurrent when the distribution network as a whole is feeding power to the overlying network. This assumption simplifies the control system, as a load increase or generation decrease can always be assumed to reduce the current. Enabling the control system to mitigate overcurrent in both directions is possible in case a similar system is to be implemented in a system where this simplification is not applicable.

The current management system is presented as a flow chart in figure 3.3. A PI controller is at the center of the current management system. As illustrated in figure 3.3, the control system iterates through all branches in the distribution network and mitigates overcurrent in all of them. In order to mitigate overcurrent, the control system can either increase load or decrease generation. To do this, the control system has access to both flexibility dispatch and sensitivity lists. The sensitivity list describes what resources in the network affect the current flow through a particular branch. The flexibility dispatch list describes the priority in which different resources are to be used to mitigate overcurrent. This dispatch list can be seen as a representation of a flexibility market, where the price of regulating different resources determine the order in which they are used. In this implementation, the resource of highest priority is used up fully before utilizing the next resource. As in the voltage management system, a number of conditions are used to limit the computed setpoints. The conditions used to limit the generator setpoints are presented in table 3.4.

The conditions applied to the generator setpoint in the current management system are similar to those applied by the overvoltage measurement system. However, there are additional actions in case the setpoint is lower than the minimum power production. In this case, the resource can be seen as exhausted. Therefore the part of the controller output removed by the minimum setpoint limit is kept, and the exhausted resource is removed from the list of available resources for the current control system iteration. The while-loop then runs for another iteration, applying the remainder of the control action to the next resource in the priority order. In all other cases the controller output is set to 0, prompting the control system to move to the next branch once the iteration is finished.

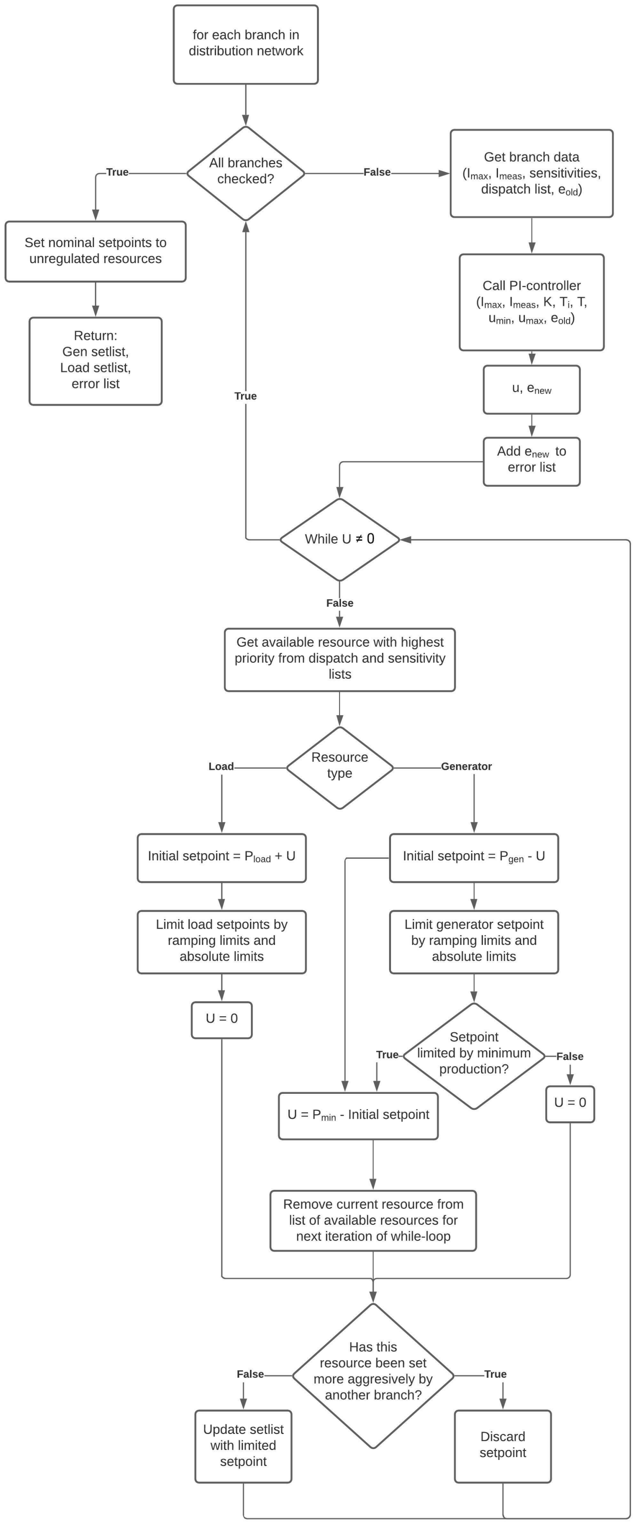

Figure 3.3: Flow chart of current management algorithm.

Table 3.4: Conditions for generator setpoints computed by current management system.

Condition (Nr)	**Action if condition is false**	**Description**
$P_{setpoint} \leq P_{max}$ (1)	$P_{setpoint,lim} = P_{max}$, $u = 0$	The generation unit cannot be set to produce more power than what is currently available.
$P_{setpoint} \geq P_{min}$ (2)	$P_{setpoint,lim} = P_{min}$, $u = P_{min} - P_{setpoint}$	The generation unit cannot be set lower than its set minimum power production.
$P_{setpoint} \leq P_{meas} + P_{ramp-max}$ (3)	$P_{setpoint,lim} = P_{meas} + P_{ramp}$, $u = 0$	The change in active power setpoint cannot exceed the ramping limit P_{ramp}.
$P_{setpoint} \geq P_{meas}$ - P_{ramp} (4)	$P_{setpoint,lim} = P_{meas}$ - P_{ramp}, $u = 0$	The change in active power setpoint cannot exceed the ramping limit P_{ramp}.

The conditions applied to the load setpoints are similar to the generator setpoint conditions, with the exception that there is no condition regulating the maximum load level. Thus, the load conditions do not include an action for when the load resource is exhausted as the load can simply be increased as much as necessary to mitigate overcurrent. In real implementations of a control system such as this one, it would not be possible to increase loads indefinitely. Therefore there would have to be a condition for determining when the load resource is exhausted, similar to the one used for the generator resources illustrated in figure 3.3.

Table 3.5: Conditions for load setpoints computed by current management system.

Condition (Nr)	**Action if condition is false**	**Description**
$P_{setpoint} \geq P_{nom}$ (1)	$P_{setpoint,lim} = P_{nom}$	The load cannot be regulated to a lower active power consumption in case of overcurrent.
$P_{setpoint} \leq P_{meas} + P_{ramp}$ (2)	$P_{setpoint,lim} = P_{meas} + P_{ramp}$	The change in active power setpoint cannot exceed the ramping limit P_{ramp}.
$P_{setpoint} \geq P_{meas}$ - P_{ramp} (3)	$P_{setpoint,lim} = P_{meas}$ - P_{ramp}	The change in active power setpoint cannot exceed the ramping limit P_{ramp}.

3.3 Complete control system

The distribution network control system has to manage voltage and current simultaneously, and thus has to implement both the described current and voltage management systems. While the voltage control system is implemented locally on each bus, the current management system is implemented for the distribution network as a whole. In order to prioritize between the actions of the different control systems, this control system would have to be implemented in a centralized manner similar to the current management system. The voltage and current control systems use the same resources to regulate their respective parameters, and thus this overlying control system has to be able to prioritize between their setpoints.

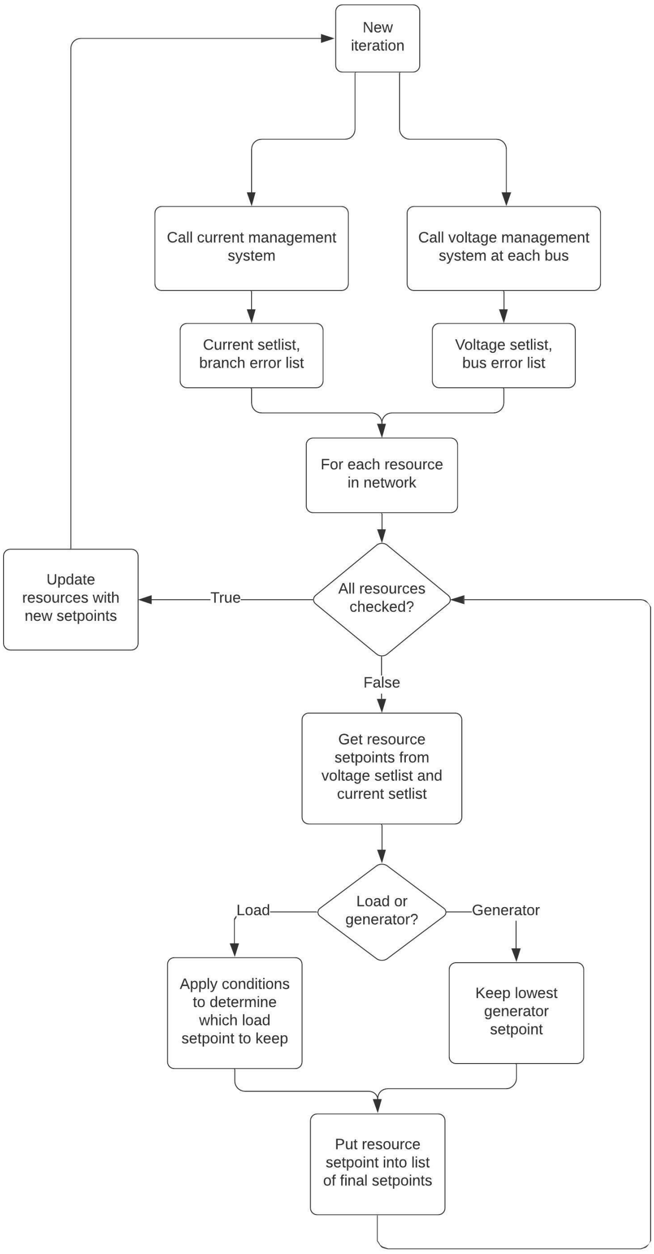

Figure 3.4: Flow chart of complete control algorithm.

Figure 3.4 illustrates the function of the overlying control system. The control system compares the setpoints generated by the voltage and current management systems and determines which to keep based on a number conditions. Generators can only be controlled to reduce their active power output by both control systems. Therefore, the setpoint that reduces the power output the most is kept in order to satisfy the need of the most urgent control signal. Loads are a bit more complex, as they can be both reduced or increased depending on the needs of the distribution network. In case an undervoltage contingency occurs simultaneously as overcurrent, the control actions of the distribution network will contradict each other. Therefore, the overlying system must be able to prioritize between the generated setpoints. The conditions used to determine which setpoint to keep are presented in table 3.6.

Table 3.6: Conditions used to determine final load setpoints.

Condition (Nr)	**Action if condition is true**	**Description**
$P_{v,set} \geq P_{nom}$ and $P_{c,set} \geq P_{nom}$ (1)	$P_{set} = max(P_{v,set}, P_{c,set})$	If both control systems have generated setpoints above nominal load power, keep the highest setpoint.
$P_{v,set} \leq P_{nom}$ and $P_{c,set} > P_{nom}$ (1) (2)	$P_{set} = P_{c,set}$	If the voltage controller has requested a lower active power setpoint while the current controller has requested a higher setpoint, prioritize the current system.
$P_{v,set} \leq P_{nom}$ and $P_{c,set} = P_{nom}$ (3)	$P_{set} = P_{v,set}$	If the voltage controller has requested a lower setpoint while the current controller has not requested an action, keep the setpoint of the voltage controller.

These conditions prioritize mitigation of overcurrent above mitigation of undervoltage, as overcurrent can be harmful to the physical network. Undervoltage may lead to instability, which in normal cases will not damage the distribution network in the way that overcurrent might.

4

Power system modelling

In order to study the behaviour of distribution networks utilizing local active power control, the different parts of the power system must be accurately modelled. Models of the transmission network and distribution networks must be combined in order to study their interaction. This chapter presents the simulation methods, the power system models used and the way in which the models are combined.

4.1 Simulation methodology

The power system simulation tool PSS/E is used to simulate the interaction between the active distribution network and the transmission network. This section intends to describe the methodology by which the simulations are carried out, and the assumptions made regarding control of power system resources.

4.1.1 Semi-static method and time dependency

The simulations are based around a semi-static simulation method utilizing power flow studies. Power flow studies rely on solving power flow equations by iterative methods, where one of the most common methods is the Newton-Raphson method [11]. If the considered power system is in such a state that a solution can be obtained, the study converges to a solution after a certain number of iterations. A solved power flow study produces a static system state that describes the flow of power through the different elements in the simulated power system, and the voltage magnitudes and angles at different points in the system. Generally, this static system state does not consider any dynamic effects. The different controllable resources in the power system are set as required to obtain a converging solution, with no limits on how much those resources are changed from one iteration to the next. There are a number of dynamic effects neglected in this type of study, that are especially important during contingency events. This neglect of dynamic effects typically limits the possibility of using power flow studies to simulate how the power system reacts to certain contingencies. However, power flow studies have the advantage of allowing simpler modelling of the system resources. Depending on the effects that are considered, power flow studies can be used as part of a simulation methodology that considers certain dynamic effects.

For this study, power flow studies are used in an iterative semi-static manner to determine how the control system of the distribution network affects the voltage in the transmission network. As dynamic effects are not considered, using static simulations is sufficient. In this method, a sequence of power flow studies are carried out. After each individual power flow solution, the setpoints of certain network resources may be changed to emulate the variations in load and intermittent generation over time. Along with updating the setpoints, the control systems are allowed to respond to the results of the last power flow and regulate their available resources if necessary. This semi-static approach fits with the premise of analysing somewhat slow control systems in stable operating conditions, and allows for efficient simulation of different scenarios regarding load and generation levels.

A Python script is used as a framework for carrying out the simulations. The control systems are implemented in Python, and it is also used for setpoint assignment and data illustration after the simulation is complete. The basic process of the python script is illustrated as a flow chart in figure 4.1.

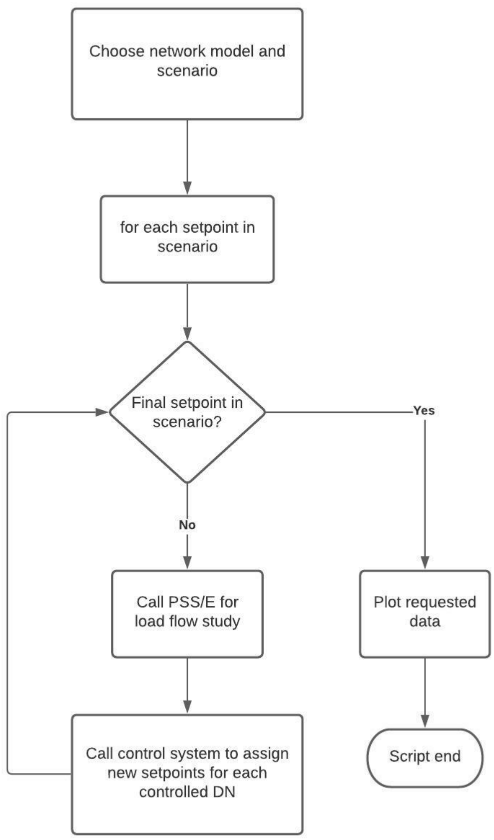

Figure 4.1: Basic flow of Python script

PSS/E is used to carry out the power flow simulations, the control system then updates the setpoints of the controlled resource in preparation for the next iteration. This process is then repeated for the number of iterations necessary to reach the final nominal setpoint in the scenario list. If a power flow fails to converge, further simulations are stopped and an error is given. Once the scenario has been fully simulated, the requested plots are generated.

A key difference between static power flow studies and dynamic studies is that there is no limit to how much resources may be changed to obtain a solution in a static study. In dynamic studies the rate of change of different resources are limited by their time constants, allowing for studies of less stable power system phenomena. By limiting the control action of certain resources, an emulation of time can be introduced to this semi-static approach. There are a few key types of network elements that affect the interaction of the transmission and distribution networks to a large extent, and must be modelled as time dependent for an accurate portrayal of the TN-DN interaction. It is assumed that the time passed between each iteration is 10 seconds, which can be used to determine the extent to which key resources are allowed to be controlled per iteration.

4.1.2 Tap changers

The control systems of the distribution network used in this study are strictly local, and thus have no way of measuring the voltages in the overlying subtransmission network. Therefore, voltage support stemming from the distribution network can only be caused by deviations of voltage or current in the distribution network itself. The behaviour of the OLTCs connecting the distribution and transmission network play a vital role in determining whether voltage deviations in the transmission network have an effect on the distribution network voltage. OLTCs are often set to delay their tap-changing reaction for 30-60 seconds after detecting a voltage deviation, in order to prevent unnecessary wear on the tap-changing mechanism. As this is the case, OLTCs are allowed to change their tap positions every third iteration.

4.1.3 Switched shunts

The transmission network model uses a number of switched shunts to regulate voltage. It is assumed that the shunts are switched manually by the grid operators in anticipation of daily load variations. As a consequence, the shunts will not be allowed to change their setpoint during the simulations. If necessary, the shunts may be adjusted to change the voltage in the transmission network for different scenarios. Once adjusted for a scenario, the shunts are once again locked for the simulation process.

4.1.4 Control of distributed generation

Regarding generation in the distribution networks, the potential rate of change of power output is dependent on the type of generation. Typical resources that are implemented into distribution networks as distributed generation are photovoltaic (PV) panels, wind turbines or batteries. PV panels and batteries are capable of very fast (<1s) changes in active power output as they are interfaced to the power system through power electronic converters. Wind turbines by themselves are capable of reducing their active power output relatively quickly by changing the pitch of their blades, but are often managed by external controllers that reduce the rate of change of their power output. The control system used in this study is designed to regulate power systems in stable operating conditions, and is not designed to instantaneously react to contingencies. Therefore, a somewhat slow regulation is acceptable. It is assumed that distributed generation can adjust their active power setpoint by 10% of the maximum power output of the resource per iteration. This limit is not the sole deciding factor when it comes to rate of change of power output, as the PI-controller parameters have a large impact as well. Limiting the change in setpoint to 10% of the maximum active power output per 10 seconds is quite conservative as most generation resources should be able to change their setpoint much faster than this, but in a real power system it is useful to limit the rate of change as not to introduce instability. It is assumed that generators cannot be set higher than their nominal power output, as it is assumed that DGUs are producing as much power as possible unless they are curtailed. When the control systems curtail generation, they can be set to any power output between no power output and their nominal power output.

4.1.5 Control of distribution network loads

The rate by which loads can be changed depends on the type of load. In emergency scenarios, load shedding can be used to quickly disconnect load in order to preserve the stability of the power system. However, this is only triggered in highly compromised scenarios. Typically, demand side management in normal power system operating conditions assumes that the electricity consumer approves shifting of load in time for economic gain. The value of load shifting depends on the consumer, but generally consumers are more likely to accept shifting loads whose function is less impaired by the load shifting. For example, heating systems such as electrical heating or domestic water heaters can act as energy storage as heat dissipates relatively slowly. Heating may be reduced for a limited amount of time, if the reduction is compensated afterwards by increasing the heating load. This way, load shifting of heating systems may go unnoticed by the consumers. Especially domestic water heaters are subject to research as a way of introducing demand side management. However, when utilizing such systems for continuous demand side management the control system must consider the characteristics of the controllable resource. Water heaters are typically quite slow to react, taking up to several minutes to respond to changes in setpoint [12]. However, the growing number of grid-connected electric vehicles provide large aggregated battery loads in distribution networks that should be quite suitable for fast load shifting. It is difficult to accurately estimate how quickly aggregated distribution network load can be shifted as the aggregations consist of many different types of loads, and so in the same manner as the generators 10% per 10 seconds is assumed. Depending on the tuning of the PI-controller, this ramping limit will have a large effect on the speed by which the ADN can regulate voltage and current.

In contrast to the generation units, it is assumed that the loads can be increased beyond their nominal power consumption in case of overvoltage or overcurrent prevention. The extent to which loads can be increased beyond their nominal power in real distribution networks depends on a number of factors, and is complicated to estimate. Therefore, there will be no limit to how much the control systems are allowed to increase the power consumption of the loads. Instead, the extent to which loads are increased by the control systems will be discussed to determine whether the required load increase is of a realistic size. Even though it is hard to predict what a realistic level of load increase may be, it seems reasonable that temporarily increasing load to 120% of nominal load is more likely to be possible than increasing the load to 200% of nominal load.

4.1.6 Result evaluation

A number of scenarios will be studied and discussed in order to provide a comprehensive view of the interaction between the transmission network and the local control system of the distribution network. Baseline simulations will be conducted with control systems deactivated, which will be used to determine the impact of the control system in the case it is turned on. The impact of the control system in different scenarios will be discussed to determine whether the control system has a positive, negative or neutral effect on the transmission network voltage stability in compromised conditions.

4.2 Transmission network model

In order to evaluate the interaction of active distribution networks with overlying networks, the distribution network model is combined with a transmission network model. The IEEE Nordic model is used for this purpose, as this model is commonly used to evaluate phenomena related to voltage stability. The version used for this project is the one supplied by IEEE as of 2021-11-22 [13]. A single line diagram of the Nordic model is presented in figure 4.2 [14].

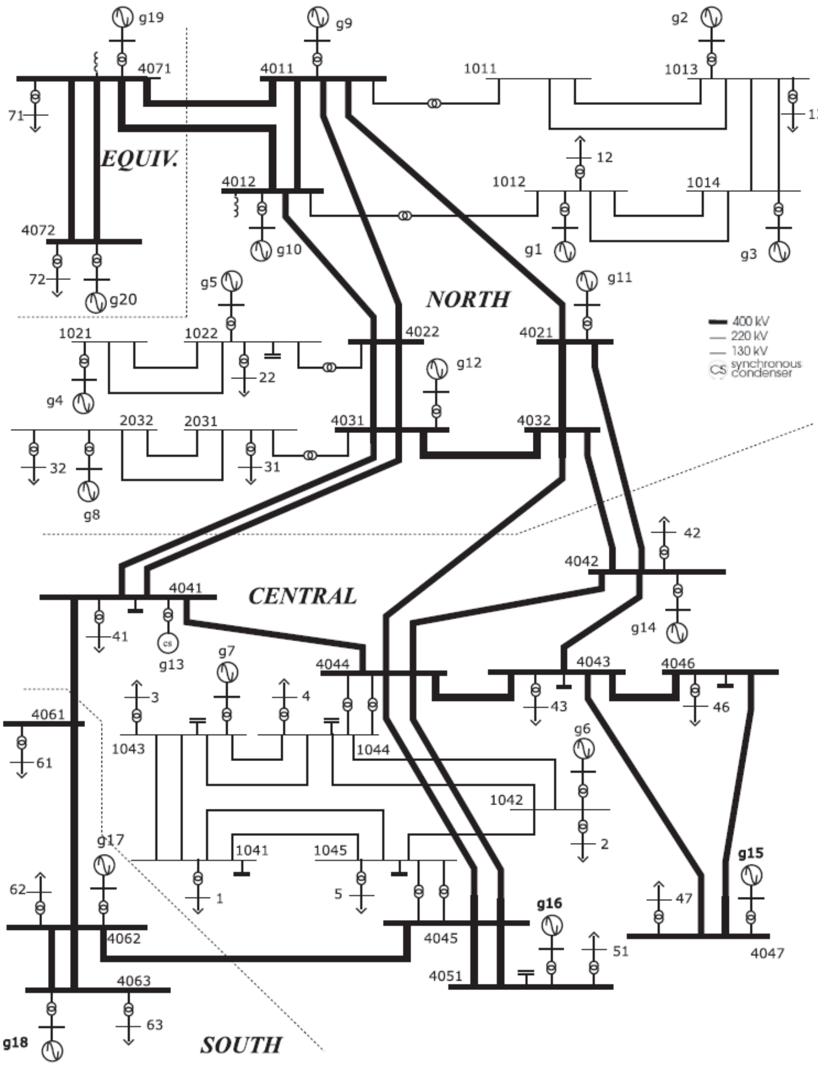

Figure 4.2: Single line diagram of IEEE Nordic model [14].

The Nordic model consists of two main sections, that can be denoted as the northern and southern sections. In this notation the northern section consists of the 'North' and 'Equiv.' sections in figure 4.2, while the southern consists of the 'Central' and 'South' sections. The northern section has a surplus of generation as well as some load, while the southern part has some generation but relies on power transferred from the north to supply its loads. The lines connecting the section are quite heavily loaded, and tripping of the lines can cause voltage instability in the southern section of the model. There are multiple voltage levels in the model, ranging from 15-400kV. A common stability benchmark for transmission networks is the N-1 stability critera. The N-1 criteria stipulates that the transmission network should be able to remain in a stable mode of operation if any one element in the transmission network, such as a generator or a transmission line, is disconnected. In the base configuration, the test system fulfills the N-1 stability criteria. However, the system can be brought into a more unstable state by reducing the generation at bus 4051 to half of the original load.

4.2.1 Integration of distribution network model in Nordic model

In the southern section of the Nordic model there are multiple 20kV loads connected to the transmission network through OLTCs and a 130kV subtransmission network. These loads can be replaced by the distribution network model described in section 4.3. However, in order to do so the power flow into the distribution network should be identical to the power flow into the load that is to be replaced in order not to tamper with the original load flow solution. The setpoints of the distribution network models taking the place of the loads may be changed, but their initial setting should be identical to the loads they replace. If the initial setting does not match the loads that are replaced, the power flow study may not be able to converge. The southern 130kV subtransmission network is illustrated in figure 4.3.

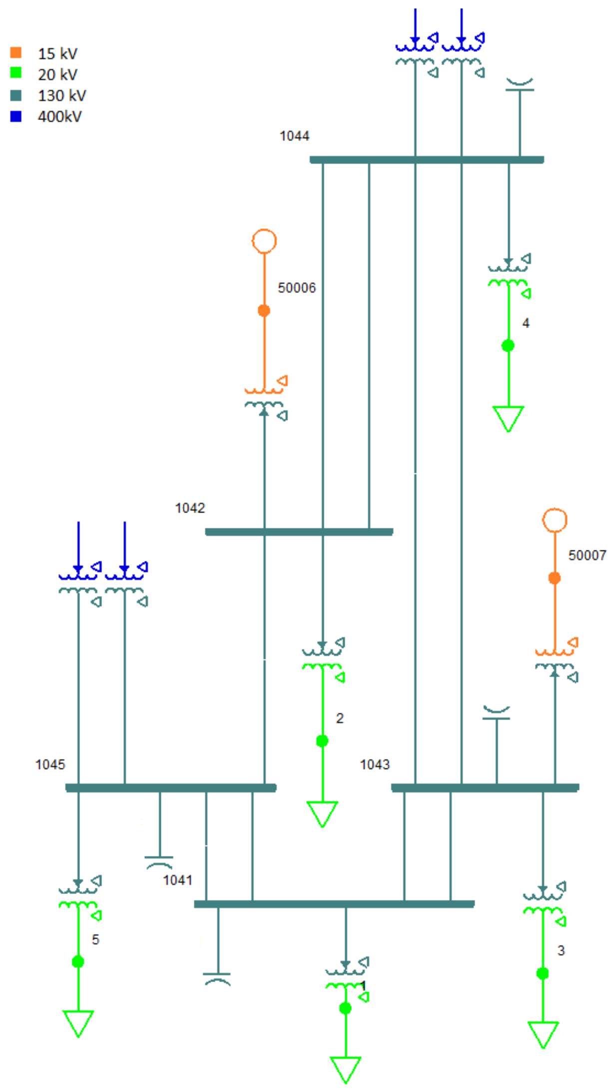

Figure 4.3: Single line diagram of the southern 130kV subtransmission network.

As illustrated in figure 4.3, the subtransmission network feeds 20kV loads at buses 1-5. Both the 20-130kV and 130-400kV transformers are equipped with OLTCs. The power consumption of loads 1-5 in the original Nordic model are presented in table 4.1.

Table 4.1: Loads supplied by southern 130kV network

Bus	P [MW]	Q [Mvar]
1	600	148.8
2	330	71.0
3	280	83.8
4	840	252.0
5	720	190.4

In order to replace the loads at buses 1-5 with distribution network models, the DN-model should be adjusted so that the power flow into the distribution network is the same as with the original loads.

4.3 Distribution network model

Distribution networks across the power system are constructed according to the circumstances of the area in which they are to operate. Therefore, there may be considerable differences between distribution networks in terms of topology, load type and size, and amount of distributed generation. As this is the case, the potential of using active power control on the distribution level to improve voltage stability may depend on the characteristics of the distribution network. In order to evaluate the impact of distribution network characteristics, a general distribution network topology with flexible characteristics will be used. The distribution network topology will be based on the rural feeder of the European medium voltage (MV) test system developed by CIGRE [15]. The topology of the complete test system is illustrated in figure 4.4.

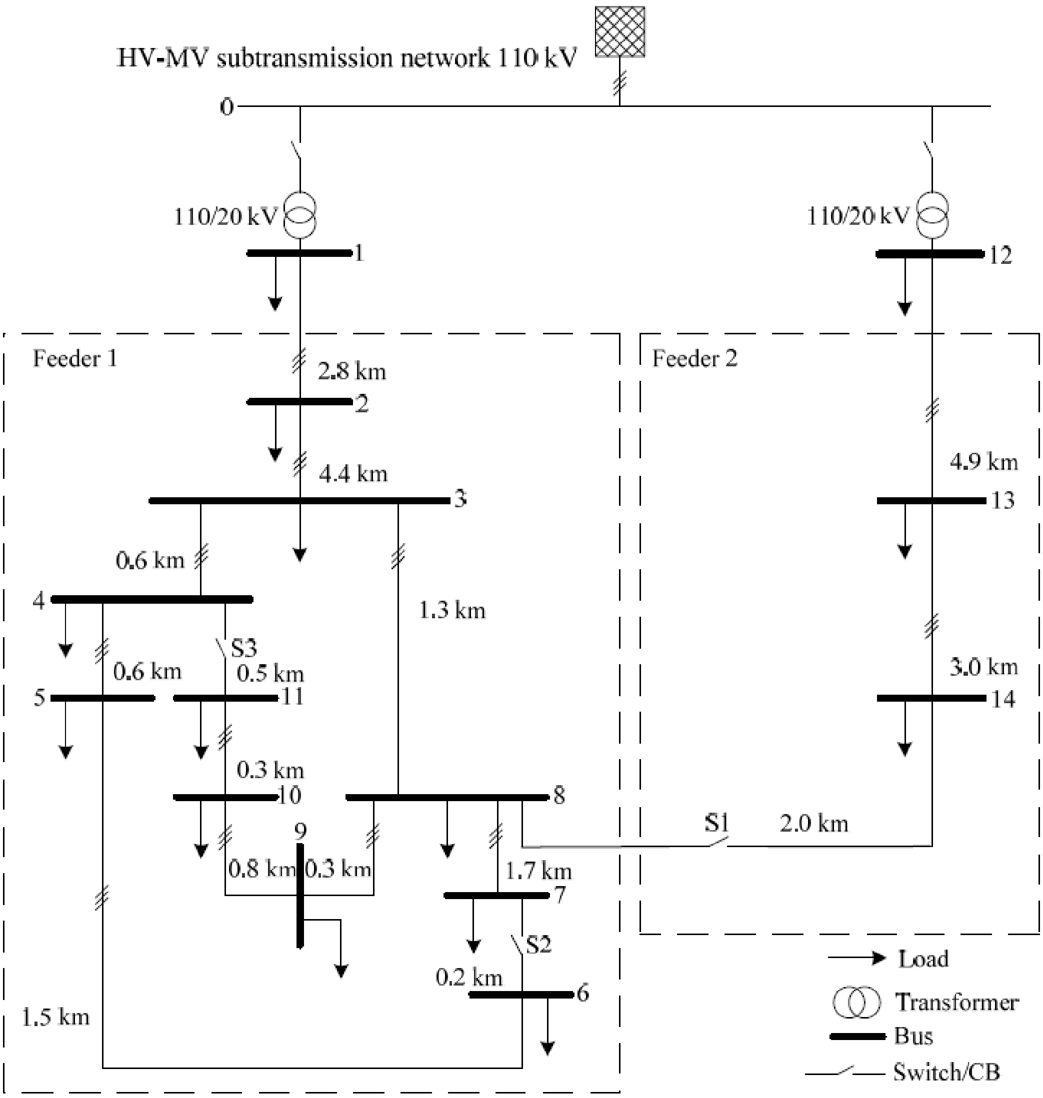

Figure 4.4: Complete single line diagram of the CIGRE medium voltage network model [15]

The Cigré MV test system is specifically developed for being used to evaluate the impact of integrating distributed energy resources (DER) in distribution networks. The two feeders of the MV test system are designed to either be part of the same network, or to represent different types of distribution networks. The topology of feeder 2 will be used to represent different types of distribution networks, as the simple topology allows it to be easily modified and simplifies integration of control systems. In the original configuration, feeder 2 is a radial 3-bus system connected by relatively long overhead lines. However, the network may be modified to represent different types of distribution networks. As a general change, the base network is modified to include distributed generation at buses 13 and 14. The topology of the modified network is presented in figure 4.5.

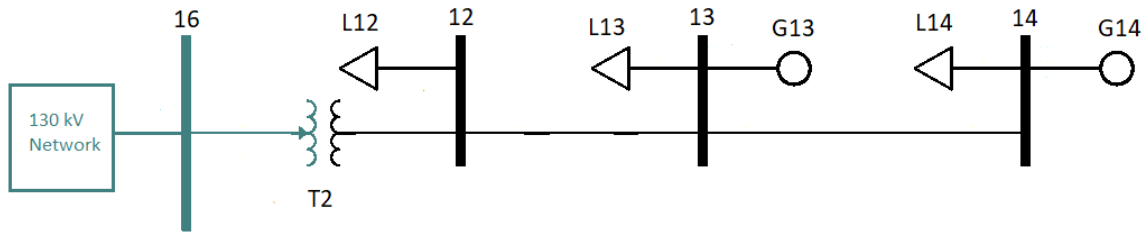

Figure 4.5: Topology of modified rural network. Triangles represent loads, and circles represent generation units.

As stated in section 4.2.1, the distribution network loads and generators must be scalable so that they can be made to equal the pre-existing loads on buses 1-5 in the Nordic model. The original load sizes are used for the control system verification in chapter 5, and are presented in table 4.2.

Table 4.2: Loads in original Cigré MV model.

Load designation	Nominal load [MW]	Power factor
L12	20.6	0.975
L13	0.04	0.85
L14	0.598	0.9

4.3.1 Distribution network branches

Typically, rural and urban distribution networks differ in their characteristics. Rural networks often predominately use OHLs as branches, while urban networks often use underground cables to a larger extent. The type of conductor used in the network affects the X/R ratio and the charging capacitance, which may impact the effectiveness of using active power control to regulate voltage. The impedance of the branches can be modified to represent different types of conductors and conductor lengths. By varying the branch characteristics, the impact of the impedance characteristics can be studied.

In the original Cigré model, branch characteristics are presented both for underground cables and overhead lines.

Table 4.3: Characteristics of conductors used in Cigré MV model

Conductor type	Impedance $[\Omega/km]$	X/R	Charging susceptance $[\mu S/km]$
OHL	0.51 + j0.37	0.73	3.17
Cable	0.50 + j0.72	1.44	47.49

The estimated ratings of the conductors are not explicitly stated in the model description, but if the branch characteristics are compared to similar conductors the ratings can be estimated to around 9.8 MVA for the cable and around 8.3 MVA for the OHL[16] [17]. This is orders of magnitude smaller than the loads presented in tables 4.1. Assuming that the loads are somewhat evenly distributed across the different loads in the distribution network, conductors such as those presented will not have sufficient capacity to supply the loads farthest out in the radial. Therefore, multiple branches will be connected in parallel.

The branch impedance magnitude can be sized in such a way that there is a certain voltage drop from the innermost to the outermost bus, while varying the X/R ratio and the charging susceptance to emulate the different conductor types. The line ratings can be based on the size of the loads supplied by the branch in question, by assuming that the branch should be able to supply the loads with 110% of their maximum load power to ensure that the network is not operating right at the limit in normal operation.

If the branch impedances are initially sized in such a way as to cause a suitable voltage drop at the outermost buses in each distribution network model, an approximation of branch length can be made.

4.4 Combined network model

The topology of the combined model is presented in figure 4.6.

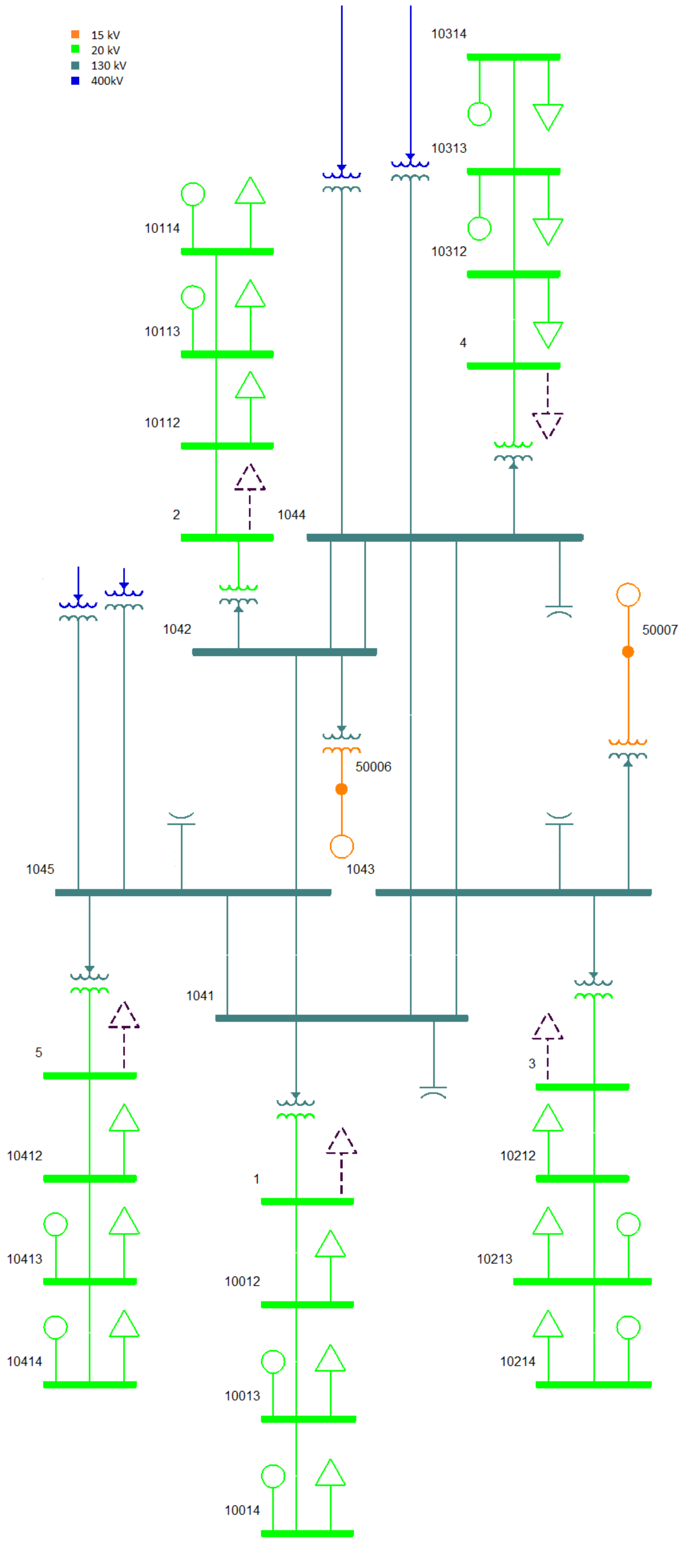

Figure 4.6: Topology of 130kV network with loads replaced by DN models.

The buses introduced as part of the distribution networks are denoted 10X1Y, where X identifies the distribution network and Y the individual bus in the distribution network. The original loads at bus 1-5 are taken out of service, and are illustrated by the dashed load symbols in figure 4.6.

The loads and generators in the distribution network models are assigned initial setpoints, presented in table 4.4. The impedances of the branches are then set so that the outermost bus is close to the minimum tolerable voltage of 0.95 p.u., in order to create a scenario where the distribution network is quite heavily loaded. This will introduce losses, changing the power drawn from the 130kV network. The loads at buses 10X12 are then adapted so that each distribution network draws the same amount of power as the load that it replaced.

Table 4.4: Initial setpoints used for impedance calculations.

Buses	Load [MVA]	Generation [MW]
10X13	70 + j17.5	0
10X14	40 + j9.98	0

The transformers connecting the 130kV subtransmission network to the 20kV distribution networks have a rating of 2500MVA.

4.4.1 Rural distribution network model

The branch impedances are presented in table 4.5. As mentioned previously, the charging susceptance is neglected for the OHLs. It is assumed that the outer branch is double the length of the inner branch. The branch connecting buses 10X12 to the transformer is not included, as it is assumed that this bus is connected directly to the transformer.

Table 4.5: Branch characteristics in case overhead lines are used.

From bus	To bus	Impedance [Ω]	Charging susceptance [μS]
10X12	10X13	0.0918+j0.0666	0
10X13	10X14	0.1836+j0.1332	0

These impedances result in a voltage of around 0.95-0.96 p.u. in the outermost distribution network buses. If this impedance value is to be represented by the OHL emulated in the Cigré MV model, 15 parallel lines provides a rating of 124.5 MVA which is around 10% higher than maximum load. The equivalent impedances of the branch with 15 parallel lines are presented in table 4.6.

Table 4.6: Equivalent impedance of parallel OHLs.

Impedance of 15 parallel lines [Ω/km]
$0.034 + j0.025$

As both the impedance per kilometer and the total impedance of the different branches are known, the length of the branches can be calculated to around 2.7km and 5.4km for the inner and outer branches respectively. The load setpoints used in case the branches are modelled as overhead lines are presented in table 4.7.

Table 4.7: Initial load setpoints.

Bus	Load P [MW]	Load Q [Mvar]
10012	486.5	118.2
10112	216.5	41.0
10212	146.4	53.8
10312	726.5	222.0
10412	606.4	160.4
10X13	70	17.5
10X14	40	10.0

4.4.2 Urban distribution network model

In case the distribution network branches are modelled as cables, the branch impedance is initially set so that the resulting voltages in the outermost buses of each distribution network are around 0.95-0.96 p.u. The impedance is then used to calculate the length of the branch, which is used to determine the capacitance. As in the rural model, the outer branch is assumed to be twice the length of the inner branch.

In a similar manner to the OHLs, 13 cables are connected in parallel which results in a rating of around 127MVA.

Table 4.8: Impedance and susceptance of parallel cables.

Branch impedance [Ω/km]	Branch susceptance $\mu S/km$
$0.038 + j0.055$	617.5

The branch impedance value used for the inner branch initially is $0.087 + j0.125[\Omega]$, which based on the branch data presented in tables 4.8 results in a branch with a length of around 2.3km. The length of the outer branch is then 4.6km. Knowing the branch length, the susceptance can be calculated. The final branch characteristics are presented in table 4.9.

Table 4.9: Branch characteristics in case overhead lines are used.

From bus	To bus	Impedance [Ω]	Charging susceptance [μS]
10X12	10X13	0.0870+j0.125	1420.3
10X13	10X14	0.1740+j0.25	2840.6

The setpoints used in case the branches are modelled as cables are presented in table 4.10.

Table 4.10: Initial load setpoints.

Bus	Load P [MW]	Load Q [Mvar]
10012	486.9	116.9
10112	216.8	39.7
10212	146.6	52.6
10312	726.7	220.8
10412	606.7	159.2
10X13	70	17.5
10X14	40	10.0

5

Control system demonstration

This chapter intends to demonstrate the function of the algorithms presented in chapter 3 when combined with the distribution network model presented in 4.3.

5.1 Demonstration of voltage management algorithm

In order to evaluate the ability of the voltage controllers at the different buses, a modified version of the rural distribution network model has been subjected to a scenario where varying loads and generation levels cause both over- and undervoltage situations. The original load levels used are those presented in Table 4.2, which are then modified by increasing the loads at buses 13 and 14 to such a level that voltage is unacceptably low in case of low distributed generation. Generation has also been added to buses 13 and 14.

Figure 5.1 demonstrates the voltage characteristic and flexibility usage while prioritizing generator curtailment. The flexibility is designated as negative when a load is decreased, and positive when load is increased or generation is decreased. Figure 5.2 illustrates the variation in load and generation during the same test case with both regulation and variations in nominal setpoint included. As illustrated in the figures, the controllers effectively maintain acceptable voltage despite varying load and generation levels by curtailing generation and decreasing loads as necessary. In order to clarify the actions of the control system in figures 5.1 and 5.2, the test case is presented segment by segment in table 5.1. Figures 5.3 and 5.4 demonstrate the actions of the controllers when prioritizing load shifting instead of curtailment. In this case, the generators at buses 13 and 14 are allowed to regulate their production freely as all regulating action changes the load setpoints.

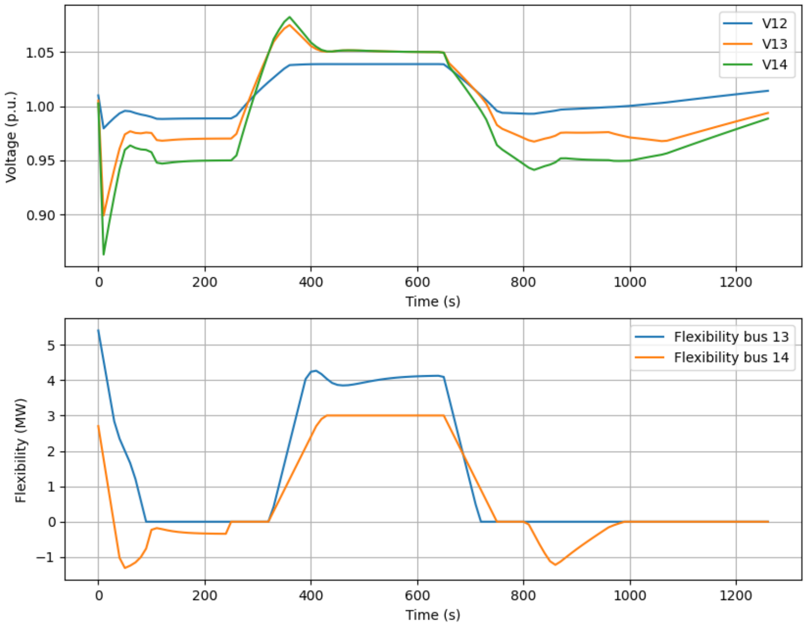

Figure 5.1: Voltage characteristic and flexibility use during voltage algorithm test case with curtailment prioritized.

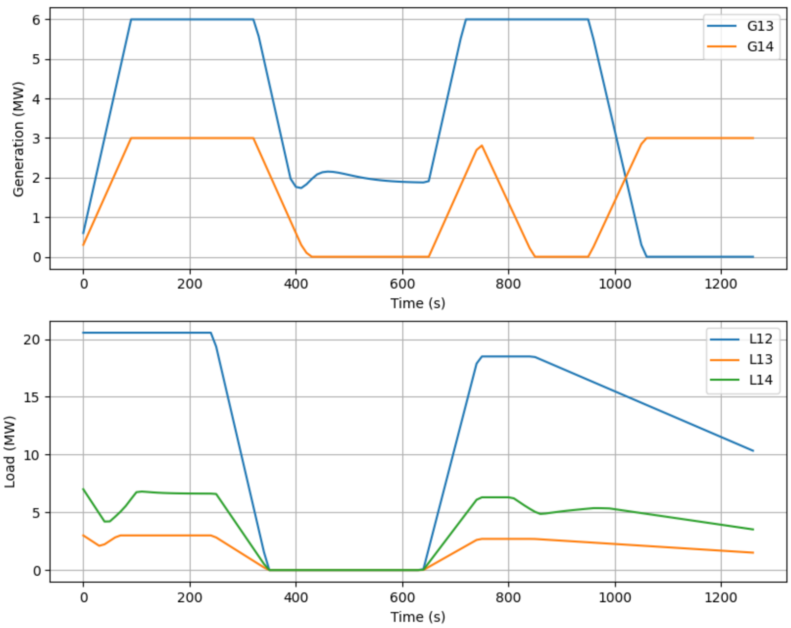

Figure 5.2: Load and generator power during voltage algorithm test case with curtailment prioritized.

Table 5.1: Description of the controller action during the voltage controller demonstration.

Time slot start (s)	**Time slot end (s)**	**Description**
0	100	During the initial 100 seconds the flexibility usage is decreasing from a high starting point. This is a consequence of the way that the setpoint is introduced, and does not represent any actual usage of flexibility resources. During this period, the generation is ramping up to nominal power but is limited to 10% per iteration.
100	240	After the initial increase in generation, loads shifted to increase voltage to 0.95 p.u. After that, level of load shifting is continuall evaluated to restore as much as possible while still keeping voltage above limit.
240	640	Fast decrease in load level causes overvoltage. Generation curtailed to prevent overvoltage. Voltage stabilized around 1.05 p.u.
640	750	Load level increases again, reducing generator curtailment as voltage levels decrease.
750	950	Reduced generation at bus 14, necessitating load shifting to prevent undervoltage. Load level starts to decrease slowly at t=850s.
950	1260	Generation at bus 13 decreases, but generation at bus 14 increases. After t=1000s, active control of voltage is no longer necessary.

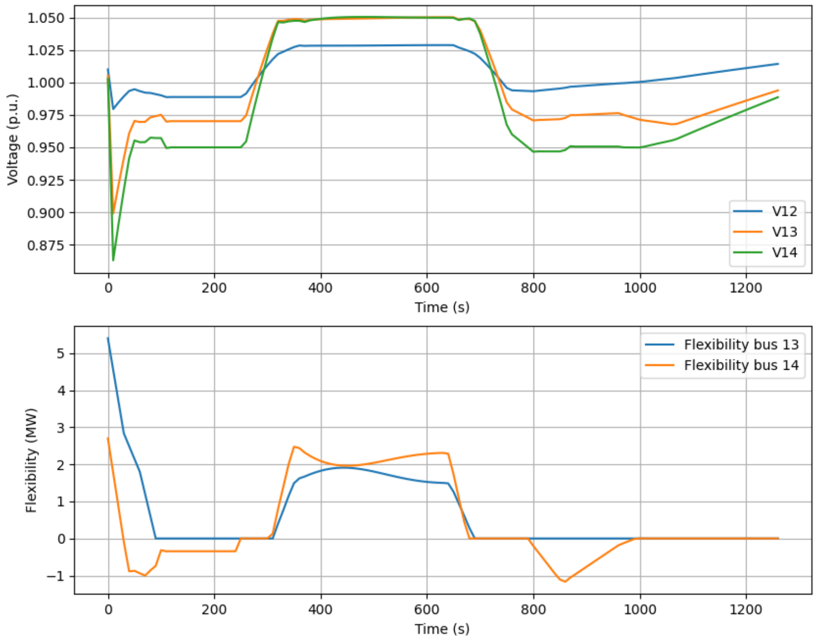

Figure 5.3: Voltage characteristic and flexibility use during voltage algorithm test case with load shift priority.

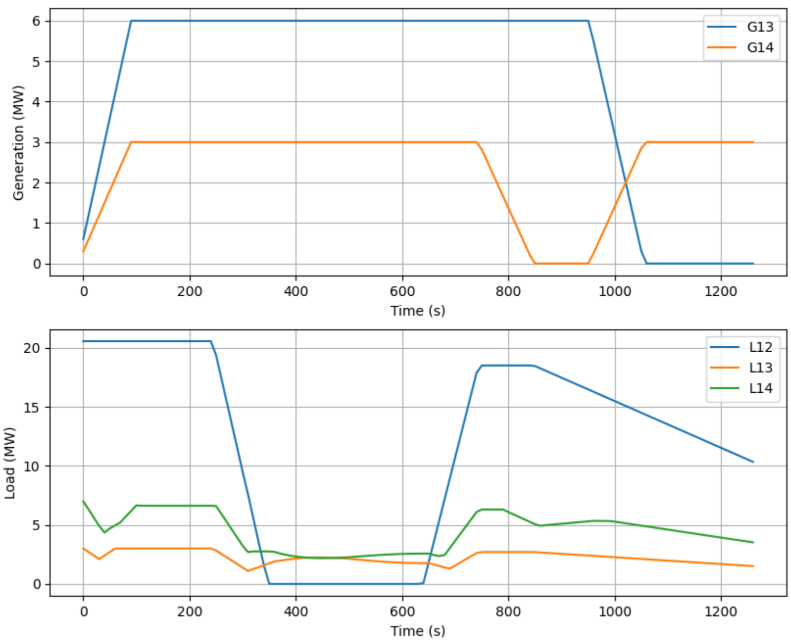

Figure 5.4: Voltage characteristic and flexibility use during voltage algorithm test case with load shift priority.

As illustrated in figure 5.3, the load shifting mode of the controller also manages to keep the voltage within tolerable intervals during the test scenario. The descriptions in table 5.1 largely apply to the case with load shifting prioritized as well, with the major difference that overvoltage is prevented by increasing load setpoints rather than decreasing generation. Comparing the cases, curtailment is tuned to be faster but has more overshoot compared to the load shifting case. This partly has to do with the tuning of the PI-controller parameters, and partly with the ramping limits.

The voltage controller is relatively simple, and relies on a number of assumptions. A key assumption is that the voltage is always increased if power consumption along the radial is reduced. Considering the PV curve presented in figure 2.2, the voltage controller assumes that the power system is operating in the stable region of operation above the bifurcation point. In the circumstance that the system is operating in the unstable region below the bifurcation point the controller may actually drive the system into voltage collapse. Therefore, real implementations of a control system such as this would require some type of emergency deactivation so that the controller does not contribute to system collapse.

5.2 Demonstration of current management algorithm

In order to demonstrate the function of the overcurrent management algorithm, the following figures illustrate a scenario where the algorithm manages the current in the branches. The rating of the branches between buses 12-13 and 13-14 has been reduced to 5 MVA in order to ensure that the algorithm has to reduce the power flow in the given scenario. The original load levels used are those presented in Table 4.2. Generation has been added to buses 13 and 14. The loads in the rural distribution network are not increased as in the demonstration of the voltage algorithm, in order not to give rise to branch flows above 5 MVA in the outward direction. The branch power flow and flexibility resources used are illustrated in figure 5.5, while the load and generation levels are illustrated in figure 5.6.

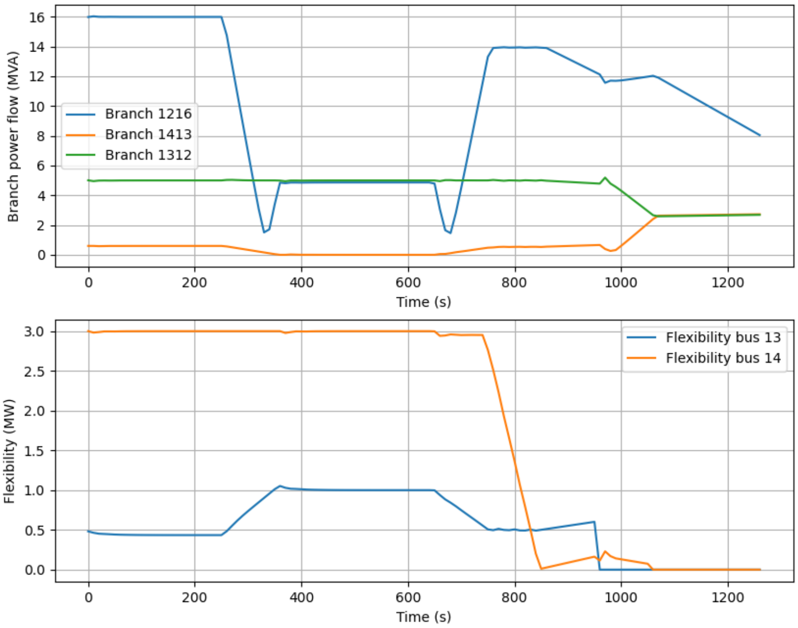

Figure 5.5: Branch power flow and flexibility use during current algorithm test case.

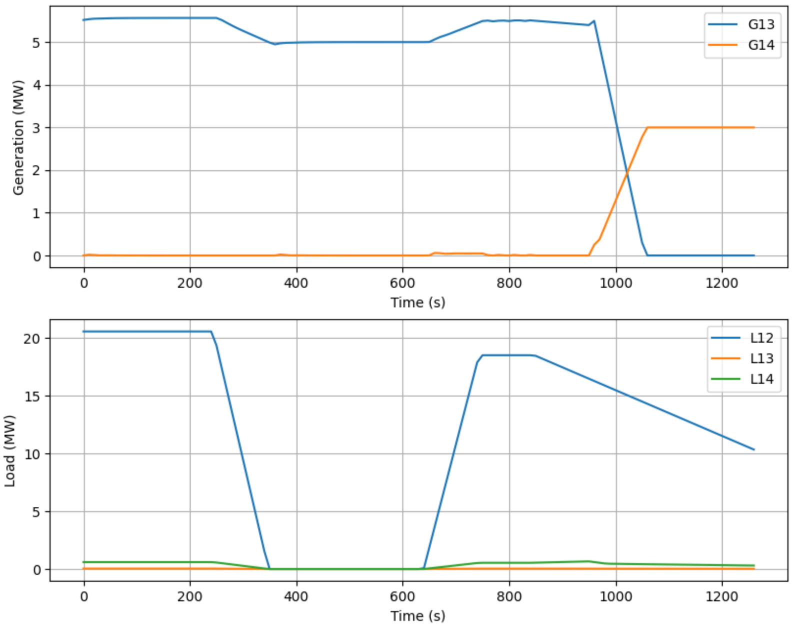

Figure 5.6: Load and generator setpoints during current algorithm test case.

In the demonstration, curtailment of the generator at bus 14 is the highest priority while curtailment of the generator at bus 13 is the secondary priority. Prioritizing load shifting is also possible, but is not practical for this specific case due to the relatively small size of the loads at buses 13 and 14. In order to clearly demonstrate the controller behaviour, generation curtailment is prioritized. A description of the controller behaviour demonstrated in figures 5.5 and 5.6 is given in table 5.2.

Table 5.2: Description of the controller action during the current controller demonstration.

Time slot start (s)	**Time slot end (s)**	**Description**
0	350	Generation at bus 14 completely curtailed, and some curtailment of generation at bus 13 required to reduce branch power flow. More curtailing necessary at around t=250s, as the load levels are declining rapidly.
350	650	Stable operation, generator at bus 14 deactivate and generator at bus 13 reduced slightly.
650	950	Load levels increase, reduced curtailing of generator at bus 13. Available generation at bus 14 drops at t=750, reducing flexibility while maintaining generation at 0.
950	1260	Generation at bus 13 decreases, but generation at bus 14 increases. Current through the regulated branch is decreased, and regulation is no longer necessary.

6
Simulated cases

A number of cases are evaluated in order to study the interaction of the transmission network and the active distribution network. This chapter intends to present the different scenarios that the power system model will be subjected to.
Regarding voltage stability, there are a number of scenarios that can cause undesirable voltage in different parts of the power system. In the transmission network section of the model, disconnections of different resources will be the primary instrument used to cause different voltage deviations. In the distribution network sections, different scenarios regarding load and generation levels will be used to study how the distribution network interacts with the transmission network when actively regulating resources in the distribution network. Different scenarios of the transmission network and distribution networks will then be combined in order to study the interactions in a number of different scenarios. The effects of OLTC usage will also be studied.

6.1 Transmission network scenarios

As described in section 4.2, the southern section of the model is dominated by loads and relies on import of power from the northern section. Therefore, the southern part is sensitive to disconnection of transmission lines between the sections and generation units in the southern section. Disconnection of such resources can be used to lower the voltage of the entire southern section. Two different transmission network operating points will serve as the basis for the study, denoted A and B [18]. There will also be a number of contingencies used to provoke the network into different conditions.

6.1.1 Operating points

Operating point A is a vulnerable, but mostly stable operating point. It can withstand some disconnected resources, but cannot withstand disconnection of the most vital generators and branches [18]. This is the base operating point of the Nordic model. The voltages of the original load flow solution provided for operating point A vary in the range of 0.99-1.07 p.u., with the majority of the bus voltages falling in the normal operation range of 0.95-1.05 p.u.

Operating point B is the most stable operating point considered. This operating point is attained by duplicating the generator at bus 4051, reducing the power transfer from the northern section to the southern section of the network. The initial load flow solution of this operating point has considerably higher voltages as compared to operating point A, reaching over 1.1 p.u. at the buses with the highest voltages. This makes operating point B interesting to analyze from an overvoltage mitigation perspective.

6.1.2 Contingencies

Contingencies in the form of disconnected resources can be used to change the load flow solutions of the pre-existing operating points considerably. If the disconnection is performed from one iteration to the next, the reaction of the control system when the network is subjected to a stepwise voltage change and the impact of the reaction on the network voltages can be studied. Disconnecting resources can cause the voltage to both increase and decrease, depending on the type of resource that is disconnected. Typically, disconnecting a generator or branch will cause the network voltage to decrease while disconnecting a load will cause the network voltage to increase. When selecting resources to disconnect, it is important that the load flow study can still converge without the disconnected resource. If the power flow study cannot converge, it is not possible to base any analysis on the scenario. Disconnected resources must be important but not critical to the load flow solution, so that the load flow study still has a converging solution. Two contingencies are evaluated, where one of the contingencies increases the network voltage and one decreases the network voltage.

The first contingency has the aim of increasing network voltage by reducing the load level in the southern section of the transmission network. Operating point A is used as a starting point. In order to cause a stepwise voltage increase, all loads in the southern section of the network except those in the introduced distribution networks are decreased to a percentage of their original load level. Reducing the load equivalents in the southern section of the transmission network to 90% of the original load levels create a considerable stepwise voltage increase. The loads subjected to a decrease in load level are those connected to buses 4041, 4042, 4043, 4046, 4047, 4051, 4061, 4062 and 4063. This contingency is referred to as the voltage rise contingency.

The second contingency aims to decrease the network voltage by disconnecting branches or generation. Multiple combinations of disconnections have been evaluated, in an attempt to find the scenario that produces the lowest network voltages while still allowing for the solution to converge. The contingency found to produce the lowest network voltages while still allowing the network to converge is a simultaneous disconnection of branch 4043-4044 and one of the two generators at bus 4051, starting from operating point B. Disconnecting a generator at bus 4051 is similar to starting from operating point A, but the larger instantaneous voltage drop caused by the simultaneous disconnection of two separate resources is interesting to study, as it results in a larger instantaneous voltage drop in the distribution network. This contingency is referred to as the voltage drop contingency.

6.2 Distribution network scenarios

At the start of each simulation, each distribution network must be set to the corresponding operating point presented in section 4.4 in order to ensure that the simulation starts from a stable operating point. After the initial load flow solution, the resources in the distribution networks can be changed slowly in order to simulate the inherent variations of loads and DGUs over time. By varying the resources in this way, different scenarios can be created. The impact of the distribution network branch characteristic will also be investigated. Three distribution network scenarios will be studied. The same scenarios will be applied to all five distribution network equivalents connected to buses 1041-1045. As part of the goal in the ANM4L project is to allow for more distributed generation by utilizing some form of demand side management, load shifting will be the prevalent method for reducing voltage rather than curtailment of distributed generation. The loads and generators are rescaled from their initial setpoint to produce the scenarios. The load power factors are considered constant.

The first distribution network scenario intends to emulate a case with low levels of distributed generation, combined with high levels of load. A scenario such as this will incur low voltages in the distribution network. The base setpoints used to introduce the distribution networks to the Nordic model are suitable for such a scenario. The load setpoints at buses 10X12 are the same as those presented in table 4.7, while the setpoints of loads and generators at 10X13 and 10X14 are increased as compared to those presented in tables 4.7 and 4.10. The modified setpoints are presented in table 6.1. This scenario is referred to as the high load scenario.

Table 6.1: Setpoints of high load DN scenario

Buses	Load [MVA]	Generation [MW]
10X13	80 + j17.5	10
10X14	50 + j9.98	10

The second scenario intends to emulate a scenario with lower load and considerable distributed generation, causing the outer parts of the distribution network radials to generate more active power than they consume. This scenario is referred to as the high generation scenario. Compared to the setpoints presented in table 6.1 the loads at buses 10X12 are kept at their nominal load, while the loads and generators at buses 10X13 and 10X14 are increased to create this scenario. The new setpoints of the loads and generators are presented in table 6.2.

Table 6.2: Setpoints of high generation DN scenario

Buses	Load [MVA]	Generation [MW]
10X13	80 + j17.5	25
10X14	50 + j9.98	125

These setpoints give rise to overvoltages in some of the distribution network buses, and thus necessitate controller action.

6.3 Tap changer and switched shunt settings

In traditional power systems, switched shunt capacitors and OLTCs are used to manage the voltage levels in different parts of the network. These devices have a large impact on the system response in case of voltage deviation, and are likely to have a considerable effect on the behaviour of the distribution network control system. Therefore, it is interesting to include a few different cases regarding OLTC and switched shunt usage.

6.3.1 Tap changer settings

Regarding OLTCs, two primary cases will be considered. In the first case, both the 130kV-400kV and 20kV-130kV tap changers are locked for the entirety of the simulation. In the second case, OLTCs at both levels will be allowed to operate every third iteration in order to emulate a 30 second delay.

6.3.2 Switched shunt settings

The switched shunts will be assumed to be locked for the duration of the study, but may be adjusted prior to the start of the simulation in order to keep the transmission network voltage levels in a suitable interval.

6.4 Overview of study cases

Combinations of TN scenarios, DN scenarios and tap changer settings create a number of different cases.

Case 1 will combine the voltage drop contingency with the high load distribution network scenario, while case 2 combines the same contingency with the high generation distribution network scenario. Case 3 combines the voltage rise contingency with the high load distribution network scenario, while case 4 combines the same contingency with the high generation scenario. The cases are presented in table 6.3 as an overview.

Table 6.3: Overview of case combinations.

Case designation	TN scenario	DN scenario
Case 1	Voltage drop	High load
Case 2	Voltage drop	High gen
Case 3	Voltage rise	High load
Case 4	Voltage rise	High gen

Each case will be simulated and discussed. Each combination of transmission network and distribution network are simulated both with OLTCs enabled and disabled, and with rural and urban branch characteristics. This results in 16 possible combinations, and therefore chapter 7 primarily illustrates the results of the simulations carried out with rural branch characteristics. The results of the simulations using urban branch characteristics are illustrated in appendix A. As a general note, the results presented in chapter 7 consist of 320-750 individual power flow studies depending on the case. Each individual power flow study takes approximately 0.25s on a computer with an Intel i7 9700 CPU, and thus each individual case takes between 85-200s to simulate.

7

Simulation results

This section intends to present the results obtained when performing simulations with the cases presented in chapter 6. The figures presented in this chapter illustrate the results with the distribution network branches modelled as overhead lines. The results attained when the branches are modelled as cables can be found in Appendix A.

7.1 Case 1 - Undervoltage with high distribution load

7.1.1 Tap changers disabled

In the high load distribution network case, some of the outermost distribution network buses are actively regulated so that their voltage is maintained at a minimum of 0.95 p.u. The voltage drop contingency subjects the entire network to a significant drop in voltage, which further lowers the distribution network voltages. An example of the voltage drop in the transmission network is illustrated in figure 7.1. The contingency occurs at 100 seconds. In this case, active power control is deactivated right before the voltage contingency so that the effect of the contingency is clearly illustrated. A number of bus voltages are illustrated, both in the 130kV and 400kV sections of the network.

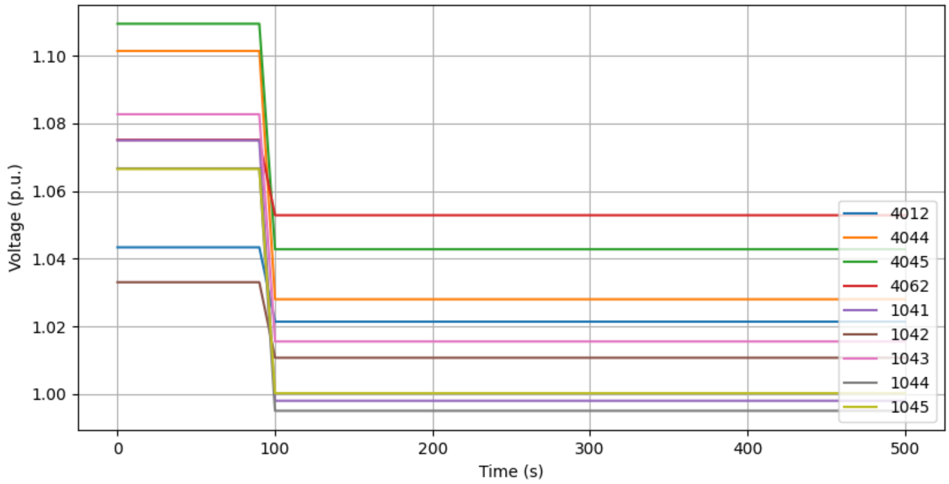

Figure 7.1: Example of voltage drop caused by contingency. Legend refers to bus numbers in the Nordic network.

In this case, some of the buses in the distribution networks fall below 0.95 p.u. which is the minimum tolerable voltage in normal operating conditions. If distribution network control is disabled before the contingency, the load levels do not react to the voltage drop. If active control is introduced to the distribution network, the loads in the distribution network will be reduced by the control system as a reaction to the voltage drop. The load response to the voltage drop is illustrated in figures 7.2 and 7.3.

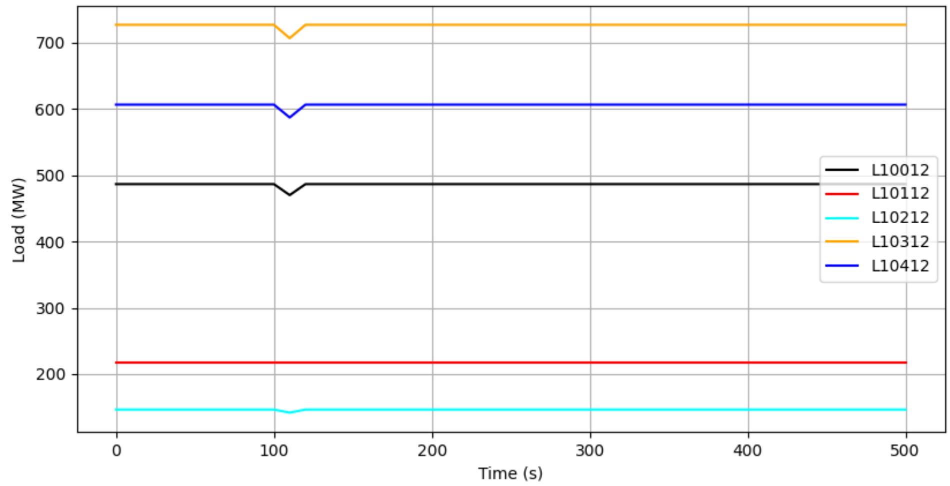

Figure 7.2: Response of the loads at buses 10X12 to voltage drop.

As illustrated in figure 7.2 the innermost loads are only adjusted slightly right after the contingency and are quickly restored to nominal levels due to the local nature of the voltage control. Figures 7.3 and 7.4 depicts the response of the smaller distribution network loads.

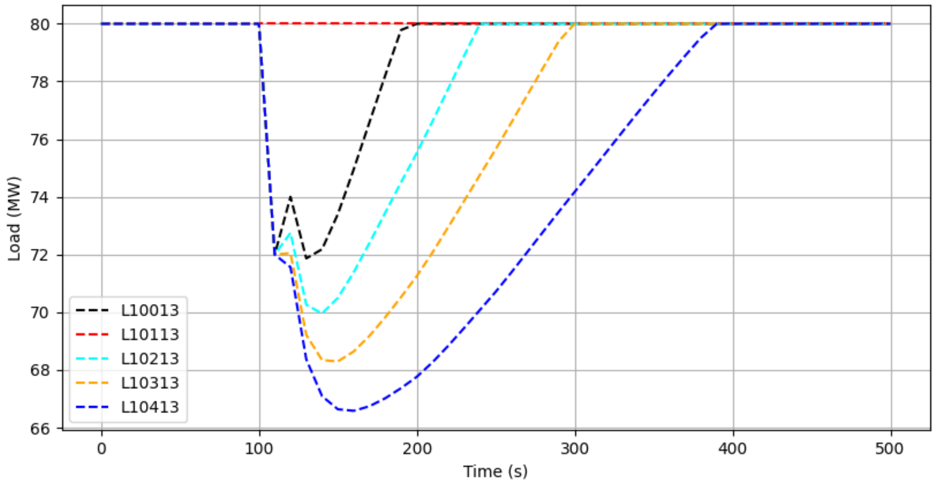

Figure 7.3: Response of the loads at buses 10X13 to the voltage drop in Case 1.

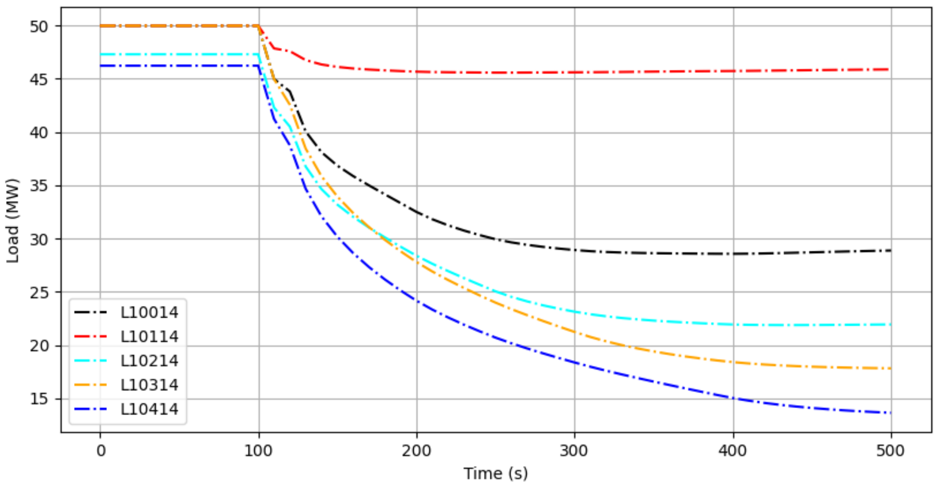

Figure 7.4: Response of the loads at buses 10X14 to the voltage drop in Case 1.

While the initial control reaction is shared by all loads in the distribution networks, after a certain amount of time the load is restored at buses 10X12 and 10X13. At this point, only the loads at buses 10X14 are reduced in order to keep the voltage within tolerable limits. The majority of the loads at buses 10X14 are reduced significantly from their nominal setpoint. The voltages of the distribution networks are illustrated in figure 7.5.

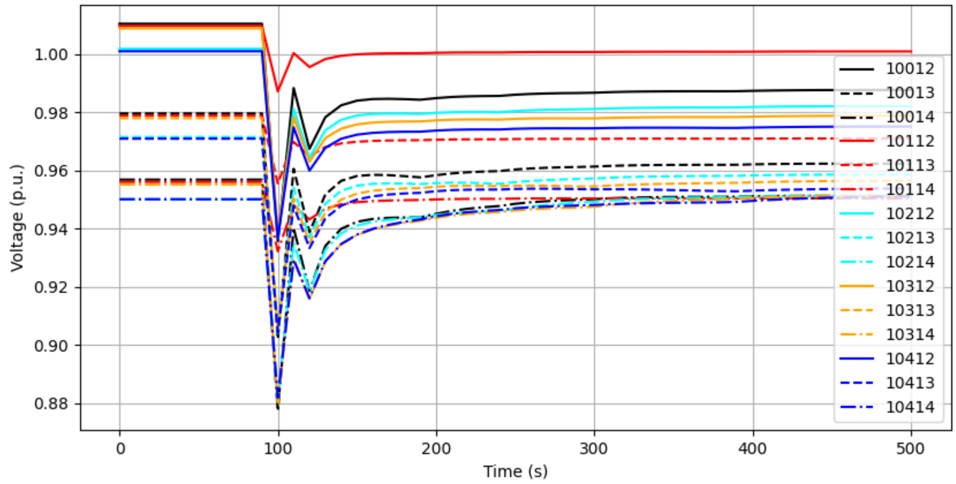

Figure 7.5: Distribution network voltages during case 1 contingency.

The distribution network voltages initially drop well below the acceptable limit, but are then restored within tolerable limits. The voltage takes some time to settle, as the controller is tuned not to overshoot. The impact of the control response on the voltages in the higher voltage levels are illustrated in figure 7.6.

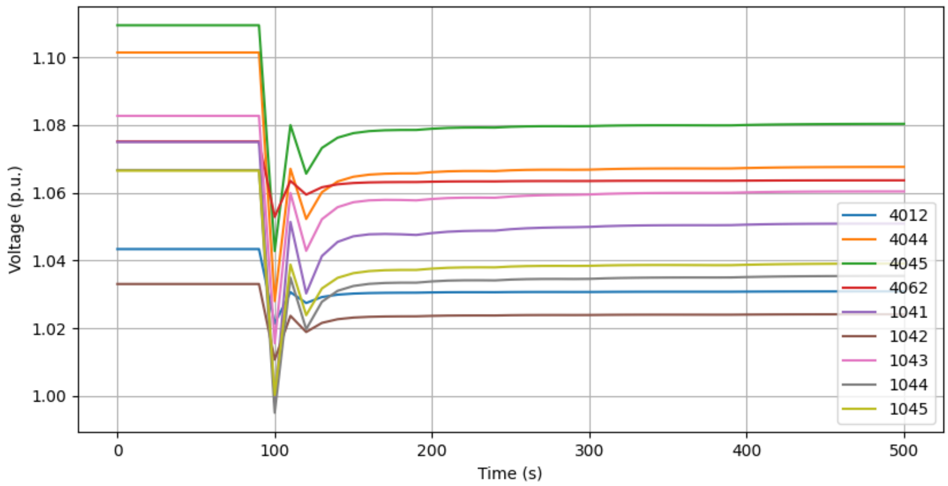

Figure 7.6: Transmission network voltages during case 1 contingency.

Comparing figures 7.1 and 7.6, the voltages are considerably higher in the case with active control enabled as a consequence of the reduction in load. The voltage level in the transmission network is generally high in this case, and thus the voltage increase caused by the distribution network control is not crucial. However, a similar response would be obtained if the transmission voltages were lower in which case a voltage increase like this could be critical to the stable operation of the transmission network. As discussed in chapter 6, this particular network only tolerates a certain level of reduced voltage before the load flow studies stop converging. As an overview of the total distribution network flexibility used, the load reductions are summarized for each distribution network and presented in figure 7.7. The legend in the figure identifies the distribution network summary by the subtransmission network bus to which it is connected.

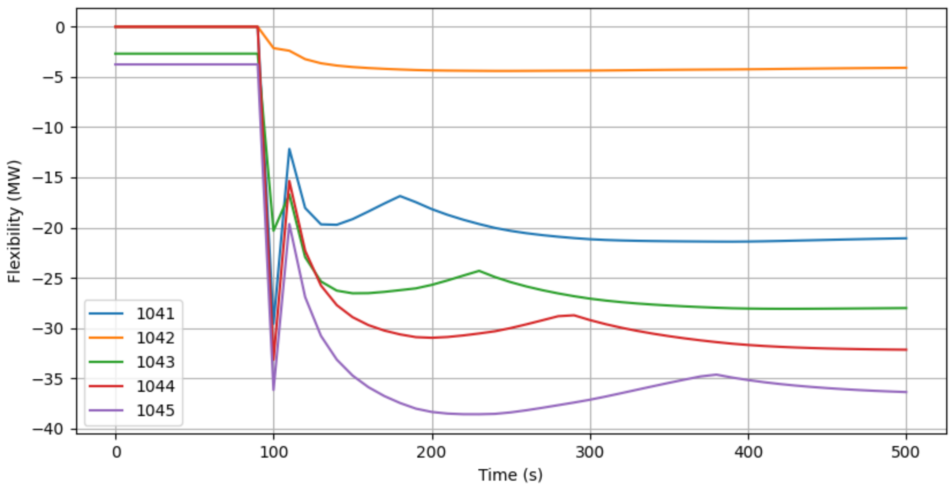

Figure 7.7: Summarized flexibility per distribution network for case 1 contingency.

Similar to the flexibility quantity described in chapter 3, a negative flexibility indicates a decrease in load while positive flexibility indicates increased load or decreased generation. In this case, the flexibility is the same as the load reduction at the loads of buses 10X14 once the system has stabilized. Right after the contingency, the relatively small change in setpoint at buses 10X12 have a large impact on the summarized flexibility in figure 7.7. The summarized flexibility of loads presented in figure 7.8 has excluded buses 10X12 in order to demonstrate the summarized flexibility of loads at buses 10X13 and 10X14.

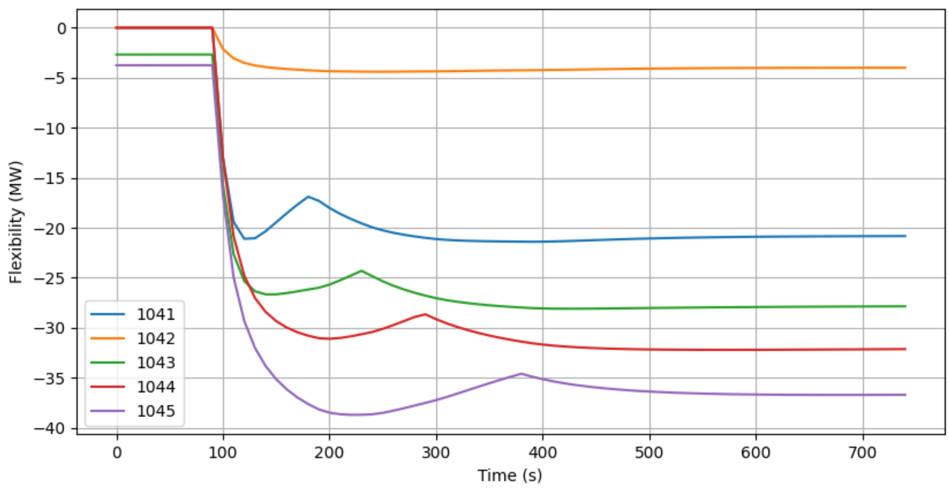

Figure 7.8: Summarized flexibility per distribution network for case 1 contingency, excluding loads at 10X12.

Regarding the feasibility of regulating voltage purely through active power control in a case such as this, it seems unlikely that the majority of the loads at buses 10X14 can be reduced to less than half of their nominal load levels for any extended duration of time with a fast initial reaction time. Further discussion of this can be found in section 8.3.

7.1.2 Tap changers enabled

When OLTCs are activated, the control systems of the distribution network and the OLTCs act to restore the voltage separately. The resulting voltages are presented in figure 7.9.

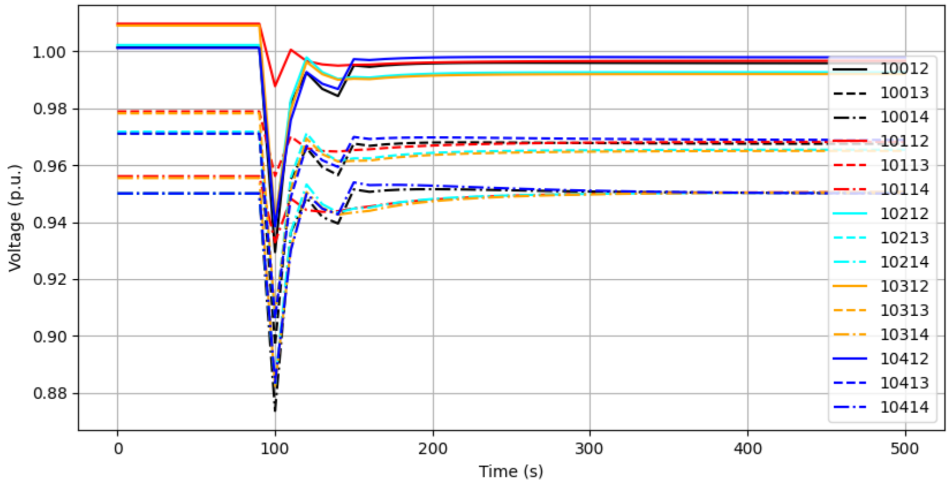

Figure 7.9: Distribution network voltages during case 1 contingency with OLTCs active.

With the OLTCs activated, the voltage fluctuates as both the OLTCs and the distribution network control systems try to restore voltage. After around 9 iterations, the fluctuations decrease and the voltages start to converge to a stable operating point.

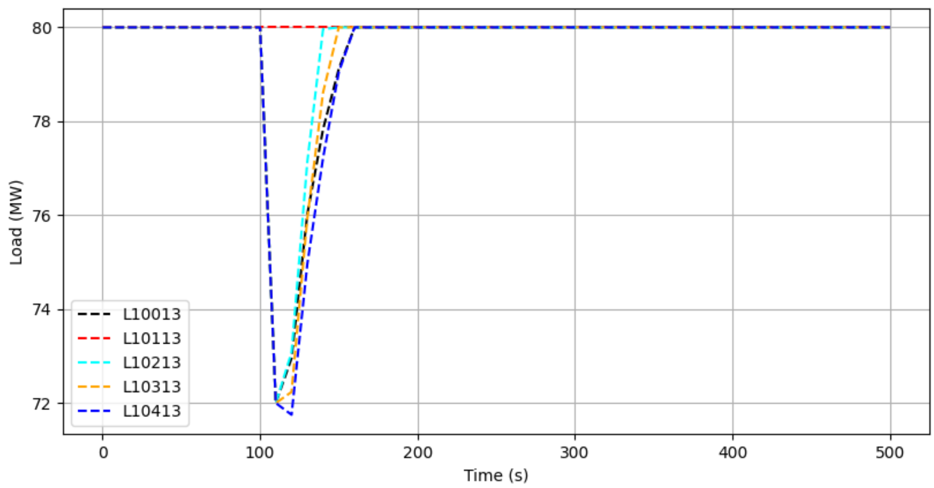

Figure 7.10: Response of loads at buses 10X13 to case 1 contingency in case OLTCs are enabled.

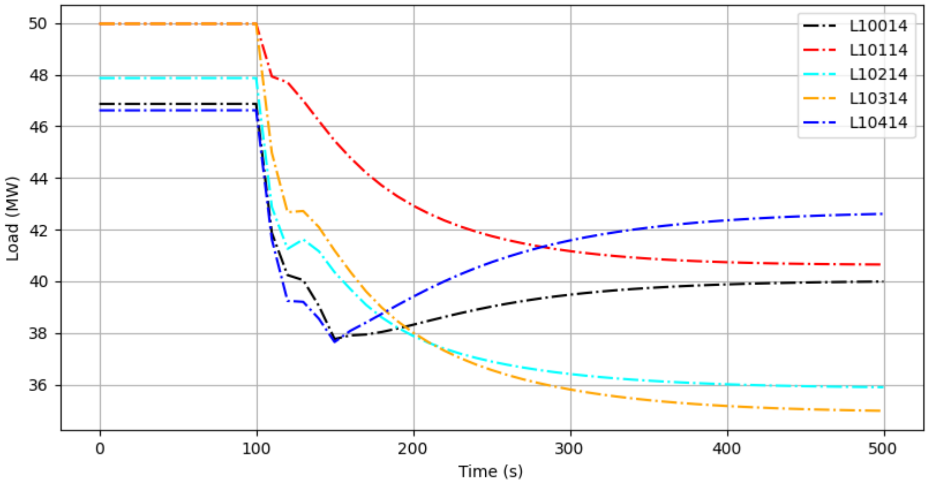

Figure 7.11: Response of loads at buses 10X14 to case 1 contingency in case OLTCs are enabled.

As shown in figures 7.10 and 7.11, the majority of loads are initially reduced to maintain sufficient voltage. The loads at buses 10X12 are reduced for a single iteration in the same way as the scenario with deactivated OLTCs, as shown in figure 7.2. After the initial fluctuations, only the loads at buses 10X14 are reduced below their nominal loads in order to maintain tolerable voltages. The resulting voltage profile in the transmission network buses are presented in figure 7.12.

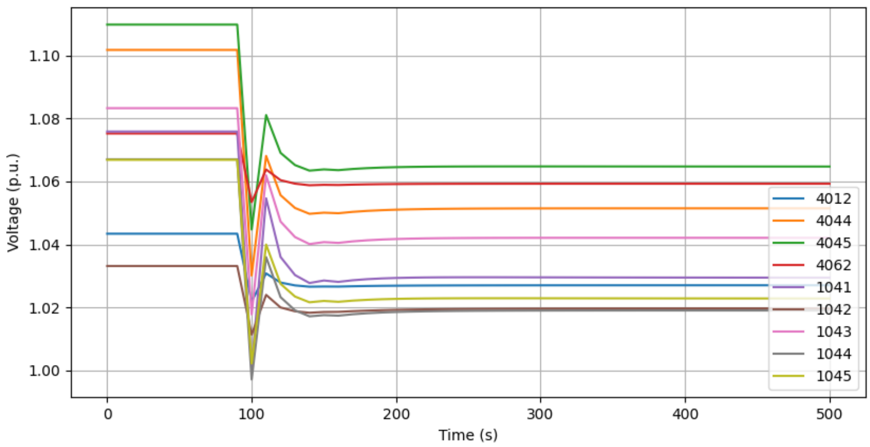

Figure 7.12: Transmission network voltages during case 1 contingency with OLTCs enabled.

If figures 7.6 and 7.12 are compared, it can be noted that the OLTC actions result in slightly lower voltages in the transmission network. The difference is relatively small, but illustrates the decoupling effect of using OLTCs. The larger amount of load shifting required without OLTC action reduces the total load in the transmission network, thus increasing voltages. A larger voltage drop in the distribution networks would result in a higher degree of indirect voltage support from the distribution networks in case OLTCs are deactivated, but if the OLTCs are activated the voltage support will be similar as long as the OLTCs do not hit their limit. The summarized flexibilities of the different distribution networks are presented in figure 7.13.

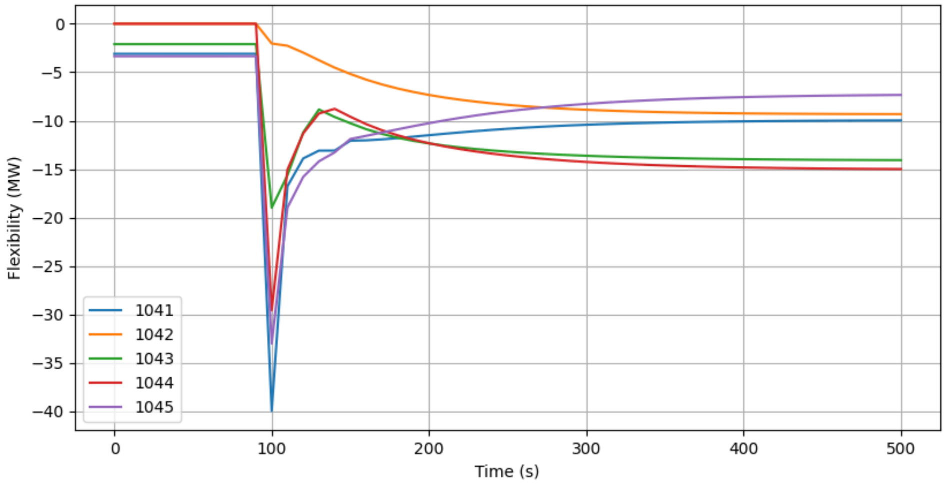

Figure 7.13: Summarized flexibility per distribution network during case 1 contingency with active OLTCs.

In a similar manner to the case without OLTCs active, figure 7.14 illustrates the summarized flexibilities excluding the loads at bus 10X12.

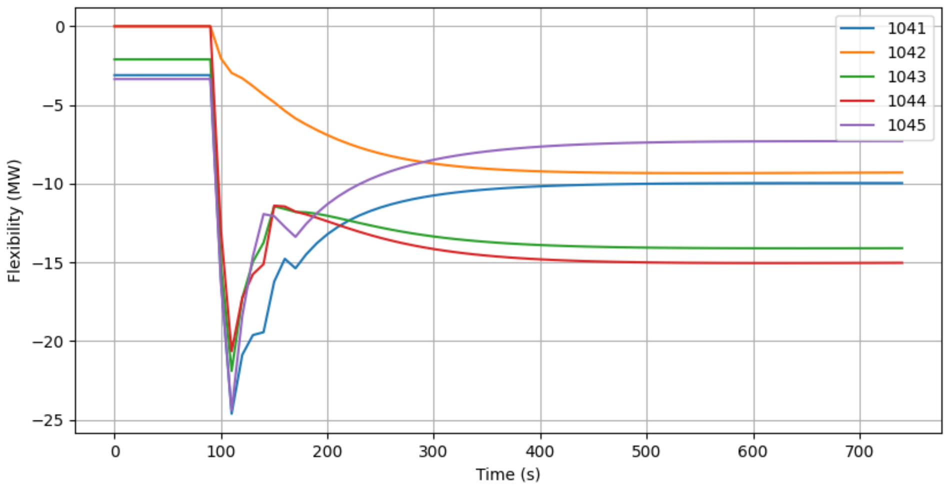

Figure 7.14: Summarized flexibility per distribution network for case 1 contingency with active OLTCs, excluding loads at 10X12.

If the summarized flexibilities presented in figures 7.7 and 7.13 are compared, the total flexibility used is considerably lower in case the OLTCs are active. As described in the previous paragraph, this comes at the expense of less indirect voltage support. However, the reduced need of load shifting that comes with the OLTCs enables a more consumer-centric power system operation. This would become more pronounced with more serious voltage drops. The more conservative use of load shifting in case the OLTCs are active seems more feasible with regard to the consumers, but the level of load shifting at some of the buses still seems unsustainable for long durations. For example, the loads at buses 10314 and 10214 are reduced to around 70% of their nominal setpoints.

7.2 Case 2

This case combines the high generation distribution network case with the voltage drop contingency. The OLTCs have a large impact on the network voltages during the process of introducing the high generation setpoint, which is illustrated in appendix B. As compared to Case 1, the transmission network voltages increase when the distribution network generation increases. In order to keep the transmission network voltages from increasing beyond 1.12 p.u., the setpoints of the switched shunt capacitors in the southern section of the Nordic model are modified. The shunts at buses 4041, 4043, 4046 and 4051 are deactivated.

7.2.1 Tap changers disabled

In case the high generation distribution network scenario is used, the increased generation has increased the voltage across the power system. The voltages at buses 10014 and 10214 are being reduced below 1.05 p.u. by the control systems, which have increased the load setpoints at those buses before the contingency as compared to Case 1. After the contingency, the regulating action at bus 10214 is no longer necessary while the regulating action at bus 10014 is reduced significantly. This is illustrated in figure 7.15.

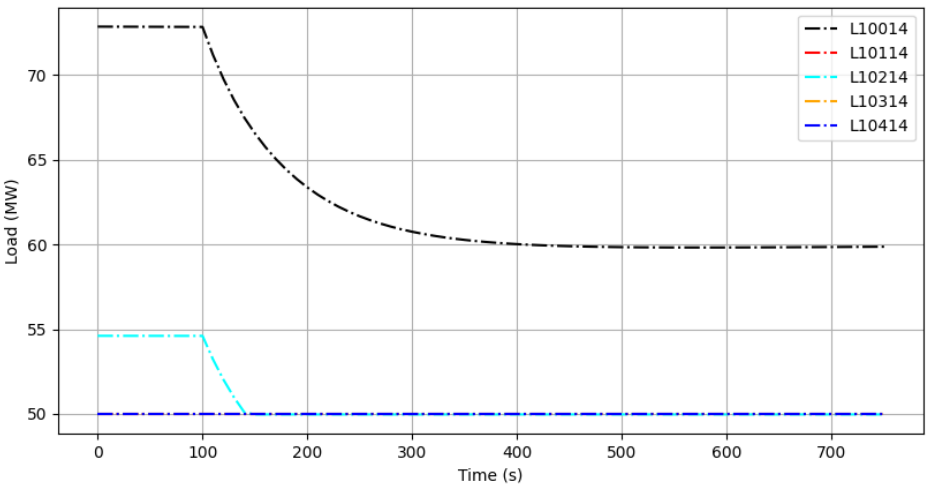

Figure 7.15: Response of loads at buses 10X14 to case 2 contingency.

Figure 7.16 illustrates the effect that the load setpoint adjusting has on the distribution network voltages.

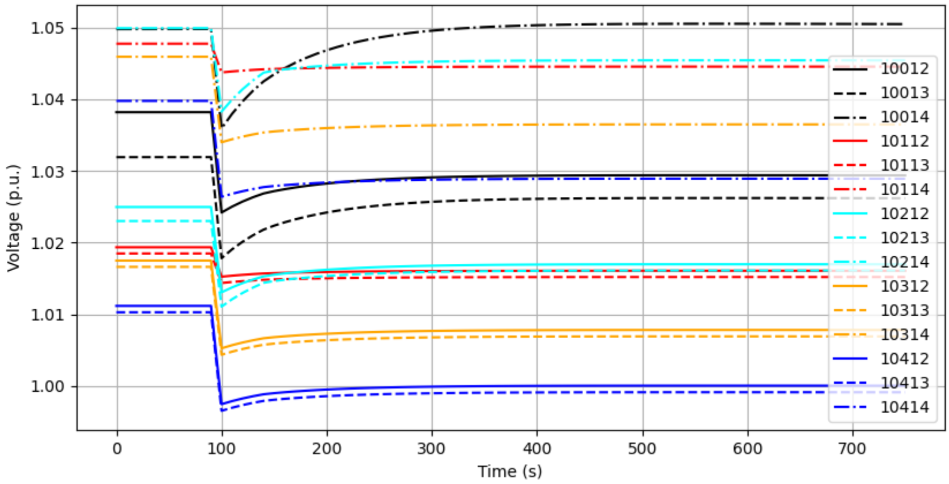

Figure 7.16: Distribution network voltages during case 2 contingency.

The reduction of the load setpoints of buses 10014 and 10214 have an effect on the other distribution networks as well, illustrated by the gradual increase in voltage across all distribution network buses after the contingency. The impact on the transmission network is illustrated in figure 7.17.

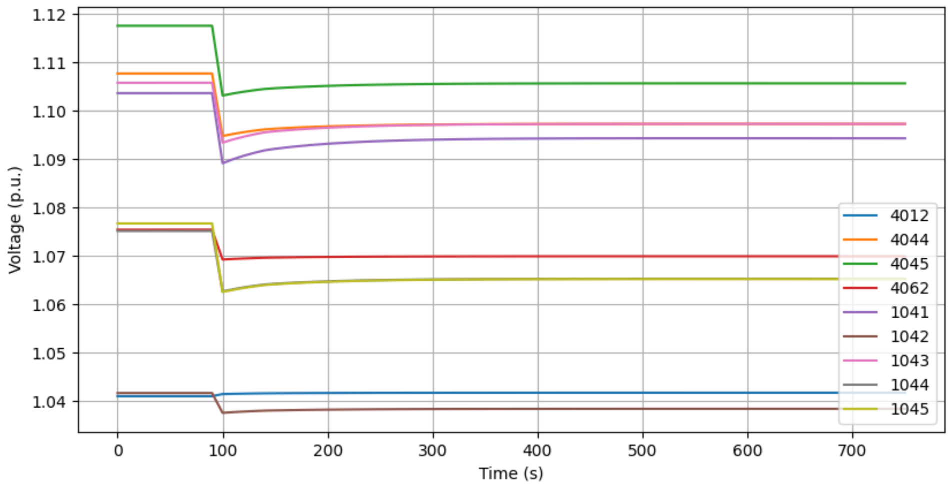

Figure 7.17: Transmission network voltages during case 2 contingency.

The increase in distribution network voltages after the contingency has an effect on the transmission network voltages, which also increase slightly after the contingency as the loads are reduced. The effect is more pronounced in the subtransmission network than in the transmission network. The voltage regulation in this scenario relies on high levels of load shifting at bus L10014, which is increased considerably both before and after the contingency. This level of load increase seems feasible for limited amounts of time, but would likely require generation curtailment to be used instead after a certain amount of time. This is due to the fact that consumers are unlikely to accept overly high levels of load shifting for prolonged periods of time.

7.2.2 Tap changers enabled

Enabling the OLTCs allows for better voltage regulation in the distribution networks, and removes the need of regulating the load at bus 10014 prior to the contingency.

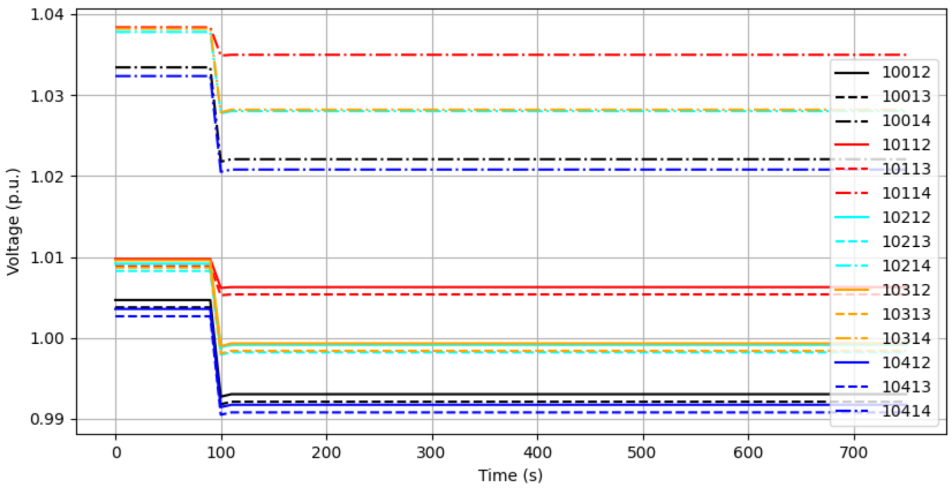

Figure 7.18: Distribution network voltages during case 2 contingency with OLTCs active.

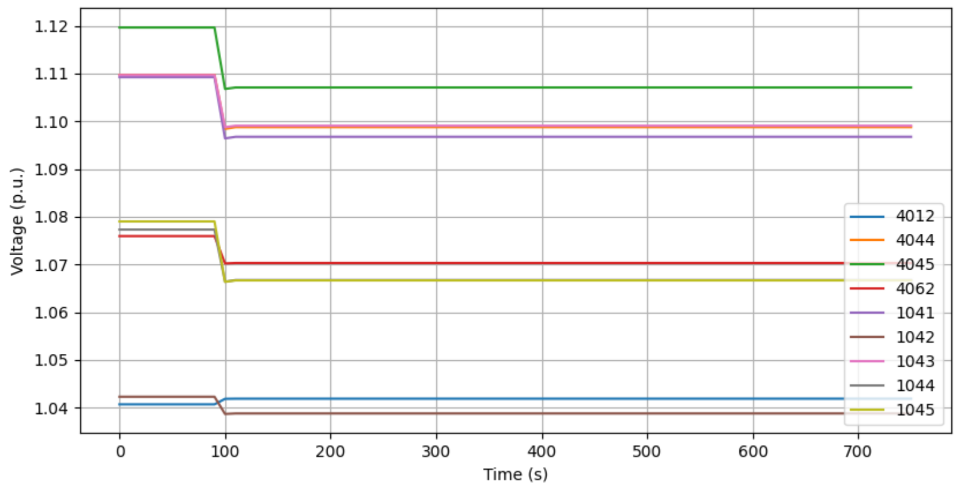

Figure 7.19: Transmission network voltages during case 2 contingency with OLTCs active.

If figures 7.17 and 7.19 are compared, it can be noted that the final transmission network voltages are more or less unaffected by the OLTC introduction. There is a slight difference, which is caused by the slight increase in active power in bus 10014 in case the OLTCs are inactivate. The pre-contingency voltages are also slightly different, also due to the regulation required to maintain distribution network voltages in case OLTCs are inactive. This difference in voltages once more illustrates the decoupling of the OLTCs, which enables tolerable distribution network voltages regardless of variations in transmission network voltages. However, this has the effect of raising the transmission network voltages. In case of more serious overvoltage conditions, this decoupling eliminates the possibility of indirect voltage support from the distribution networks. However, the decoupling also removes the need of load shifting in the distribution network. Assuming that there are other resources able to regulate the transmission network voltage, this could be preferable in certain situations.

7.3 Case 3

This section intends to present the results of simulating the voltage rise contingency combined with the high load distribution network case.

The stepwise voltage increase caused by the voltage rise contingency is illustrated in figure 7.20. In this case the high load distribution network case is used, the distribution network control and OLTCs are deactivated. The magnitude of voltage rise may change depending on the distribution network case, but the general shape will remain the same.

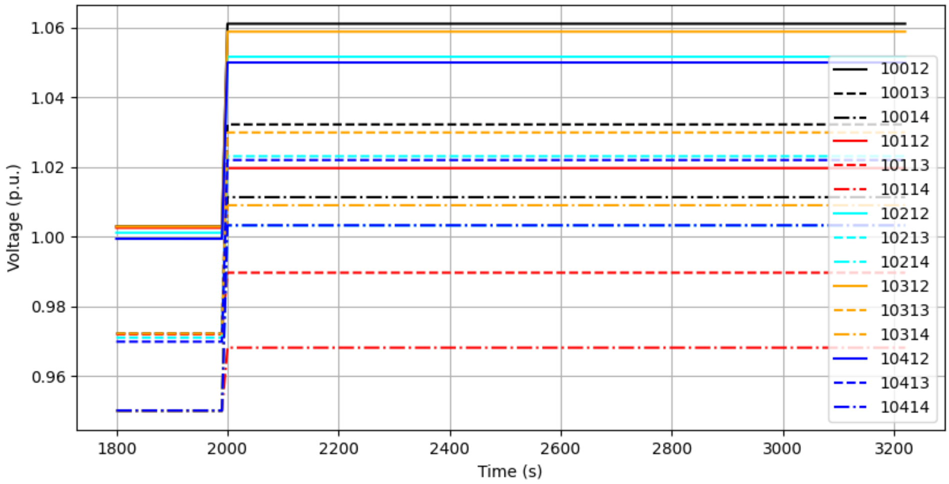

Figure 7.20: Illustration of voltage rise contingency.

7.3.1 Tap changers disabled

In case the high load distribution network case is used and OLTC action is disabled, the distribution networks are actively increasing the voltage in the outermost buses of a few distribution networks. When the voltage rise contingency is introduced, the voltage of the entire power system is increased. The response of the loads in the distribution network are illustrated in figures 7.21 and 7.22.

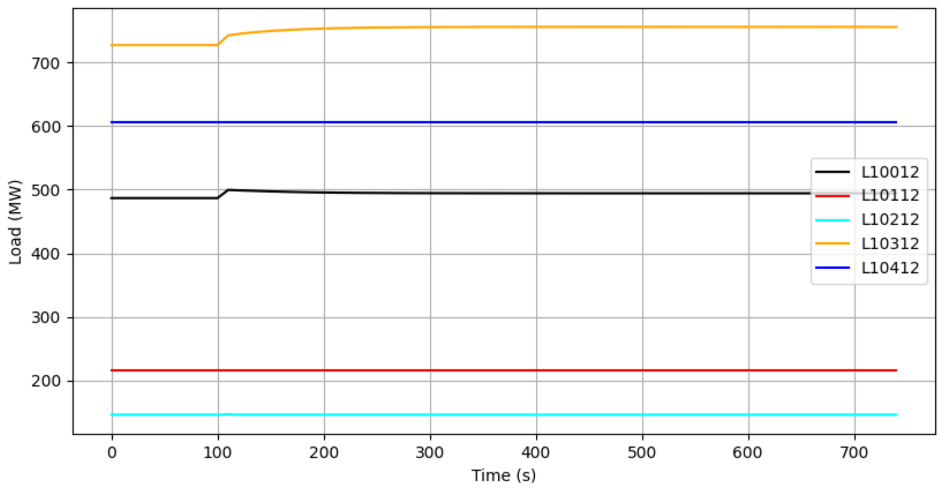

Figure 7.21: Response of loads at buses 10X12 to case 3 contingency.

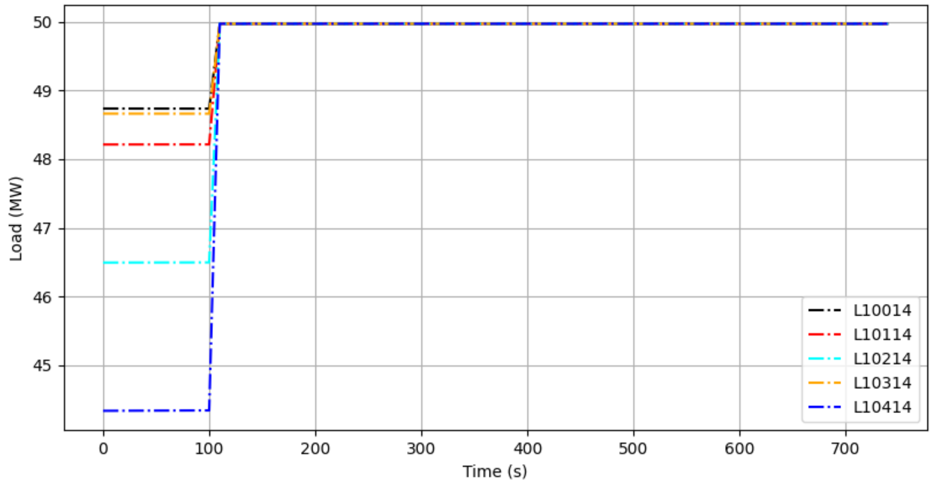

Figure 7.22: Response of loads at buses 10X14 to case 3 contingency.

As can be observed in figure 7.21 and 7.22, the loads at buses 10012 and 10312 increase their setpoint to reduce the local voltage. At the same time, the loads at buses 10X14 are restored to their nominal values as the voltages at the corresponding buses are raised to within acceptable limits. Loads at buses 10X13 are unchanged from their nominal setpoints, and are not illustrated. The distribution network voltages are illustrated in figure 7.23.

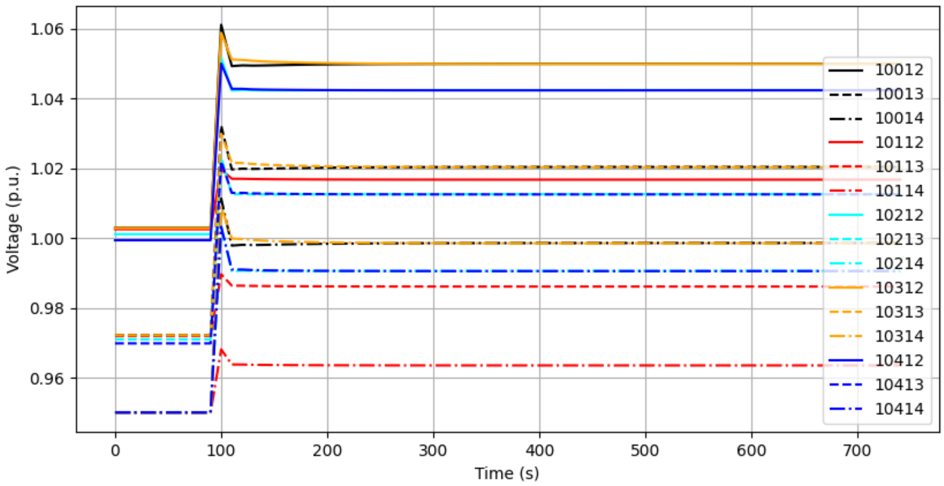

Figure 7.23: Distribution network voltages during case 3 contingency.

As shown in figure 7.23, the contingency increases the voltage across the distribution network by up to 0.06 p.u. The effect that the actions of the control systems have on the transmission network are illustrated in figure 7.24.

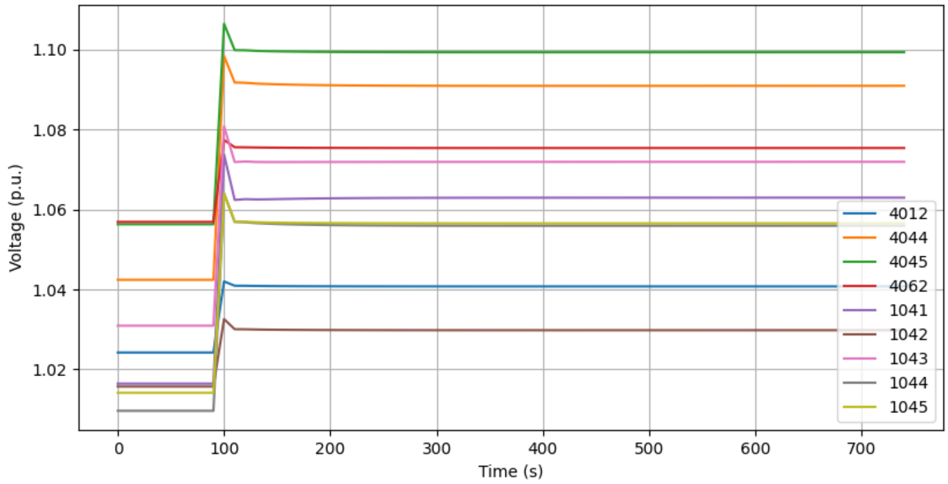

Figure 7.24: Transmission network voltages during case 3 contingency.

The summarized flexibilities used by the control systems are presented in figure 7.25.

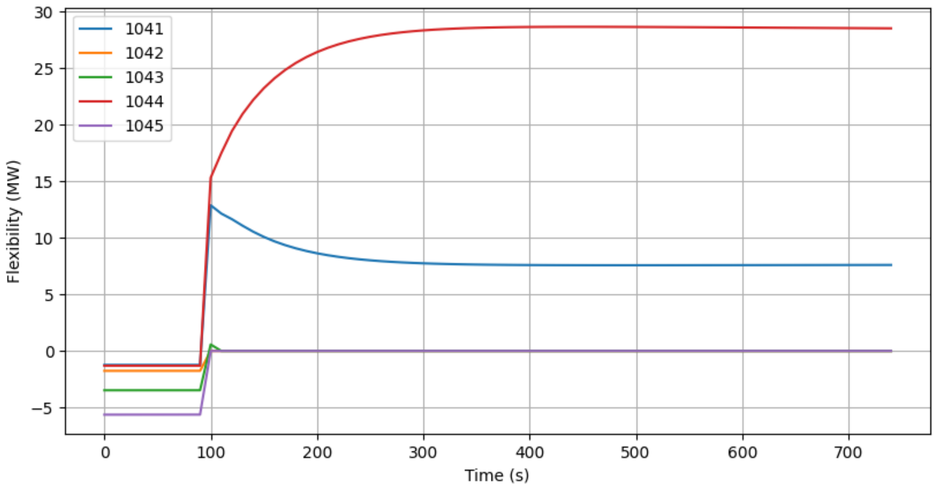

Figure 7.25: Summarized flexibility per distribution network during case 3 contingency.

The actions of the distribution network controllers result in a slight voltage reduction across the transmission network right after the contingency. The amount of load shifting used is small relative to the total size of the loads that are regulated, with the largest relative change being an increase of around 5%.

7.3.2 Tap changer enabled

In case the OLTCs are enabled, the pre-contingency operating point does not change. However, once the contingency is introduced the OLTCs act to restore the distribution network voltages. In comparison to the case where the OLTCs are disabled, the

OLTC action eliminates the need to increase the loads at buses 10012 and 10312. However, the voltages at buses 10014 and 10314 are below the threshold of 0.95 p.u. and thus require the loads at those buses to be reduced by the control system. The response of the loads when subjected to the contingency is illustrated in figure A.23.

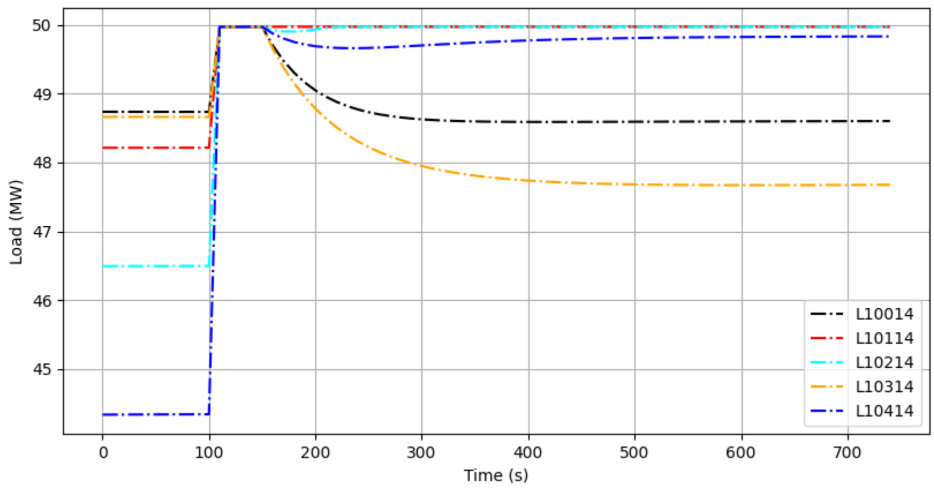

Figure 7.26: Response of loads at buses 10X14 to case 3 contingency with OLTCs enabled.

The distribution network voltages are temporarily increased by the contingency, until the OLTCs act to decrease the distribution network voltages. Once the OLTCs have acted, the distribution network voltages are somewhat similar to the pre-disturbance voltages. The distribution network voltages are illustrated in figure 7.27.

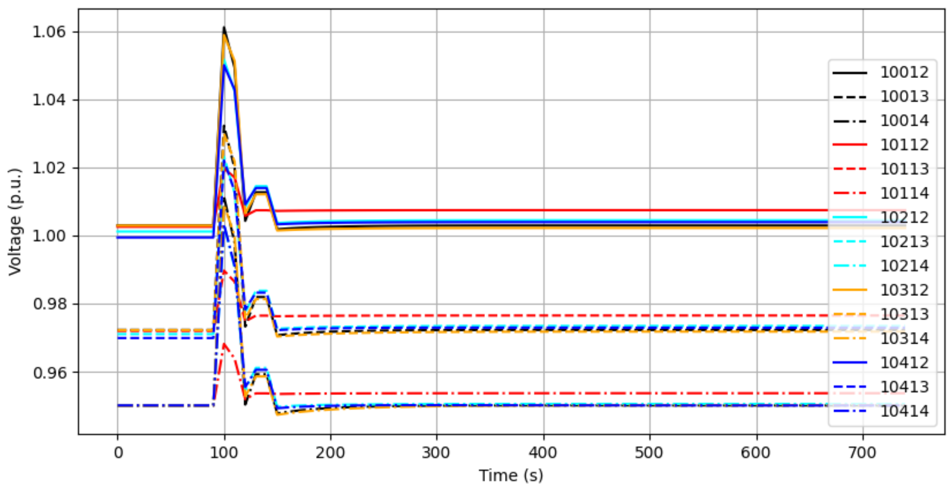

Figure 7.27: Distribution network voltages during case 3 contingency with OLTCs enabled.

The resulting transmission network voltages are presented in figure 7.28.

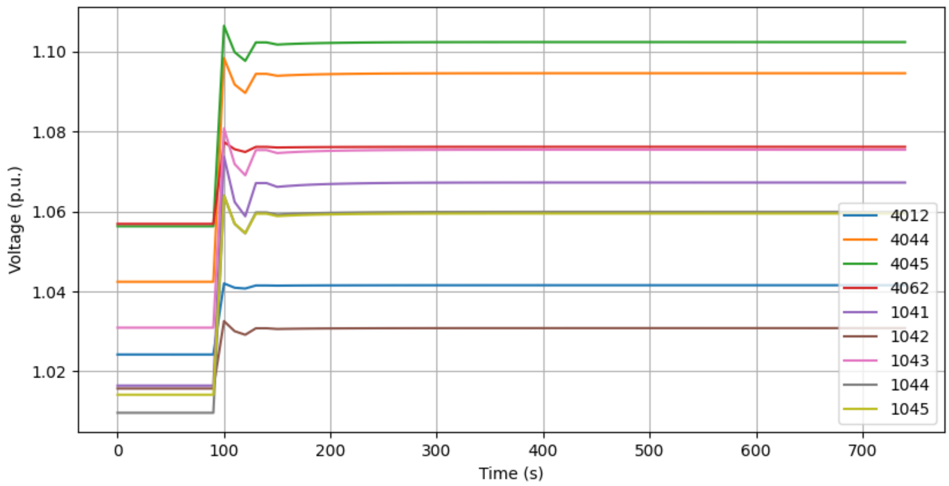

Figure 7.28: Transmission network voltages during case 3 contingency with OLTCs enabled.

The summarized flexibilities of the distribution networks are presented in figure 7.29.

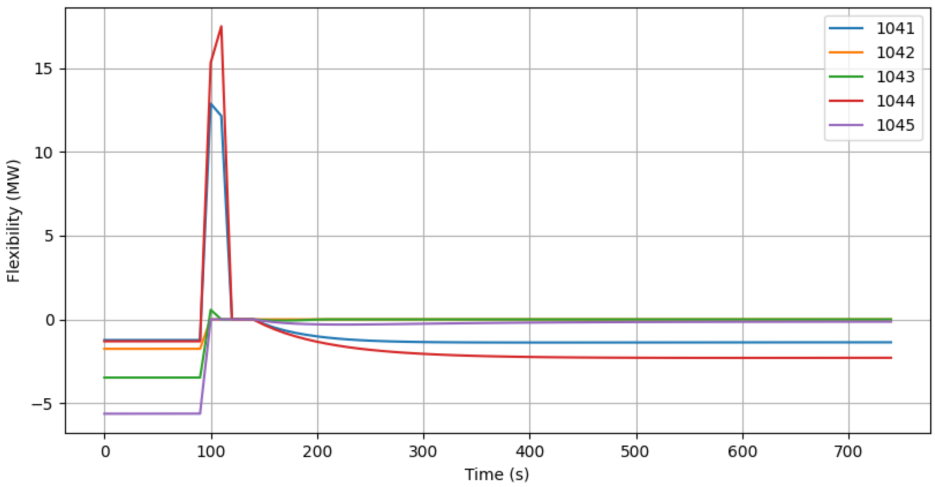

Figure 7.29: Summarized flexibility per distribution network during case 3 contingency with OLTCs enabled.

If the transmission network voltages of the case with and without OLTCs active are compared, presented in figures 7.24 and 7.28, it can be observed that the voltages are generally lower if the OLTCs are deactivated. The difference is relatively small, but once again points to the effects of decoupling transmission and distribution network voltages. If figures 7.25 and 7.29 are compared, less flexibility resources are used in case the OLTCs are active. However, the larger amount of flexibility used in case the OLTCs are deactivated has the direct effect of reducing the transmission network voltages. In this case, utilizing the OLTCs benefit the electricity consumers at the expense of the transmission network voltage. In a real implementation, the increase in load necessary when the OLTCs are inactive may be unavailable for the required time length. However, the same effect can be attained by reducing the generation. If the generation is curtailed, the OLTCs can instead be seen as allowing further power production in the distribution network assuming that the transmission network voltage reduction is not critical to the system operation.

7.4 Case 4

In this case the voltage rise contingency is combined with the high generation distribution network case. In this case, the distribution network controllers are actively reducing the voltages in some of the buses before the contingency is introduced.

7.4.1 Tap changers disabled

In case the tap changers are disabled, most of the outermost buses (10X14) require a substantial amount of flexibility to keep their voltage below the upper threshold of 1.05 p.u. prior to the contingency. Once the contingency is introduced, the required flexibility increases due to the increase in subtransmission network voltage. The load response and the initial load setpoints are illustrated in figures 7.30, 7.31 and 7.32.

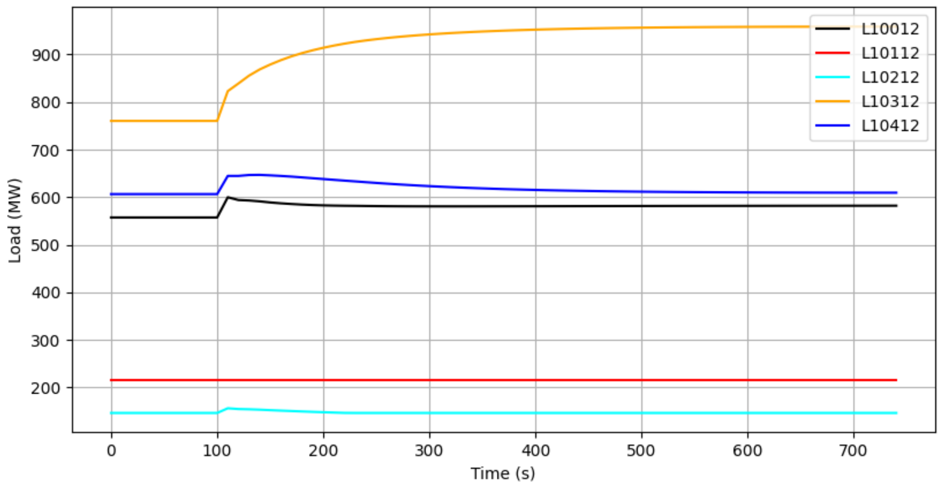

Figure 7.30: Response of loads at buses 10X12 to case 4 contingency.

The load at bus 10312 is increased prior to the contingency, and is increased considerably after the contingency in order to prevent overvoltage. The load at bus 10012 is also increased by around 10%, while the other loads at buses 10X12 are increased marginally both before and after the contingency.

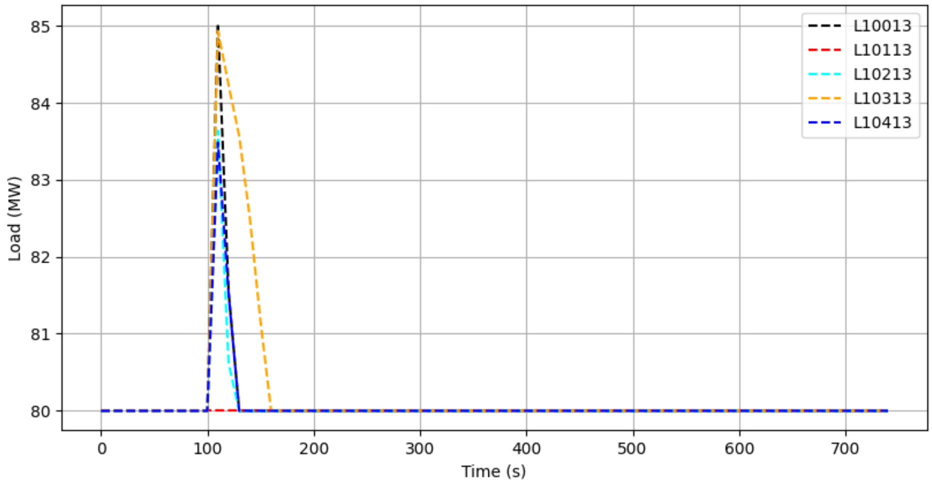

Figure 7.31: Response of loads at buses 10X13 to case 4 contingency.

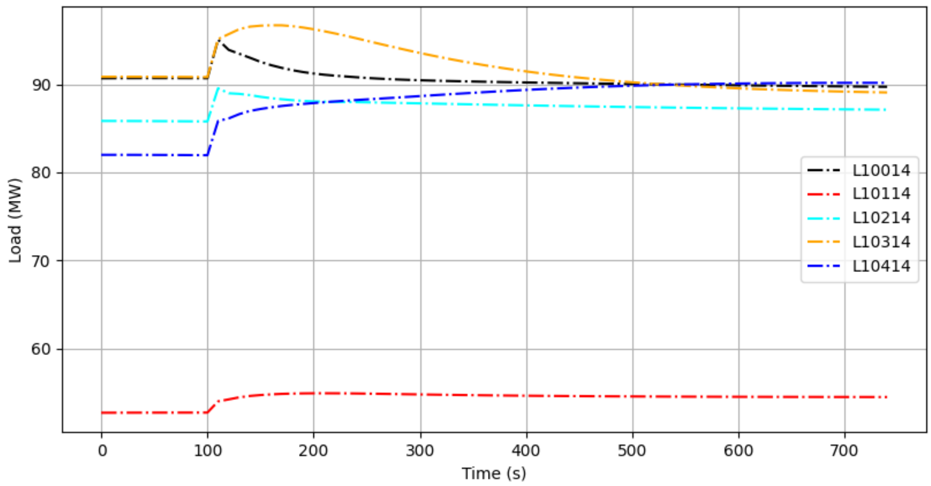

Figure 7.32: Response of loads at buses 10X14 to case 4 contingency.

The loads at buses 10X14 are increased considerably both before and after the contingency, with the exception of the load at 10114. The loads at buses 10X13 are mostly kept at their nominal setpoint. The impact that the load response has on the distribution network voltages is illustrated in figure 7.33.

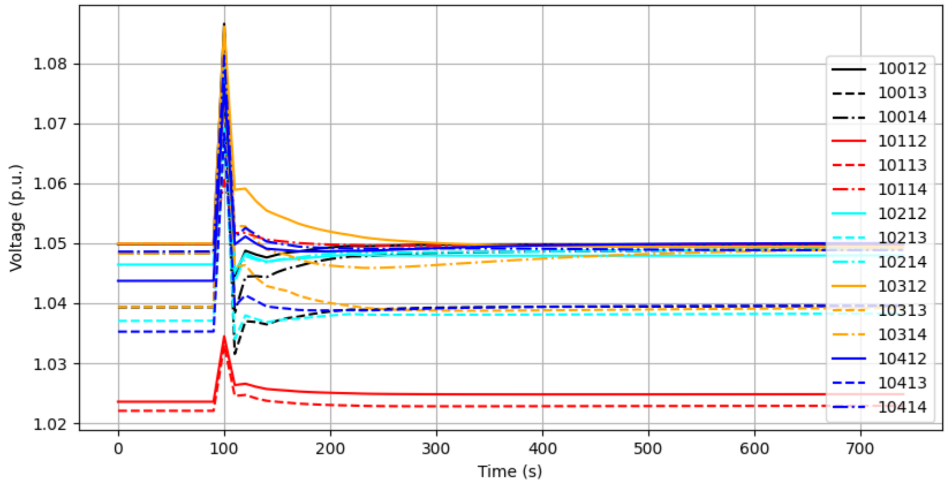

Figure 7.33: Distribution network voltages during case 4 contingency.

The contingency initially causes a voltage rise in the distribution network, which is quickly countered by the distribution network controllers. Once the controllers have found a new stable operating point, the voltages are relatively similar before and after the contingency. The effect that the distribution network controllers have on the transmission network voltages is illustrated in figure 7.34.

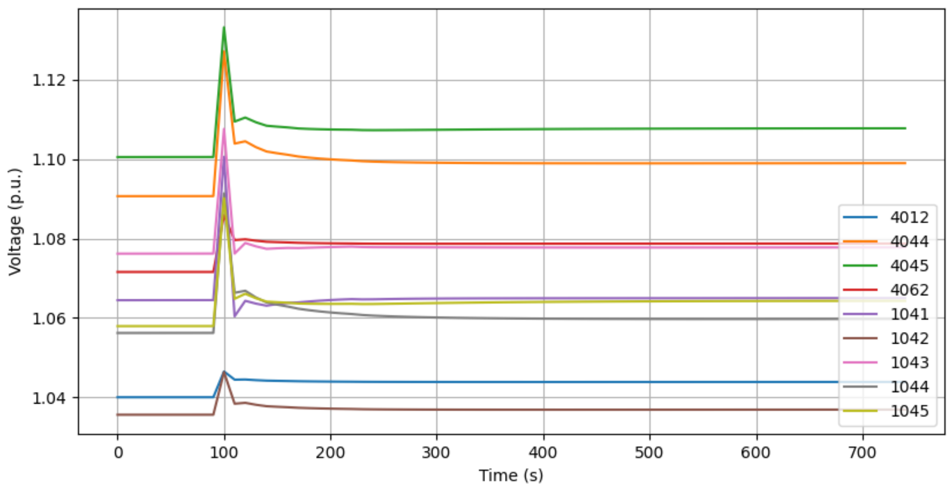

Figure 7.34: Transmission network voltages during case 4 contingency.

The summarized flexibilities are presented in figure A.32.

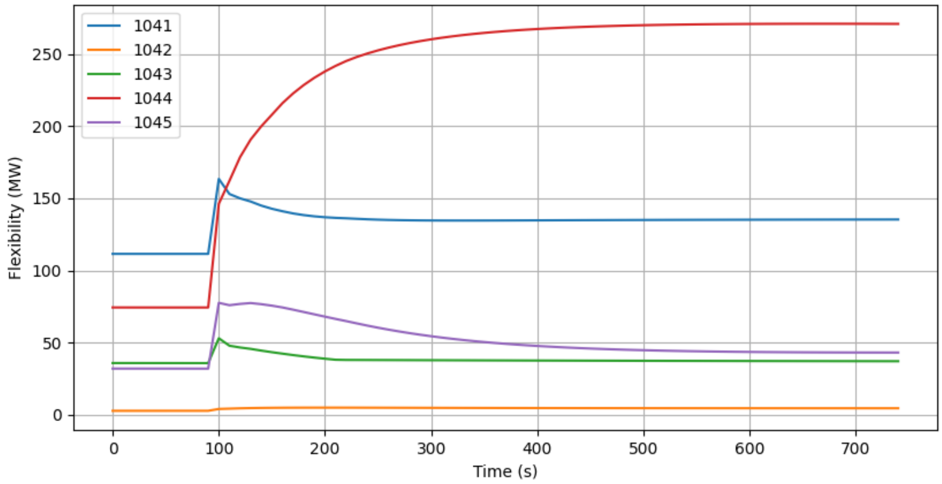

Figure 7.35: Summarized flexibilities during case 4 contingency.

The reaction of the loads to the voltage rise in the distribution network has a considerable effect on the transmission network voltages. The voltages are increased to a varying degree compared to their pre-contingency operating point, but the actions of the control systems decrease the transmission network voltages considerably compared to the highest point of the voltage rise. Even though it works in this theoretical scenario, the loads at multiple buses are likely increased to a degree that is not feasible for prolonged periods of time. The buses in question are 10312 and a number of the 10X14 buses. Buses 10X14 have generation that can be curtailed once the load shifting resources are exhausted, which may allow the voltage to remain within tolerable intervals. However, there is no generation at bus 10312 that can be curtailed when the load shifting resources are exhausted and thus the distribution network is at risk of overvoltage. However, the level of load shifting utilized may be used to provide passive voltage support for a shorter period before there is a need for support from other resources.

7.4.2 Tap changers enabled

In case the tap changers are enabled, the distribution network voltages are kept within tolerable intervals by the tap changers. Therefore, no flexibility resources are utilized either prior to the contingency or after the contingency. Flexibility resources are only utilized briefly before the tap changers have adjusted. The distribution network voltages are illustrated in figure 7.36.

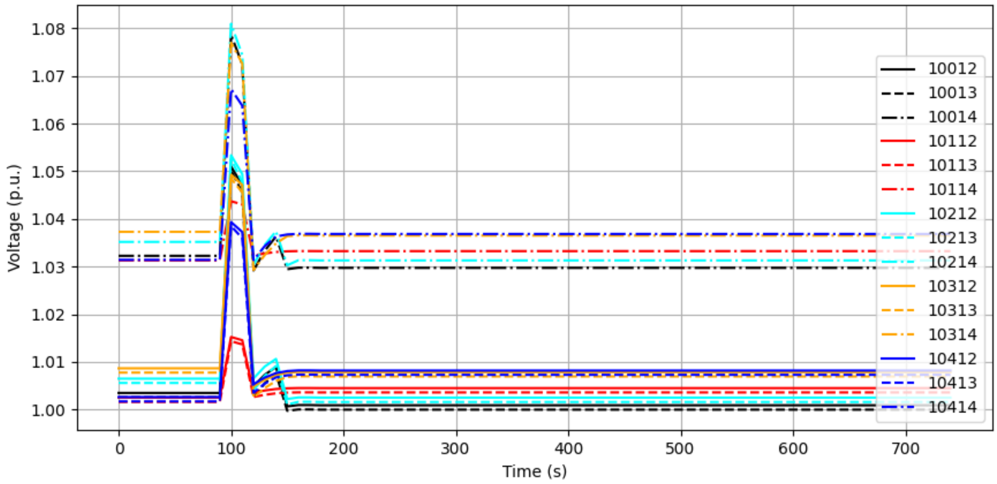

Figure 7.36: Distribution network voltages during case 4 contingency with OLTCs enabled.

The distribution network voltages increase after the contingency, but are quickly restored once the tap changers have adjusted. The resulting transmission network voltages are illustrated in figure 7.37.

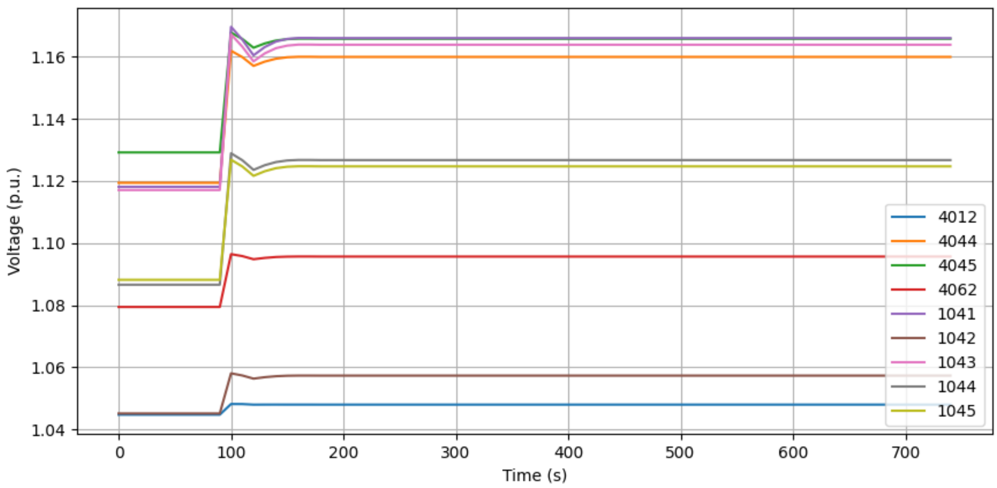

Figure 7.37: Transmission network voltages during case 4 contingency with OLTCs enabled.

Once the OLTCs have adjusted, the transmission network voltages are considerably higher than the voltages obtained with the OLTCs deactivated as illustrated in figure 7.34. This can once more be attributed to the decoupling of the distribution network voltages from the transmission network voltages. As in the previously discussed cases, it may be advantageous to use the OLTCs to maintain voltages so that more distributed generation can be utilized in case the power system operation allows it.

8
Discussion

The results presented in chapter 7 indicate that local active power control in distribution networks can provide indirect voltage support to the transmission network in case of sudden voltage deviations. However, the voltage support is still dependent on compromised operating conditions in the distribution networks themselves. The voltage support ability of this type of control system is affected by a number of different factors and assumptions, and thus the extent to which voltage support can be provided is difficult to specify.

8.1 On-load tap changers

As presented in chapter 7, the OLTCs have a profound impact on the behaviour of the control systems when a voltage contingency is introduced. The decoupling effect of the OLTCs effectively maintains the distribution network voltages within tolerable intervals, which is the very reason the OLTCs are used. However, when the distribution networks in question have this type of local active power control traditionally controlled OLTCs effectively prevent the control systems from providing voltage support to the transmission network. Whether this warrants locking OLTCs in order to enable this type of indirect voltage support is a complex question that requires careful consideration and further research. OLTCs have a number of advantages from the consumer point of view, and generally work well with the consumer-centric power system that is prevalent today. However, they also have drawbacks in that their operation may bring the network closer to voltage collapse during contingencies due to load restoration. Generally, using OLTCs to regulate voltage allows the consumers to be more flexible in their power consumption compared to using active power control for voltage regulation. It is also worth noting that this particular implementation of local active power control is theoretically able to regulate voltages in distribution networks without the use of OLTCs, but in reality a control system such as the one developed may be limited by its access to flexibility resources. Therefore, it is not certain that a real active power management system could manage voltages effectively without the use of OLTCs.

8.2 Feasibility of local control

The reason that this type of control system is made less effective by the OLTCs regarding transmission network support is the local nature of the control system. In case a similar control system is developed to include the OLTCs and certain transmission network parameters, the supportive effects of load shifting could be combined with the OLTCs. As mentioned previously there are certain advantages to the simpler control strategy of the local control systems, but in this case it seems like a more sophisticated control system would have substantial advantages. It is also possible that such a system could be used to mitigate longer term voltage collapse caused by the load restoration of the OLTCs, which has not been directly studied in this thesis but is an important phenomena. Introducing such a system would likely also allow the system operator to coordinate this type of active power regulation with other supporting resources to a greater extent, with regard to suitability and efficiency.

In a number of the simulated scenarios, the outermost loads in the distribution network are subjected to relatively large changes in setpoint to keep voltage within acceptable limits. From a consumer perspective, it may be more reasonable to share the required regulatory action between the different distribution network loads. If a local control system such as the one used in this thesis is used, the regulatory action would affect the outermost buses in a disproportionate manner. In case the consumers affected are adequately compensated, this may not be an issue. Otherwise, this may be another reason for exploring the use of more sophisticated control systems.

8.3 Load shifting

The simulations conducted in this study have been conducted as if loads can be set as required by the local control systems, with some relatively loose limitations set on the rate of change of load setpoints. In real power systems, the power system is expected to allow consumers to freely increase or decrease their load at any time during normal power system operation. Using forced changes in load setpoint such as this to manage the power system voltage both requires a technical ability to change the setpoint of a considerable amount of load on demand, as well as an acceptance from private consumers and industry that their power consumption may be subject to external control. Pilot projects introducing this type of DSM to real power systems are being conducted, but the concept is likely quite far from widespread introduction. In order to create acceptance, market structures incentivizing a more flexible use of active power would likely play a key role. Even with such structures, there would probably be limits to the amount of load shift and duration of changes in setpoints. There would also be a number of technical limitations that impact the duration and amount of load shifting as well as the response speed of loads. The technical limitations depend greatly on the types of loads that are to be used for DSM, and may vary between different distribution networks.

Reconnecting to the research question of providing voltage support in the defined short term period, the rate of change of loads and generators have a large impact on the speed by which the control system can start to provide support. It is difficult to ascertain how fast the setpoint of loads can be adjusted when controlled by a control system such as the one considered in this thesis, but since public acceptance is a key part of the introduction of such systems it seems likely that this type of control system is more suited for providing longer term voltage support. It is possible that a real implementation could utilize certain converter interfaced loads for faster setpoint adjustment while allowing other loads to be adjusted more slowly. Loads such as electric boilers, electric vehicle charging and electrolyzers may be used for fast setpoint adjustments while other loads such as traditional industrial processes can be much slower in terms of setpoint adjustment.

8.4 Impact of branch characteristics

The trend of using cables rather than OHLs in distribution networks has been a recent topic of research and discussion, due to the increasing amount of reactive power injection stemming from the high charging capacitance of cables as compared to OHLs. In this study, the branch characteristics only had a minor impact on the results when the impact of branch model was evaluated. The considerable reactive power injection caused by a large number of parallel cables did not materialize. This is likely due to the fact that a real urban distribution network would include a much larger amount of parallel cables compared to the modelled distribution network, which would increase the charging capacitance. In order to emulate this effect, the charging capacitance could be increased to such a level that the branches start injecting a level of reactive power that is found reasonable. However, this would require an adjustment of the loads at buses 10X12 as it is vital to keep both the active and reactive power fed from the subtransmission network constant.

8.5 Sustainable and ethical aspects

The primary incentive for introducing active distribution networks is to enable more efficient utilization of the power system. Implementing active control of distribution networks may enable further integration of renewable energy without strengthening the distribution network. Active distribution networks may also serve to alleviate congestion in the power system, which may also reduce the need of strengthening the power system. A more efficient use of resources across society is a fundamental part of reducing greenhouse gas (GHG) emissions. Active distribution networks may therefore enable additional renewable energy production while making efficient use of the power system, at relatively low cost in resources. Active distribution networks may therefore be useful in the effort to make society more sustainable.

From an ethical perspective, the consequences of introducing active distribution networks are more nuanced. Contributing to reduction of GHG emissions is positive from an ethical standpoint, as GHG emissions and their consequences have a negative impact on ecosystems and the lives of billions of people around the world. However, this type of active control may be used in unethical ways. Introducing active power control to distribution networks may give network operators or other entities more advanced options regarding who they sell electricity to, which can be used to discriminate certain groups in society. This is due to the fact that the control systems introduce a more sophisticated method of regulating power flow than what is typically available to system operators. In case authorities ensure that no discrimination takes place, the benefits of introducing active distribution networks seem to outweigh the disadvantages from an ethical perspective.

9
Conclusions and Future Work

9.1 Conclusions

The results of this thesis imply that there is potential in using local active power control to provide indirect voltage support to the transmission network during contingencies. However, the local nature of the control system makes the voltage support unreliable. It is found that OLTC usage may reduce the level of voltage support provided by the distribution network. On the other hand, the control system is dependent on considerable flexibility in active power usage from consumers if the system is to reliably manage the distribution network voltages. This means that the availability of regulatory resources is dependent on type, size, location and willingness of the local loads. Using the control system together with OLTCs is likely the most reliable solution, as this reduces the required level of flexibility in active power usage while allowing for voltage and current control in the outer sections of the radial where the OLTC has limited impact. Real implementations of a control system would likely be more suited to relatively slow voltage adjustment, as there are a number of factors indicating that fast setpoint adjustment may be difficult to attain in real networks.

A non-local distribution network control system would bring a number of advantages if actively controlled distribution networks are to reliably provide voltage support to the transmission network. However, the threshold for introducing more sophisticated control systems into traditional distribution networks is higher as compared to introducing a simpler control system such as the local system considered in this thesis. This type of local system may be used together with OLTCs to regulate voltage and current in radial distribution networks. In that case, the decoupling effect of the OLTCs generally results in better distribution network control at the expense of the transmission network voltage.

9.2 Future work

To build upon the results of this thesis, a few topics seem interesting to research further. First of all, continued development of the control algorithms to integrate reactive power control may allow for more effective voltage control with less dependency on active power control. Further studies and pilot projects regarding load shifting are paramount to accurately study the potential of active power control systems such as the one used in this thesis. Both the share of load that can realistically be shifted and the speed by which it is possible to change setpoints have large impacts on the results, and are thus interesting to study further. Dynamic studies regarding the behaviour of this type of controller when subjected to contingencies would complement this thesis, and is important when evaluating whether this type of active power control is suitable for implementation in real systems. Finally, the way that a control system such as the one used in this thesis interacts with other control systems in the network is interesting to study further. Controller interactions may have unforeseen side effects, and are becoming increasingly important as converter interfaced elements are becoming more prevalent in power systems.

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A

Case results with branches modelled as cables

This appendix presents the results obtained when modelling the branches as cables rather than OHLs. The appendix is split into a number of subsections in the same manner as chapter 7. For each subsection, the figures found in the corresponding section of chapter 7 are included so that the figures can be compared to discern any impact of the different type of branch. In the end of each subsection, differences between the OHL and cable cases are discussed.

A.1 Case 1

A.1.1 Tap changers disabled

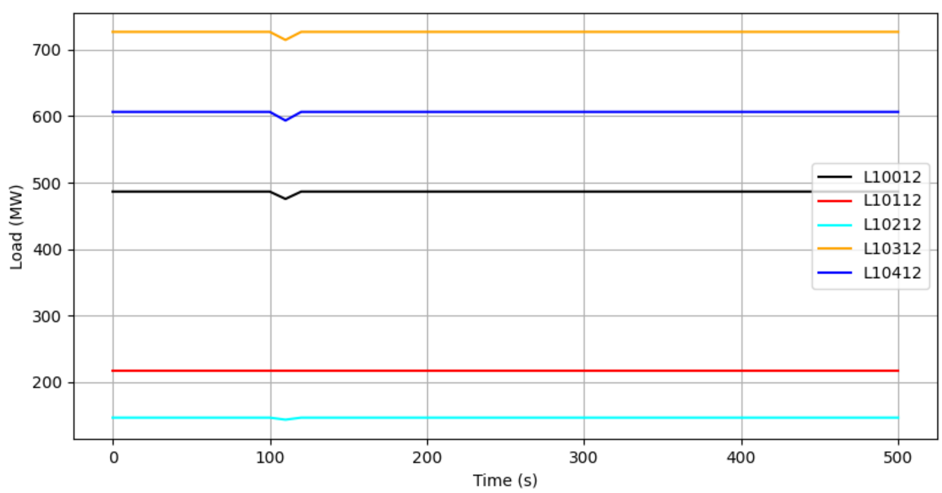

Figure A.1: Response of loads at buses 10X12 to case 1 contingency with branches modelled as cables.

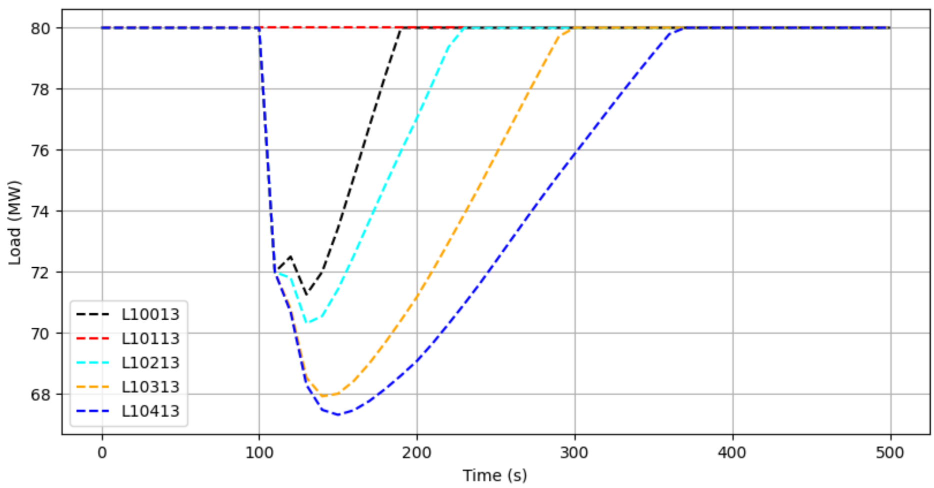

Figure A.2: Response of loads at buses 10X13 to case 1 contingency with branches modelled as cables.

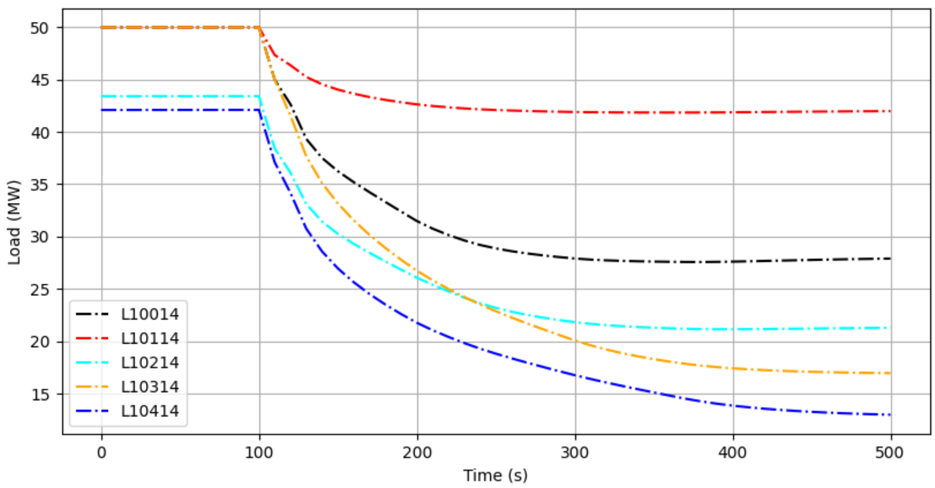

Figure A.3: Response of loads at buses 10X12 to case 1 contingency with branches modelled as cables.

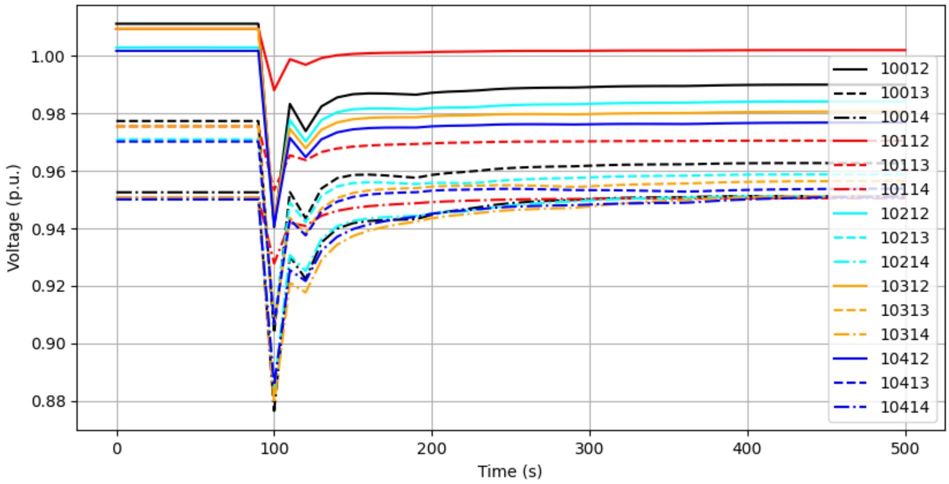

Figure A.4: Distribution network voltages during case 1 contingency with branches modelled as cables.

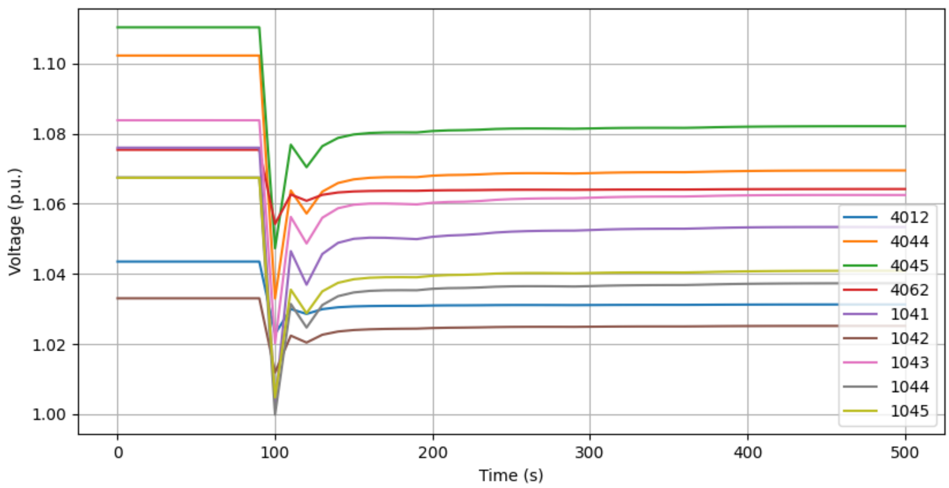

Figure A.5: Transmission network voltages during case 1 contingency with branches modelled as cables.

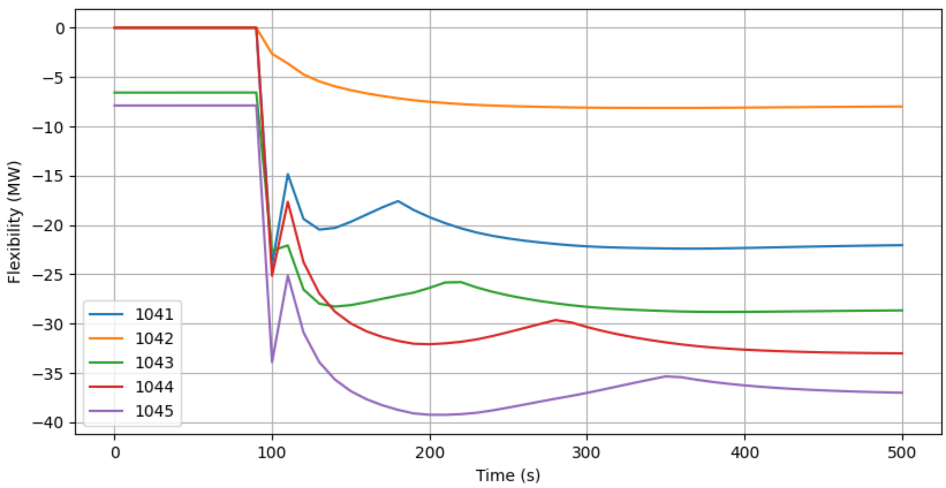

Figure A.6: Summarized flexibility during case 1 contingency with branches modelled as cables.

In this combination of scenarios, the results are only marginally different to the results obtained when modelling the branches as OHLs.

A.1.2 Tap changers enabled

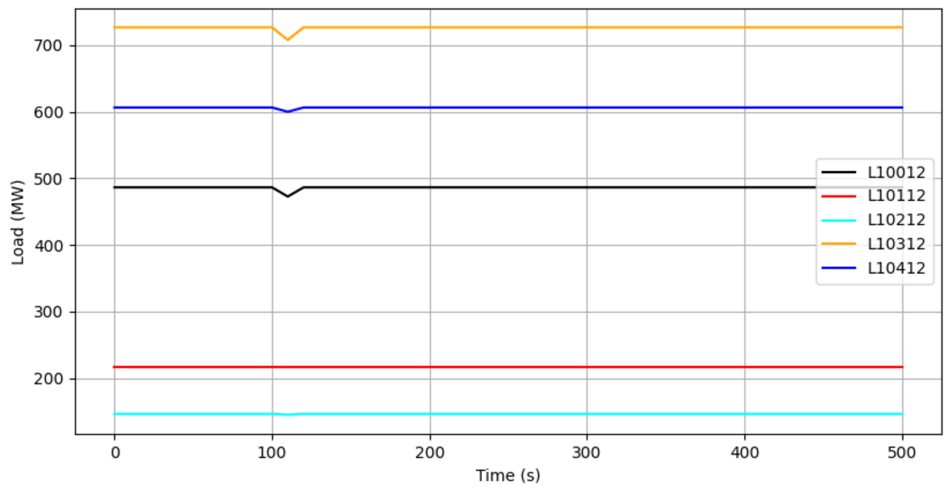

Figure A.7: Response of loads at buses 10X12 to case 1 contingency with branches modelled as cables and OLTCs in use.

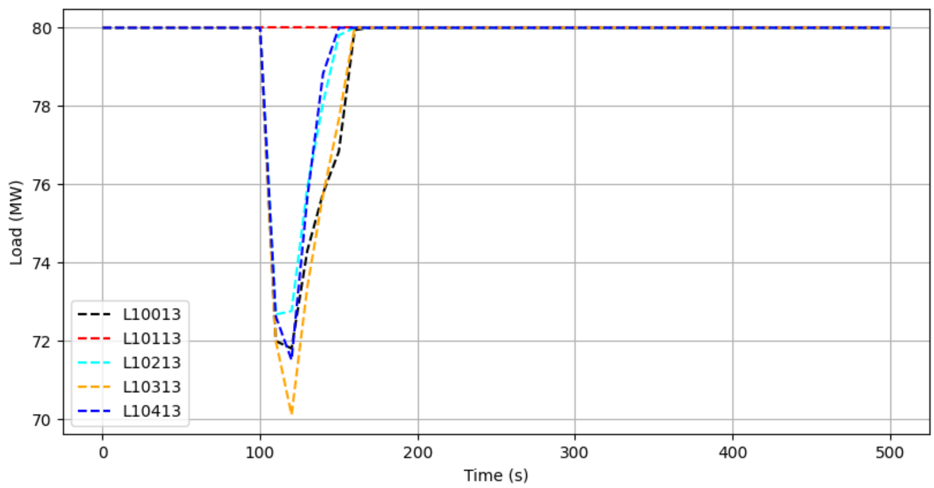

Figure A.8: Response of loads at buses 10X13 to case 1 contingency with branches modelled as cables and OLTCs in use.

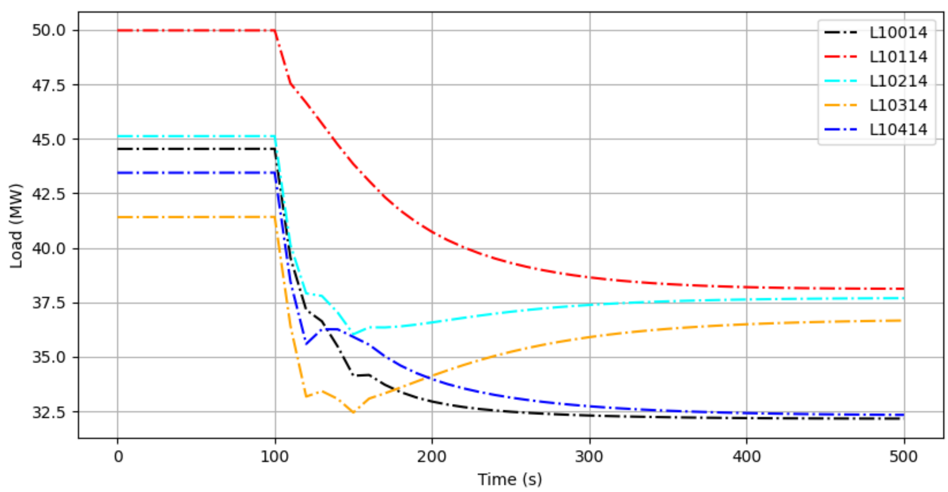

Figure A.9: Response of loads at buses 10X14 to case 1 contingency with branches modelled as cables and OLTCs in use.

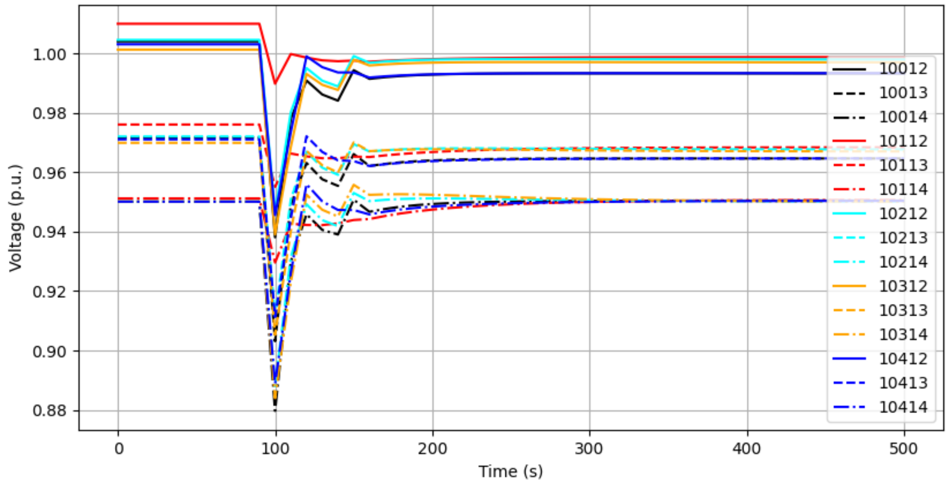

Figure A.10: Distribution network voltages during case 1 contingency with branches modelled as cables and OLTCs in use.

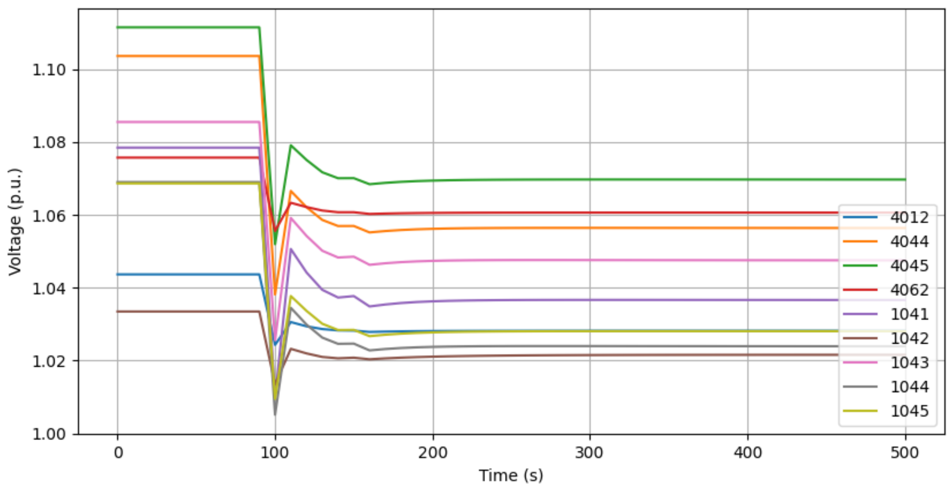

Figure A.11: Transmission network voltages during case 1 contingency with branches modelled as cables and OLTCs in use.

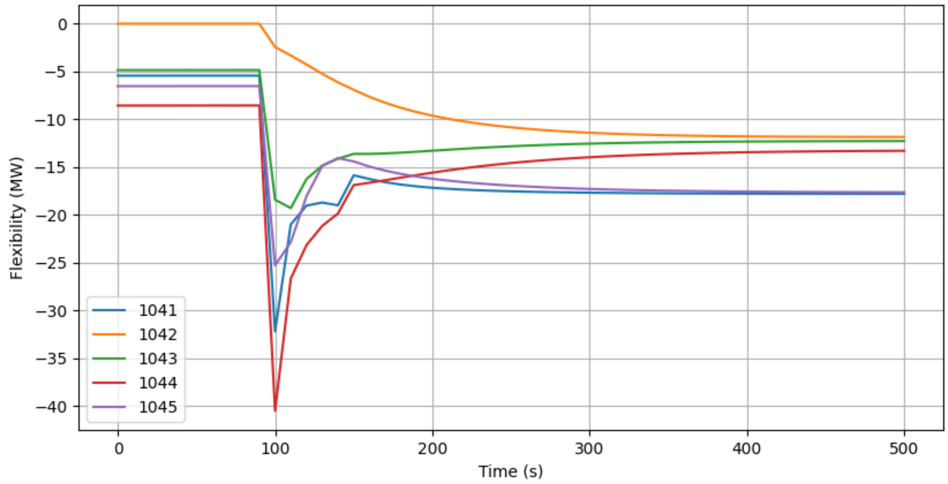

Figure A.12: Summarized flexibilities during case 1 contingency with branches modelled as cables and OLTCs in use.

Compared to the results obtained when modelling the branches as OHLs, the loads are reduced slightly more to prevent undervoltage when the branches are modelled as cables.

A.2 Case 2

A.2.1 Tap changers disabled

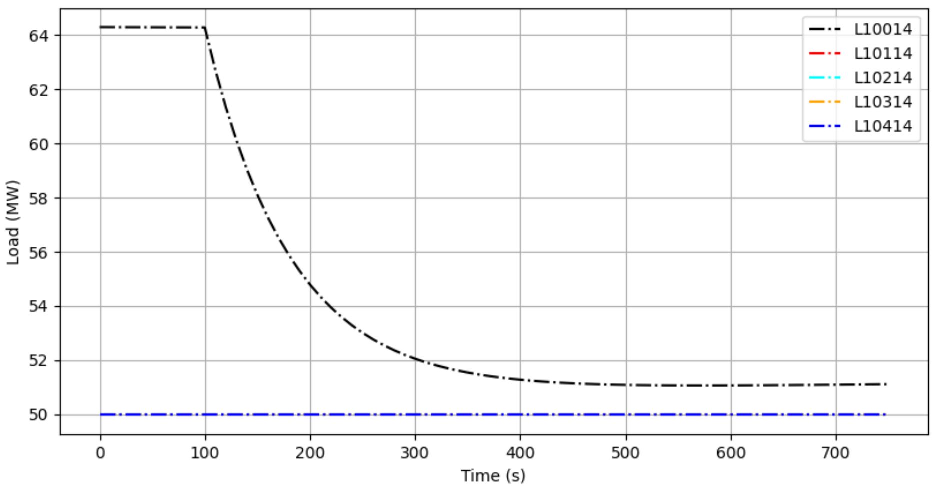

Figure A.13: Response of loads at buses 10X14 to case 2 contingency with branches modelled as cables.

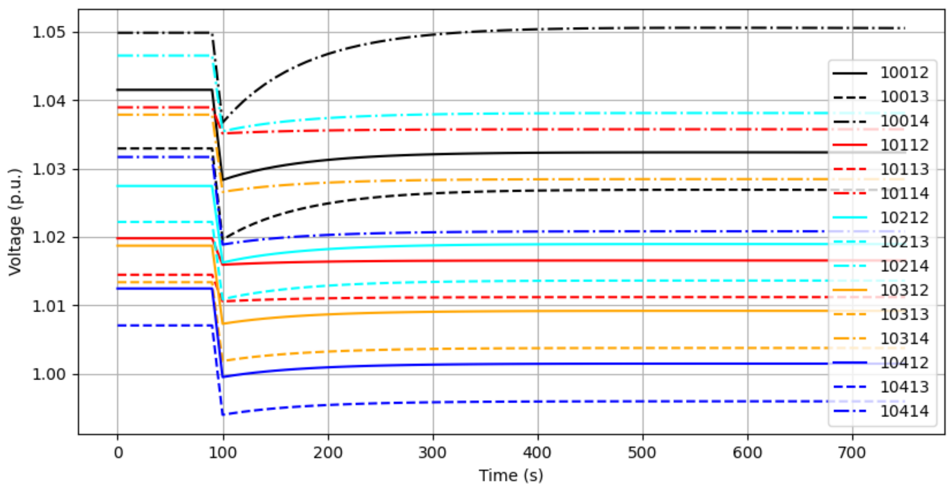

Figure A.14: Distribution network voltages during case 2 contingency with branches modelled as cables.

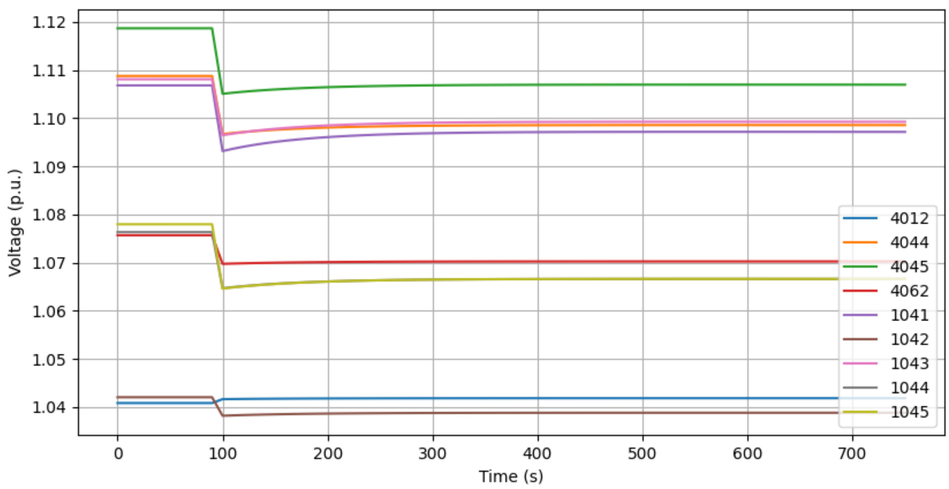

Figure A.15: Transmission network voltages during case 2 contingency with branches modelled as cables.

If these results are compared to the corresponding results with branches modelled as OHLs, a notable difference in setpoints of the loads at buses 10014 and 10214 can be observed. Both before and after the contingency, the OHL scenario requires a larger increase in load setpoint to keep voltages below the upper tolerable limit.

A.2.2 Tap changers enabled

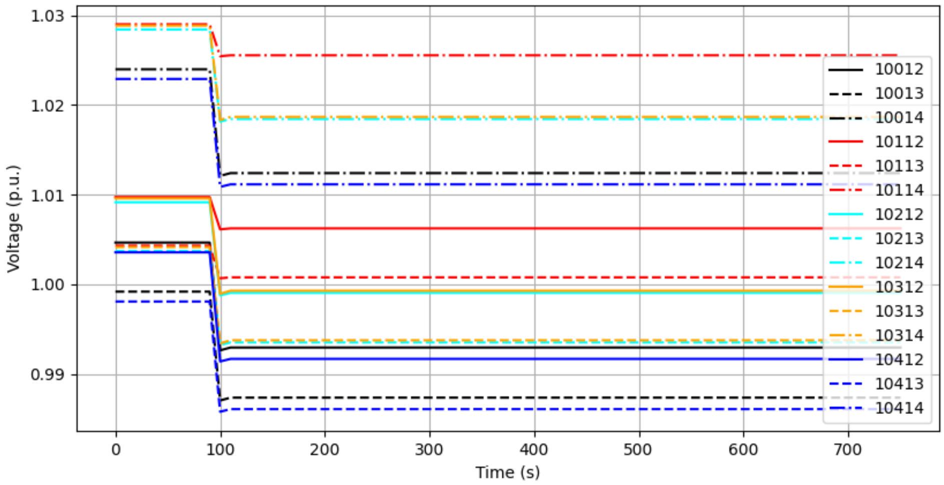

Figure A.16: Distribution network voltages during case 2 contingency with branches modelled as cables and OLTCs enabled.

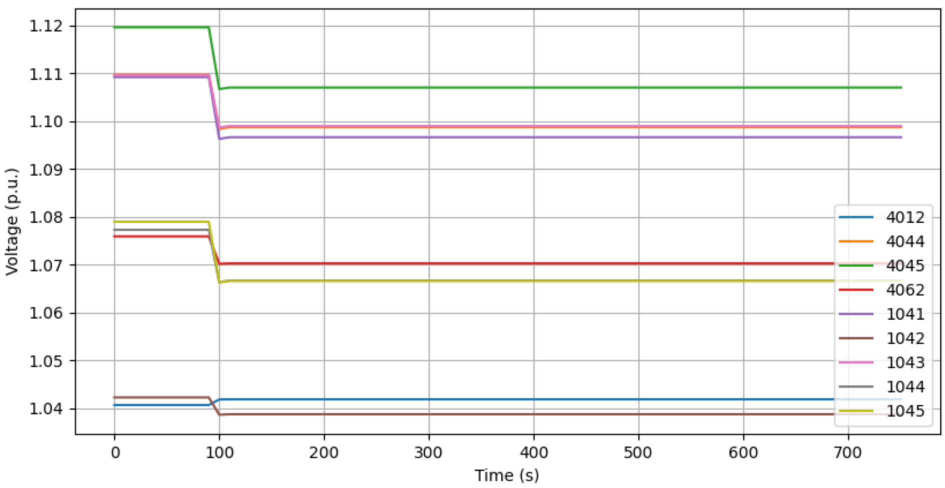

Figure A.17: Transmission network voltages during case 2 contingency with branches modelled as cables and OLTCs enabled.

Very similar results regardless of whether branches are modelled as OHLs or cables.

A.3 Case 3

A.3.1 Tap changers disabled

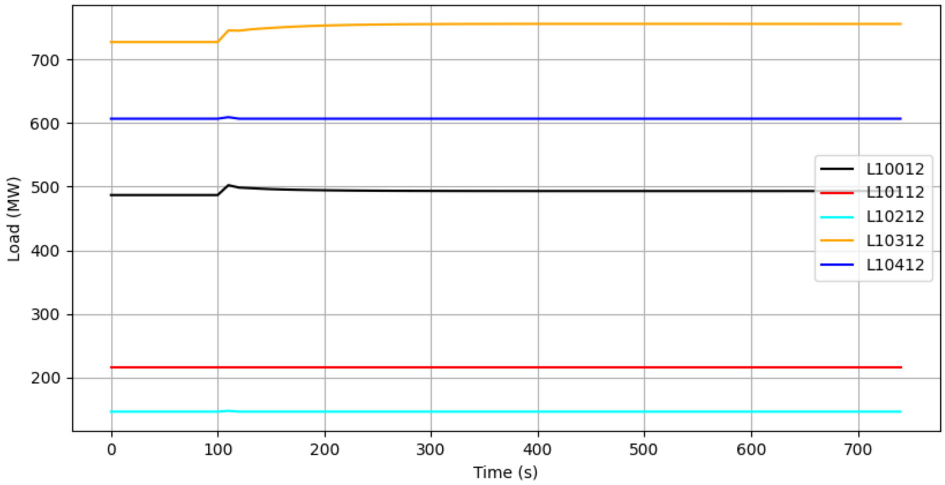

Figure A.18: Response of loads at buses 10X12 to case 3 contingency with branches modelled as cables.

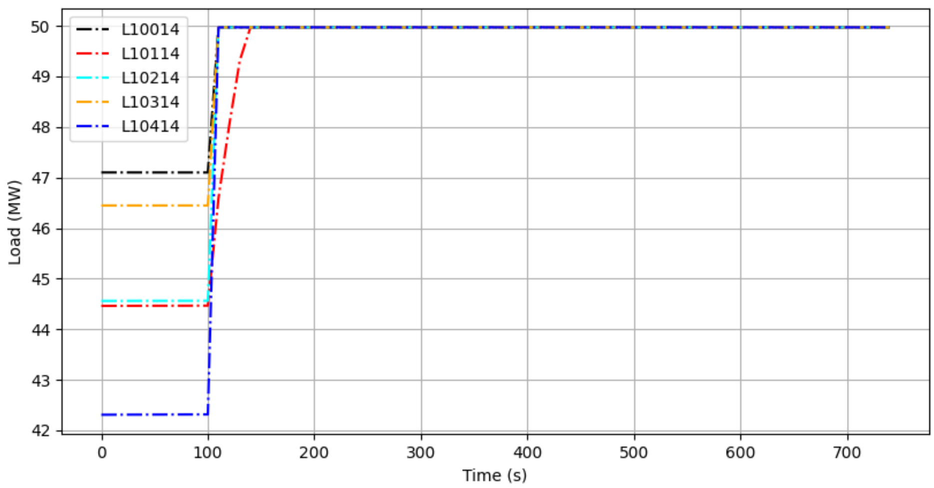

Figure A.19: Response of loads at buses 10X14 to case 3 contingency with branches modelled as cables.

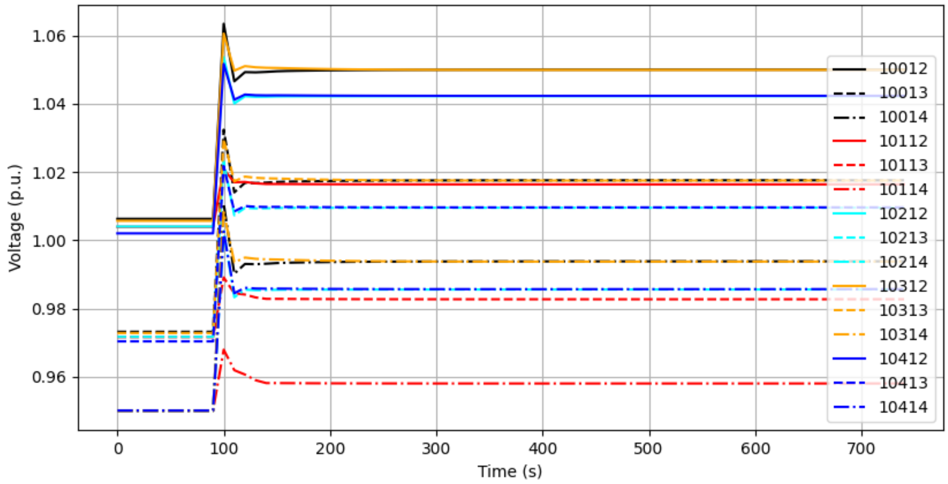

Figure A.20: Distribution network voltage during case 3 contingency with branches modelled as cables.

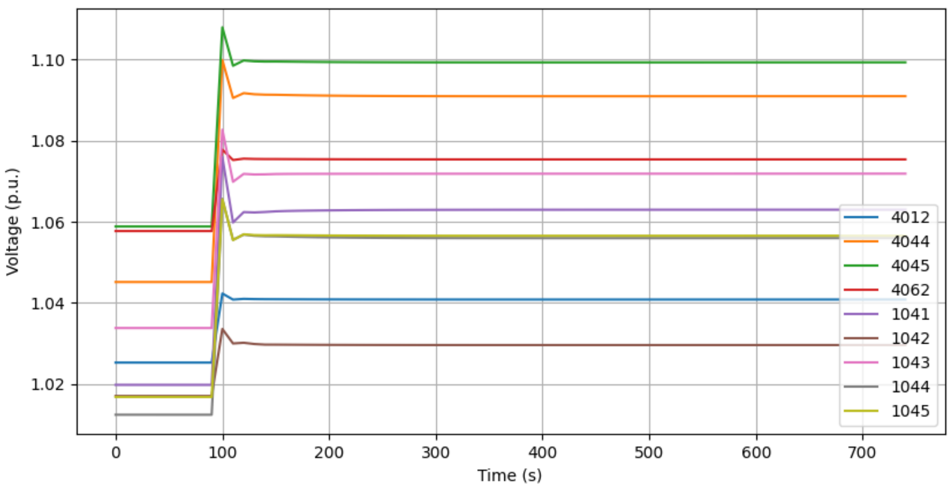

Figure A.21: Transmission network voltages during case 3 contingency with branches modelled as cables.

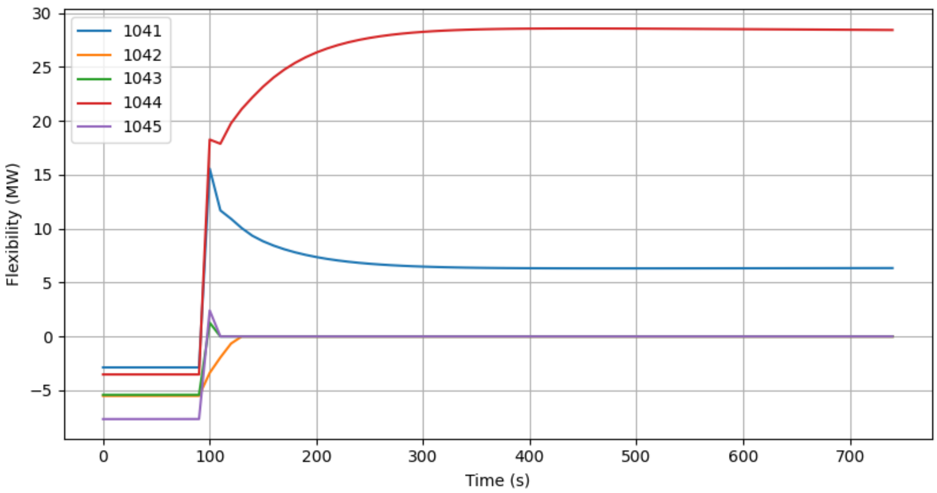

Figure A.22: Summarized flexibilities during case 3 contingency with branches modelled as cables.

In this case, the results are very similar both before and after the contingency. After the contingency, some of the loads at buses 10X12 are adjusted to lower voltage at their buses. It is to be expected that the results are similar in that scenario, as the characteristic of the connection between buses 10X12 and the subtransmission network is the same for both the OHL and cable simulations.

A.3.2 Tap changers enabled

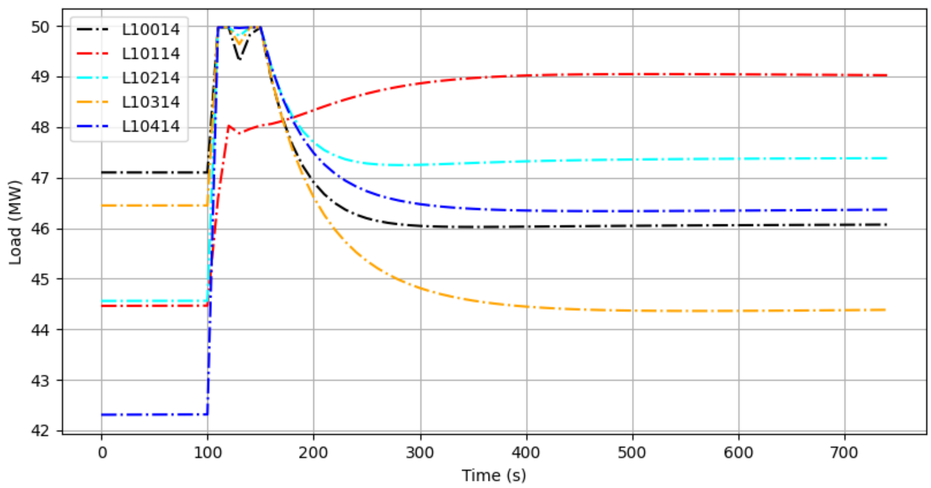

Figure A.23: Response of loads at buses 10X14 to case 3 contingency with branches modelled as cables and OLTCs enabled.

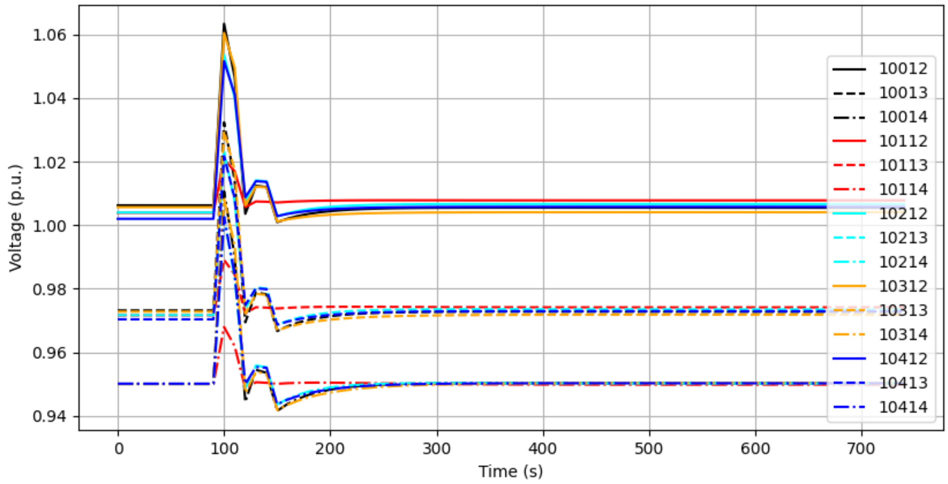

Figure A.24: Distribution network voltages during case 3 contingency with branches modelled as cables and OLTCs enabled.

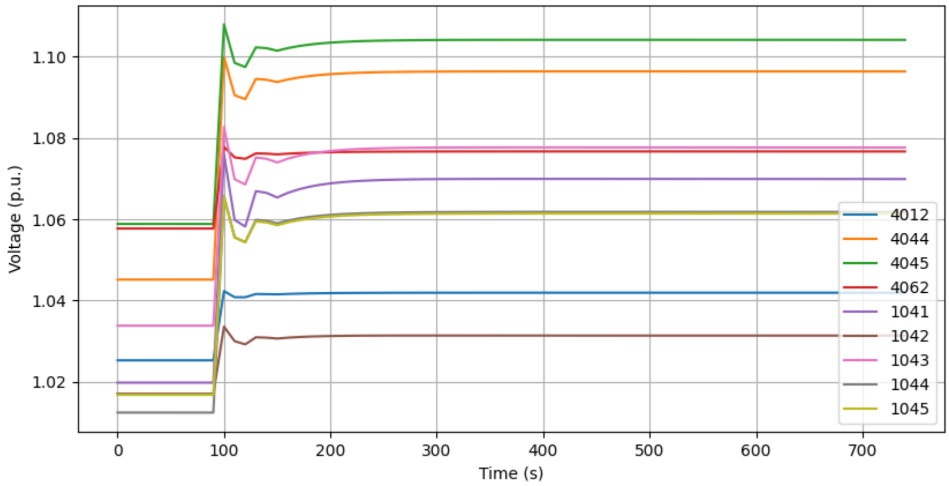

Figure A.25: Transmission network voltages during case 3 contingency with branches modelled as cables and OLTCs enabled.

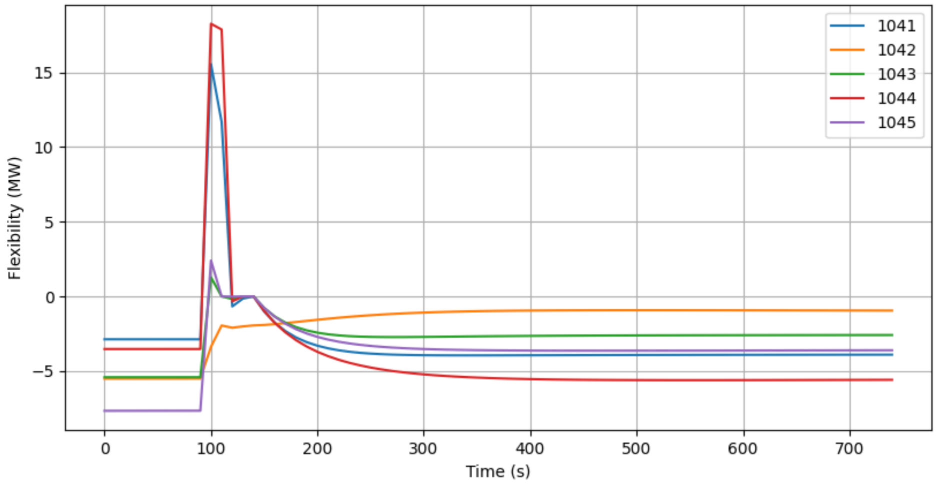

Figure A.26: Summarized flexibilities during case 3 contingency with branches modelled as cables and OLTCs enabled.

Similar results regardless of branch characteristics.

A.4 Case 4

A.4.1 Tap changers disabled

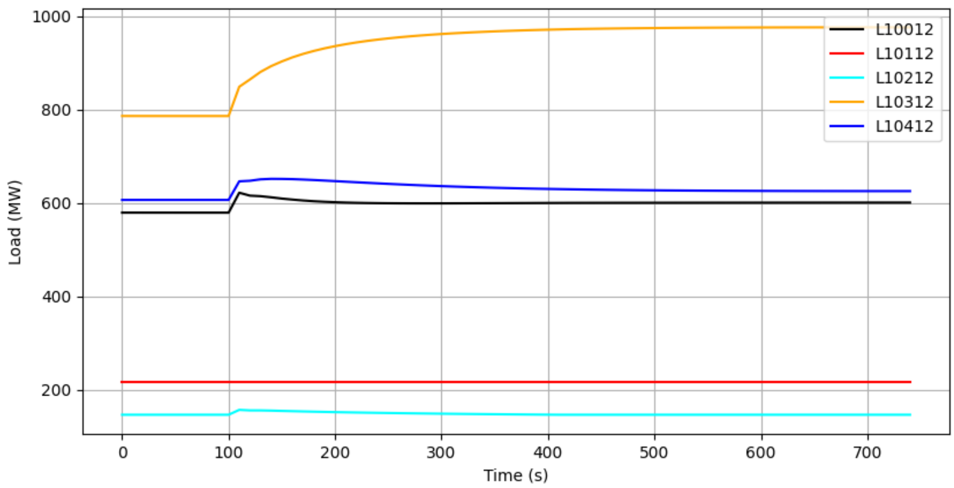

Figure A.27: Response of loads at buses 10X12 to case 4 contingency with branches modelled as cables.

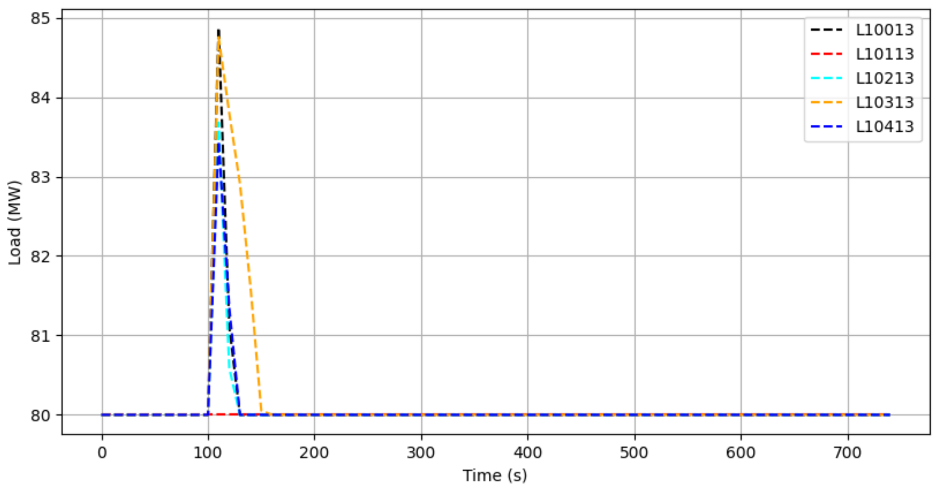

Figure A.28: Response of loads at buses 10X13 to case 4 contingency with branches modelled as cables.

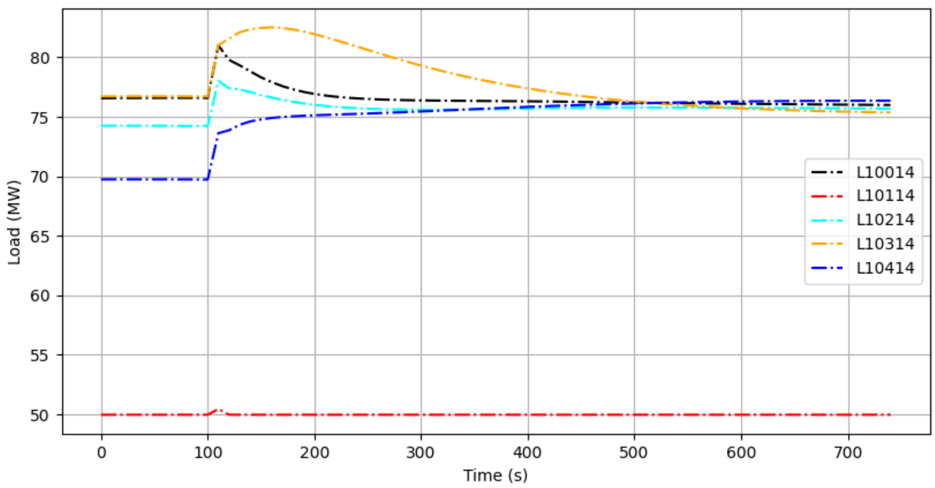

Figure A.29: Response of loads at buses 10X14 to case 4 contingency with branches modelled as cables.

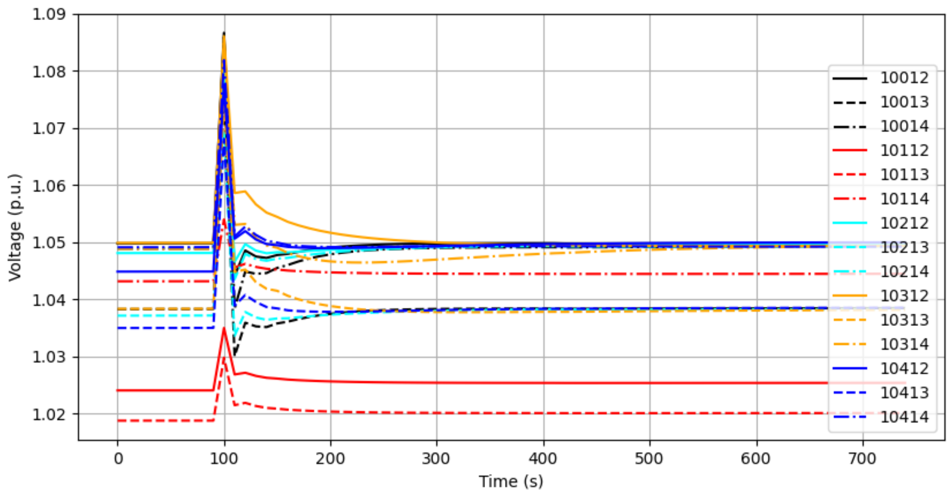

Figure A.30: Distribution network voltages during case 4 contingency with branches modelled as cables.

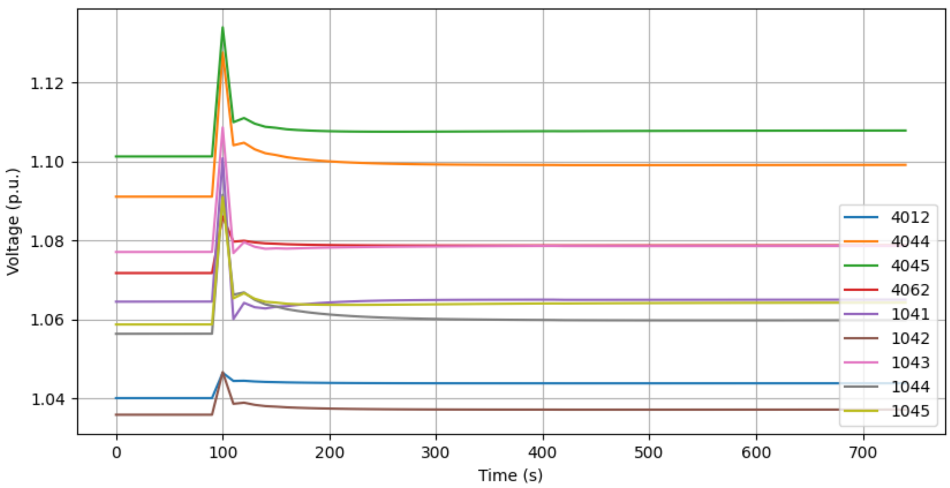

Figure A.31: Transmission network voltages during case 4 contingency with branches modelled as cables.

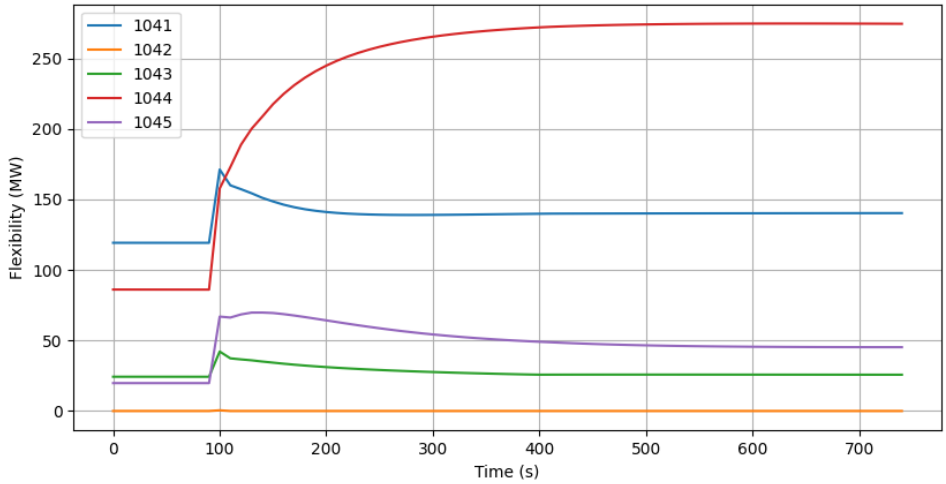

Figure A.32: Summarized flexibilities during case 4 contingency with branches modelled as cables.

Results are similar regardless of branch characteristics.

A.4.2 Tap changers enabled

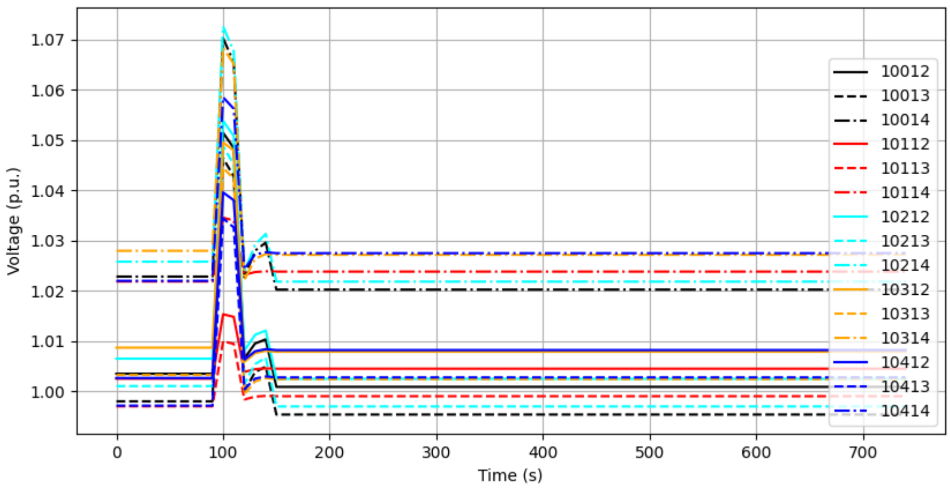

Figure A.33: Distribution network voltages during case 4 contingency with branches modelled as cables and OLTCs enabled.

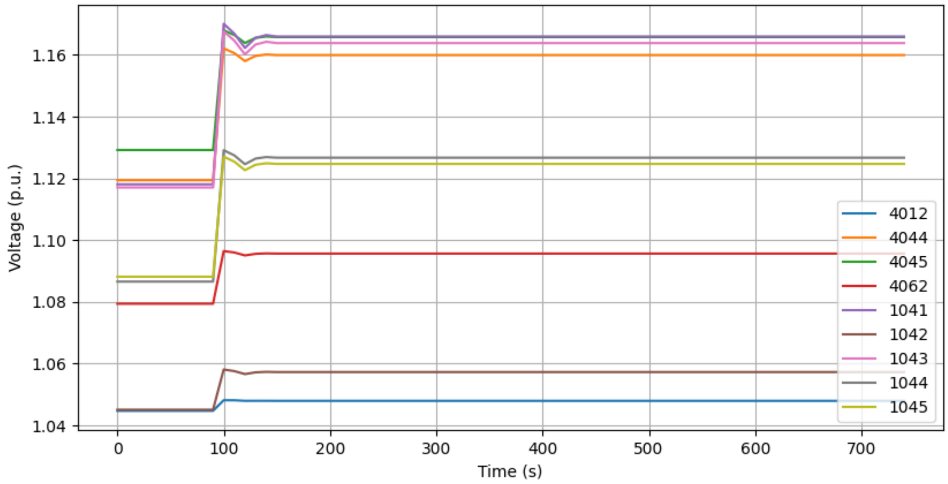

Figure A.34: Transmission network voltages during case 4 contingency with branches modelled as cables and OLTCs enabled.

Results are similar irrespective of branch characteristics.

B
Impact of OLTC on high generation setpoint introduction

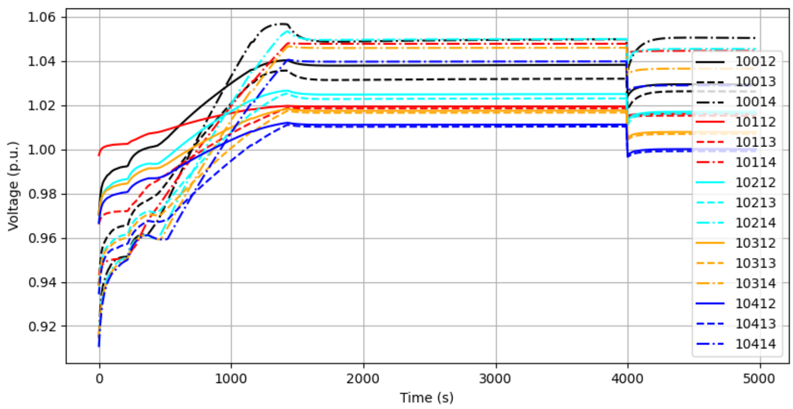

Figure B.1: Distribution network voltages during the setpoint introduction with OLTCs disabled.

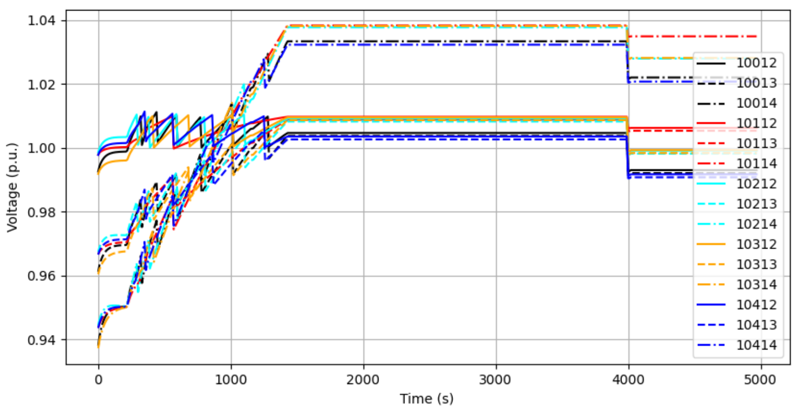

Figure B.2: Distribution network voltages during the setpoint introduction with OLTCs enabled.

As can be observed when comparing figures B.1 and B.2, the OLTCs keep the voltages of the distribution network closer to nominal voltage when introducing the high generation distribution network setpoints. In case the OLTCs are off, the distribution network controller has to limit the voltage at bus 10014. In case the OLTCs are on, no such action is necessary.

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