Coordinated Agent-Based Control for On-line Voltage Instability Prevention

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Coordinated Agent-Based Control for On-line Voltage Instability Prevention

Proefschrift

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Summary

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Service interruptions have a significant impact on society and therefore the main objective of power system planning and operation is to ensure that they do not happen. Because voltage instability is one of the dynamic phenomena that may result in a system-wide blackout, this type of stability problem has been an important research topic for many years. Grid developments, like the increase of Renewable and Distributed Generation (RDG) and the impact of deregulation, in combination with the steadily increasing electricity demand, have their impact on the vulnerability of the power system to voltage stability problems. On the other hand, developments in power system monitoring and control such as the use of accurate Phasor Measurement Units and the development of Smart Grid control concepts, introduce new possibilities for voltage instability prevention.

The objective of this thesis is:

To develop a new control strategy to prevent voltage instability in a power system by making effective use of decentralized control possibilities, accurate phasor measurements and renewable and distributed generation.

The main contribution of this thesis is the conceptual design of the Hierarchical Agent Based Voltage Instability Prevention (HABVIP) controller and its verification through a hardware set-up.

In chapter 3 two voltage instability indicators are chosen that are used in this thesis. The first indicator is used for off-line evaluation of the post-fault steady-state. It is based on the set of bus voltage magnitudes and corresponds to the effect of voltage stability.

The second indicator is the Maximum Loadability Index (MLI). This indicator is a measure for the distance of the current operating point to the point of maximum power transfer and is based on the cause of voltage (in)stability. The indicator is used in this thesis for on-line detection and control. In order to make the MLI more generally applicable an extension for the standard MLI is proposed, which includes an on-line estimation method for the equivalent branch parameters based on PMU-measurements. With this extension the MLI can be determined for each connection between two adjacent buses, and topology changes are immediately followed.

In chapter 4 the impact of Distributed Generation (DG) on voltage stability at transmission network level is investigated. Two studies are done.

In the first study, generic types of DG are connected to load buses. It is assumed that the prime-mover supplies a constant amount of power. It is investigated for which DG penetration levels the system stays voltage stable after a trip of one of the transmission lines between the generation and load area (without DG this initiates a collapse). The main conclusion is that, due their ability to provide active (and in some cases reactive) power in the load area, DG can be beneficial for voltage stability.

In the second study a wind farm is added to the receiving-end area. The wind farm contains turbines of the Doubly-Fed Induction Generator type and is connected via an High-Voltage Direct Current link to the test system. From this study it is concluded that a wind-farm which experience fluctuations in power production due to some turbulence, is almost equally beneficial for voltage stability as DG with a constant prime-mover. For a large wind farm (11 % of the local load), a severe decrease in wind speed (75 % of rated speed) can, however, theoretically cause unacceptable low voltages. Such a dip in wind speed is, however, unrealistic.
Generally it is concluded that three factors are of most importance for the impact a DG can have on voltage stability: active power support, reactive power consumption, and voltage support. An intelligent controller can make use of the positive factors (active power and voltage support) to prevent a system from reaching a voltage unstable situation.

To prevent voltage instability making use of DG, a controller is designed. The control strategy and architecture are proposed in chapter 5. The emergency control method uses the MLI to detect voltage instability and quantify the amount of load relief required to restore stability with a certain margin to instability. The load relief is obtained by: increase of local generation, indirect load shedding with LTC action, smart load control and the increase of reactive power compensation from SVCs.

The control is implemented in a novel agent-based system called the HABVIP controller. In this system each substation is controlled by a substation agent and every actuator is controlled by an actor agent. Among the agents there is a hierarchical structure: actor agents are supervised by substation agents and between the substation agents the classical power system hierarchy, based on voltage levels, is being followed. When voltage instability is foreseen, all agents detecting this cooperate. This cooperation is supervised by the substation agent highest in hierarchy sensing the problem: the so-called supervisory agent.

The actor agents controlling the actuators should convert a required amount of load relief to a control action from the actuator. The control of the SVC and the load are briefly described. The control of the LTC and the local generation is described in more detail in two separate chapters.

In chapter 6 the control strategy for the Load Tap Changer is introduced and implemented in an actor agent. The strategy is based on the fact that the LTC’s secondary voltage is controllable. Normally the LTC tries to keep the voltage near nominal value. When the voltage is, however, reduced, voltage sensitive loads will also be lowered. In this way it is possible to shed load indirectly. Based on an assumed accurate load model a new voltage set-point for the secondary voltage is calculated to obtain a certain amount of indirect load shedding.

In chapter 7 the control strategy is proposed for Combined Heat and Power (CHP)-based local and decentralized generators. The decentralized and local nature of these generators make them especially suitable to be used as actuators in the proposed HABVIP control. For the CHP-based DG the active power is controlled. The increase in output power of a CHP results in an increase in temperature of the space that is heated. In the HABVIP controller it is assumed that customers can set a maximum rise in average temperature.

Two types of CHP units are discussed: the thermostatically controlled unit and the continuously controlled unit. In case of the thermostatically controlled unit the average output power is controlled by adjusting the duty-cycle. Either the unit supplies nominal power or nothing. The HABVIP controller, however, should rely on continuous power production. It is shown that with a proper Virtual Power Plant coordination of the micro-CHPs, constant power supply can be assumed on an aggregated level.

In case of the continuously controlled unit the electrical output power is increased by adjusting the mechanical power of the prime-mover. The control per electrical generator type differs. Two types are distinguished in this thesis: the synchronous generator and the induction generator. The control of continuously controlled CHP units with both types of generators are discussed.

In chapter 5 a verification of the complete HABVIP controller is given based on simulations in Matlab/Simulink. It can be concluded that the HABVIP controller works properly: voltage instability can be prevented with the new system and coordination between agents works as expected. The local generator actuator class is the main contributor to the good performance. Communication delays and uncontrolled LTCs have no major impact on the system performance. A sensitivity analysis showed that the tuning of three of the six parameters is of major importance for the HABVIP controller.

In chapter 6 the HABVIP controller is implemented in a real-time demonstration set-up consisting of a Real-Time Digital Simulator that is used for emulating the test power system and the real-time industrial computers of a Triphase converter system that are used to implement the agent-based control. The tests with the demonstrator show that a hardware implementation of the HABVIP controller is feasible and that with the system voltage instability can be prevented. During building the demonstrator set-up no important bottlenecks for industrial implementation were discovered. The local character of the agent-based control and the ability to cooperate among agents make that local voltage problems are solved locally before they spread.
**Samenvatting**

**Gecoördineerde op Agenten Gebaseerde Regeling om Spanningsinstabiliteit On-line te Voorkomen**

Onderbrekingen in de elektriciteitsvoorziening hebben grote invloed op de samenleving. Het hoofddoel van de planning en bedrijfsvoering van het elektriciteitsvoorzieningssysteem is daarom ook om onderbrekingen te voorkomen. Aangezien spanningsinstabiliteit één van de dynamische fenomenen is die kan leiden tot een black-out van het hele systeem, is dit type stabiliteitsproblemen al vele jaren een belangrijk onderwerp van onderzoek. Ontwikkelingen in het elektriciteitsnet, zoals de toename in duurzame en gedistribueerde bronnen en de deregulering, in combinatie met het gestaag groeiende elektriciteitsverbruik, hebben invloed op de gevoeligheid van het elektriciteitssysteem voor spanningsstabiliteitsproblemen. Aan de andere kant zorgen ontwikkelingen in meet- en regelsystemen voor het elektriciteitsnet, zoals het gebruik van nauwkeurige Phasor Measurement Units (PMUs) en de ontwikkeling van Smart Grid regelconcepten, voor nieuwe mogelijkheden om spanningsinstabiliteit te voorkomen.

Het doel van dit proefschrift is:

Het ontwikkelen van een nieuwe regelstrategie om spanningsinstabiliteit in het elektriciteitsnet te voorkomen door effectief gebruik te maken van de mogelijkheden die decentrale regeling, nauwkeurige fasormetingen en duurzame en gedistribueerde opwekking bieden.

De belangrijkste bijdrage van dit proefschrift is het conceptuele ontwerp van een hiërarchisch, op agenten gebaseerd, regelsysteem om spanningsinstabiliteit te voorkomen (Hierarchical Agent-Based Voltage Instability Prevention controller, HABVIP) en de verificatie daarvan door middel van een hardware-opstelling. In hoofdstuk 5 worden twee spanningsinstabiliteitsindicatoren gekozen die door het hele proefschrift heen gebruikt zullen worden. De eerste indicator wordt gebruikt voor offline evaluatie van de steady state na een gebeurtenis die mogelijk een instabiliteit initieert. De indicator bevat de verzameling van spanningsgroottes op alle bussen in het systeem en is gebaseerd op het effect van spanningsstabiliteit.

De tweede indicator die gebruikt wordt is de zogenaamde index tot de maximale belastbaarheid (Maximum Loadability Index, MLI). Deze indicator is een maat voor de afstand van het huidige werkspunt tot het werkspunt waar de maximale belastbaarheid van een verbinding wordt bereikt. Deze indicator is gebaseerd op de oorzaak van spanningsinstabiliteit en wordt in dit proefschrift gebruikt voor online detectie en regelen. Om de MLI meer generiek toepasbaar te maken, wordt als uitbreiding in dit proefschrift een online methode voorgesteld om de equivalentelijnparameters te schatten. Met deze uitbreiding kan de MLI bepaald worden voor elke willekeurige verbinding tussen twee bussen. Veranderingen in de topologie van het netwerk worden automatisch meegenomen.

In hoofdstuk 4 wordt de invloed van gedistribueerde opwekking op de spanningsstabiliteit op transmissiesysteemniveau onderzocht. Er zijn twee onderzoeken uitgevoerd. In het eerste onderzoek worden generieke typen gedistribueerde opwekking aangesloten op bussen met de belasting. Er wordt aangenomen dat de primaire energiebron een constant vermogen levert. Onderzocht wordt bij welke percentages gedistribueerde opwekking het systeem spanningsstabiel blijft nadat één van de transmissielijnen tussen een gebied met voornamelijk opwekking en een gebied met voornamelijk belasting uit bedrijf wordt genomen (zonder decentrale opwekking leidt deze gebeurtenis tot een ineenstorting van de spanningen). De belangrijkste conclusie uit dit onderzoek is dat de gedistribueerde opwekking een positief
effect heeft op de spanningsstabiliteit, omdat deze opwekking actief (en in sommige gevallen ook reactief) vermogen levert in het gebied waar dit nodig is.

In de tweede studie wordt er een wind farm toegevoegd aan de ontvangende kant van het elektriciteitsysteem. De wind farm bevat generatoren van het type Doubly-Fed Induction Generator en wordt via een hoge gelijkspanningsverbinding aan het testsysteem gekoppeld. Uit deze studie wordt er geconcludeerd dat een wind farm die een fluctuerende hoeveelheid vermogen levert (door turbulentie in de windsnelheid), een bijna even positief effect heeft op de spanningsstabiliteit als gedistribueerde opwekking met een primaire energiebron die een constant vermogen levert. Echter, voor een grote wind farm (11% van de lokale belasting) kan een significante vermindering in windsnelheid (75% van de nominale snelheid) leiden tot onacceptabel lage spanningen. Dit is echter theoretisch, want zulke grote verminderingen in windsnelheid komen in werkelijkheid niet voor.

In algemene zin kan er geconcludeerd worden dat voornamelijk drie factoren van belang zijn voor de invloed van gedistribueerde opwekking op spanningsstabiliteit: ondersteuning van actief vermogen, reactief vermogen consumptie en ondersteuning van de spanning. Een intelligente regeling zal gebruik moeten maken van de positieve factoren (ondersteuning van actief vermogen en van de spanning) om te voorkomen dat het systeem een instabiele situatie bereikt.

Om spanningsinstabiliteit te voorkomen door effectief gebruik te maken van gedistribueerde opwekking, is er een regelsysteem ontworpen. De regelstrategie en de systeemarchitectuur worden in hoofdstuk 5 geïntroduceerd. De regeling gebruikt de MLI voor spanningsinstabiliteitsdetectie en om de hoeveelheid belastingvermindering te bepalen die nodig is om ervoor te zorgen dat het systeem een zekere marge heeft tot deze instabiliteit. De belastingvermindering wordt verkregen door: een toename in lokale opwekking, indirecte belastingverlaging met behulp van een transformatore met variabele tap instelling (Load Tap Changer, LTC), intelligente regeling van de belasting en compensatie van het reactief vermogen met een zogenaamde Static Var Compensator (SVC).

De regeling is geïmplementeerd in een nieuw, op agenten gebaseerd, systeem die de HABVIP regeling wordt genoemd. In dit systeem wordt elk onderstation geregeld door een zogenaamde substationagent en elke actuator door een actoragent. Tussen de agenten bestaat een hiërarchische structuur: actoren hebben een substatiagent boven zich en tussen de substatiagenten zelf wordt de op spanningsniveaus gebaseerde hiërarchie van het elektriciteitsnet gevolgd. Op het moment dat gedetecteerd wordt dat het systeem dichtbij spanningsinstabiliteit is, werken alle agenten die dit detecteren samen. Deze samenwerking wordt aangestuurd door de substationagent die het hoogste in hiërarchie is en het probleem detecteert: de zogenaamde supervisory agent.

De actoragenten zetten de gevraagde belastingverlaging om in een actie van de actuator. De regeling voor de SVC en de intelligente belastingregeling worden kort beschreven. De regeling van de LTC en de lokale opwekking worden meer in detail beschreven in twee aparte hoofdstukken.

De regelstrategie voor de LTC wordt in hoofdstuk 6 geïntroduceerd en geïmplementeerd in een actuator. De strategie is erop gebaseerd dat de secundaire spanning van een LTC geregeld wordt. Onder normale omstandigheden probeert een LTC deze spanning zo dicht mogelijk bij de nominale spanning te houden. Als de referentiespanning van de LTC echter verlaagd wordt, worden spanningsgevoelige belastingen ook verlaagd. Op deze manier is het mogelijk om indirect de belasting te verlagen. In de regelstrategie voor de LTC wordt, gebaseerd op een voorondersteld belastingmodel, de benodigde belastingverlaging omgezet in een nieuwe referentie voor de secundaire spanning van de LTC.

In hoofdstuk 7 wordt de regelstrategie voor lokale opwekkers met een warmtekrachtkoppeling (Combined Heat and Power, CHP) voorgesteld. Doordat deze opwekkers decentraal en lokaal zijn, zijn ze uitermate geschikt als actuator in de voorgestelde HABVIP regeling. Bij op CHP-gecombineerde opwekking wordt het actieve vermogen geregeld. Een toename in het uitgangsvermogen van zo’n opwekker leidt tot een toename in temperatuur van de ruimte die de CHP verwarmt. In de HABVIP regeling wordt er aangenomen dat de eigenaren van zo’n unit een maximale temperatuurtoename instellen.

De regelingen van twee typen CHP-opwekkers worden besproken: de thermodynamisch aangedreven eenheid en de continue aangedreven eenheid. In het geval van de thermodynamisch aangedreven eenheid wordt het gemiddelde uitgangsvermogen geregeld door de zogenaamde duty-ratio aan te passen. Instantiën levert de eenheid echter zijn nominale vermogen of helemaal niets. De HABVIP regeling moet kunnen vertrouwen op een continue levering van vermogen. Er is aangetoond dat, met een adequate regeling van verschillende CHP eenheden als één virtuele opwekker, op geaggregeerd niveau het uitgangsvermogen als constant kan
worden verondersteld.
In het geval van een continue aangedreven eenheid wordt het elektrische uitgangsvermogen geregeld door het mechanische vermogen van de primaire energiebron aan te passen. De regeling verschilt per type elektrische generator. In dit proefschrift worden twee typen onderscheiden: de synchrone generator en de inductie generator. De regeling wordt voor beide typen generatoren beschreven.
In hoofdstuk 8 wordt het complete HABVIP systeem geverifieerd door middel van simulaties in Mat-lab/Simulink. Op basis van deze simulaties kan geconcludeerd worden dat de HABVIP regeling zich gedraagt zoals verwacht: spanningsinstabiliteit kan worden voorkomen en de coördinatie tussen de agenten werkt zoals verwacht. De goede prestaties van het systeem worden met name bereikt door de lokale opwekking. Vertragingen in de communicatie en LTC’s die niet mee worden genomen in de HABVIP regeling hebben geen belangrijke invloed op de prestaties. Een gevoeligheidsanalyse laat zien dat drie van de zes parameters die moeten worden ingesteld in de HABVIP regeling speciale aandacht verdienen tijdens het instellen.
In hoofdstuk 9 wordt de HABVIP regeling geïmplementeerd in een real-time demonstratie-opstelling die bestaat uit een Real-Time Digital Simulator, die wordt gebruikt om een testnetwerk te emuleren, en de real-time industriële computers van TriPhase vermogensomzetters, die gebruikt worden om de regeling te implementeren. De tests laten zien dat een hardware implementatie van de HABVIP regeling haalbaar is en dat met zo’n systeem spanningsinstabiliteit voorkomen kan worden. Tijdens het bouwen van de opstelling zijn er geen beperkingen voor industriële implementatie boven tafel gekomen. Het lokale karakter van de regeling en de mogelijkheid voor agenten om samen te werken, maken dat een lokaal spanningsprobleem lokaal opgelost wordt, vooral dat deze zich verspreidt door het systeem.
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Chapter 1

Introduction

1.1 Introduction

The electric power system is the interconnected system of generation, transmission, distribution and loads; and has as main goal to supply electrical power to the loads [171]. Although not many people realize, this system plays an important role in their life. This is something that is not recognized until the electricity supply is interrupted due to some failure resulting in a blackout. People cannot watch television, use their computers, their fridges start thawing, the pump of the central heating system stops, etcetera. But a blackout can have even more far-reaching consequences as can be learned from the 1977 incident in New-York. This power failure resulted in looting, arson and riots [135].

Conditions of the power system that might result in a blackout include: overloads; voltages and frequency that are beyond their limits; voltage-, frequency- and rotor angle instability; disconnection of substations or generation stations; and islanding [94]. These conditions can be initiated by different kinds of disturbances ranging from human errors and weather conditions to shortages in fuel. Due to the large consequences a power failure has on society, power system operation is focused on preventing the aforementioned conditions and, when such a condition unexpectedly occurs, emergency control should restore the system to a 'healthy' state.

Voltage instability is one of the power system’s dynamic phenomena which might result in a blackout. This type of stability problems appeared in the 1970s in large interconnected power systems for the first time [185]. The mechanism of this type of instability is the load dynamics that try to restore the power consumption beyond the capabilities of the combined transmission and generation system [200]. Since the first voltage instabilities occurred a lot of research has been done to analyze the problem and to develop countermeasures against it [4, 35, 36, 50, 99, 155, 200].

The voltage instability problem is thus a classical and well-understood power system problem. Recent developments, however, have put new interest on these problems. Grid developments, like the increase of Renewable and Distributed Generation (RDG) and the impact of deregulation, in combination with the steadily increasing electricity demand, impact the flow of electricity in the power system [171]. Furthermore, developments in the Information and Communication Technology (ICT) introduce new opportunities for control. These developments will be reviewed in the next sections.

1.2 Recent developments in power systems

1.2.1 Renewable and Distributed Generation

Renewable Generation (RG) technologies generate electrical power based on renewable sources. Examples are wind power and solar power. Distributed Generation (DG) technologies are (small) generation technologies that are distributed throughout the power system. Examples are solar power generated by small Photo-Voltaic (PV)-panels and electrical power generated by micro-Combined-Heat-and-Power (micro-CHP) units. These generation technologies have their particular characteristics that should be taken into
account when implementing a large share of them. The prime-mover of RG is, in example, often intermittent. DG is often supplied in the load areas. Note that a certain type of generator can be both renewable and distributed. The term Renewable and Distributed Generation (RDG) is used for all generation that is either DG or RG or both.

Renewable and Distributed Generation technologies are mature today. In the Dutch grid already about 2 GW onshore wind capacity is installed [234]. The goal of the Dutch government was to increase this capacity to 2.9 till 4 GW in 2020 [59]. Furthermore it is assumed that 6 GW installed offshore wind power by 2020 is reasonable [51].

In addition to wind power, if in the worst case the heating equipment of all Dutch households (approximately 7 million in 2008 [180]) is replaced by 1 kW micro Combined Heat and Power (micro-CHP) units (for instance Whispergen units [232]), this would result in a total micro-CHP capacity of about 7 GW. This number will for several reasons be smaller, such as the introduction of the heat-pump, the relative low heat demand of new build houses and limitations in space for existing buildings. But even when 20% of the assumed 7 GW of micro-CHP would eventually be realized, the penetration of micro-CHP is considerable. Solar power generated by Photo-Voltaic (PV)-panels plays a minor role in the Dutch grid. By the end of 2011 only 130 MW was installed [180]. Compared to the worlds largest PV market, Germany, the Dutch PV generation can be neglected. In Germany a minimum increase in PV generation capacity of 6 GW was predicted for 2012 [179]. In the Netherlands there is, nevertheless, a steady growth in PV power and it is possible that in future this type of generation will also play role in the Dutch grid.

When the assumptions regarding the grow in Renewable and Distributed Generation capacity become true, it means a total capacity of this type of generation of 16 to 17 GW in 2020 [180]. If the total conventional (centralized) generation capacity in the Netherlands stays about the same as in year 2006 (20 GW [189]) it follows that a major part of the production capacity will be based on RDG. The same trend of including RDG in the grid can be seen all over the world.

Having such a large share of Renewable and Distributed Generation will have its impact on power system operation and on its voltage stability. The present power system is vertically operated. Power flows from large production units at generation sites, via the transmission and distribution system to the consumers. The power flow is from high voltage levels to low voltage levels. With RDG this will change: the micro-CHP unit of one household can supply power to a neighbor and on a larger scale the excess in power production from one neighborhood can be consumed in another neighborhood. Power system protection and controls are not designed for these reversed power flows and problems might be introduced. In particular problems with coordinating voltage control might occur [122].

Another possible problem can occur with large wind-farms. These are typically located at a distant location and voltage instability problems typically occur when a large amount of power needs to be transferred from a generation area to a load area [185, 200]. In addition the wind speed, and thus the power production of a wind-farm, fluctuates. A sudden decrease in wind power would mean that this deficit in production should be produced somewhere else. When the part of the network where this balancing power needs to come from is already heavily loaded, this extra amount can initiate voltage instability. The problem of fluctuating power production could also occur in power systems with a large share of PV.

The two above-mentioned situations are problems with having RDG for the voltage stability of the system. There are, however, also advantages: DG is often located in the load area. This is, for instance, the case for micro-CHP units and PV generation. The amount of power that needs to be transferred from the generation to the load area reduces. This can, potentially, be beneficial for voltage stability.

1.2.2 Phasor Measurement Units

The state of the power system can be defined as a set of voltage magnitudes and phase angles of all buses in the system. The voltage magnitude and voltage phase angle of a bus form together the voltage phasor. Determination of the voltage magnitude is easy and widely used for conventional power system control. Measurements of voltage magnitudes are measurements of the potential of one point with respect to another.

\[\text{Note that the RDG capacity and year in which it will be reached are an approximation. It can, nevertheless, be concluded that around 2020 the calculated capacity is reasonable.}\]
point. So, in order to compare measurements of bus voltage magnitudes a common reference is required. This common reference is the ground.

Determination of the phase angle of a phasor also requires a reference. In this case the reference is the time. In order to compare different phase angles the same time reference should be used throughout the system. Note that for a 50 Hz system a 10 ms error in this reference corresponds to a 180° error in the phase angle. In the past it was not possible to distribute a time reference to all measurement units in a large system with an accuracy that is enough to prevent large errors. To circumvent this problem, phase angles were indirectly determined with the help of State Estimation (SE). With SE the state is calculated based on voltage magnitude, active power and reactive power measurements \[171\]. When applying SE the non-linear power flow equations are solved and this requires an iterative method.

As a solution for the aforementioned problem, synchronized phasor measurements were introduced in the 1980s \[152\]. Synchronism is obtained via a Global Positioning System (GPS) signal. The advantage of using the GPS signal is that it can be received almost everywhere and does not require a wired connection. The synchronized phasor measurements are performed with Phasor Measurement Units (PMUs). These devices provide a synchronized measurement of the voltage phasor at a bus and the currents in branches adjacent to that bus.

The IEEE has standardized phasor measurements in standard 1344-1995 \[85\]. This standard provides that different manufacturers’ PMUs can easily be used in the same system. The method to calculate the phasors itself is, however, not standardized and a measurement with PMUs of different manufacturers can give different results. Synchronization should, nevertheless, be obtained within 1 µs accuracy. This gives an accuracy in a 50 Hz system of 0.018° and in a 60 Hz system of 0.022° \[85,152\].

When PMUs are implemented at all buses in the system they can potentially replace the state estimator. Some form of SE can, nevertheless, still be valuable for detection of bad data. The advantage of having SE with only PMUs is that it its formulation can be linear and only local information is required \[133,243\].

It is, however, point of discussion whether it is feasible to have PMUs on all busses. For that reason in literature different papers can be found that combine PMUs with the classical SE \[71,153,242\]. Because of their advantages, Phasor Measurement Units are used for recently developed Wide-Area Monitoring Systems and Wide-Area Control Systems \[10,187\]. These systems give, with the help of PMUs, new possibilities for power system control and real-time voltage stability evaluation.

### 1.2.3 Smart grids

A final development is the introduction of the Smart Grid. As is the case with DG, also for the Smart Grid multiple definitions exist. In this thesis the definition as given by the European Smart Grids Technology Platform is adopted:

“A smart grid employs innovative products and services together with intelligent monitoring, control, communication, and self-healing technologies in order to:

- Better facilitate the connection and operation of generators of all sizes and technologies.
- Allow consumers to play a part in optimizing the operation of the system.
- Provide consumers with more information and better options choosing their energy supplier.
- Significantly reduce the environmental impact of the whole electricity supply system.
- Maintain and improve the existing high levels of system reliability, quality, and security of supply.
- Maintain and improve the existing services efficiently.
- Foster the development of an integrated European market.” \[59\]

The aim of the smart grid is to enable RDG integration in the electricity production and provide the ICT infrastructure to make more efficient use of the electricity infrastructure, e.g. by charging electric vehicles in a smart way. So with the smart grid the two-way power flow is possible that is required for having a large share of Renewable and Distributed Generation capacity. This requires a change in control and protection strategies, and re-dimensioning of cables, lines and transformers.
As mentioned before, an important aspect of DG is the fluctuation in the power production. One way of balancing these power fluctuations is using smart load control. Examples of this type of load control can be found in [110][228]. With smart load control non-critical loads can be temporarily paused. In this way shortages in production can be balanced.

This smart grid should also be plug-and-play. So future devices should be easily integrated in an existing smart grid. Note that this is, of course, already the case with the conventional power system due to various standards (e.g. for voltage levels). The plug-and-play requirement focuses thus mainly on the control and protection and the data communication that underlies the smart grid.

The main enabler for the smart grid is the Information and Communication Technology. The number of transistors on a computer processor follows Moores Law, which state that the number of transistors in an integrated circuit doubles every two years. The speed of the processor changes accordingly and nowadays computers can be used to supervise protection systems in a substation [131]. Note that originally this protection was implemented in electromechanical relays.

In addition to the possibilities for data processing there are the possibilities for fast data communication. In the civilized world broadband Internet is widely available. There are even projects where optic fiber connections are provided. But also wireless technologies are available: mobile (smart) phones are common property. The smart grid could use these existing infrastructures but also specific technologies for the power system are under development such as the IEC 61850 standard [81] and the IEEE Guide for Smart Grid Interoperability [83].

State-of-the-art ICT enables new possibilities for power system control. But, the potential these technologies provide are not fully used yet. This, basically, is the focus of smart grid research.

Until now, only the advantages of having a smart grid are discussed. One important remark should, however, be made about cyber-security. The ICT infrastructure that is used by the smart grid is vulnerable to malicious cyber attacks. Well known examples of this vulnerability can be found in other domains: banks have continuously to adapt the security of their on-line banking systems and the Stuxnet worm has penetrated the Supervisory Control And Data Acquisition (SCADA) system of industrial processes. The security of the smart grid is consequently an important subject for research.

1.3 Research objective and approach

1.3.1 Objective

In the previous sections the importance of voltage stability is discussed. The absence of voltage stability may result in a blackout which in its turn may have a significant impact on society. Furthermore three new power system developments were outlined: the increased penetration of Renewable and Distributed Generation in the grid, the use of accurate Phasor Measurement Units and the development of Smart Grid control based on state-of-the-art ICT. These developments have renewed the interest in voltage stability.

In this thesis the three power system developments are coupled with voltage stability. The objective of this thesis is

To develop a new control strategy to prevent voltage instability in a power system by making effective use of decentralized control possibilities, accurate phasor measurements and renewable and distributed generation.

The sub-objectives are:
1.3 Research objective and approach

- To develop a method for on-line detection of potential voltage instability problems based on local measurements.
- To investigate the impact of renewable and distributed generation on voltage stability and determine how these units can be used to prevent voltage instability.
- To design and test a decentralized controller that is capable of preventing voltage instability problems.
- To build a real-time demonstrator to prove the defined control strategy.

1.3.2 Approach

The approach of the thesis closely follows the objectives and the thesis is mainly based simulations in Matlab/Simulink with the SimPowerSystem toolbox [80]. A detailed list of the solver settings that are used can be found in appendix [J].

First of all, based on the definition of voltage (in)stability two detection methods are chosen and tested that will be used throughout the thesis. The reason for using two detection methods is that two definitions for voltage instability are widely used in literature and the stability of the system is tested based on both definitions. One definition is related to the effect of voltage instability, i.e. unacceptable voltages [99], and one definition is related to the cause of voltage instability, load restoration beyond the capability of the combined transmission and generation system [200]. The second detection method provides a parameter for the distance to instability.

Secondly, the influence of having a large share of renewable and distributed generation for the voltage stability at transmission level is investigated. For this investigation two approaches are used. In the first approach for different types of generation units it is investigated for which penetration levels a typical voltage instability problem is prevented. In the second approach it is investigated whether the variability in wind power production can introduce voltage instability. In both studies the previously defined voltage instability detection methods are used to evaluate the results.

Thirdly, a controller is developed that is able to prevent voltage instability. A global control strategy and an agent-based architecture are designed. The distance to voltage instability determined by the cause-based detection method is used as control parameter. Actuators are used to implement the control strategy. For the most important actuators interfaces are developed. The control of these actuators is coordinated. Extensive simulations are performed in order to test the controller under different conditions and to investigate which control parameters are important for the system performance.

In this thesis the terms preventive and emergency control are used interchangeable. The developed controller should prevent the system from becoming voltage unstable. From that perspective it is preventive control. When the controller starts acting the system is, however, most probably already in an emergency state. From that perspective it is emergency control.

Finally, the control system is implemented in a real-time hardware-in-the-loop demonstration set-up to investigate the feasibility of a real hardware implementation. The demonstration set-up consists of a Real-Time Digital Simulator (RTDS) [167] for emulating the test system and real-time industrial computers of the Triphase converter systems [194] for the agent-based control.

1.3.3 Limitations

The thesis covers a wide variety on topics related to voltage stability in grids with a large share of renewable and distributed generation: from the impact and control of individual types of renewable and distributed generation to the detection of voltage instability and the development of a coordinated control system and its evaluation with a real-time demonstration set-up. This has put some limitations on the depth in which an individual topic can be investigated.

Dependent on the dynamics that are involved, short-term and long-term voltage instability problems can be distinguished [200]. Short-term voltage instability is caused by load dynamics that try to restore power
in the time frame of a second. An example is the induction motor. Long-term voltage instability is caused by load dynamics that try to restore power in the minutes to hour time frame. An example is the Load Tap Changer. The focus of this thesis are long-term voltage stability problems.

Another limitation is the types of RDG that are investigated. For the study of the impact of RDG on voltage stability standard types of electrical generators such as induction generators, synchronous generators and a generator connected via a power electronics converter are used. In this study the different prime-movers are not taken into account. In a second study, the impact of a wind-farm, with the power generation level determined by the wind-speed, is investigated.

DG is used as an actuator class in the control system. For this, the control of two types of prime-movers and two types of generators are discussed: continuous and thermostatically controlled CHP units and induction and synchronous generators. With this a variety of DG can be represented. Photo-Voltaics and wind turbines are, however, not considered as actuator in the controller. The reason for this is that the developed system should rely on deterministic prime-movers only.

Finally, the testing of the control strategy is based on a well-known textbook transmission system with a limited number of voltage levels. The reason for this is that the system behavior is transparent and can be easily explained. Based on this system all functions of the control can be evaluated. Furthermore, only aggregated models for the loads and DG are used in these tests. The theory is, nevertheless, general enough for implementation in networks with multiple voltage levels.

1.4 Research framework: the DEVS-project

This thesis work is part of the "Dynamic State-Estimation and Voltage Stability of Transmission and Distribution Grids with a large share of Decentralized Generation Capacity" project. This project is abbreviated as DEVS-project and is financially supported by AgentschapNL under the EOS-LT program\footnote{EOS-LT is a dutch abbreviation for Energie Onderzoek Subsidie - Lange Termijn which means in English Financial Support for Long Term energy research. The DEVS project is registered under project number: EOSLT06017.}.

The DEVS-project is a joint project of TNO Smart Grids (in the past ECN) and TU Delft. The project has as industrial partners Alliander and KEMA. There is also a stakeholders advisory group which consists of Delta N.V. and Stedin.

The objectives of the DEVS-project are \[\text{[155]}\]:

"For a future grid with a large share of decentralized generation, in particular several thousands MegaWatt of wind energy (onshore and offshore) and several thousands MegaWatt of micro-CHP units in households, the objectives are:

1. Identification of the main voltage stability problems in the network.
3. To device and test control strategies as a solution to the identified voltage stability problems."

1.5 Thesis contribution

The main scientific contributions of this thesis are:

- Investigation of the impact of RDG on voltage stability at the transmission system level.
- Coordination among different types of actuators and between actuators of the same class.
- A general framework for incorporating specific actuators in the agent-based system.
- Development of a real-time agent-based system for detecting, preventing and solving voltage instability problems.
- Implementation of a real-time demonstrator set-up to test the control concepts and architecture.
1.6 Outline

To guide the reader through the thesis, in this section the outline of the chapters will be given.

Carson W. Taylor stated in his book on Voltage Stability that: "Voltage stability covers a wide range of phenomena. Because of this, voltage stability means different things to different engineers." [185]. For that reason in chapter 2 it is defined what voltage stability means for the purpose of this thesis. The basics of this type of instability are outlined and the main power system aspects that are related to the problem are discussed. To clarify the different concepts that are discussed in this chapter the simulations of a textbook example are shown. The test circuit is in various forms used throughout the thesis for proof of concept.

Finally, in this chapter an outline is given of the different controls for voltage instability prevention.

In chapter 3 the control of the LTCs and DG is described in in two separate chapters. In chapter 6 the control of the LTCs is described.

The control of Combined-Heat-and-Power (CHP)-based DG is discussed in chapter 7. First of all the control of two types of prime-movers is outlined: the thermostatically controlled CHP unit and the continuously controlled CHP unit. In case of the thermostatically controlled unit a Virtual Power Plant (VPP) coordination scheme is introduced that controls the CHP units in such a way that a constant electrical output power can be obtained from multiple units. Secondly, the control of two types of electrical generators are discussed: the synchronous generator and the induction generator.

A proof of concept based on off-line simulations in Matlab/Simulink is given in chapter 8. A slightly modified version of the typical voltage-unstable network also discussed in [99,185] is used to demonstrate the operation of the HABVIP controller. Emphasis is put on the coordination among substation agents when two instability problems occur in the system. Furthermore, the influence of communication delays between agents is investigated. A sensitivity analysis is performed in order to determine the influence of the parameters of the HABVIP control system on its performance. Finally the HABVIP controller is compared to two classical emergency control strategies: LTC tap blocking and Under Voltage Load Shedding (UVLS).

Finally in chapter 10 the main conclusions of the thesis work are given. This chapter also gives recommendations.
Chapter 2

Voltage Stability

2.1 Introduction

Voltage Stability problems appeared in the 1970s in large interconnected power systems for the first time [185]. The main mechanism behind this type of instability is the load dynamics that try to restore the power consumption beyond the capabilities of the transmission and generation system [200]. Grid developments, like the increase of renewable and distributed generation and the impact of deregulation, in combination with the steadily increasing electricity demand, will continue to influence the flow of electricity in the power system [171] and hence effect voltage stability.

Two classical and one more recent textbook on voltage stability are published and Kundur dedicates in his book one chapter on this subject [99]. In the book of Taylor [185] the problem is described from a practical point of view. Hands-on knowledge is provided and useful procedures are outlined to counteract an emerging instability. In the book of van Cutsem and Vournas [200] voltage stability is discussed based on a more analytical approach. The theory of differential algebraic equations, in combination with bifurcation theory, is applied to the problem to obtain a thorough full understanding. Finally, the more recent book [4], written by Ajjarapu, is related to voltage stability assessment and control.

Besides these three books, study committees of IEEE and Cigré have published several reports on the subject. Cigré has, for instance, a report on: Modeling of voltage collapse [34]; Indices predicting voltage collapse [35]; Criteria and countermeasures for voltage collapse [36]; and a report on Voltage stability in combined AC/DC systems [33]. The IEEE has a report on the Concepts, practices and tools for voltage stability assessment [50].

The cited books and reports are based on the research performed from the 1970s onward. The research in this field still continues.

As stated in [185]: “Voltage stability covers a wide range of phenomena. Because of this, voltage stability means different things to different engineers.” The goal of this chapter is to provide the basics about voltage stability. It defines what voltage stability means in the context of this thesis. The chapter is mainly based on the book of Taylor [185] and the book of van Cutsem and Vournas [200].

In section 2.2 the fundamentals of voltage instability will be outlined and its definitions will be discussed. Subsequently in section 2.3 the aspects of the power system that are particularly important for this type of stability are discussed. Section 2.4 follows with the simulations of a typical voltage instability scenario. The model introduced will be used throughout the thesis. In section 2.5 existing methods for voltage instability prevention will be discussed. Finally in section 2.6 the conclusions are given.

The thesis covers a wide range of subjects related to voltage instability: detection, the impact of renewable and distributed generation to this problem, an agent-based system to prevent voltage instability and the control of different actuators for this system. The state-of-the-art on these subjects is discussed later in the respective chapters.
2.2 Fundamentals of Power System Voltage Instability

2.2.1 Classification of Power System Stability

Voltage stability is part of the family of power system stability phenomena. This family of phenomena is defined by the IEEE/CIGRE Joint Task Force on Stability Terms and Definitions as follows:

"Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact." [100]

Power system stability can be classified into three categories: rotor angle stability, voltage stability and frequency stability. This classification is illustrated in figure 2.1, taken from [100].

Rotor angle stability is the ability of electrical machines to stay synchronized after a disturbance [99,100]. The power system is rotor angle unstable if one or more synchronous machines lose synchronism with respect to the rest of the system. Rotor angle stability is a short-term phenomenon and can be subdivided into small-disturbance and transient rotor angle stability.

Frequency stability is the ability to maintain a steady frequency following a significant imbalance between generation and load [99,100]. For frequency stability no distinction between small disturbance and large disturbance stability is made. This type of stability can be both, a long-term or a short-term phenomenon. It depends on the mechanism underlying the specific situation in which time-frame it manifests.

Voltage stability is the ability of the power system to maintain steady voltages in the power system during steady state and after a disturbance [99,100]. It is related to the ability of the generation and transmission system to follow the load dynamics [200]. Voltage stability can be either small-disturbance or large disturbance. And depending on the mechanism it can be either a short-term or a long-term phenomenon. The focus of this thesis is long term voltage stability.

2.2.2 Definition of Voltage Stability and Voltage Collapse

Voltage (In)stability

Two definitions of voltage (in)stability are proposed in the literature. The first definition is, amongst others, given in the book of Kundur:

"Voltage stability is the ability of a power system to maintain steady acceptable voltages at all buses in the system under normal operating conditions and after being subjected to a disturbance." [99]
Voltage instability is the absence of voltage stability [99]. Two important remarks need to be made regarding this definition. First of all, the definition is based on the effect of voltage (in)stability: (un)steady and (un)acceptable voltages. When the term acceptable is properly defined, it is easy to evaluate whether the system is voltage stable. This introduces the second remark: it should be defined when voltages are acceptable. In chapter 3 the term acceptable will be quantified. The second definition is given in the book of van Cutsem and Vournas:

"Voltage instability stems from the attempt of load dynamics to restore power consumption beyond the capability of the combined transmission and generation system." [200]

This second definition is based on the cause of voltage instability: load dynamics that try to restore operation beyond the capabilities of the grid. Note that this definition does not directly impose a measure to evaluate whether the system is voltage stable. The definition is, nevertheless, more unambiguous than the first definition: low voltages could also be caused by, for instance, rotor angle instability and in such case the question is whether rotor-angle instability causes voltage instability or vice versa. In this thesis both definitions will be used because they are based on different aspects and they do not contradict. The definition of Kundur will be referred to as the symptom-based definition of voltage stability. The definition of van Cutsem and Vournas will be referred to as the cause-based definition.

Voltage Collapse
The result of a voltage instability for a system might be that the voltages in the system collapse. Voltage collapse is defined as follows:

"Voltage collapse is the process by which the sequence of events accompanying voltage instability leads to a low unacceptable voltage profile in a significant part of the power system." [99]

Often the terms voltage collapse and voltage instability are used interchangeably. From the definitions these two terms are, however, not the same. A voltage collapse might be the final result of voltage instability sequence of events. But, when in time appropriate countermeasures are taken, the collapse can still be avoided.

2.2.3 Voltage Stability Basics
In this section basic voltage stability concepts are reviewed. Consider the simple system of figure 2.2. This system consists of a load fed by an infinite source through a reactance $X$. The complex receiving-end power is given by:

$$S = P + jQ = U \cdot I^* = -\frac{|E||U|}{X} \sin(\delta) + j \frac{|E||U| \cos(\delta) - |U|^2}{X}$$

(2.1)

Where $P$ is the active power, $Q$ the reactive power, $U = |U| \angle \delta$ the complex voltage at the receiving-end, $E = |E| \angle 0$ the complex voltage at the sending-end and $I$ the complex current. This equation can be decomposed into terms of $P$ and $Q$ to obtain the power flow equations:
Voltage Stability

\[ P = \frac{|E||U|}{X} \sin(\delta) \]
\[ Q = \frac{|E||U| \cos(\delta) - |U|^2}{X} \]  

(2.2)

Elimination of \( \delta \) from equation (2.2) gives the following second-order equation:

\[(|U|^2)^2 + (2QX - |E|^2)|U|^2 + X^2 (P^2 + Q^2) = 0\]

(2.3)

Solving for \( U \) gives two solutions:

\[ |U| = \sqrt{\frac{|E|^2}{2} - QX \pm \sqrt{\frac{|E|^4}{4} - X^2 P^2 - X|E|^2 Q}} \]  

(2.4)

This equation describes the so-called PV-curve. In such a curve, the receiving-end voltage is given as a function of the active part of the receiving-end power, given a fixed ratio between active and reactive power. An example of a PV-curve is given in figure 2.3. In this figure \( P_{\text{max}} \) is defined as the point where the discriminant of equation (2.3) becomes zero.

In the PV-curve, operation modes can be distinguished:

1. \( P < P_{\text{max}} \): in this case, the system is operated below the point of maximum power transfer. The power can be supplied at two voltage levels: a higher one and a lower one.

2. \( P = P_{\text{max}} \): in this case, the system is operated at the point of maximum power transfer. There is only one voltage value at which the power can be supplied.

3. \( P > P_{\text{max}} \): in this case, there is no solution for the power flow equations. There is no operating point.

Based on the PV-curve of figure 2.3, two fundamental aspects of voltage instability can be distinguished. First of all, for an operating point, the load characteristic should intersect the PV-curve. When the power

\[ \text{It can be shown that this equation only has a solution when} - \frac{P^2}{X} - \frac{|E|^2}{X^2} Q + \left( \frac{|E|^2}{2X^2} \right)^2 \geq 0 \]
2.3 Power System Aspects related to Voltage Stability

that is required by the load exceeds \( P_{\text{max}} \) there is no equilibrium point and the system collapses. Note that the point where the equilibrium point vanishes is not necessarily at \( P_{\text{max}} \) as defined in figure 2.3 but depends on the voltage dependency of the load (the load characteristic will be discussed in more detail in subsection 2.3.3).

So voltage instability occurs when the load dynamics try to restore consumption to a point that does not intersect the PV-curve (cause-based definition). This loss of a stable operating point will result in a progressive decrease of network voltages to unacceptable levels (symptom-based definition).

The second fundamental aspect relates to operation at the lower half of the PV-curve. As can be seen, for \( P < P_{\text{max}} \) a certain amount of power can be provided at a higher and at a lower voltage. From static operation point of view it is better when the load is supplied at the higher voltage, because this higher voltage involves a lower current and consequently lower losses. But there might be another problem when operating on the lower half of the PV-curve: an increase in receiving-end power results in an increase in receiving-end voltage (or conversely, a decrease in receiving-end power results in a decrease in receiving-end voltage). This is the opposite from what is expected. Power system control is not designed for this opposite behavior and when load restoring dynamics, such as Load Tap Changers, are present voltage instability will occur.

2.2.3.1 Reactive Power

Voltage instability is often related to the lack of reactive power support in the system. This is based on the assumption that active and reactive power can be decoupled and active power is solely related to the frequency and reactive power to the voltage. Although the relation between voltage stability and reactive power indeed exists, decoupling does not fully cover the complexity of the problem.

As discussed before, voltage stability is caused by load dynamics that try to restore power consumption (active and reactive) beyond what the transmission and generation systems are able to provide. It can be demonstrated that in a purely DC network load dynamics are also able to restore operation beyond the systems capability, resulting in extremely low voltages and zero power transfer [200]. So voltage instability can occur when no reactive power is involved at all.

Secondly, the decoupling of active and reactive power is mainly appropriate for transmission networks. Distribution networks have a lower \( X/R \)-ratio and cables generate reactive power. In these networks there is therefore a stronger coupling between active power and voltage. At least theoretically, also in these distribution grids voltage instability problems might appear when load dynamics try to restore power consumption beyond the capability of the combined transmission and generation system.

Reactive as well as active power is thus important for voltage instability.

2.3 Power System Aspects related to Voltage Stability

2.3.1 Generation Aspects

Conventional power plants with synchronous generators play an important role in the production of active and reactive power. Although the focus changes to decentralized production units, these conventional plants still produce an important part of the consumed power. In this subsection the power systems generation aspects of conventional generators related to voltage instability will be discussed. In chapter 4 the consequences of having a large share of renewable and distributed generation on the voltage instability problem will be discussed.

2.3.1.1 Voltage control

Voltage at generation plants is controlled by adjusting the reactive power production. This is based on the assumed decoupling of active and reactive power. As discussed in section 2.2.3.1 the validity of this assumption is limited. This reactive power production, on its turn, can be controlled with the generator field current. The Automatic Voltage Regulator (AVR) takes care of this. The AVR system provides a DC voltage for the field-winding. Under normal conditions the control signal is determined by the difference
between the measured terminal voltage of the generator and the desired voltage ($U_{ref}$). The AVR response is fast (order of seconds).

The AVR controls the voltage locally: either the voltage at a generator bus or, in the case of line drop compensation, a bus-close-by is controlled. So following a disturbance, generators close to the disturbance that see the voltage dip will react and increase their reactive power production. This local behavior may lead to an uneven distribution of voltages and unacceptable voltage levels at non-generator buses. The generator’s AVR response is a primary, uncoordinated, response. Coordination between generators is often done manually by system operators. Some network operators, however, have implemented secondary voltage control (see for instance [40,41,101]). The aim of this type of control is to maintain a voltage profile within an area by controlling the voltages of pre-defined pilot buses. This level of control is implemented in regional voltage regulators. This type of regulator changes the generator voltage set-points, and also adapts the Load Tap Changers (LTC) tap positions and controls the switching of capacitors. The reaction time of the secondary voltage control is about three minutes [220].

The impact of secondary voltage control on voltage stability can be summarized as follows [200]:

- Secondary voltage control takes into account the reactive reserve of all the actuators it controls, so the limit of these reserves will be reached at about the same time for all devices. This will result in a sudden decrease in voltage when, due to a load increase, this limit point is reached.
- The maximum power that can be transferred in the system is increased.
- Load restoring dynamics act within the same time frame as the secondary voltage control. This might result in oscillatory behaviour.
- With secondary voltage control the voltage in the network will be more constant over time and consequently the voltage magnitude becomes a less accurate measure for voltage instability problems.

A recent development is the Wide Area Control System (see for instance [10,187].) In this type of systems a large area is controlled centrally based on accurate phasor measurements. In the discussion of [39,186] it is argued that this type of control can be classified under secondary voltage control. In addition to the primary and secondary voltage control a third control level is defined. The tertiary control determines the optimal power flow of the entire network and sets the reference values of the pilot buses of the secondary voltage control. The aim of this optimal power flow is to ensure economic criteria and keeping reactive reserve in all areas. The optimal power flow is typically calculated every 15 minutes. In [79] an agent-based method for the tertiary control is proposed. In this thesis it is assumed that the standard primary voltage control by means of AVRs is available. The secondary and tertiary control are unavailable.

2.3.1.2 Limiters

Two limiting devices play an important role during voltage instability: the Overexcitation Limiter (OXL) and the armature current limiter. The reactive power production of one or more important generators was limited in the case of most of the known voltage stability events [200].

The OXL protects the field winding from overheating by limiting the field current [99]. In its most simple form, the OXL just prevents the field current (or voltage) from exceeding a certain level. However, small over-currents are less detrimental than large over-currents and the duration of the over-current is also important. The relationship between field winding overcurrent capability and time is illustrated in figure 2.4 [84].

In most cases the OXL takes this into account and has an inverse time characteristic [200]. This leads to an improvement of the first-swing angle stability, since short-term boosting of the exciter voltage can mitigate transient voltage dips. Furthermore, it gives some time to implement a long-term solution before the reactive power supply from the generator must be limited.

In this thesis as model for the overexcitation limiter the OXL with integral control of field current is used [200]. The block diagram is given in figure 2.5. When the field current $|I_{fd}|$ is below its maximum $|I_{fd,max}|$ the switch in this model is in its lower position. Because the integrator at the output has as lower limit zero, the output signal $|U_{oxl}|$ is also zero. When $|I_{fd}|$ becomes larger than $|I_{fd,max}|$ the first
2.3 Power System Aspects related to Voltage Stability

2.3.1 Capability diagram

The active and reactive power capability of a synchronous generator can be summarized in a capability diagram (see figure 2.6). In this figure the field-heating limitation, armature current limitation, prime-mover limitation and the under excitation limitation are illustrated. During a typical voltage stability problem the generator is operated in overexcitation mode: so only the part with $Q > 0$ is of importance. Both the

![Figure 2.4. Current overload capability of field winding [84].](image)

![Figure 2.5. OXL with integral control of field current [200]. $p$ is the Laplace operator.](image)

integartor starts integrating. As soon as the output of the integrator becomes larger than zero, the switch changes its position to the higher position and relays $|I_{fd}| = |I_{fd,max}|$. This signal is integrated to determine $|U_{oxl}|$. So the amount with which $|I_{fd,max}|$ is exceeded determines the moment the OXL start acting and the magnitude of the control signal. $|U_{oxl}|$ is used as input for the AVR.

Operation of the OXL limits the reactive power supply capability of the generator. Generally, when the OXL of a local generator acts, the shape of the PV-curve changes: the maximum power transfer decreases and is reached at a higher voltage.

The armature current limiter protects the armature winding from overheating [99]. An automatic armature current limiting device is less common than the OXL because the armature winding has a higher thermal time constant [200]. There is more time to take countermeasures against over-currents and the human plant operator will often take care of these actions. Countermeasures to prevent armature overheating the operator can take are: limiting the reactive power output of the generator by limiting the field current or reducing the supplied active power.

![Capability diagram](image)
field-heating and armature-heating limitation have been discussed before. The prime-mover limitation is a limitation in the amount of active power that can be provided by the prime-mover. By showing the current operating point in a capability diagram the generator conditions can be evaluated very quickly as the distance to the different limitations can be seen at a glance.

2.3.1.4 Frequency control

The active output power of a generator is controlled based on the frequency. Three levels of control can be distinguished: primary control, secondary control and tertiary control [171].

The primary frequency control is done by the generator’s speed governor. The difference in generated and consumed power will be supplied (or consumed) by the kinetic energy of the generator’s rotating mass. This results in a change in mechanical speed. The primary frequency control restores the power balance. The speed governor of the generator measures the mechanical speed and compares this with the nominal speed. Based on the difference, the power of the prime-mover is changed to arrest the change. Note that although more power is provided, the mechanical speed may deviate from its nominal value. The mechanical speed of the generators is related to the system frequency, so this deviation in mechanical speed results in a deviation in system frequency.

The secondary control restores the system frequency to its nominal value. This control changes the reference value of the output power of the generators according to the agreements about balancing power provision and inter-area exchange. Nowadays secondary frequency control is referred to as balancing service and procured by the TSO through a one-sided auction.

The last type of control is the tertiary control. Classically this control determines the economic dispatch. Set points for the output power of the generators are calculated from an economic point of view. In a deregulated environment the hourly exchange schedules are set by the market and it is up to market players to distribute the schedules among their units in an economically advantageous way.

The frequency control has some secondary effects on the voltage stability problem [200]:

- A loss of a generator in a load area has, due to the reaction on the frequency deviation of the generators in a generation area, the same effect as an increase in load power. In such a situation the power transfer between the two area’s increases. This may lead to a voltage unstable situation.

- If a line is lost between a sending area and a receiving area and in the sending area load shedding is applied, the generators in the load area will, due to the frequency control, increase the local generation (assuming that enough generation is available.) This may improve the voltage stability.

- The decrease in power consumed by the voltage sensitive loads will be followed by frequency control actions of the generators.
2.3 Power System Aspects related to Voltage Stability

2.3.2 Transmission System Aspects

The fundamental influence of the transmission system on voltage stability has been discussed in subsection 2.2.3. For voltage stability it is first of all important that the load-characteristic intersects the network characteristic (PV-curve). If this is not the case, there is no operating point. Secondly it has been shown that at the lower part of the PV-curve the relationship between power and voltage reverses. It depends on the load restoring process whether this leads to voltage instability. In this subsection three aspects will be discussed that influence the characteristics of the transmission network: the change in system due to the loss of a line, reactive power compensation and tap changing transformers.

2.3.2.1 Changing system characteristics due to loss of a line

During operation of the power system several contingencies might occur. For voltage stability two types of contingencies are of particular interest: the loss of a line and loss of generation equipment. These contingencies result in an increase in the line reactance and/or a decrease in the sending-end voltage [200]. We will focuses on the loss of a line, but a similar analysis can be performed for the loss of generation equipment.

Assume a load that is fed by an infinite source via two parallel transmission lines. This can be modeled with the diagram of figure 2.2 where $X$ is the equivalent reactance of the two lines. The PV-curve of the transmission system with two lines in service is given by the solid line in figure 2.7.

A loss of one of the two transmission lines results in an increase in the equivalent reactance $X$. When both lines are identical, the reactance doubles. The PV-curve for this case with one line out of service is shown by the dashed line in figure 2.7.

It can be seen that the PV-curve of the transmission system with one line in service does significantly differ from the system with two parallel lines in service. When initially there is an intersection between the load characteristic and the network characteristic (PV-curve) after the trip of the line this operating point might be lost (as illustrated by the dotted line for a constant power load). Depending on the load characteristic it can also happen that the operating point shifts from the stable upper part of the PV-curve to the unstable lower part of the PV-curve. The influence of load characteristics will be discussed in subsection 2.3.3.
2.3.2.2 Compensation

Two types of compensation can be distinguished: load compensation and network compensation. This subsection focuses on network compensation. In subsection 2.3.3, load compensation will be discussed.

Transmission lines consume and produce reactive power. Consumption of reactive power is dependent on the loading of the line:

\[ Q_{\text{loss}} = X |I|^2 \]  

Where \( X \) is the reactance of the line. So the reactive power losses increase with increasing line loading.

The production of reactive power is dependent on the voltage:

\[ Q_{\text{gen}} = B |U|^2 \]  

Where \( B \) is the total line shunt susceptance. Because the voltage is not allowed to vary too much (typically ±10% of nominal), the reactive power production is not significantly influenced by the line loading.

The goal of reactive power compensation is to influence the above described balance between reactive power consumption and production. This can either be done by placing elements in series with the transmission line (series compensation) or by placing elements in parallel with the transmission line (shunt compensation). Series compensation devices are for instance: (switched) series capacitors, thyristor controlled series capacitances and reactances, and Static Synchronous Series Compensators. Shunt compensation devices are for instance: (switched) shunt capacitor banks, (switched) shunt reactors, Static Var Compensators (SVCs), Synchronous Condensers and Static Synchronous Compensators (StatComs). Shunt compensation influences both: the maximum power transfer of the line \( P_{\text{max}} \) and the voltage at which this maximum power is supplied. Series compensation influences the maximum power transfer of the line only.

In the remaining of this subsection two compensation devices will be discussed in more detail: shunt capacitor banks and SVCs. These two devices are important for understanding some of the concepts presented further in this thesis.

**Shunt capacitor banks**

The main purpose of capacitor shunt compensation is voltage control and load compensation. Capacitor banks are beneficial for voltage stability. The effect of capacitor banks at nearby generators is that they can operate at unity power factor, which maximize fast acting reactive reserve [185].

The reactive power supplied in steady-state by a shunt capacitor is given by [200]:

\[ Q_c = B_c |U_c|^2 \]  

In this equation \( U_c \) is the voltage across the capacitor and \( B_c \) is the susceptance of the capacitor.

In figure 2.8 the model of a network with shunt compensation is given. In this figure \( B \) is the shunt susceptance of the line. For this system the Thévenin equivalent seen by the load is given by [200]:

\[ |E_{\text{th}}| = \frac{1}{1 - (B_c + B)} |E| \]  

In this equation \( E \) is the voltage across the line and \( B \) is the total shunt susceptance of the line.


\[ X_{th} = \frac{1}{1 - (B_c + B)} X \]  

The shunt capacitors can be fixed or switched. Switched capacitor banks have the opportunity to control the voltage. The effect of switched capacitors on the PV-curve is illustrated in figure 2.9.

Because the reactive power output depends on the square of the voltage, in emergency situations (where the voltage is very low) the capacitor banks are less useful [185]. A low voltage means low generation of reactive power.

Switching of capacitor banks takes some time. For that reason, capacitor banks are more appropriate to solve long-term voltage instability than short-term voltage instability.

A dangerous situation might occur when due a voltage stability problem a part of the system is disconnected and the capacitor banks stay connected to the grid [185]. In such a situation, in the stable part of the grid large overvoltages might occur.

Static Var Compensators (SVC)

An SVC is a shunt compensator that is voltage controlled [200]. Static within this context means that there are no rotating parts in this compensator. A distinction can be made between Static Var Systems and Static Var Compensators. A Static Var System is a Static Var Compensator that also controls mechanically switched shunt capacitors or reactors [185].

Most common Static Var Compensators are build up from Thyristor Switched Capacitors (TSC) and Thyristor Controlled Reactors (TCR):

- A TSC consists of one or more parallel capacitors which are switched by thyristors. The structure of the TSC is given in figure 2.10.

- A TCR consists of a reactor in series with a thyristor and parallel to a fixed capacitor. The firing angle of the thyristor controls the amount of reactive power that is consumed by the reactor. In this way a continuously controllable source or sink of reactive power is created. The structure of the TCR is given in figure 2.11.

A compensator can also be built up from a combination of the described components. The reactive power supplied in steady-state by the SVC is given by [200]:

\[ Q_{svc} = B_{svc} |U_{svc}|^2 \]  

(2.10)
The desired voltage current characteristic of the SVC is given in figure 2.12. This characteristic can be described by:

\[
|U| = \begin{cases} 
|U_{\text{ref}}| + X_{\text{svc}}|I_{\text{svc}}| & \text{if } B_{\text{min}} < B_{\text{svc}} < B_{\text{max}} \\
|I|/B_{\text{svc}} & \text{if } B_{\text{svc}} \geq B_{\text{max}} \\
-|I|/B_{\text{svc}} & \text{if } B_{\text{svc}} \leq B_{\text{min}} 
\end{cases}
\] (2.11)

In this equation $U$ is the voltage that is regulated by the SVC, $U_{\text{ref}}$ is the voltage reference, $X_{\text{svc}}$ is the droop of the SVC characteristic in regulating mode, $I_{\text{svc}}$ the SVC current, $B_{\text{svc}}$ the SVC susceptance and $B_{\text{min}}$ and $B_{\text{max}}$ are the limits of the SVC susceptance.

This characteristic is obtained by controlling the effective susceptance of the SVC by changing the fire angle of the thyristors. Several control schemes exist to control the SVC. In this thesis the control scheme of the SVC model of the SimPowerSystems toolbox of Matlab/Simulink is followed [80]:

\[
B_{\text{svc}} = \frac{|U_{\text{ref}}| - |U|}{X_{\text{svc}}|U| + \frac{k_p + k_I}{p}}
\] (2.12)

subject to:

\[
B_{\text{min}} \leq B_{\text{svc}} \leq B_{\text{max}}
\] (2.13)

In this equation $k_p + k_I/p$ is a PI control action. If $B_{\text{svc}} < B_{\text{min}}$ the SVC behaves as a fixed reactor, if $B_{\text{svc}} > B_{\text{max}}$ the SVC behaves as a fixed capacitor.

The typical QV-characteristic of a SVC based on a TCR is shown in figure 2.13. As can be seen from this figure, the SVC can operate in both inductive and capacitive mode. For $B_{\text{min}} \leq B_{\text{svc}} \leq B_{\text{max}}$ the characteristic is by approximation a straight line with a small droop. This droop is important for coordination between several voltage supporting devices.

The effect of an SVC based on a Thyristor Controlled Reactance on the PV-curve is shown in figure 2.14. In this figure it is clearly shown that for $B_{\text{min}} \leq B_{\text{svc}} \leq B_{\text{max}}$ the SVC keeps the voltage more or less constant.

### 2.3.2.3 Tap Changing Transformers

Tap-changing transformers are transformers with an adjustable tap ratio and can be found at different levels in the power system [200]:

- at distribution level, connecting the distribution system to the transmission system;
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- at transmission level, connecting the sub-transmission system to the transmission system or connecting two transmission levels to each other;
- at generator level, as step-up transformer.

Tap changing transformers at the distribution level have a major influence on the load dynamics. In subsection 2.3.3 a detailed discussion of this class of tap changing transformers will be given. In the current subsection only the influence of the last two types of transformers on voltage stability will be discussed. With transmission level tap-changing transformers voltage and reactive power control can be obtained. By decreasing the tap ratio at the primary side, under normal conditions the secondary voltage increases. At the primary side more reactive power is required and because of this the primary voltage drops. This can be (partly) prevented by reactive power compensation at the primary side.

Consider the circuit of figure 2.15. In this system a load is fed by an infinite source via a simple transmission system. This transmission system consists of a transmission line (modeled as a reactance \( X_1 \)), a tap changing transformer and another transmission line (modeled as reactance \( X_2 \)). It is assumed that the leakage reactance of the transformer is represented in the reactances \( X_1 \) and \( X_2 \). The tap changing takes place at the primary side of the transformer. A decrease in tap position \( r \) should, under normal conditions,
result in an increase in secondary voltage and vice versa. The equivalent Thévenin voltage and reactance as seen by the load are:

\[
|E_{th}| = \frac{|E|}{r} \quad \text{and} \quad X_{th} = \frac{X_1}{r^2} + X_2
\]

So a decrease in tap position has a positive effect (an increase in \(E_{th}\)) and a negative effect (an increase in \(X_{th}\)). The positive effect increases the load voltage, the negative effect counteracts this. This shows that there is a limitation in the normal operation of the tap changer: for a very small tap ratio and for a weak system (large \(X_1\)), the negative effect is larger than the positive effect and a decrease in tap position leads to a decrease in load voltage. This is the unstable behavior of the tap changer.

The PV-curve for various values of the tap ratio is given in figure 2.16. In this curve the chosen values of \(X_1\) and \(r\) do not introduce the unstable behavior described before. From the figure it can be seen that a decrease in tap ratio leads to an increase in the maximum amount of power transfer.

The tap changing can be either performed manually or automatically. In the case of the automatic tap changing the transformer is equipped with a voltage controller that controls the secondary voltage. The secondary voltage can be assumed constant and the downstream network becomes independent from the upstream network. For the circuit of figure 2.15 this means that when evaluating the load PV-curve only \(U_2\) and \(X_2\) are taken into account. Reactance \(X_1\) and the voltage \(E\) do not play a role.

Regarding the above statement three remarks should be made. First of all there is a limitation in the number of tap changes that can be made. Secondly, for weak systems (larger \(X_1\)) and low values of \(r\) the voltage control is in an unstable mode. Consequently the validity of the assumption that the secondary side of a tap
changing transformer is independent from the primary side, is limited. As a third point: the tap position is not controlled continuously but in discrete steps. So the secondary voltage will be constant but vary a little bit.

2.3.3 Load Aspects

Loads that try to restore their power consumption are the main driver for the voltage instability mechanism [200]. In order to understand this it is important to distinguish two concepts: the load demand \( z \), which is a relative measure for the amount of load that is required, and the actual amount of load consumption \( P \). Note that \( P \) is dependent on the voltage and \( z \) not.

When the load demand \( z \) corresponds to a larger amount of power consumption \( P \) than actually is achieved, a load restoration process will try to restore this. This load restoring process assumes that the load has some dynamics. Typical loads with restoring dynamics are: a load behind a load tap changing transformer, thermostatically controlled loads and induction motor loads.

The concept of load restoration and its effect on voltage stability will be discussed in this subsection. First a generic load model will be introduced. This model will subsequently be used to discuss three load restoration processes. Finally, the effect of load compensation on voltage instability will be discussed.

2.3.3.1 Generic load models

Static load model

The general static load characteristics can be described by the exponential load model:

\[
\begin{align*}
P_{\text{load}} &= zP_0 \left( \frac{|U|}{|U_0|} \right)^{\alpha_P} \\
Q_{\text{load}} &= zQ_0 \left( \frac{|U|}{|U_0|} \right)^{\alpha_Q}
\end{align*}
\]

In this equation \( z \) is the load demand, \( P_0 \) and \( Q_0 \) are the active and reactive power consumption at nominal voltage \( U_0 \), and \( \alpha_P \) and \( \alpha_Q \) characterize the voltage dependency of the load. This exponential model is not valid for low voltages because when the voltage drops below a certain threshold, most loads will be disconnected. A common threshold is \( U = 0.6 \text{ pu} \) [200].

In figure 2.17 the exponential load is plotted for \( \alpha_P = \alpha_Q = 1.5 \) and a power factor of 0.95 together with the PV-curve of the transmission system. Note that the assumption of a constant power factor of the load, allows us to plot both characteristics in the same figure.

As discussed before, a certain amount of power can be transferred at the high voltage (operating point S) and at the low voltage (operating point U). Note that this power transfer is for a different load demand \( z \)! If the system is operated at operating point S and the load power demand \( z \) increases, the load power indeed increases. If, however, the system is operated at operating point U and the load demand \( z \) increases, the load power decreases. For static loads the system will set itself to this new operating point\(^{ii}\). When load restoring dynamics are, however, present, they will try to restore the load consumption by increasing the load demand. The voltage will keep decreasing and eventually collapses.

Exponential load model

Three particular cases of the load exponents \( \alpha_P \) and \( \alpha_Q \) can be distinguished:

- For \( \alpha_P = \alpha_Q = 0 \) the load behaves as a constant power load (constant P).
- For \( \alpha_P = \alpha_Q = 1 \) the load behaves as a constant current load (constant I).
- For \( \alpha_P = \alpha_Q = 2 \) the load behaves as a constant impedance load (constant Z).

\(^{ii}\)This new operating point might however be unfavorable because of the low voltage and the high currents.
Load at a common node that have the same exponent, can be added to each other. In this way an aggregated polynomial load is obtained. A special case is when the three particular cases for load components, constant impedance (Z), constant current (I) and constant power (P) are added to each other. This results in a so-called ZIP model. The ZIP model is given by:

\[
\begin{align*}
P_{\text{load}} &= zP_0 \left( a_P \left( \frac{|U|}{|U_0|} \right)^2 + b_P \left( \frac{|U|}{|U_0|} \right)^1 + c_P \right) \\
Q_{\text{load}} &= zQ_0 \left( a_Q \left( \frac{|U|}{|U_0|} \right)^2 + b_Q \left( \frac{|U|}{|U_0|} \right)^1 + c_Q \right)
\end{align*}
\] (2.17)

In this equation \(a_P, b_P, c_P, a_Q, b_Q,\) and \(c_Q\) are the fractions of the load for which it hold that \(a_P + b_P + c_P = a_Q + b_Q + c_Q = 1.\)

**Dynamic load model**

The load dynamics will be discussed further on in this subsection for three typical load restoring processes. Although these processes have their own specific characteristics (the load behind a load tap changer has, for instance, a deadband), they can be included in a generic load model:

\[
\begin{align*}
P_{\text{load}} &= zP_0 \left( \frac{|U|}{|U_0|} \right)^{\alpha_P} \frac{1 + T_{P,1}p}{1 + T_{P,2}p} \\
Q_{\text{load}} &= zQ_0 \left( \frac{|U|}{|U_0|} \right)^{\alpha_Q} \frac{1 + T_{Q,1}p}{1 + T_{Q,2}p}
\end{align*}
\] (2.18)

In these equations \(T_{P,1}, T_{P,2}, T_{Q,1},\) and \(T_{Q,2}\) are the time constants of the load restoration process and \(p\) is the Laplace operator.

**2.3.3.2 Load tap changing transformer**

The term Load Tap Changing (LTC) transformer is used for transformers feeding the distribution grid that can automatically control the tap position. The control objective of the LTC is to maintain the secondary
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Voltage: when this voltage deviates from a set-point \( U_{\text{ref}} \) the tap position is changed in order to obtain a new transformer ratio. When line drop compensation is used in the voltage control, it is also possible that the objective is to maintain a voltage further downstream. Generally the tap position is changed at the primary (high voltage) side of the transformer as at this side more windings are present, resulting in a more accurate control, and the currents are lower.

The voltage regulation by means of LTCs is a key element in the load restoration seen from the high-voltage side. Following a voltage drop, voltage sensitive loads initially reduce their power consumption (see equation 2.16 with \( \alpha_P \neq 0 \) and \( \alpha_Q \neq 0 \)). In due course, however, the LTC will try to restore the secondary voltage. With the restoration of the voltage, the power consumption is increased. The load as seen from the primary side of the transformer behaves as constant power load.

Control with the load tap changer is discrete. First of all the operation of the LTC is delayed. The mechanical time delay for this process is in the order of magnitude of 5 seconds, in addition to this an intentional time delay is added in the order of magnitude of 30 seconds to prevent that the LTC acts too soon. Secondly, the tap position changes in discrete steps of \( \Delta r \) every 5 seconds.

The control of the LTC can be described with the following equation:

\[
\begin{align*}
    r_{k+1} &= \begin{cases} 
    r_k + \Delta r & \text{if } |U_m| > |U_{\text{ref}}| + \frac{1}{2} \Delta |U_{\text{DB}}| \text{ and } r_k < r_{\text{max}} \\
    r_k - \Delta r & \text{if } |U_m| < |U_{\text{ref}}| - \frac{1}{2} \Delta |U_{\text{DB}}| \text{ and } r_k > r_{\text{min}} \\
    r_k & \text{otherwise}
    \end{cases}
\end{align*}
\]

(2.19)

In this equation \( r_k \) is the current tap position, \( r_{k+1} \) is the new tap position, \( U_m \) is the measured secondary voltage, \( U_{\text{ref}} \) is the reference for the voltage, \( \Delta |U_{\text{DB}}| \) is the deadband in the voltage control, and \( r_{\text{min}} \) and \( r_{\text{max}} \) are the minimum and maximum tap position.

The LTC transfers a voltage problem from the secondary side to the primary side. Under normal conditions (strong grid) a change in tap position leads to a change of \( \Delta |U_{\text{tap}}| \) in secondary voltage. In the case of a weak grid, the magnitude or sign might change.

As discussed before, tap changing transformers can also be present in the transmission system. Some form of coordination is required between these higher level tap changers and the LTCs at distribution level to prevent unnecessary tap changes and oscillations. This coordination is reached by choosing larger time delays for higher level tap changers than for lower level tap changers. The reason for this particular choice is that when both the higher level tap changer and the lower level tap changer require a tap change, the higher level tap changer most probably solves both problems. The lower level tap changer only solves the lower level problem and because this problem is effectively transfered to the higher level, the higher level problem worsens.

The impact of an LTC that feeds a load based on the previously defined PV-curves will be explained for the simple system of figure 2.18. For the load an exponential model with \( \alpha_P = \alpha_Q = 1.5, P_0 = Q_0 = 1 \text{ pu} \) and \( z = 0.2 \) is assumed. The PV-curve and the load characteristics are illustrated in figure 2.19.

Let's first have a look at the load characteristics shown with the dashed lines. The transformer ratios are 0.9 and 0.8. It can be seen that with a decrease in tap position the intersection of the network PV-curve and the load characteristic (operating point) moves to the right. This means that with decreasing values of \( r \), more power is consumed and the primary receiving-end voltage decreases. This is normal, stable behavior.

In the case of the dotted lines the transformer ratios are 0.3 and 0.2. It can be seen that for decreasing values of \( r \) the operating point shifts to the left. The power consumption and the primary receiving-end voltage reduce. This is unstable behavior.
2.3.3.3 Thermostatic loads

Another important type of loads with load recovery behavior are the thermostatically controlled loads. All kinds of electrical heating can be classified as thermostatic load. Thermostatic loads try to maintain a room temperature by switching on and off a heating element. The demand variable is the energy requirement. The heating element itself is an impedance. The room temperature is determined by the duty cycle:

\[ D = \frac{\Delta t_{\text{on}}}{\Delta t_{\text{on}} + \Delta t_{\text{off}}} \]  \hspace{1cm} (2.20)

Where \( \Delta t_{\text{on}} \) is the time the load is connected to the grid and \( \Delta t_{\text{off}} \) is the time the load is disconnected from the grid.

Following a decrease in voltage, the thermostatic load initially reduces its power consumption. Because energy is the integral of power over time, to maintain a given temperature the on-time should increase. So the load will stay connected to the power system for a longer period of time. A single thermostatically controlled unit behaves, nevertheless, still as a constant impedance load.

When multiple thermostatic loads are connected to the network, the longer on-time of the individual units results in an increased chance that units are on at the same time. So when a large enough amount of units are connected to the power system, the required load power increases.

Due to the fact that at the moment in the Netherlands heating and cooking is mainly based on natural gas, thermostatic loads play no major role in the Dutch power system. In future this might, however, change since there are new houses built without a natural gas connection. In this thesis this type of load is, however, not taken into account.

2.3.3.4 Induction motor loads

An important part of the electric power is consumed by induction motors at industrial, residential and commercial sites. These induction motors influence the voltage stability of the power system significantly. As discussed before, load restoration is an important aspect regarding voltage stability. The demand variable of induction generator loads is the mechanical torque. The load restoring dynamics of this type of load are fast.
Besides the load restoration, there are two other important effects of induction motor loads on voltage stability. First of all, induction motors consume reactive power. This reactive power consumption leads to a voltage reduction when it is not sufficiently compensated. Secondly, induction motors stall at low voltage and/or increasing mechanical load. During stalling a large amount of reactive power is consumed and no torque is produced. Undervoltage protection should disconnect the motor in this situation.

The steady-state equivalent circuit for the induction motor is given in figure 2.20. In this equivalent circuit the rotor electrical transients are neglected. From this figure the relation between the electro-magnetic torque, the slip and the terminal voltage can be derived:

\[
T_{em}(U_t, s) = \frac{|U_t|^2 X_m^2 R_s}{(R_k + \frac{R_s}{s})^2 + (X_k + X_r)^2} \left[ R_s^2 + (X_s + X_m)^2 \right] \left[ R_r^2 + (X_r + X_m)^2 \right] (2.21)
\]

In this equation:

\[
R_k = \frac{X_m (X_s + X_m) - R_s X_m X_s}{R_s^2 + (X_s + X_m)^2},
\]

\[
X_k = \frac{X_m R_s^2 + X_m X_s (X_s + X_m)}{R_s^2 + (X_s + X_m)^2},
\]

\[
s = \frac{\omega_s - \omega_m}{\omega_s} \quad (2.22)
\]

\[U_t\] is the terminal voltage, \(X_m\) the magnetizing reactance, \(R_s\) the rotor resistance, \(X_s\) and \(X_r\) the stator and rotor leakage reactances, \(\omega_s\) is the synchronous speed of the rotating field and \(\omega_m\) is the mechanical rotor speed.

The operation of the induction motor is determined by the intersection of the electromagnetic torque-speed characteristic and the mechanical torque-speed characteristic. The mechanical torque-speed \(T_{mech}(s)\) can have several possible characteristics such as the constant torque model, quadratic torque model and the composite torque model.

When there is a difference between the electro-magnetic torque and the mechanical torque, the motor will operate according to the rotor-motion equation:

\[
2H \frac{ds}{dt} = T_{mech}(s) - T_{em}(U_t, s) \quad (2.24)
\]

Where \(H\) is the inertia constant.

The torque-slip characteristic for a typical induction motor is given in figure 2.21. In this figure also the mechanical torque for a constant torque mechanical load is given. A positive torque means motor operation.
For the motor to function, an intersection between the electromagnetic and mechanical torque-slip characteristics is required. The operating point can be lost when either the mechanical torque increases or when the electromagnetic torque-speed characteristic shrinks due to a voltage reduction. When the operating point is lost the motor will stall and start to consume a large amount of reactive power thus worsening a voltage instability event.

As can be seen from figure 2.21 a constant mechanical torque can be provided at two different values for the slip. In the case of operating point S a small increase in the slip results in an increase in the electromagnetic torque. As can be seen from the rotor-motion equation (2.24) this increase in electromagnetic torque results in a decrease in the slip. The operating point will restore to S and this operating point is a stable one. On the other hand, when the system is operated at point U, a small increase in slip results in a decrease in the electromagnetic torque. According to equation (2.24) this decrease in torque results in a further increase in slip. The operating point is unstable and the motor will finally stall.

2.3.3.5 Load compensation

With load compensation the quality of supply for a single load (or a group of loads) is improved with reactive power compensating equipment near the load. The main objectives of load compensation are: power factor correction; voltage regulation; and load balancing. The ideal compensator must be able to: supply instantaneously the reactive power demand of the load; maintain constant voltage at its terminals under all conditions; and operate independently for the three phases. The effect of load compensation on voltage stability is shown in figure 2.22. In this figure PV-curves are given for different values of the load power factor. The dashed line gives the PV-curve when the load is drawn at a power factor 0.95 inductive, the solid line gives the PV-curve for a load with a power factor of 1 and the dotted line gives the PV-curve when the load is drawn at a power factor 0.95 capacitive.

It can be seen from figure 2.22 that the more the load is compensated (load power factor changes from inductive to capacitive) the larger the maximum amount of power transfer becomes. This can generally be considered as positive for the voltage stability of the system.

There is, however, a drawback from stability point of view. With increasing the power factor, the point of maximum power transfer will also occur at higher voltage levels. For an overcompensated load the point of maximum power transfer reaches the normal operating voltage. This makes it difficult to detect voltage instability based on the voltage magnitude. With overcompensation the receiving-end voltage can even exceed the sending-end voltage at low loads.
2.4 Typical Voltage Instability Scenario

Some general observations can be made before and during a typical voltage instability situation. During the onset of instability the power system experiences [94, 99, 200]:

- High power transfers due to the loss of one or more important connections, high demands and/or important generating units at the load centers being out of service.
- Limited resources of reactive power.

The time-scale for the onset situation ranges from minutes to hours. The reaction of the operator is less confident than for other situations, like frequency and overload problems [94]. During the collapse the following observations can be made [94, 99, 200]:

- A triggering event, as often the loss of one or more of the still in service heavily overloaded circuits, occurs.
- The increase of reactive power generation does not result in an increase in voltage.
- Field excitation of generators reaches their limits.
- The effect of the tap-changers is a decrease of the secondary voltage instead of an increase.

The time-scale for the collapse ranges from seconds to minutes [94]. In the remainder of this section a typical example of voltage instability will be given based on simulations. The simulation model will be used in subsequent chapters as a test system to investigate the impact of renewable and distributed generation on voltage stability and to test the preventive control system that will be developed.

2.4.1 Test System

The test system that is used throughout this thesis is given in figure 2.23. The system is first introduced in the textbooks of Taylor and Kundur [99, 185]. It consists of two areas: a generation area (on the left side) and an area with mainly loads (on the right side). These two areas are interconnected by means of a
200 km long transmission corridor of five parallel transmission lines. The nominal voltage of this corridor is 500 kV. The system is heavily shunt compensated.

The system contains three generators: two in the generation area (GEN1 and GEN2) and one in the load area (GEN3). GEN1 represents the rest of the system and is modeled as infinite bus (constant voltage, infinite power supply). GEN2 is a normal synchronous generator of 2200 MVA equipped with an automatic voltage regulator and a speed governor with speed droop control. GEN3 is a normal synchronous generator of 1400 MVA. This generator is equipped with an automatic voltage regulator, a speed governor and an OXL. For both, GEN2 and GEN3 a thermal power plant is assumed as prime-mover.

Loads are connected to two buses: bus 9 and bus 10. Both loads are aggregated load models that represent the individual loads connected to the particular bus. The load connected to bus 9 consists of commercial and residential loads and consumes at nominal voltage 3384 MW and 971 MVar. 50 % of the load is constant power and 50 % of the load is constant impedance. The load at bus 9 is connected via an LTC to the rest of the system. The load connected to bus 10 consists of industrial loads and consumes at nominal voltage 3271 MW and 971 MVar. The load is 100 % constant power.

The event that initiates the voltage instability is the trip of one of the five transmission lines between buses 5 and 6 at \( t = 10 \text{ s} \).
2.4 Typical Voltage Instability Scenario

2.4.2 Simulation Approach

The simulations in this thesis are performed in Matlab/Simulink using the SimPowerSystems toolbox [80]. The reason for using Matlab/Simulink instead of dedicated software, is that Matlab/Simulink is highly flexible for developing custom models. Furthermore the conversion of the developed models to the demonstrator that is developed in chapter 9 can be easily done. Finally the models could be easily exchanged between project partners within the DEVS project.

The simulations are done with the phasor solution method [80]. For the electrical network this method uses a set of algebraic equations. The voltage and current phasors are determined at fundamental frequency (magnitude and phase angle). For the machines, turbines and regulators a reduced state-space model is used with the slow dynamic states of these devices. With this solution method fast oscillation modes are neglected and the simulation time is drastically reduced. This is a significant advantage for voltage stability studies. Note that because in voltage stability studies we are especially interested in voltage magnitudes and phase angles and not in fast oscillation modes, the simplifications will not have a major impact on the result.

The standard models of SimPowerSystems are used. One exception for this is the model for the OXL, for which the OXL model with integral control of field current is used (see section 2.3.1.2). The exact models and data used in this simulation are given in appendix A.

2.4.3 Simulation Result

The simulation result is given in figures 2.24 and 2.25. In figure 2.24 the magnitude of the voltages at all buses in the system are shown. These voltages are sorted per bus type: the first (upper) graph contains the generator voltages, the second graph the transmission voltages, the third graph the sub-transmission level voltages and finally the fourth (lower) graph shows the load voltages. Figure 2.25 shows measures of devices that play an important role in voltage (in)stability. The first (upper) graph gives the LTCs secondary voltage (both reference and measured) and the second graph shows the LTCs tap position. The third graph gives the field current of generator 3 (both the measurement and the limit value) and the fourth (lower) graph shows the control signal from the OXL.

Following the trip of one of the parallel transmission lines at \( t = 10 \) s all voltages drop except the voltage of generator 1, which was modeled as infinite bus. Generator 3 reacts on the drop in bus 3 voltage by increasing its field current to provide more reactive power. This field current is increased above its long-term limitation. This is allowed for some time because an OXL with integral control of field current is used.

30 s after the trip of the line, the LTC decreases its tap in order to restore its secondary voltage. The primary voltage reduces and this results in an even higher field current of the generator. At \( t \approx 50 \) s the OXL start to limit the field current.

As a result of the operation of the OXL, the system voltages decrease further. Note that the voltage drop at buses in the load area (buses 3 and 6 through 10) is much more severe than the voltage drop at the buses in the generation area (buses 1, 2, 4 and 5). The problem is thus, located in the load area.

The bus 9 voltage is decreased far below its reference value. The LTC reacts on this by decreasing its tap position. Because the reactive power supply in the load area is limited, each decrease in tap position lowers both the LTCs primary and secondary voltage. Each change in tap position deteriorates the system further. At \( t \approx 230 \) the system has been deteriorated so much that the voltages collapse. The short-term load dynamics of the load model play a role in this. Note that all system voltages collapse and the problem has spread throughout the system. So although the instability started locally (in the load area), the collapse is system-wide.

In section 2.3 the power system aspects related to voltage instability have been discussed. The given example shows these aspects. The problem starts at the transmission system level where the power transfer is limited. Subsequently one generator limits its reactive power production. The LTC tries to restore its secondary voltage and contributes to the deterioration of the system voltages.
Figure 2.24. The bus voltages sorted per bus type.
Figure 2.25. The LTC voltage (first graph), the LTC tap position (second graph), the field current of generator 3 (third graph) and the control signal of the OXL (fourth graph).
2.5 Voltage Instability Prevention

An important goal of this thesis is to design a system for voltage instability prevention. In subsection 2.5.1 an overview will be given of the existing countermeasures against voltage instability. Subsequently in subsection 2.5.2 two of these methods will be applied to the typical problem discussed in section 2.4.

2.5.1 Countermeasures

To avoid voltage instability, several countermeasures have been proposed in literature. An overview and comparison of the different methods is given in [201, 218].

A very effective means of preventive control, and often applied in practice, is load shedding [12, 70, 184, 199, 223]. This option results in service interruption of customers. Recent studies focus on fast instability detection and on determining the minimal amount of load that has to be shed [12, 70].

The Load Tap Changing transformer (LTC) plays an important role in load restoration and consequently contributes to voltage instability [200]. Another countermeasure is preventive control of LTCs, like: tap blocking [198, 217], tap locking [218], tap reversing [138, 216] and voltage set-point reduction [202]. The LTC preventive control can stop the process of voltage degradation, but it generally results in low customer voltages.

A countermeasure which has less negative consequences is controlling reactive power compensating devices [161, 188]. With these devices the reactive power losses in the system can be compensated and the power transfer can be increased to some extent. But, this is not always sufficient. Furthermore, voltage instability detection based on voltage levels becomes more difficult because they have higher values [200].

The last countermeasure is found in control of local generation. From the generators in the problem area virtual load reduction can be obtained by increasing the active power output [28]. The generator can be used for reactive power supply as well [158].

Several attempts to coordinate the different countermeasures are reported in [16, 67, 102, 202, 231]. For most methods a cost function is optimized to determine the optimal control strategy [16, 67, 102, 231]. The optimization is solved iteratively and that takes some time. For online control it is important that the optimization is fast enough so that the corrective action can be taken before the voltage collapses. The method described in [202] assists the decision making process and the actual handling is left to the operator. Voltage problems start locally and should therefore be solved locally. Smart grid architectures with a considerable amount of RDG are suitable for voltage control in general and voltage instability preventive control in particular. Several methods are described in literature [9, 143, 163, 237]. Many of these control schemes have a multi-agent structure [111, 112].

In [143] the coordination of two strategies: load shedding and reactive power increase are analyzed. Voltage instability detection is based on measuring voltage levels and the reactive power output of generators. The control is in heuristic closed loop form. In [9, 163] coordination of reactive power supply devices is described. The reactive power supply is determined based on optimization of the system voltages. In [237] the principles of multi-agent based load-shedding are described. The focus is how to reach consensus amongst the agents about the amount of load that needs to be shed.

2.5.2 UVLS and LTC Tap Blocking applied to Typical Instability Scenario

With the proper countermeasures voltage instability can be prevented. To demonstrate this, two types of countermeasures are applied to the typical voltage instability problem discussed in section 2.4. The applied countermeasures are: Under Voltage Load Shedding (UVLS) and LTC tap blocking.

For UVLS the method proposed in [184], which is designed for the same test circuit, is used. Load shedding is applied to the load at bus 10. The following heuristic rule describes the control:

If the voltage stays below 0.90 pu for 1.5 s: shed 5% of the area load.

This load shedding can be repeated two times.

LTC tap blocking is applied to the LTC between buses 8 and 9. The control is given by the following heuristic rule [201]:
2.6 Conclusion

In this chapter the theory of power system voltage stability has been outlined. This problem appeared in the 1970s in large interconnected systems for the first time. Voltage instability is caused by load dynamics that try to restore power consumption beyond the capability of the power system [200]. In the chapter the fundamentals of the voltage instability problem have been discussed and the power system aspects that play a major role in this type of problems have been outlined. The sequence of a typical voltage instability has been discussed based on simulation results obtained from a test system. This test system will be used throughout the thesis to investigate the impact of renewable and distributed generation on voltage instability and to test the control system that will be introduced. In the final section of this chapter the classical methods for voltage instability prevention were outlined.

If the primary voltage stays below 0.90 pu for 4 s: block the LTC.

The result for UVLS is given in figure 2.26. The first (upper) graph shows the bus 6 (solid line) and bus 9 (dashed line) voltage. The second graph contains the LTCs tap position. The third graph gives the field current of generator 3 and the fourth (lower) graph the control signal for the load shedding. The system behaves the same as in the case no preventive control is available up to the second tap movement. Each decrease in tap position results in a decrease in the load area voltages. The bus 10 voltage drops below 0.90 pu and when this pursues for 1.5 s the first 5 % of load is shed. Following this control action the voltages increase immediately. The LTC tries to restore the bus 9 voltage further, but due to the still limited amount of reactive power production this works counterproductive: the voltage is decreased instead of increased. The system does not collapse and the final voltages have a reasonable value: within 10 % of their initial values and the voltages are considered to be acceptable.

The result for LTC tap blocking is given in figure 2.27. The first (upper) graph shows the bus 6 (solid line) and bus 9 (dashed line) voltage. The second graph contains the LTCs tap position. The third graph gives the field current of generator 3 and the fourth (lower) graph the control signal for the tap blocking. In the case of LTC tap blocking the preventive control starts right after the operation of the OXL: the bus 9 voltage reaches the boundary value of 0.90 pu much sooner than the bus 10 voltage. Before the LTC is blocked, it makes one tap movement. After the blocking signal is sent, the tap stays at its current level and the load restoration mechanism is blocked. The system does not collapse and the voltages stay just within the bound of 10 %. Note, however, that the voltage drop with LTC tap blocking is much larger than was the case with UVLS, yet no actual load was shed.
Figure 2.26. The bus 6 and bus 9 voltage (first graph), the LTC tap position (seconds graph), the field current of generator 3 (third graph) and the control signal for the load shedding (fourth graph) for simulations with Under Voltage Load Shedding.
Figure 2.27. The bus 6 and bus 9 voltage (first graph), the LTC tap position (seconds graph), the field current of generator 3 (third graph) and the control signal for the LTC tap blocking (fourth graph) for simulations with LTC tap blocking.
Chapter 3

Voltage Instability Detection Methods

3.1 Introduction

In the previous chapter two definitions for voltage (in)stability were given: a symptom-based and a cause-based. The symptom-based definition states that the system is voltage stable when voltages stay steady and acceptable during normal operation and after being subjected to a disturbance [99]. The cause-based definition states that voltage instability stems from the attempt of load dynamics to restore consumption beyond the capability of the combined transmission and generation system [200]. In order to determine whether the system is voltage stable an indicator is required that translates the definitions in a measure that can be evaluated.

Following the symptom-based definition such an indicator should measure whether the system voltages are acceptable. A direct way of doing this, is measuring the voltage magnitudes and determine whether they are within acceptable limits.

Following the cause-based definition the indicator should provide information on whether the combined transmission and generation system is capable to provide the load demand. This indicator should be a measure for the distance to the loadability limit. This loadability limit is the point where the operating point, given by the intersection of the network and load characteristics, vanishes. In [200] it is proven that this loadability limit coincides with the saddle-node bifurcation point of both the long and short-term dynamics of the power system.

The point of maximum power transfer and the loadability limit are not necessarily the same. In figures 3.1.a, 3.1.b and 3.1.c the PV-curve of a radial transmission and generation system is illustrated with respectively the characteristic of a constant power load (a), a constant impedance load (b) and a general ZIP load with \( a = 0.4 \), \( b = 0.5 \), and \( c = 0.1 \) (c). The PV-curve is illustrated by the solid lines. The load characteristics are illustrated by the dashed lines for different values of the load demand \( z \). It is assumed that the power factor of the load is constant for increasing values of \( z \).

As can be seen, for a the constant power load, the point of maximum power transfer equals the loadability limit. For the constant impedance load there is no loadability limit and for the ZIP load (with the given parameters) the loadability limit is on the lower part of the PV curve. This operation at the lower part of the PV-curve is, however, unacceptable because it involves low voltage and high current and inverts the whole control and protection philosophy. The point of maximum power transfer is, consequently, a reasonable assumption for the loadability limit in voltage instability detection.

Load restoration by thermostatic loads or Load Tap Changers changes the behavior of the load. In this way a ZIP load exhibits in the long-term a constant power behavior when it is fed through a LTC [200]. So for loads behind a LTC the point of maximum power transfer is equal to the loadability limit of the longer-term dynamics.

Whether an indicator uses the the real loadability limit or the point of maximum power transfer, depends on the way the loads are modeled.

In this chapter the voltage instability indicators and detection methods used in this thesis are introduced. Section 3.2 will start by giving an overview of the existing methods. Subsequently in section 3.3 for
each of the definitions of voltage (in)stability a choice will be made for an indicator and these will be
discussed in more detail. One of the indicators is symptom-based, the other indicator is cause-based. In
section [3.4] for cause-based indicator an extension is proposed that makes the parameter more generally
applicable. Because in determining the cause-based parameter a simplified model is used, in section [3.5] it
is theoretically derived whether this simplification is valid. Section [3.6] will follow with a proof of concept
of the chosen methods. In section [3.7] a discussion will be given followed by conclusions in section [3.8].

3.2 Overview of Voltage Instability Detection Methods

A large number of detection methods for voltage (in)stability are proposed in the literature. An overview
and comparison of the methods proposed until 1994 can be found in [35]. A more recent overview of
computational techniques for voltage instability analysis is given in [4]. In this section a classification and
overview of the existing voltage instability detection methods are given.

3.2.1 Classification

In [35] voltage instability detection methods are classified in two main categories: given state-based indexes
and large deviation-based indexes. Given state based indexes are based on a particular operating state [35].
This can be the current operating point or a simulated post-contingency state. Large deviation based
indices take into account non-linearities (such as OXL operation) [35]. These indices generally give a
more accurate measure for voltage instability, but are computationally more demanding.
### 3.2 Overview of Voltage Instability Detection Methods

The distinction between both classes becomes vague. With the techniques presented in [4] it becomes possible to determine for a large number of operating points the given state-based indices. In this way given state based indices can be used in a large deviation based sense. Note that with the increasing computational capabilities the frontier will become even more vague.

In [221] it is argued that the main differences between voltage instability detection methods is whether they need wide area information or local information only. From this, two new classes appear: local measures and system wide measures. Local measures are indicators that require local information only. In this thesis we will consider information local when it can be obtained by measurements at two neighboring substations. System wide measures need information from a larger part of the system. In this thesis we will consider a measure system wide when it requires measurements from non-neighboring substations.

#### 3.2.2 Overview

In this subsection an overview of existing types of voltage instability detection methods is given. An overview of the classification of these indicators is given in Table 3.1

<table>
<thead>
<tr>
<th>Indicator</th>
<th>given state / large deviation</th>
<th>local / system-wide</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bus voltages</td>
<td>given state</td>
<td>local</td>
</tr>
<tr>
<td>Sensitivity analysis</td>
<td>given state</td>
<td>local</td>
</tr>
<tr>
<td>Eigenvalue analysis</td>
<td>given state</td>
<td>local / system-wide</td>
</tr>
<tr>
<td>Impedance-based methods</td>
<td>given state</td>
<td>local</td>
</tr>
<tr>
<td>Line loadability</td>
<td>given state</td>
<td>local</td>
</tr>
<tr>
<td>Continuation-based methods</td>
<td>large deviation</td>
<td>system-wide</td>
</tr>
<tr>
<td>Optimization-based methods</td>
<td>large deviation</td>
<td>system-wide</td>
</tr>
<tr>
<td>Point-of-collapse-based methods</td>
<td>large deviation</td>
<td>system-wide</td>
</tr>
<tr>
<td>Minimum singular value-based methods</td>
<td>given state</td>
<td>local / system-wide</td>
</tr>
</tbody>
</table>

The L-index [93, 120] and the Equivalent Node Voltage Collapse Index (ENVCI) [226] are measures which are derived from the bus voltages. These indicators give the distance to the point of maximum power transfer. The derived measures need the voltages at its own and neighboring buses.

**Sensitivity analysis**

Sensitivities are well-known indicators for voltage instability [29,62,68,69,146,154,183,213]. Various sensitivities are proposed as $\frac{d|U|}{dQ}$, $\frac{dS}{dY}$ [146,154] and $\frac{dQ_{load}}{dU_{gen}}$ [68,69]. For the $\frac{d|U|}{dQ}$ indicator, for instance, in case of a reactive power injection the voltage should increase ($\frac{d|U|}{dQ} > 0$). When this is not true the system is voltage unstable. Sensitivities provide information about the proper direction for countermeasures as well [35].

The sensitivities can be determined from the power system equations or from measurements. For the first case the power system equations are linearized around an operating point and from this the sensitivities can be found. In the second case, at two subsequent time instants $|U|$ and $Q$ (in the case of $\frac{d|U|}{dQ}$) are determined,
from this $\Delta |U|$ and $\Delta Q$ follow. Note that in this last case the indicator can only be determined when the measures at both time instants differ. Furthermore, when the differences are small, the measurement based sensitivities might hide a problem [35].

Eigenvalue analysis

Another way of voltage instability detection is based on eigenvalue analysis [65, 121, 141, 170]. For this type of analysis the non-linear power system equations are linearized around an operation point:

$$
\begin{bmatrix}
\Delta P \\
\Delta Q
\end{bmatrix} =
\begin{bmatrix}
J_{PS} & J_{PU} \\
J_{QS} & J_{QU}
\end{bmatrix}
\begin{bmatrix}
\Delta \delta \\
\Delta |U|
\end{bmatrix}
$$

(3.1)

Where $\Delta P$ and $\Delta Q$ are the vectors with the incremental changes in active and reactive bus power, $\Delta \delta$ and $\Delta |U|$ are the vectors with the incremental changes in bus voltage angle and magnitude, and $J_{PS}$, $J_{PU}$, $J_{QS}$ and $J_{QU}$ are submatrices of the Jacobian matrix.

Assuming $\Delta P = 0$, the relation between $\Delta Q$ and $\Delta |U|$ becomes:

$$
\Delta Q = [J_{QV} - J_{QS}J_{PU}^{-1}J_{PV}] \Delta |U| = J_R \Delta |U|
$$

(3.2)

Where $J_R$ is called the reduced Jacobian. From $J_R$ the left and right eigenvectors are determined. The system is voltage stable when all real parts of the eigenvalues are positive and unstable when at least the real part of one eigenvalue is negative. When one or more eigenvalues are zero, the system is on the edge of voltage stability. The left and right vectors of eigenvectors provide specific information: the right eigenvectors determine in which direction the system will evolve and the left eigenvectors shows which actuators are more effective to control [200].

Impedance-based methods

Several methods exist that are based on equivalent impedances [42, 66, 74, 105, 221, 222, 227, 229]. The most well-known impedance based method is based on the fact that at the point of maximum power transfer it holds that [221]:

$$
|Z_{\text{load}}| = |Z_{\text{line}}|
$$

(3.3)

Where $Z_{\text{load}}$ is the equivalent complex impedance of the load and $Z_{\text{line}}$ is the equivalent complex impedance of the line. The ratio between the magnitudes of these impedances gives a measure for the distance to the point of maximum power transfer. The main difference among the methods based on this principle is the determination of the equivalent impedances.

Line loadability

Another class of the methods are those that immediately determine the distance of the current operating point to the point of maximum power transfer [11, 21, 88, 116, 211, 212, 239]. The difference with the impedance-based methods is that the line loadability is a more intuitive measure than the impedance margin and can be used in a more straightforward way to determine a countermeasure against voltage instability [88].

In [88] a method is proposed where an impedance based method is converted to a line loadability based method. In [11, 21, 116, 211, 212, 239] methods are proposed where the line loadability is directly determined based on the power flow equations of the line.

Continuation-based methods

In continuation based methods the PV (or QV) curve is tracked in order to determine the distance to the point of maximum power transfer [3, 26, 32, 119]. A continuation parameter $\mu$ is defined (often the load demand) and the power flow equations are solved for increasing values of this parameter. The problem with solving the power flow equations is that the solution diverges around the point of maximum power
3.3 Voltage Instability Detection Indicators used in this thesis

In order to solve this problem the continuation based methods solve the load flow in two steps: first a prediction of the solution for the next value of the continuation parameters is made, secondly the prediction is corrected based on the actual load flow solution. Differences among the methods found in literature are in the prediction and correction stages.

When in the correction stage the load flow diverges, the continuation parameter has a value beyond the point of maximum power transfer. Either the step in the continuation parameters should be reduced [99] or another continuation parameter should be chosen (so for instance instead of the load demand the voltage should be used during the last steps) [200].

Optimization-based methods

The continuation parameter as defined for the continuation methods can also be maximized by direct optimization [92,136,149,197]. The objective is to maximize $\mu$ subject to the load flow equations. Limitations introduced by, for instance, overexcitation limiters can be taken into account as inequality constraints. The optimization problem is solved by an iterative method. Note that such a computation method is expected to be faster than a continuation-based method because the point of maximum power transfer is determined directly [200]. With the continuation methods, on the other hand, a complete trajectory of the system behavior is determined.

Point-of-collapse-based methods

With the point-of-collapse based methods the maximum loadability is also directly determined, but not by optimization [6,26,27]. In this method the critical point is expressed as solution of the power flow equations with as constraint that the Jacobian becomes singular. The singularity constraint can be formulated as:

$$J \pi \pi^T \text{ or } \pi^T J$$

where $\pi$ and $\pi^T$ are the right and left eigenvectors of the Jacobian for which it should hold that $\sum_{i=1}^{m} r_i e_i^2 = 1$ and $\sum_{i=1}^{m} l_i e_i^2 = 1$, where $m$ is the number of elements in the vector. The point-of-collapse based methods can, as was the case for the optimization based methods, be solved by an iterative approach as the Newton-Rhapson or Broyden techniques [162].

Minimum singular value based methods

Another voltage instability detection method based on the state Jacobian matrix is the minimum singular value of this matrix [20,107]. In order to determine this indicator the Jacobian $J$ is decomposed in the following way:

$$J = U \Sigma V^T = \sum_{i=1}^{m} \sigma_i u_i v_i^T$$

where $U$ and $V$ are $m \times m$ orthonormal matrices, $\pi$ and $\pi^T$ are the left and right singular vectors (which are the columns of matrices $U$ and $V$), $\sigma_i$ are the singular values and $\Sigma$ is a diagonal matrix $\Sigma = \text{diag} \{\sigma_i\}$. This decomposition can also be applied to the reduced Jacobian matrix $J_R$ (see equation (3.2)). The minimum singular value ($\min(\sigma_i)$) indicates whether the load-flow Jacobian is singular or not. The closer $\min(\sigma_i)$ is to zero, the closer the system is to singularity. When $\min(\sigma_i) = 0$ the system is singular. Furthermore the right singular vector $\pi$ indicates critical areas and $\pi^T$ indicates possible directions for emergency control.

3.3 Voltage Instability Detection Indicators used in this thesis

In this thesis two voltage instability indicators will be used: one mainly for on-line detection and control; and one for off-line evaluation of the system. The reason for using two indicators is twofold. The appropriate reason is that it is not fair to use the same parameter for evaluating the controller as what is used for
determining the control action. The second reason is that two definitions for voltage instability are both relevant for this work and for both definitions a different measure should be used.

3.3.1 Voltage Levels

The first measure that will be used in the thesis are the voltage magnitudes. This measure is based on the symptom-based definition of voltage stability and will be used for off-line evaluation of the system performance. According to this definition, for a voltage stable system all voltages should be steady and acceptable. So in order to use the voltage level as measure for instability, the term acceptable should be quantified. For this the Dutch grid code is used [57]. This code requires that the voltages due to long varying dynamics stay within $\pm 10\%$ of the nominal voltage.

To make a comparisons between different cases, the pre-disturbance voltage is used for evaluating the stability of the system instead of the nominal value. When all voltages stay within the $10\%$ of this initial value, the system is considered voltage stable.

Note that it is difficult to predict voltage instability with the voltage magnitude. In a highly compensated system the voltage will stay pretty constant for a long time. As soon as the voltage starts to deteriorate, this deterioration process can be very fast leaving no time to take countermeasures [200].

3.3.2 Maximum Loadability Index

As a measure for on-line detection and control a line loadability index is used: the Maximum Loadability Index ($MLI$). It is a measure of the distance of the current operating point to the point of maximum power transfer ($P_{\text{max}}$) of a certain line (see figure 3.2) and follows the cause-based definition of voltage (in)stability. From the $MLI$ a control strategy can easily be derived [212]. The $MLI$ is developed in [116,212]. The original method is extended in [211] to be able to use only local data from one of the buses. Furthermore in [211] the measure is updated to be able to include the impact of the tap changer. The $MLI$ assumes a constant power load. In [116] a method is proposed to include a generic ZIP load model in the $MLI$. In this thesis the original form of the $MLI$ as proposed in [212] will be used, because the original formulation is suitable to implement the parameter estimation method that will be introduced in section 3.4 with which the $MLI$ can be determined based on measurements only.

The derivation of the $MLI$ is as follows [212]. Consider the simple transmission system of figure 3.3. The complex conjugate of the receiving end power is:

---

*For dips in voltage on a shorter time scale, smaller dips are allowed. In this thesis, however, only the $10\%$ criterion is used.*
3.3 Voltage Instability Detection Indicators used in this thesis

\[ S^* = P - jQ = |U| \angle \delta_2 \cdot \left( \frac{|E| \angle \delta_1 - |U| \angle \delta_2}{R + jX} \right) \]  

(3.6)

Rearranging this equation we obtain:

\[ (PR + XQ) + j(PX - RQ) = |U| \angle \delta_2 \cdot |E| \angle \delta_1 - |U| \angle \delta_2 \]  

(3.7)

This equation can be rewritten in Cartesian form as:

\[ (PR + XQ) + j(PX - RQ) = |E||U| \cos(\delta_1 - \delta_2) - |U|^2 \]  

(3.8)

Separating the real and imaginary parts gives:

\[ (PR + XQ) = |E||U| \cos(\delta_1 - \delta_2) - |U|^2 \]  

(3.9)

\[ (PX - RQ) = |E||U| \sin(\delta_1 - \delta_2) \]  

(3.10)

Substitution of (3.10) for the cosine in (3.9) and solving for \(|U|^2\) gives:

\[ |U|^2 = - \left( RP + XQ - \frac{|E|^2}{2} \right) \pm \sqrt{ \left( RP + XQ - \frac{|E|^2}{2} \right)^2 - (R^2 + X^2) \left( P^2 + Q^2 \right) } \]  

(3.11)

The power flow equation has a solution if and only if:

\[ \left( RP + XQ - \frac{|E|^2}{2} \right)^2 - (R^2 + X^2) \left( P^2 + Q^2 \right) \geq 0 \]  

(3.12)

Note that the existence of a solution for the power flow equation is required for voltage stability. The maximum load that can be obtained from the transmission system is reached when:

\[ \left( RP + XQ - \frac{|E|^2}{2} \right)^2 - (R^2 + X^2) \left( P^2 + Q^2 \right) = 0 \]  

(3.13)

To determine the maximum loadability, \((P + jQ)\) is replaced by \(MLI \cdot (P + jQ)\):

\[ \left( R \cdot (MLI) \cdot P + X \cdot (MLI) \cdot Q - \frac{|E|^2}{2} \right)^2 - (R^2 + X^2) \cdot (MLI)^2 \cdot (P^2 + Q^2) = 0 \]  

(3.14)

Solving this equation for \(MLI\) gives [212]:

\[ MLI = \frac{|E|^2 \left[ \sqrt{(R^2 + X^2)(P^2 + Q^2)} - (R \cdot P + X \cdot Q) \right]}{2 \cdot (X \cdot P - R \cdot Q)^2} \]  

(3.15)

Three cases can be distinguished [212]:

- \( MLI > 1 \): there are two solutions for the power flow equation and \( P < P_{\text{max}} \);
• \( MLI = 1 \): there is one solution for the power flow equation and \( P = P_{\text{max}} \);
• \( MLI < 1 \): the solution of the power flow equation does not exist and the voltage will collapse.

So in case the \( MLI > 1 \) the system is voltage stable. When the \( MLI = 1 \) the system is at the stability limit. For \( MLI < 1 \) the system is unstable and might collapse. Taking \( MLI = 1 \) as threshold in off-line power system studies is reasonable. However, because the \( MLI \) is related to the cause of instability, taking \( MLI = 1 \) as threshold for emergency control, is wrong. As soon as this threshold is reached it is unlikely that stability can be restored. So the threshold should be chosen more conservatively. The exact value should be determined based on detailed power system studies.

From the \( MLI \) the margin to the point of maximum power transfer can be calculated with:

\[
\left( 1 - \frac{1}{MLI} \right) \cdot 100 \%
\]

### 3.4 Parameter Estimation for Maximum Loadability Index

In order to determine the \( MLI \), the parameters \( R + jX \) of the line should be known. In case of a transmission corridor the equivalent of these parameters can be used. In this thesis a transmission corridor is defined as the parallel transmission lines between two adjacent buses. For the \( MLI \) a fixed topology is assumed.

In a typical voltage instability scenario it is often possible that one of the parallel transmission lines trips and the equivalent parameters \( R + jX \) change \([99, 185, 200]\). The original \( MLI \) is unable to deal with these topology changes. To solve this, in this section a rather simple method is proposed to estimate in real-time the equivalent parameters of a connection.

The extended method for determining the \( MLI \) now consists of equations \( 3.15 \) and \( 3.19 \). The \( MLI \) can be computed for connections in a radial as well as in a meshed system. In this work it is used as an indication whether the connection between any two adjacent substations is beyond the capability limit. The method can be used in real-time if it is assumed that the dynamics can be modeled in quasi-steady state.

Voltage stability problems often coincide with topology changes, e.g. lines that trip, and generators with limited reactive power production. The extended method for determining the \( MLI \) does not need any prior knowledge of the topology. Topology changes in the connection will be reflected in the \( R \) and \( X \) of the connection and these are determined based on measurements. When generation gets limited, this will be reflected in the sending-end voltage \( E \). Also this parameter is determined based on measurements. So the \( MLI \) will automatically be updated when such an event occurs.
3.5 Application of MLI in the presence of line shunt capacitances

Both the MLI and the parameter estimation method are based on the transmission line model of figure 3.3. This model is, however, only valid for short transmission lines (< 80 km) [171]. For longer transmission lines and cable networks more sophisticated models are required. For medium length (80 to 240 km) transmission lines the $\pi$-equivalent model should be used, and for long (> 240 km) transmission lines the distributed model [171]. In these more sophisticated models the capacitances of the line are taken into account. In this section and its subsections it will be mathematically proven that neglecting these shunt capacitances when determining the MLI has no influence on the obtained value.

The $\pi$-equivalent model of a transmission line is given in figure 3.4. This $\pi$-equivalent will be the focus of this section, because in most cases it will be sufficient for voltage stability analysis.

When comparing figures 3.3 and 3.4 it becomes clear that the shunt capacitances introduce an error in the current measurements. Determining the MLI is based on $I_1$, but this current cannot be measured directly. For the voltage measurements no error is made: the voltages expected in determining the MLI can be measured.

The sending-end current and the receiving-end current are given by:

$$ I_1 = I + I_{1c} $$
$$ I_2 = I - I_{2c} $$

(3.20)

Where $I_1$ and $I_2$ are respectively the complex sending- and receiving-end currents and $I$ is the current through the series elements $R$ and $X$. $I_{1c}$ and $I_{2c}$ are the capacitor currents:

$$ I_{1c} = j \frac{1}{2} \omega C E $$
$$ I_{2c} = j \frac{1}{2} \omega C U $$

(3.21)

Where $U$ is the complex capacitor voltage. Determining the MLI is based on the current $I$. Because this current cannot be measured, it is estimated as follows:

$$ I_m = \frac{I_1 + I_2}{2} $$

(3.22)

3.5.1 Influence of line shunt capacitances on impedance measurements

Because the line shunt capacitances are neglected, the impedance measured by the impedance estimation method is:

Note that the model that should be used also depends on the frequency of the phenomena under study. In the case of voltage stability quasi steady-state analysis is preferred [200].
\[
Z_m = \frac{E - U}{I_m} = \frac{E - U}{I} \left(2I + j \frac{1}{2} \omega C E - j \frac{1}{2} \omega C U\right) = \frac{E - U}{1 + j \frac{1}{2} \omega C (E - U)}
\]

(3.23)

This can be rewritten as:

\[
Z_m = \frac{E - U}{1 + j \frac{1}{2} \omega C (E - U)}
\]

(3.24)

Recognizing that \( \frac{E - U}{I} = Z \) (see equation (3.17)) this becomes:

\[
Z_m = \frac{Z}{1 + j \frac{1}{2} \omega C Z} = \frac{(R + jX)}{1 + j \frac{1}{2} \omega C (R + jX)}
\]

(3.25)

Multiplying the numerator and denominator with the complex conjugate of the denominator gives:

\[
Z_m = \frac{R + j \left(X - \frac{1}{2} \omega C \left(R^2 + X^2\right)\right)}{1 - \frac{1}{2} \omega C X + \frac{1}{16} \omega^2 C^2 \left(R^2 + X^2\right)}
\]

(3.26)

So the measured resistance \( R_m \) and reactance \( X_m \) in terms of the real quantities \( R, X \) and \( C \) are:

\[
R_m = \text{Re} \left\{ Z_m \right\} = \frac{R}{1 - \frac{1}{2} \omega C X + \frac{1}{16} \omega^2 C^2 \left(R^2 + X^2\right)}
\]

\[
X_m = \text{Im} \left\{ Z_m \right\} = \frac{X - \frac{1}{2} \omega C \left(R^2 + X^2\right)}{1 - \frac{1}{2} \omega C X + \frac{1}{16} \omega^2 C^2 \left(R^2 + X^2\right)}
\]

(3.27)

The error in the resistance (\( \epsilon (R_m) \)) and the error in the reactance are (\( \epsilon (X_m) \)):

\[
\epsilon (R_m) = \frac{R_m - R}{R} \cdot 100 \% = \left(1 - \frac{1}{2} \omega C X + \frac{1}{16} \omega^2 C^2 \left(R^2 + X^2\right)\right) \cdot 100 \%
\]

\[
\epsilon (X_m) = \frac{X_m - X}{X} \cdot 100 \% = \left(\frac{X - \frac{1}{2} \omega C \left(R^2 + X^2\right)}{X - \frac{1}{2} \omega C X^2 + \frac{1}{16} \omega^2 C^2 X \left(R^2 + X^2\right)}\right) \cdot 100 \%
\]

(3.28)

3.5.2 Influence of line shunt capacitances on power measurements

Due to the shunt capacitances the measured receiving-end complex power is:

\[
S_m = U \cdot I_m^* = U \left(I + \frac{1}{4} j \omega C (E - U)\right)^* = \begin{small}S\end{small} - \frac{1}{4} j \omega C \left(U \cdot E^* - |U|^2\right)
\]

(3.29)

Rewriting \( E \) and \( U \) in their Cartesian form and substituting \( P + jQ \) for \( S \) gives:

\[
S_m = P + jQ - \frac{1}{4} j \omega C \left(|E||U| \cos (\delta_2 - \delta_1) + j|E||U| \sin (\delta_2 - \delta_1) - |U|^2\right)
\]

(3.30)

Splitting into the real and imaginary parts gives the measured active and reactive power:

\[
P_m = \text{Re} \left\{ S_m \right\} = P + \frac{1}{4} \omega C |E||U| \sin (\delta_2 - \delta_1)
\]

\[
Q_m = \text{Im} \left\{ S_m \right\} = Q + \frac{1}{4} \omega C \left(|U|^2 - |E||U| \cos (\delta_2 - \delta_1)\right)
\]

(3.31)

Because \( RQ - XP = |E||U| \sin (\delta_2 - \delta_1) \) and \( - (PR + XQ) = |U|^2 - |E||U| \cos (\delta_2 - \delta_1) \) equation (3.31) can be rewritten as:
3.5 Application of \( MLI \) in the presence of line shunt capacitances

\[
P_m = P - \frac{1}{4} \omega C (XP - RQ)
\]
\[
Q_m = Q - \frac{1}{4} \omega C (PR + XQ)
\]

(3.32)

The error in the measured active and reactive power due to the line shunt capacitances is thus:

\[
\epsilon(P_m) = \frac{P_m - P}{P} \cdot 100\% = -\frac{1}{4} \omega C \left( X - \frac{RQ}{P} \right) \cdot 100\%
\]
\[
\epsilon(Q_m) = \frac{Q_m - Q}{Q} \cdot 100\% = -\frac{1}{4} \omega C \left( X + \frac{PR}{Q} \right) \cdot 100\%
\]

(3.33)

3.5.3 Influence of line shunt capacitances on \( MLI \)

With the proposed detection method applied to a medium length transmission line or distribution cable (modeled by the \( \pi \)-equivalent), the \( MLI \) that is actually measured is:

\[
MLI_m = \frac{|E|^2}{2 \cdot (X_m \cdot P_m - R_m \cdot Q_m)^2} \left[ \sqrt{(R_m^2 + X_m^2)(P_m^2 + Q_m^2)} - (R_m \cdot P_m + X_m \cdot Q_m) \right]
\]

(3.34)

Substituting the quantities found for \( R_m, X_m, P_m \) and \( Q_m \) with equations (3.27) and (3.32) this equation becomes:

\[
MLI_m = \frac{|E|^2}{2 \cdot (X \cdot P - R \cdot Q)^2} \left[ \sqrt{(R^2 + X^2)(P^2 + Q^2)} - (R \cdot P + X \cdot Q) \right]
\]

(3.35)

Comparing equations (3.15) and (3.35) it becomes clear that:

\[
MLI_m = MLI
\]

(3.36)

So with the proposed measurement of the current, no error is introduced by neglecting the shunt capacitances of the line or cable model.

3.5.4 Transmission corridor

During the discussion so far, one line (or cable) was assumed. A transmission corridor (defined in this thesis as all parallel transmission lines between two adjacent buses) can, however, consist of several parallel circuits, modeled by parallel \( \pi \)-sections. To generalize the discussion, in this subsection the consequences of having parallel lines on the equivalent resistance, reactance and capacitances will be discussed.

In case \( N \) equal \( \pi \)-sections are connected in parallel the equivalent line parameters are:

\[
R_{eq} = \frac{R}{N}
\]
\[
X_{eq} = \frac{X}{N}
\]
\[
C_{eq} = \frac{N C}{2}
\]

(3.37)

In this equation \( R, X \) and \( C/2 \) are the parameters of a single transmission line.

So in case of a transmission corridor the equivalent line parameters and power flows should be used. These can be determined by taking the sum of the currents and power flows between two adjacent buses.
3.6 Test Voltage Instability Indicators

To test the chosen voltage instability indicators, simulations are done with the circuit of figure 2.23. The data is as given in appendix A. In this system at $t = 5 \text{s}$ one of the five parallel transmission lines of the transmission corridor between the generation and load area trips. As discussed in section 2.4.1, this initiates a voltage instability process, that finally results in a collapse.

The magnitude of the voltages in the system are given in figures 3.5 and 3.6. Buses 1, 2 and 4 are excluded, because they do not provide any additional information. The solid lines are the measured voltages and the dashed lines the respective lower 10% bounds. As discussed before, this 10% bound is based on the pre-disturbance voltage.

The voltage collapse is clearly visible from all bus voltages. In all cases, except the bus 5 voltage, the voltage drops below its 10% bound at the moment the overexcitation limiter of GEN3 starts to reduce the field-current. The bus 5 voltage drops below this bound at the moment the voltage collapses. The bottleneck in the power transfer is the transmission corridor between the generation and load area, so the fact that the problem is sooner detected in the load area is obvious.

From figures 3.5 and 3.6 it becomes clear that voltage instability detection based on voltage levels can give an early warning for voltage instability. Because in the problematic area (the load area) the voltages are lower than in a non-problematic (the generation area) the problem can be located.

The $MLI$ is determined for the line between buses 4 and 5, the transmission corridor between buses 5 and 6 and the line between buses 7 and 8. The equivalent resistance and reactance are determined from equation (3.19). The current required to determine these quantities is calculated from equation (3.22). In case of the transmission corridor $I_1$ and $I_2$ are the sum of the individual line currents of the transmission corridor. The result is given in figure 3.7.

The $MLI$ between buses 4 and 5 is high. So the loading of this connection is relatively light. On the contrary the $MLI$ between buses 5 and 6 is low. At the moment the line trips, it reduces considerably and drops even further at the moment the OXL starts limiting the field-current of GEN3 at $t \approx 50 \text{s}$. The $MLI$ of the connection between buses 7 and 8 is larger than the one of the connection between buses 5 and 6, but lower than for the connection between buses 4 and 5.

Based on the $MLI$, the fault location can easily be detected: the connection for which the $MLI$ is the lowest, is the one closest to the maximum loadability. Comparing the different values in figure 3.7 shows that this is the transmission corridor between buses 5 and 6. This result is as expected (it is the connection where the line trip occurs) and comparable to the results obtained with the voltage magnitudes. Note that the $MLI$ provides additional information compared to the voltage levels, because it is a measure for the distance to the point of maximum loadability.

A remark should be made about the accuracy of the $MLI$. As can be seen, the $MLI$ between buses 5 and 6 becomes one just at the moment the system collapses. However, the system crosses the point of maximum transfer before the system collapses. This can be clearly seen from the fact that the effect of the LTC reverses. There is thus an inaccuracy in the $MLI$, which could potentially be solved by using a Wide Area Measurement System type of measurement. Note that such a type of measurement can, however, not
Figure 3.6. The magnitude of the voltages at different buses in the system (solid lines) and the corresponding lower 10% bounds (dashed lines).
be determined based on local measurements only. 

Due to the above mentioned inaccuracy in the \(\text{MLI}\) and because taking countermeasures takes some time, for a preventive control system a threshold \((\text{MLI}_{\text{ref}})\) should be defined for which it holds that \(\text{MLI}_{\text{ref}} > 1\). Comparing the values of the different \(\text{MLI}\)s in figure 3.7 a preliminary guess for a threshold value can be made. This threshold should be below 1.8, because otherwise a false alarm will be given. When an early alarm should be given, a relative large \(\text{MLI}\) can be used as threshold (e.g. 1.6 or 1.5). In case the alarm should only be given at the moment the system starts to deteriorate, a smaller value for the \(\text{MLI}\) can be taken as threshold (e.g. 1.4 or 1.3). Later on in this thesis the threshold used for preventive control will be studied in more detail.

When determining the \(\text{MLI}\) the convention is that the power flows from the sending-end to the receiving-end. In order to determine what will happen when this is reversed, in figure 3.8 the \(\text{MLI}\) between buses 5 and 6 and the \(\text{MLI}\) between buses 6 and 5 is shown. As can be seen, the reverse \(\text{MLI}\) gives a different result. This result is actually meaningless because it increases when the system starts to deteriorate. So the direction of the power should be determined before measuring the \(\text{MLI}\) and based on this knowledge the correct convention should be used. Note that when during operation the power direction changes, the algorithm to determine the \(\text{MLI}\) should also change.

The measured and actual values of the equivalent resistances and reactances are listed in table 3.2. In this table also the error in the measured parameter is given. The pre-fault and post-fault measurements
3.6 Test Voltage Instability Indicators

Figure 3.8. MLI between buses 5 and 6 and the MLI between buses 6 and 5.

Table 3.2. Measurements and actual values of the resistances and reactances in the system and the error between them.

<table>
<thead>
<tr>
<th></th>
<th>( R_{45} )</th>
<th>( X_{45} )</th>
<th>( R_{56} )</th>
<th>( X_{56} )</th>
<th>( R_{65} )</th>
<th>( X_{65} )</th>
<th>( R_{78} )</th>
<th>( X_{78} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-fault</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Measured</td>
<td>0.00 ( \Omega )</td>
<td>1.00 ( \Omega )</td>
<td>0.78 ( \Omega )</td>
<td>14.65 ( \Omega )</td>
<td>0.78 ( \Omega )</td>
<td>14.65 ( \Omega )</td>
<td>0.13 ( \Omega )</td>
<td>0.40 ( \Omega )</td>
</tr>
<tr>
<td>Actual</td>
<td>0.00 ( \Omega )</td>
<td>1.00 ( \Omega )</td>
<td>0.75 ( \Omega )</td>
<td>14.40 ( \Omega )</td>
<td>0.75 ( \Omega )</td>
<td>14.40 ( \Omega )</td>
<td>0.13 ( \Omega )</td>
<td>0.40 ( \Omega )</td>
</tr>
<tr>
<td>Error</td>
<td>0.0 %</td>
<td>0.0 %</td>
<td>3.5 %</td>
<td>1.7 %</td>
<td>3.5 %</td>
<td>1.7 %</td>
<td>0.0 %</td>
<td>0.0 %</td>
</tr>
<tr>
<td>Post-fault</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Measured</td>
<td>0.00 ( \Omega )</td>
<td>1.00 ( \Omega )</td>
<td>0.97 ( \Omega )</td>
<td>18.31 ( \Omega )</td>
<td>0.97 ( \Omega )</td>
<td>18.31 ( \Omega )</td>
<td>0.13 ( \Omega )</td>
<td>0.40 ( \Omega )</td>
</tr>
<tr>
<td>Actual</td>
<td>0.00 ( \Omega )</td>
<td>1.00 ( \Omega )</td>
<td>0.94 ( \Omega )</td>
<td>18.00 ( \Omega )</td>
<td>0.94 ( \Omega )</td>
<td>18.00 ( \Omega )</td>
<td>0.13 ( \Omega )</td>
<td>0.40 ( \Omega )</td>
</tr>
<tr>
<td>Error</td>
<td>0.0 %</td>
<td>0.0 %</td>
<td>3.5 %</td>
<td>1.7 %</td>
<td>3.5 %</td>
<td>1.7 %</td>
<td>0.0 %</td>
<td>0.0 %</td>
</tr>
</tbody>
</table>

are shown. The measured values are determined based on the procedure described in section 3.4. For the connection between buses 4 and 5 there is only a reactance. This is also reflected in the measurements: no error is made. In the measurements for the transmission corridor for both, resistance and reactance, an error is made. The error in this measurement is equal to the error due to the shunt capacitances as determined from equation (3.28). Note that the line resistance and reactance in the post-fault period are larger than in the pre-fault stage. This is because the number of parallel lines is less. For the reverse detection method applied to the connection between buses 6 and 5 the measurements of the equivalent resistance and reactance are the same. For the connection between buses 7 and 8 no error in the measurements are made. This can be explained by the fact that this line has no shunt capacitances in the model.

3.6.1 Comparison of MLI with Equivalent Node Voltage Collapse Indicator

To evaluate the performance of the MLI, it is compared with the Equivalent Node Voltage Collapse Index (ENVCI). The ENVCI is a bus based voltage stability indicator. The method is proposed by Wang et. al. [226].

The ENVCI will be explained based on the transmission system of figure 3.3. This system represents a larger part of the power system [226]. As with the MLI, with the ENVCI it is determined whether a
solution of the power flow equations exist. If the power flow equations have a solution for all buses in the system, the system is voltage stable. For the circuit of Fig 3.2 the power flow equation of the receiving end is given by:

\[ P + jQ = |U| \angle \delta_2 \left( \frac{|E| \angle \delta_1 - |U| \angle \delta_2}{R + jX} \right)^* \]  \hspace{1cm} (3.38)

The voltages expressed in rectangular form are:

\[
\begin{align*}
|E| \angle \delta_1 &= \text{Re}\{E\} + j\text{Im}\{E\} \\
|U| \angle \delta_2 &= \text{Re}\{U\} + j\text{Im}\{U\}
\end{align*}
\]  \hspace{1cm} (3.39)

Substituting equation (3.39) in equation (3.38) and separation in real and imaginary parts gives:

\[
\begin{align*}
P \cdot R + Q \cdot X &= \text{Re}\{U\} \left( \text{Re}\{E\} - \text{Re}\{U\} \right) + \text{Im}\{U\} \left( \text{Im}\{E\} - \text{Im}\{U\} \right) \\
P \cdot X - Q \cdot R &= \text{Im}\{E\} \text{Re}\{U\} - \text{Re}\{E\} \text{Im}\{U\}
\end{align*}
\]  \hspace{1cm} (3.40)

When this system of equations is solvable, a solution for the power flow equations exist and the receiving end node is voltage stable [226]. The Jacobian is:

\[ J = \begin{bmatrix} \text{Re}\{E\} - 2\text{Re}\{U\} & \text{Im}\{E\} - 2\text{Re}\{U\} \\ \text{Im}\{E\} & -\text{Re}\{E\} \end{bmatrix} \]  \hspace{1cm} (3.41)

Equation (3.40) is solvable when:

\[ \det(J) = 2 \left( \text{Re}\{E\} \text{Re}\{U\} + \text{Im}\{E\} \text{Re}\{U\} \right) - \left( \text{Re}\{E\}^2 + \text{Im}\{E\}^2 \right) \geq 0 \]  \hspace{1cm} (3.42)

The Equivalent Node Voltage Collapse Index is now defined as:

\[ ENVCI = 2 \left( \text{Re}\{E\} \text{Re}\{U\} + \text{Im}\{E\} \text{Re}\{U\} \right) - \left( \text{Re}\{E\}^2 + \text{Im}\{E\}^2 \right) \]  \hspace{1cm} (3.43)

If for a certain bus \( ENVCI \geq 0 \) there is a solution for the power flow equations and the bus voltage is stable [226]. If the \( ENVCI \) is close to zero, it is an indication of a voltage instability problem. In figure 3.3 the \( ENVCI \) for the connections between buses 4 and 5, 5 and 6 and 7 and 8 of the system of figure 2.23 is given. It can be seen that the \( ENVCI \) is smaller for connection 7-8 than for connection 5-6. This might result in the incorrect localization of the instability problem. So we believe that the \( MLI \) is a better measure for voltage instability detection than the \( ENVCI \).

### 3.6.2 Influence on the \( MLI \) of an error in the phasor measurements

In this subsection it is investigated what the influence is on the \( MLI \) of an error in the phasor measurement. It is assumed that the \( MLI \) is determined based on phasor measurements only. This means that \( R \) and \( X \) are determined with equation (3.19) and the active and reactive power with:

\[ P = |U||I| \cos(\delta_2 - \theta) \]  \hspace{1cm} (3.44)

Substitution of equations (3.19) and (3.44) in equation (3.15) and rewriting gives:

\[ MLI = \frac{\sqrt{|E|^2 + |U|^2 - 2|E||U| \cos(\delta_1 - \delta_2) + |U| - |E| \cos(\delta_1 - \delta_2)}}{2|U| \sin^2(\delta_1 - \delta_2)} \]  \hspace{1cm} (3.45)

This means that when \( X, R, P \) and \( Q \) are determined by phasor measurements, the \( MLI \) is dependent on voltage related quantities only (\(|E|, |U|, \delta_1 \) and \( \delta_2 \)). Consequently, only an error in the voltage phasor measurements will influence the accuracy of the \( MLI \) and it is not necessary to take the current measurement
into account. Note furthermore that for the voltage phase angles ($\delta_1$ and $\delta_2$) it is the difference between them that is important. An error in both phase angles equal in sign and magnitude, will cancel. But, when these errors are equal in magnitude and opposite in sign, the overall error in the phase angle doubles.

In figure 3.10 the error in the $MLI$ of connection 5-6 (in per cent) is given as function of a deviation in one of the voltage phasor quantities $|E|$, $|U|$, $\delta_1$ and $\delta_2$ for the system of figure 2.23. The result is given for both the pre-disturbance (solid line) and a post-disturbance case (dashed line). The phasors are determined from the previous simulations and this data is used in equation (3.45) to determine the $MLI$. In each graph of figure 3.10 one of the parameters is varied during the calculation of the $MLI$.

The upper and middle graph of figure 3.10 show the error in the $MLI$ as function of a deviation in sending-end voltage (upper graph) and the receiving-end voltage (middle graph). It can be seen that the $MLI$ is not significantly influenced. For the pre-disturbance case an error of 1% in the voltage leads to an error of 2% in the $MLI$. Note that an error of 1% in the voltage magnitude is very large for accurate phasor measurements and are not likely to occur. So it can be concluded that the accuracy in phasor magnitudes does not significantly influence the accuracy of the determination of the $MLI$.

The lower graph of figure 3.10 shows the error in the $MLI$ as function of the error in the combined voltage phase angle $\delta_1 - \delta_2$. According to the standards for the PMU the phase angle should be measured with an accuracy of $0.018^\circ$ in a 50 Hz system and $0.022^\circ$ in a 60 Hz system [85][152]. The deviation in $\delta_1 - \delta_2$ given in the figure ranges from $-0.044^\circ$ till $0.044^\circ$ and corresponds with the largest deviation in the phaseangle.
angles that are allowed by the standard. It can be seen that this deviation has only a small influence on the MLI. So for the given system a deviation in the phase angle has no significant impact on the MLI (both in the pre- as well as in the post-disturbance case).

Regarding the previous conclusion one remark should be made. A deviation in the voltage phase angle appears via the sine and cosine functions in the MLI (see equation (3.45)). Because of the non-linear behavior of these functions, the value of the phase angles itself might influence the impact of a deviation in these quantities on the MLI. In order to investigate this, in figure 3.11 the error in the MLI is given as function of the phase angle $\delta_1 - \delta_2$. The error in the phase angle is $0.044^\circ$ (corresponding to the maximal allowed deviation). As in the former case the pre- and post-disturbance cases are studied. From figure 3.11 it can be seen that for small values of the phase angle (corresponding to short lines) the error in the phase angle has a large influence on the accuracy of the MLI. For these small values of $\delta_1 - \delta_2$ there is an important difference between the pre- and the post-disturbance case. In the pre-disturbance case the influence of the error is much smaller than in the post-disturbance case. This is because the ratio of the sending-end voltage magnitude and receiving-end voltage magnitude is different. The ratio between these quantities determines the ratio between the sine and cosine terms.
3.7 Discussion

In this section the results obtained in this chapter will be discussed. Based on the $MLI$ a direct control action can be determined. When the system should keep a margin $MLI_{ref}$ to the point of maximum power transfer and the current value of the $MLI$ is smaller than this threshold, the active and reactive power transfer of the connection should be reduced by \[\Delta P_{MLI} = -(MLI - MLI_{ref}) P \] \[\Delta Q_{MLI} = (MLI - MLI_{ref}) Q \]

in order to restore the margin. In these equations $P$ and $Q$ are the receiving-end active and reactive power. Consequently, the $MLI$ will be used for on-line detection and control. In section 3.6 it was discussed that when determining $MLI_{ref}$ it should be taken into account that the $MLI$ gives not a fully accurate measure for the point of maximum power transfer.

Both the $MLI$ and the voltage magnitudes are local measures. This property is of great importance for the decentralized control system that will be proposed in chapter 5.

The $MLI$ is a line loadability based index. In \cite{226} it was stated that the disadvantage of this type of indicators is that they ignore the system outside the line. In case of the $MLI$ this ’outside world’ is, however, incorporated in the measurements for the sending-end voltage and the receiving-end power. Changes in the remainder of the system will be reflected in these measures.

In section 3.1 it was discussed that for the cause-based definition the point of maximum loadability should be measured and that this measure is not necessarily the same as the point of maximum power transfer. The $MLI$ determines this point of maximum power transfer, because it assumes a constant power load. It is questionable whether this is a problem: in most cases the point of maximum power transfer is reached before the point of maximum loadability and with choosing a proper threshold for the controller, instability could be prevented in the cases the maximum loadability is before the point of maximum power transfer.

One final remark should be made. The $MLI$ suffers from one major drawback: when $XP = RQ$ the denominator becomes zero \cite{239}. In this case the $MLI$ tends towards infinity and becomes meaningless. In \cite{239} it was, however, also noted that this will not often happen. Nevertheless, when using the $MLI$ one should be aware of this deficit.

3.8 Conclusion

In this chapter two voltage instability indicators were chosen that will be used in this thesis. The first indicator will be used for off-line evaluation of the system performance. It is based on the bus voltage magnitudes and corresponds to the symptom-based definition of voltage stability which states that
the system is voltage stable when all voltages in the system are steady and acceptable during normal operation and after being subjected to a disturbance [99]. Simulations have shown that with this indicator the system behavior can easily be determined for off-line studies. For on-line detection and control the indicator is, however, less suitable. First of all it is not directly possible to determine a control action based on the voltage magnitudes. Secondly, in a highly compensated system the voltages can be rather high when the system is actually operated close to the point of collapse.

The second indicator is the Maximum Loadability Index [116, 212]. This indicator is a measure for the distance of the current operation point to the point of maximum power transfer. This indicator follows the cause-based definition of voltage (in)stability which states that voltage instability stems from the attempt of load dynamics to restore power consumption beyond the capability of the combined transmission- and generation system [200]. The indicator is suitable for on-line detection and control, because from the MLI a direct control measure can be derived.

In order to make the MLI more generic applicable, in this chapter an extension to the MLI is proposed, which is an on-line parameter estimation method. With this extension the MLI can be determined for each connection between two adjacent buses, and topology changes are immediately followed. Note that it is also possible to determine the MLI in a meshed system because the on-line parameter estimation method ensures that the equivalent line parameters of the connection between any two adjacent buses is used.

The MLI is based on a simplified transmission line (or cable) model and neglects line shunt capacitances. It is theoretically derived what the influence of these measures is on the estimated and measured parameters. Furthermore it is proven that in the MLI these influences cancel, so shunt capacitances have no effect on the MLI.

Based on simulations both indicators are proven to be able of determining the voltage (in)stability of the power system. The extension to the MLI works properly. The error that is measured in this estimation method equals the theoretical error introduced by neglecting the shunt capacitances. These simulations furthermore proof that the determination of the MLI should be conditional: the direction of the power-flow should be determined and based on this the sending-end and receiving-end should be determined. The MLI is compared with the equivalent node voltage instability indicator and it was concluded that the MLI gives a more accurate measure for voltage instability because it localizes the problem area. Furthermore it is studied what the influence is of errors in the phasor measurements on the accuracy of the MLI and it was concluded that these errors only become significant when the difference between the phase angles of the sending- and receiving-ends are small.
Chapter 4

Impact of Renewable and Distributed Generators on Voltage Stability at the Transmission System Level

4.1 Introduction

Renewable and Distributed Generators (RDG) influence the power flow and they have their influence on voltage stability. In this chapter the impact of having a large share of Renewable and Distributed Generators on voltage stability at the transmission system level will be investigated. The consequences of several particular RDGs on voltage stability are studied in the literature [1, 5, 21, 23, 25, 51, 78, 87, 103, 123, 125, 142, 150, 165, 175, 211, 215, 241]. In [5] it is proven that if a DG is able to provide fast dynamic reactive power injection it can prevent a power system from reaching a voltage unstable situation. Note that reactive power support is required by the grid code of the ENTSO-E from generation modules of 1 MW onward [58].

In [51] the impact of DG based on a Synchronous Generator (SG) and a DG based on an Induction Generator (IG) is studied. The SG is beneficial for voltage stability and the IG has a small negative impact on voltage stability due to its reactive power consumption. The negative impact of a general DG based on an IG is also shown in [87].

The consequences of Wind Turbines (WTs) equipped with IG are discussed in [21, 78, 123, 124, 142, 165, 211]. A large wind gust leads to a large variation in the electromechanical torque of the machine and subsequently in the generated active power. The reactive power consumption also increases. This may lead to a voltage collapse. Compensation of the reactive power requirement of the WTs with an IG can be beneficial [123, 142].

WTs based on IG are outdated nowadays and replaced by the Doubly Fed Induction Generator (DFIG) type. The impact of this type of WTs is investigated in [78, 125, 165, 175, 215, 241]. The converters of the DFIG have the possibility to provide voltage control. This is beneficial for voltage stability. When the control strategy of the DFIG is to prioritize active power production under all conditions this advantage might, however, disappear. At low voltages the DFIG works than at its converter limits. This implies that the DFIG behaves as directly connected IG.

The impact of a WT connected via a back-to-back Voltage Source Converter (VSC) to the grid is investigated in [165]. As with the DFIG, the VSC gives the possibility of voltage control. Generally it can be concluded that all RDGs interfaced through power electronics can be used in voltage control [122]. Although the voltage control capability these converters provide is beneficial for voltage stability, there is one major drawback. The converter current is limited to protect the power electronic components to a fixed value and this cannot be exceeded as is the case for a SG. When the converter current is limited, the voltage control capability has also its limitations.

In [125] the impact of WTs grouped in wind farms is investigated. Having a large wind farm might
introduce some voltage stability problems because the power production fluctuates with the wind speed and the wind speed at different locations in a farm is correlated. It is, consequently, better to have multiple smaller wind farms in the system where the wind speed at the different locations is less correlated. The impact of a micro-CHP is investigated in [23, 90, 144]. Two aspects of this type of generation are important for voltage stability. First of all, the micro-CHPs are located in the load area. Secondly, in a household with a micro-CHP the heat consumption and consumption of the electrical loads are correlated. The micro-CHPs have thus a positive impact on voltage stability because they reduce the power flow in the system.

Besides the positive and negative effects discussed above, in [25, 103, 123] the problem is addressed that small RDGs are not required to control the voltage. This might lead to high or low voltages at certain points in the grid. The contribution of this chapter is to provide a sound basis for including requirements regarding voltage support in the grid code.

Each of the discussed papers gives the result and conclusion for only one or two types of RDG. Furthermore only [51] has a generalized approach. The objective of this chapter is to give a clear overview of the consequences of Renewable and Distributed Generation on voltage stability at transmission level and to investigate how they can be applied for preventive control. In order to do this, in section 4.2 it is investigated what happens when a DG based on a certain generator type is connected to a system with a voltage instability problem. This general approach is based on the work of [51]. The prime-mover power is assumed to be constant.

In section 4.3 the impact of a wind farm on voltage stability is investigated. Two case studies are done. In the first study the wind farm is used in addition to the conventional local generation. This study follows the same line as section 4.2. In this study, however, power fluctuations due to turbulence are also taken into account. In the second case study the wind farm is used to replace part of the conventional generation. In this case the wind power experiences a significant dip. It is determined what the impact is of this dip on the voltage stability of the system.

In section 4.4 based on the simulations in the preceding sections, the possibilities for intelligent control of the RDGs are outlined. This is followed in section 4.5 with a discussion of the obtained results. Finally in section 4.6 the conclusions will be given.

### 4.2 General Impact of Distributed Generation on Voltage Stability

In this section the impact of DG in general on voltage stability is investigated. The goal is to provide an overview of the consequences of having different types of generators in the load area in case of a voltage instability. The types of generators under consideration are: the Synchronous Generator, the Induction Generator and the DG connected via a power electronic converter. For the SG both cases: with and without Automatic Voltage Regulator, are investigated. For the IG the cases with fixed compensation and variable compensation are considered. Typical application areas of the different types of generators are shown in table 4.1.

<table>
<thead>
<tr>
<th>DG type</th>
<th>Application area</th>
</tr>
</thead>
<tbody>
<tr>
<td>Synchronous Generator without AVR</td>
<td>Small greenhouse CHP</td>
</tr>
<tr>
<td>Synchronous Generator with AVR</td>
<td>Large greenhouse CHP</td>
</tr>
<tr>
<td>Induction Generator with Fixed Compensation</td>
<td>Locally compensated micro-CHP</td>
</tr>
<tr>
<td>Induction Generator with SVC</td>
<td>Centrally compensated micro-CHP</td>
</tr>
<tr>
<td>VSC interfaced DG</td>
<td>Variable speed Wind Turbine; solar PV</td>
</tr>
</tbody>
</table>

Simulations are done with the typical test system of figure 2.23 which was introduced in chapter 2. DGs are connected to both load buses 9 and 10. They thus represent the DG connected at the same substation as the loads. The adapted test circuit is shown in figure 4.1. For the DGs an aggregated model is assumed. The simulation model data, including the data of the different generators, is listed in appendix B. For the initialization the Load Flow and Machine Initialization tool of SimPowerSystems is used [80].

The initiating event is a trip of one of the transmission lines between buses 5 and 6. It is determined whether
4.2 General Impact of Distributed Generation on Voltage Stability

Figure 4.1. Simulation model for typical voltage instability scenario with DG connected to the load buses \([99, 185]\).

the system stays voltage stable and if the voltages stay acceptable. Simulations will be done for all five
types of generators and for different installed power for the DG.
In order to evaluate the impact of DG, the voltage magnitude of buses 6 and 9, and the \( MLI \) are used.
Note that the voltage of bus 10 is directly related to the voltage of bus 6. A detailed discussion of these
parameters is given in chapter \( [3] \).
Based on the \( MLI \) the margin to the point of maximum power transfer is determined with:

\[
\left( 1 - \frac{1}{MLI} \right) \cdot 100 \%
\]

This margin is determined for all cases and provides direct insight in the distance to instability.

4.2.1 Synchronous Generator without AVR

In this subsection the impact of adding DG of the type Synchronous Generator without AVR to the test
system is investigated. The Synchronous Machine pu Standard model of the Matlab/Simulink toolbox
SimPowerSystems is used \([80]\). The default parameters for this model are used.
The result for 150 MVA of DG connected to both load buses is given in figure 4.2. The active output power
is set to 100 MW. The DGs are initialized in such a way that \( \cos \phi = 0.98 \).
The first graph of figure 4.2 shows the bus 9 voltage (solid line) and the bus 6 voltage (dashed line). The second
graph shows the tap position of the LTC between buses 8 and 9. The first conclusion that can be drawn
from this figure is that the voltages do not collapse. So, the two DG's supply enough active and reactive
power to prevent the system from a collapse.
Although the system is prevented from a collapse, the LTC works counterproductive from \( t > 62 \) s: a
decrease in tap leads to a decrease in secondary (bus 9) voltage. This is the opposite behavior as expected
during normal operation. The decrease in tap position also leads to a decrease in the bus 6 voltage. Both
voltages drop a little below 10 % of the pre-disturbance voltage and are consequently unacceptably low.
The third graph of figure 4.2 shows the field current (upper graph) and the fourth graph the action of the
OXL of GEN3. The field current of this generator is limited for the longer term to 3.06 pu. This limits the
reactive power support from GEN3 and explains the fact that the LTC is counterproductive for \( t > 62 \) s.
The fifth graph of figure 4.2 gives the \( MLI \) of the transmission corridor between buses 5 and 6. Immediately
after the trip of the line the \( MLI \) drops, indicating that the system gets closer to \( P_{max} \). The subsequent
control actions result in a further decline in \( MLI \). After the OXL acts, the \( MLI \) deteriorates further, but
stays above one. This is, however, in contradiction with the reversed operation of the LTC. This inaccuracy
in the \( MLI \) was already addressed in chapter \( [3] \).
Figure 4.2. Simulation result of adding DG of the type synchronous generator without AVR to both load buses.
4.2 General Impact of Distributed Generation on Voltage Stability

Table 4.2. Simulation results for the impact of Synchronous Generator without AVR based DG on voltage stability.

| S [MVA] | P [MW] | Δ|U₀| [%] | MLI (post) [%] | Margin |
|--------|-------|------|------|--------------|--------|
| 30 20  | 69.7  | 1.00 | 0    | Collapse     |        |
| 60 40  | 69.7  | 1.00 | 0    | Collapse     |        |
| 90 60  | 69.7  | 1.00 | 0    | Collapse     |        |
| 120 80 | 16.5  | 1.22 | 18   | Low voltage  |        |
| 150 100| 13.8  | 1.26 | 21   | Low voltage  |        |
| 180 120| 11.9  | 1.29 | 22   | Low voltage  |        |
| 210 140| 10.1  | 1.32 | 24   | Low voltage  |        |
| 240 160| 10.1  | 1.34 | 25   | Low voltage  |        |
| 270 180| 1.8   | 1.55 | 35   | Stable       |        |
| 300 200| 0.9   | 1.58 | 37   | Stable       |        |

The simulation of figure 4.2 shows that a DG based on a synchronous generator without AVR can prevent the considered system from a voltage collapse, the voltages, however, stabilize to a value lower than prescribed in the grid code.

The same study is done for a total DG penetration at each load bus ranging from 30 MVA to 300 MVA. This corresponds with 0.86% to 8.6% of the local loads. The system is initialized so that for the DGs \( \cos \phi = 0.98 \) capacitive.

The table shows that the impact the DG based on SG has on voltage stability is dependent on the DG’s size. For the considered test system a typical voltage collapse can be avoided if the total DG capacity in the load area is 3.5% (120 MVA) of the load. The voltages can be maintained to an acceptable value when the total DG capacity in the load area is 7.8% (270 MVA) of the load.

4.2.2 Synchronous Generator with AVR

In this subsection the impact of adding DG of the type Synchronous Generator with AVR to the test system is investigated. For the AVR the Excitation System of the SimPowerSystems toolbox is used [80]. The voltage set-point of the AVR is chosen in such way that initially \( \cos \phi = 0.98 \) capacitive. For the rest the simulation model and conditions are the same as in section 4.2.1.

The result for 150 MVA of DG (active output power 200 MW) connected to both load buses is given in figure 4.3. The first graph shows the bus 9 voltage (solid line) and the bus 6 voltage (dashed line). The second graph gives the tap setting of the LTC. The combined actions of the AVR's of GEN3 and the two DG’s immediately following the trip of the line, stabilize the post disturbance voltages. For the LTC it is not necessary to change its tap position. Both voltages drop a little bit, but stay clearly within the 10% limit. So as can be expected, a DG of the type SG with AVR is better capable of maintaining the post-disturbance voltages than the SG without AVR.

The third graph of figure 4.3 shows the field current and the fourth graph the action of the OXL of GEN3. The field current stays slightly below 3.06 pu, so the OXL does not react.

The fifth graph of figure 4.3 gives the MLI of the transmission corridor between buses 5 and 6. The \( MLI > 1 \) indicates that the transmission corridor is not operated beyond \( P_{\text{max}} \) and the system is voltage stable regarding the cause-based definition. Note, however, that the \( MLI \) drops considerably. The margin to \( P_{\text{max}} \) reduces from 47% to 35%.

As was the case for the SG without AVR, the same study is done for different DG penetrations. The results are listed in table 4.3.

When comparing these results with the results for SG without AVR (table 4.2), it can be noticed that a much lower penetration is required in the case the generators have an AVR. A voltage collapse can be avoided if the total DG capacity in the load areas is about 0.5% (18 MVA) of the load. The voltages can be maintained to an acceptable value if the total DG capacity in the load area’s is about 4.3% of the load (150 MVA). The difference with the SG without AVR is because the AVR provides voltage support. The most important limitation of this is the allowable field current.

The simulation with the generator of 60 MVA should be discussed in some more detail because it starts...
Figure 4.3. Simulation result of adding DG of the type synchronous generator with AVR to both load buses in the test system.
Table 4.3. Simulation results for the impact of Synchronous Generator with AVR based DG on voltage stability.

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<td></td>
<td></td>
<td></td>
<td>Oscillate</td>
</tr>
<tr>
<td>90</td>
<td>60</td>
<td>3.07</td>
<td>4.41</td>
<td>1.2</td>
<td>1.50</td>
</tr>
<tr>
<td>120</td>
<td>80</td>
<td>2.63</td>
<td>3.10</td>
<td>0.6</td>
<td>1.52</td>
</tr>
<tr>
<td>150</td>
<td>100</td>
<td>2.18</td>
<td>2.61</td>
<td>0.6</td>
<td>1.53</td>
</tr>
<tr>
<td>180</td>
<td>120</td>
<td>1.94</td>
<td>2.39</td>
<td>0.6</td>
<td>1.54</td>
</tr>
<tr>
<td>210</td>
<td>140</td>
<td>1.77</td>
<td>2.22</td>
<td>0.5</td>
<td>1.55</td>
</tr>
<tr>
<td>240</td>
<td>160</td>
<td>1.64</td>
<td>2.09</td>
<td>0.5</td>
<td>1.56</td>
</tr>
<tr>
<td>270</td>
<td>180</td>
<td>1.53</td>
<td>1.98</td>
<td>0.5</td>
<td>1.57</td>
</tr>
<tr>
<td>300</td>
<td>200</td>
<td>1.44</td>
<td>1.89</td>
<td>0.5</td>
<td>1.58</td>
</tr>
</tbody>
</table>

4.2 General Impact of Distributed Generation on Voltage Stability

The simulation results for the impact of Synchronous Generator with AVR based DG on voltage stability show that an AVR might introduce oscillatory behavior which can be prevented by a power system stabilizer [99]. In this study no power system stabilizer is used. The simulation without exciter endorse this: under the same conditions the synchronous generator without AVR does not oscillate.

4.2.3 Induction Generator with Fixed Compensation

Induction generators consume reactive power when they produce active power. When using this type of generator as DG this reactive power consumption should be compensated. There are different technologies for this. In this thesis fixed compensation and variable compensation are considered. In this subsection the impact of adding a DG of the type Induction Generator with fixed compensation to the test system on voltage instability is investigated.

For the IG the Asynchronous Machine pu Units model of SimPowerSystems is used, which is a standard model for an induction machine [80]. For the compensation a fixed capacitor is used which is modeled with the Three-Phase Parallel RLC Load model of SimPowerSystems. The compensation is set such that during normal operation the reactive power consumption of the uncompensated induction generator is fully compensated.

The detailed result for 150 MVA of DG connected to each of the two load buses is given in figure 4.4. For the DGs the mechanical input power is 105 MW which gives an output power of approximately 100 MW. The reactive power compensation at nominal voltage for the generator at bus 9 is 102 Mvar and at bus 10 120 Mvar.

The first graph of figure 4.4 shows the bus 9 voltage (solid line) and the bus 6 voltage (dashed line). The second graph gives tap setting of the LTC between buses 8 and 9. None of the voltages collapse, but they drop below the 10 % bound and are thus unacceptably low.

The third graph of figure 4.4 gives GEN3's the field current and the fourth graph the action of the OXL. These graphs show that after $t = 49$ s the OXL starts to limit the field current. The decrease of the tap setting does not increase the bus 9 voltage anymore and even decreases the bus 9 voltage. This is because the reactive power injection of GEN3 is limited.

The fifth graph of figure 4.4 gives the $MLI$ of the transmission corridor between buses 5 and 6. Immediately after the trip of the line the $MLI$ drops, indicating that the system gets closer to $P_{\text{max}}$. The subsequent control actions after the trip of the line result in a further decline in $MLI$. After the OXL acts, the $MLI$ deteriorates further, but stays above one. This is, however, in contradiction with the reversed operation of the LTC. This inaccuracy in the $MLI$ was already addressed in chapter 3.

The simulations of figure 4.4 show that a DG based on an induction generator with fixed compensation can prevent the system from a voltage collapse, but it cannot prevent that the system voltages become unacceptably low.

The same study is done for a total DG penetration at each load bus ranging from 30 MVA to 600 MVA.
Figure 4.4. Simulation result of adding DG of the type induction generator with fixed compensation to both load buses in the test system.
4.2 General Impact of Distributed Generation on Voltage Stability

Table 4.4. Simulation results for the impact of Induction Generator with fixed compensation based DG on voltage stability. \( Q \) in this table is the reactive power supplied by the DG’s fixed compensation.

<table>
<thead>
<tr>
<th>( S ) [MVA]</th>
<th>( P ) [MW]</th>
<th>( P_{\text{mech}} ) [MW]</th>
<th>( Q ) DG1 [Mvar]</th>
<th>( Q ) DG2 [Mvar]</th>
<th>( \Delta(\Delta U_0) ) [%]</th>
<th>MLI (post)</th>
<th>Margin [%]</th>
</tr>
</thead>
<tbody>
<tr>
<td>30</td>
<td>20</td>
<td>21</td>
<td>21</td>
<td>24</td>
<td>69.6</td>
<td>1.00</td>
<td>0</td>
</tr>
<tr>
<td>60</td>
<td>40</td>
<td>42</td>
<td>41</td>
<td>48</td>
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<td>63</td>
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<td>72</td>
<td>69.6</td>
<td>1.00</td>
<td>0</td>
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<tr>
<td>120</td>
<td>80</td>
<td>84</td>
<td>82</td>
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<td>1.00</td>
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<td>126</td>
<td>124</td>
<td>144</td>
<td>14.3</td>
<td>1.25</td>
<td>20</td>
</tr>
<tr>
<td>210</td>
<td>140</td>
<td>146</td>
<td>144</td>
<td>167</td>
<td>13.8</td>
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<td>205</td>
<td>238</td>
<td>10.2</td>
<td>1.34</td>
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<tr>
<td>390</td>
<td>260</td>
<td>272</td>
<td>267</td>
<td>307</td>
<td>7.7</td>
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<td>29</td>
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<tr>
<td>420</td>
<td>280</td>
<td>293</td>
<td>287</td>
<td>331</td>
<td>7.5</td>
<td>1.41</td>
<td>29</td>
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<tr>
<td>450</td>
<td>300</td>
<td>312</td>
<td>307</td>
<td>354</td>
<td>0.8</td>
<td>1.60</td>
<td>38</td>
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<tr>
<td>600</td>
<td>400</td>
<td>418</td>
<td>411</td>
<td>467</td>
<td>0.8</td>
<td>1.66</td>
<td>40</td>
</tr>
</tbody>
</table>

This corresponds with 0.9 % to 17 % of the local loads. The results of the simulation are listed in Table 4.4. The table shows that a typical voltage collapse can be avoided if the total DG capacity in the load areas is about 4.3 % (150 MVA) of the load. The voltages can be maintained to an acceptable value if the total DG capacity in the load areas is about 11 % of the load (390 MVA). A DG based on a synchronous machine performs, however, better (see Tables 4.2 and 4.3).

To investigate the impact of the size of the compensation of the compensated Induction Generator, simulations are done for a varying amount of compensation. The size of the IG is 300 MVA. The active output power of the generator is 200 MW. The compensation is varied between 0 MVAR and 400 MVAR. The results are listed in Table 4.5.

The table shows that 250 MVAR of compensation is required to prevent unacceptably low voltages. So the relative amount of compensation that is required during steady state.

Table 4.5. Simulation results for the impact of fixed compensation on voltage stability for an Induction Generator of 300 MVA. \( Q \) is the reactive power supplied by the compensation.

<table>
<thead>
<tr>
<th>( Q ) [MVAR]</th>
<th>( \Delta(\Delta U_0) ) [%]</th>
<th>MLI</th>
<th>Margin [%]</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>67.8</td>
<td>1.00</td>
<td>0</td>
</tr>
<tr>
<td>50</td>
<td>29.5</td>
<td>1.22</td>
<td>18</td>
</tr>
<tr>
<td>100</td>
<td>15.1</td>
<td>1.26</td>
<td>21</td>
</tr>
<tr>
<td>150</td>
<td>13.0</td>
<td>1.29</td>
<td>22</td>
</tr>
<tr>
<td>200</td>
<td>11.2</td>
<td>1.32</td>
<td>24</td>
</tr>
<tr>
<td>250</td>
<td>9.5</td>
<td>1.35</td>
<td>26</td>
</tr>
<tr>
<td>300</td>
<td>0.8</td>
<td>1.57</td>
<td>36</td>
</tr>
<tr>
<td>350</td>
<td>0.9</td>
<td>1.57</td>
<td>36</td>
</tr>
<tr>
<td>400</td>
<td>0.8</td>
<td>1.58</td>
<td>37</td>
</tr>
</tbody>
</table>

4.2.4 Induction Generator with Variable Compensation

In this subsection the impact of adding a DG of the type Induction Generator with variable compensation is investigated. As variable compensation the Static Var Compensator is used. The models and simulation data are the same as in section 4.2.3 except that for the compensation the Static Var Compensator (Phasor Type) model of SimPowerSystems is used. The nominal reactive power of the SVC and the reactive power limits are taken the same as the nominal power of the IG.

The detailed result for small generators of 150 MVA connected to both load buses is given in figure 4.5. For the DGs the mechanical input power is 104 MW which gives an output power of approximately 100MW.
Figure 4.5. Simulation result of adding DG of the type induction generator with variable compensation to both load buses.
4.2 General Impact of Distributed Generation on Voltage Stability

Both SVCs operate in voltage control mode. The voltage reference of the SVC at bus 9 is 0.95 pu and of the SVC at bus 10 1.04 pu. These values are chosen in such way that in the pre-disturbance time period the SVCs have still some margin for voltage control.

The upper graph of figure 4.5 shows the bus 9 voltage (solid line) and the bus 6 voltage (dashed line). The second graph shows the tap setting of the LTC. Both voltages exceed the 10 % bound and are thus unacceptably low.

The third graph of figure 4.5 shows the field current of GEN3 and fourth graph the action of the OXL. It can be seen that at $t = 48.6$ s the field current is limited to 3.06 pu. So despite the SVCs the disturbance forces GEN3 to operate at its field current limit. After the OXL starts limiting the field current, the LTC is counterproductive and its dynamics contribute to the voltage instability.

The lower graph of figure 4.5 shows the $MLI$ of the transmission corridor. The trip of the line introduces a considerable drop in the $MLI$. The field current limiting and the subsequent operation of the LTC results in a further drop of this indicator. The $MLI$ stays, however, above one. This is in contradiction with the reversed operation of the LTC. This inaccuracy in the $MLI$ was already addressed in chapter 3.

Figure 4.6 shows the operation of the SVC. The upper graph depicts the bus voltages, the second graph the SVCs susceptances $B_{SVC}$ and the lower graph the consumed reactive power (negative means production). First point that can be noticed is that the voltage is at a lower value than the references. This is because the SVC is droop-controlled. It can be seen that the reactive power consumption of the IG is effectively compensated (see period $t < 5$ s.) After the trip of the line the SVC’s are able to keep the voltages at a reasonable level. At $t = 48.6$ s the voltage drops. This is caused by the operation of the OXL. This voltage drop forces the SVCs to their limits: the SVC’s behave as constant capacitors at 1 pu.

The simulations of this subsection show that a DG based on an induction generator with SVC compensation can prevent the considered system from a voltage collapse, but cannot prevent the system from unacceptably low voltages.

**Figure 4.6.** The bus voltage, susceptance $B$ and the reactive power consumption $Q$ of the SVC. A positive $B_{SVC}$ (and negative $Q_{SVC}$) means operation in the capacitive region.
Impact of RDG on Voltage Stability at the Transmission System Level

Table 4.6. Simulation results for the impact of Induction Generator with variable compensation based DG on voltage stability. $Q_{\text{max}}$ in this table is the SVC’s maximum reactive power and $B$ is the susceptance of the SVC where a positive susceptance means capacitive.

| $S$ [MVA] | $P$ [MW] | $P_{\text{back}}$ [MW] | $Q_{\text{max}}$ [Mvar] | $B_9$ (post) | $B_{10}$ (post) | $\Delta|U_6|$ [%] | MLI Margin [%] |
|-----------|----------|------------------------|------------------------|-------------|--------------|----------------|--------------|
| 30        | 20       | 21                     | 30                     | 1.00        | 1.00         | 69.6          | 1.00 0       |
| 60        | 40       | 42                     | 60                     | 1.00        | 1.00         | 69.6          | 1.00 0       |
| 90        | 60       | 63                     | 90                     | 1.00        | 1.00         | 69.6          | 1.00 0       |
| 120       | 80       | 84                     | 120                    | 1.00        | 1.00         | 69.6          | 1.00 0       |
| 150       | 100      | 105                    | 150                    | 1.00        | 1.00         | 69.6          | 1.00 0       |
| 180       | 120      | 126                    | 180                    | 1.00        | 1.00         | 69.6          | 1.00 0       |
| 210       | 140      | 146                    | 210                    | 1.00        | 1.00         | 69.6          | 1.00 0       |
| 240       | 160      | 167                    | 240                    | 1.00        | 1.00         | 69.6          | 1.00 0       |
| 270       | 180      | 188                    | 270                    | 1.00        | 1.00         | 69.6          | 1.00 0       |
| 300       | 200      | 209                    | 300                    | 1.00        | 1.00         | 69.6          | 1.00 0       |
| 330       | 220      | 230                    | 330                    | 1.00        | 1.00         | 69.6          | 1.00 0       |
| 360       | 240      | 251                    | 360                    | 0.91        | 0.91         | 69.6          | 1.00 0       |
| 390       | 260      | 272                    | 390                    | 0.91        | 0.91         | 69.6          | 1.00 0       |
| 420       | 280      | 293                    | 420                    | 0.88        | 0.88         | 69.6          | 1.00 0       |

The same study is done for a total DG penetration at each load bus ranging from 30 MVA to 420 MVA. This corresponds with 0.9 % to 12 % of the local loads. The results are given in table 4.6.

The results for the IG with SVC are more or less similar to the results with fixed compensation. For the considered test system a typical voltage collapse can be avoided if the total DG capacity in the load areas is about 4.3 % (150 MVA) of the load. The voltages can be maintained to an acceptable value if the total DG capacity in the load area’s is about 8.6 % of the load (300 MVA). This similar behavior is mainly caused by the fact that the SVC operates at its limits, where behaves as constant capacitor. Furthermore the simulations show that a DG based on a SG performs better than the DG based on the IG with SVC.

The impact of the size of the SVC is investigated in table 4.7. It can be seen that the SVC should be a little bit larger than the fixed capacitor to maintain acceptable voltages (compare to table 4.5). The difference is, however, small and not considered to be significant.

Table 4.7. Simulation results for the impact of variable compensation on voltage stability for an Induction Generator of 300 MVA. $Q_{\text{max}}$ in this table is the SVC’s reactive power limit.

| $Q_{\text{max}}$ [Mvar] | $B_9$ [pu] (post) | $B_{10}$ [pu] (post) | $\Delta|U_6|$ [%] | MLI Margin [%] |
|-------------------------|------------------|---------------------|----------------|----------------|
| 0                       | 1.00             | 1.00                | 67.8          | 1.00 0         |
| 50                      | 1.00             | 1.00                | 67.8          | 1.00 0         |
| 100                     | 1.00             | 1.00                | 67.8          | 1.00 0         |
| 150                     | 1.00             | 1.00                | 67.8          | 1.00 0         |
| 200                     | 1.00             | 1.00                | 67.8          | 1.00 0         |
| 250                     | 1.00             | 1.00                | 67.8          | 1.00 0         |
| 300                     | 1.00             | 1.00                | 67.8          | 1.00 0         |
| 350                     | 0.88             | 0.88                | 67.8          | 1.00 0         |
| 400                     | 0.88             | 0.88                | 67.8          | 1.00 0         |

The same study is done for a total DG penetration at each load bus ranging from 30 MVA to 420 MVA. This corresponds with 0.9 % to 12 % of the local loads. The results are given in table 4.6.

4.2.5 Generator connected via Power Electronics Converter

In this subsection the impact of adding a DG connected via an inverter to the grid on voltage instability is investigated. For the inverter the Voltage Source Converter model described in appendix C is implemented in Matlab using the Simulink and simPowerSystems toolbox [80]. The VSC decouples the DG from the grid.

The detailed result for 150 MVA of DG (active power output 100 MW) connected to both load buses is
Figure 4.7. Simulation result of adding a DG connected via a VSC to both load buses in the test system.
Impact of RDG on Voltage Stability at the Transmission System Level

Figure 4.8. The output power and reference current of the VSC at bus 9.

The voltage reference of the VSC at bus 9 is 0.93 pu and for the one at bus 10 1.025 pu. These values give during the pre-disturbance interval an acceptable margin to control the voltage. The upper graph of figure 4.7 shows the bus 9 voltage (solid line) and the bus 6 voltage (dashed line). The second graph shows the tap setting of the LTC. Both voltages drop below the bound of 10 % and are thus unacceptably low. The third graph of figure 4.7 shows the field current of GEN3 and the fourth graph the action of the OXL. The field current of GEN3 is for the long term limited to 3.06 pu. Note that the start of operation of the OXL initiates the deterioration of the voltages. The decrease in tap position results in a decrease in secondary voltage (the bus 9 voltage) instead of an increase. The fifth graph of figure 4.7 shows the MLI of the transmission corridor. Immediately after the trip of the line the MLI drops, indicating that the system gets closer to $P_{\text{max}}$. The subsequent control actions after the trip of the line result in a further decline in MLI. After the OXL acts, the MLI deteriorates further, but stays above one. This is, however, in contradiction with the reversed operation of the LTC. This inaccuracy in the MLI was already addressed in chapter 3.

The VSC has a current limiter to protect the power electronics. Because, during current limitation priority should be given to either active or reactive power, the reactive power is limited beforehand to 0.5 pu. Note that this is a simplification from what will happen in practice. Figures 4.8 and 4.9 show the output power of the VSC (upper graph) and the VSC current (lower graph) for respectively the VSC at bus 9 and the VSC at bus 10. Both VSCs supply reactive power at the reactive power limits and consequently the voltage support is limited. The current of the VSCs is within its limits. The simulations show that DG connected via a VSC at buses 9 and 10 can prevent the system from a voltage collapse. The system voltages are, however, not prevented to become unacceptably low.

The same study is done for a total DG penetration at each load bus ranging from 30 MVA to 300 MVA. This corresponds with 0.9 % to 8.6 % of the local loads. The results of the simulation are given in table 4.8. The currents $I_9$ and $I_{10}$, and the reactive powers $Q_9$ and $Q_{10}$ are supplied by the DG at bus 9 respectively bus 10. The simulations once more highlight the importance of the DG’s penetration rate. For the considered test system a typical voltage collapse can be avoided if the total DG capacity in the load areas is about 2.6 %
4.3 Impact of Wind Farms on Voltage Stability

In the previous section the impact was investigated of general types of DG on voltage instability. From this study it can be concluded that the extra active and reactive generation in the load area is beneficial for voltage stability. The output power of the DGs was assumed to be constant. Although this assumption

(90 MVA) of the load. Low voltages can be prevented if the total DG capacity in the load areas is about 5.2% of the load (180 MVA). The VSC-coupled DG performs a little bit better than the SG without AVR. The SG generator with AVR performs better. This difference is due to the converter limits. When these would be chosen differently, this conclusion might change. The full converter coupled DG performs better than the IG based DGs.

### Table 4.8. Simulation results for the impact of VSC coupled DG on voltage stability. The currents $I_9$ and $I_{10}$, and the reactive powers $Q_9$ and $Q_{10}$ are supplied by the DG at bus 9 respectively bus 10.

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
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</tr>
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</tr>
<tr>
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<td>0.99</td>
<td>0.50</td>
<td>0.50</td>
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<tr>
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<td>1.00</td>
<td>0.95</td>
<td>0.50</td>
<td>0.50</td>
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</tr>
<tr>
<td>150</td>
<td>100</td>
<td>0.98</td>
<td>0.93</td>
<td>0.50</td>
<td>0.50</td>
<td>11.77</td>
<td>1.28</td>
<td>22</td>
</tr>
<tr>
<td>180</td>
<td>120</td>
<td>0.95</td>
<td>0.91</td>
<td>0.50</td>
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<td>9.90</td>
<td>1.32</td>
<td>24</td>
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<tr>
<td>210</td>
<td>140</td>
<td>0.93</td>
<td>0.89</td>
<td>0.50</td>
<td>0.50</td>
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</tr>
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<td>240</td>
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<td>0.82</td>
<td>0.28</td>
<td>0.50</td>
<td>1.19</td>
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<td>35</td>
</tr>
<tr>
<td>270</td>
<td>180</td>
<td>0.77</td>
<td>0.73</td>
<td>0.24</td>
<td>0.34</td>
<td>0.73</td>
<td>1.56</td>
<td>36</td>
</tr>
<tr>
<td>300</td>
<td>200</td>
<td>0.76</td>
<td>0.71</td>
<td>0.22</td>
<td>0.29</td>
<td>0.73</td>
<td>1.56</td>
<td>36</td>
</tr>
</tbody>
</table>

Figure 4.9. The output power and reference current of the VSC at bus 10.
might hold for several types of DG, this is not true for all types, in particular for Renewable Generation, such as wind and solar. For wind turbines the output power changes with the cube of the wind speed $[2]$. The wind speed is not constant but fluctuates, so does the output power of a wind turbine.

In this section the impact of a wind farm on voltage instability will be investigated. Simulations are done with the circuit of figure 4.10. The difference with the system of figure 2.23 is that a wind farm consisting of $N$ DFIG wind turbines is connected via a VSC-HVDC link to bus 6. The data of the simulation model is given in appendix B.

Two case studies are done. The first study is similar to the one done in the previous section: the wind farm is supplying power in addition to generator GEN3. The size of the wind farm is varied between 16 and 208 turbines of $2.5 \text{ MW}$ (0.6 % to 7.4 % of the load). The farm experiences a typical amount of turbulence with an intensity $i$ of 0.16. At $t = 100$ s one of the parallel transmission lines trips. As shown before, without a wind farm the voltage collapses after this disturbance.

In the second study the wind farm replaces a part of generator GEN3. Two wind farm sizes are investigated: 100 and 300 turbines. Each turbine is 2.5 MW so the penetration is respectively 3.6 % and 10.8 %. GEN3 is reduced by the nominal power rating of the wind farm. The settings for the voltage references of GEN3, the HVDC-line and the LTC are chosen in such a way that the generator field-current and the VSC’s reactive power output are below their limits. The voltage reference for the LTC is 0.9 pu and for the grid-side VSC 1.02 pu. The voltage reference of GEN3 is lowered because of the lower power rating (for the 100 turbine case this reference is 1.03 pu and for the 300 turbine case 1.015 pu). The impact of different dips in wind speed are investigated: 25 %, 50 % and 75 %. The initial wind speed is the rated one.

The wind farm and the grid are coupled by the HVDC link. The wind farm is modeled in two separate parts. The first part represents the behavior of the $N$ wind turbines and provides an active power injection to the farm-side HVDC bus. The second part represents the VSC. The electrical lay-out and the interconnection of the two models are depicted in figure 4.11. The HVDC-link is assumed to be lossless.

For the wind farm the aggregated model proposed in $[191,192]$ is used. This model represents the behavior of identical turbines and approximates qualitatively the power fluctuations. The fluctuations from each turbine are partially incoherent and therefore cancel out each other. This smoothing effect can be properly described by rescaling the output (the real power) of a single turbine model. Assuming that the wind speeds acting on the different turbines of the wind farm are incoherent, the aggregated model is based on the following function:

$$P_a(t) = \sqrt{N} \left( P(t)|w(t) - \bar{\mu}_P \right) + N \cdot \bar{\mu}_P$$

where $P(t)|w(t)$ is the output of a single turbine model produced by the wind speed $w(t)$ and $\bar{\mu}_P$ is an

---

$\dagger$ Defined as the root-mean-square of the wind fluctuations due to turbulence, divided by the mean wind speed.
estimation of the statistical mean of the produced power from one turbine $\mu_P = E\left[ P(t) \big| w(t) \right]$. A detailed description of this model is given in appendix D.

The power output of the aggregated wind farm ($P_a(t)$) is used as a feed-forward input to the grid-side VSC. Because of the decoupling of the relatively fast power fluctuations in the wind farm from the grid through the DC bus and the grid-side VSC, this simplification is allowable. Note furthermore, that it is allowed for studying slower phenomena like voltage stability to neglect the fast-decaying dynamics in the DC link.

Note that if the current is limited and the AC grid-side voltage of the converter experiences a dip, the active power that will be fed into the DC-bus will be decreased by the farm-side converter and the power production of the wind-farm will be lowered by means of pitch control. For that reason a constant DC-bus voltage is assumed.

The VSC model described in appendix C is implemented in Matlab using the Simulink and SimPowerSystems toolbox. The parameters used for the simulation can be found in appendix B.

### 4.3.1 Case study 1: Wind farm in addition to conventional generation

Figure 4.12 shows the result of the first case study for two of the investigated sizes of the wind farm: 48 and 204 turbines (respectively 120 MW and 510 MW). In this case study the wind farm is used in addition to the local generator. The power rating of the VSC is 50 % larger than the power rating of the wind farm. This overdimension is chosen in such a way that the results of this study can be compared with the results of section 4.2.5 where the results are given for a VSC connected DG with a constant active power source. The 48 turbine case corresponds thus to a penetration of 2.6 % of the load and the 204 turbine case with 11 % of the load. The solid lines in figure 4.12 show the result for the wind farm of 48 turbines and the dashed lines the result for the wind farm of 208 turbines.

The first (upper) graph shows the bus 6 and the second graph the bus 9 voltages. The third graph shows the tap position of the LTC. For the wind farm of 48 turbines both voltages collapse. For the wind farm of 208 turbines the voltages do not collapse and stay within a band of 10 % of their initial voltage. So regarding the symptom-based definition, the addition of a wind farm of 208 (11 % of the load) turbines is beneficial for voltage stability.

The fourth graph of figure 4.12 shows the field current of GEN3. For both sizes of the wind farm, after the trip of the line the field current increases to a value above the OXL limit of 3.06 pu. The OXL limits the field current. In the case of the smaller wind farm this field-current limiting starts the deterioration process which finally results in the collapse. In the case of the larger wind farm the field-current limiting has no major impact on the system since the WF also contributes to local reactive power support.

The fifth graph of figure 4.12 shows the MLI of the transmission corridor. In case of the 48 turbine wind farm, the collapse can be followed in the MLI. In the case of the wind farm of 208 turbines the MLI stays clearly above one. The margin to the point of maximum power transfer ($P_{max}$) decreases due to the disturbance from 50 % to 39 %.

Figure 4.13 shows the active power output of the VSC (upper graph) the reactive power output of the VSC (middle graph) and the VSC current (lower graph). The solid lines represent the 48 turbine case and the
Figure 4.12. Simulation result of adding a Wind Farm connected via a VSC to bus 6 in the test system.
### 4.3 Impact of Wind Farms on Voltage Stability

#### Figure 4.13.
The active and reactive power output and the current of the VSC.

#### Table 4.9. Simulation results for the impact of a wind farm with oversized converter on voltage stability. \( P_{VSC}, Q_{VSC} \) and \( I_{VSC} \) are injected to the test system.

<table>
<thead>
<tr>
<th># Turbines</th>
<th>Size WF [MW]</th>
<th>Size VSC [MVA]</th>
<th>( P_{VSC} ) [pu]</th>
<th>( Q_{VSC} ) [pu]</th>
<th>( I_{VSC} ) [pu]</th>
<th>( \Delta U ) [%]</th>
<th>MLI</th>
<th>Margin [%]</th>
</tr>
</thead>
<tbody>
<tr>
<td>16</td>
<td>40</td>
<td>60</td>
<td>0.54</td>
<td>0.3</td>
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<td>1.00</td>
<td>0</td>
</tr>
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<td>120</td>
<td>0.55</td>
<td>0.3</td>
<td>1.10</td>
<td>-44.8</td>
<td>1.00</td>
<td>0</td>
</tr>
<tr>
<td>48</td>
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<td>180</td>
<td>0.56</td>
<td>0.3</td>
<td>1.10</td>
<td>-44.8</td>
<td>1.00</td>
<td>0</td>
</tr>
<tr>
<td>64</td>
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<td>240</td>
<td>0.85</td>
<td>0.4</td>
<td>1.10</td>
<td>-15.8</td>
<td>1.23</td>
<td>19</td>
</tr>
<tr>
<td>80</td>
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<td>300</td>
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<td>0.4</td>
<td>1.10</td>
<td>-12.9</td>
<td>1.28</td>
<td>22</td>
</tr>
<tr>
<td>96</td>
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<td>360</td>
<td>0.90</td>
<td>0.4</td>
<td>1.10</td>
<td>-10.8</td>
<td>1.32</td>
<td>24</td>
</tr>
<tr>
<td>112</td>
<td>280</td>
<td>420</td>
<td>0.92</td>
<td>0.5</td>
<td>1.10</td>
<td>-9.1</td>
<td>1.36</td>
<td>26</td>
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<tr>
<td>128</td>
<td>320</td>
<td>480</td>
<td>0.94</td>
<td>0.5</td>
<td>1.10</td>
<td>-7.6</td>
<td>1.39</td>
<td>28</td>
</tr>
<tr>
<td>144</td>
<td>360</td>
<td>540</td>
<td>1.01</td>
<td>0.4</td>
<td>1.05</td>
<td>-0.8</td>
<td>1.58</td>
<td>37</td>
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<tr>
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<td>600</td>
<td>1.00</td>
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<td>1.02</td>
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<td>1.60</td>
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<tr>
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<td>38</td>
</tr>
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<td>0.2</td>
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<td>0.2</td>
<td>0.99</td>
<td>-0.5</td>
<td>1.65</td>
<td>39</td>
</tr>
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</table>
Table 4.10. Simulation results for the impact of a wind farm on voltage stability. $P_{\text{VSC}}$, $Q_{\text{VSC}}$ and $Q_{\text{VSC}}$ are injected to the test system.

<table>
<thead>
<tr>
<th># Turbines</th>
<th>Size WF [MW]</th>
<th>Size VSC [MVA]</th>
<th>$P_{\text{VSC}}$ [pu]</th>
<th>$Q_{\text{VSC}}$ [pu]</th>
<th>$I_{\text{VSC}}$ [pu]</th>
<th>$\Delta U_{\text{bus}}$ [%]</th>
<th>MLI</th>
<th>Margin</th>
</tr>
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<tr>
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<td>40</td>
<td>40</td>
<td>0.55</td>
<td>0.29</td>
<td>1.10</td>
<td>-44.7</td>
<td>1.00</td>
<td>Collapse</td>
</tr>
<tr>
<td>32</td>
<td>80</td>
<td>80</td>
<td>0.55</td>
<td>0.29</td>
<td>1.10</td>
<td>-44.7</td>
<td>1.00</td>
<td>Collapse</td>
</tr>
<tr>
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<td>120</td>
<td>120</td>
<td>0.55</td>
<td>0.29</td>
<td>1.10</td>
<td>-44.8</td>
<td>1.00</td>
<td>Collapse</td>
</tr>
<tr>
<td>64</td>
<td>160</td>
<td>160</td>
<td>0.56</td>
<td>0.28</td>
<td>1.10</td>
<td>-44.8</td>
<td>1.00</td>
<td>Collapse</td>
</tr>
<tr>
<td>80</td>
<td>200</td>
<td>200</td>
<td>0.56</td>
<td>0.28</td>
<td>1.10</td>
<td>-44.8</td>
<td>1.00</td>
<td>Collapse</td>
</tr>
<tr>
<td>96</td>
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<td>240</td>
<td>0.85</td>
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<td>1.10</td>
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<td>18 Low voltage</td>
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<tr>
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<td>280</td>
<td>0.87</td>
<td>0.43</td>
<td>1.10</td>
<td>-13.9</td>
<td>1.26</td>
<td>21 Low voltage</td>
</tr>
<tr>
<td>128</td>
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<td>320</td>
<td>0.89</td>
<td>0.44</td>
<td>1.10</td>
<td>-12.4</td>
<td>1.29</td>
<td>22 Low voltage</td>
</tr>
<tr>
<td>144</td>
<td>360</td>
<td>360</td>
<td>0.90</td>
<td>0.45</td>
<td>1.10</td>
<td>-11.0</td>
<td>1.31</td>
<td>24 Low voltage</td>
</tr>
<tr>
<td>160</td>
<td>400</td>
<td>400</td>
<td>0.91</td>
<td>0.45</td>
<td>1.10</td>
<td>-9.9</td>
<td>1.34</td>
<td>25 Stable</td>
</tr>
<tr>
<td>176</td>
<td>440</td>
<td>440</td>
<td>0.93</td>
<td>0.46</td>
<td>1.10</td>
<td>-8.8</td>
<td>1.36</td>
<td>26 Stable</td>
</tr>
<tr>
<td>192</td>
<td>480</td>
<td>480</td>
<td>0.94</td>
<td>0.47</td>
<td>1.10</td>
<td>-7.8</td>
<td>1.39</td>
<td>28 Stable</td>
</tr>
<tr>
<td>208</td>
<td>520</td>
<td>520</td>
<td>1.00</td>
<td>0.47</td>
<td>1.09</td>
<td>-1.0</td>
<td>1.57</td>
<td>36 Stable</td>
</tr>
</tbody>
</table>

dashed lines the 208 turbine case. For 48 turbines, after the trip of the line the reactive power output is limited to its maximum of 0.5 pu. The reactive power support is thus limited. At the moment the OXL starts to limit the field current of GEN3, the VSCs output current is limited to 1.1 pu which limits the complex power. In the case of the farm of 208 turbines the VSC is operated far from its limits.

The simulations so far have shown that a large wind farm (rating 11 % of local load) connected via a VSC based HVDC line is able to prevent the system from a voltage instability but a small wind farm (rating 2.5 % of local load) not.

The results for the sizes of 16 turbines (rating 0.9 % of local load) through 208 turbines (rating 11 % of local load) are listed in table 4.10. $P_{\text{VSC}}$, $Q_{\text{VSC}}$ and $Q_{\text{VSC}}$ are injected to the test system.

The simulations in this table show that a voltage collapse can be avoided if the WF capacity in the load areas is about 3.5 % (240 MVA) of the load. The voltages can be maintained to an acceptable value if the total RDG capacity in the load areas is about 5.8 % of the load (420 MVA). Compared to the simulations of a constant power source connected via a VSC (see section 4.2.5), the wind farm with turbulence leads to similar results. A slightly larger wind farm is needed in order to prevent a collapse and instability, but the differences are small. The difference can have two causes. First of all the variations in wind speed, and produced output power, have their influence on the dynamic behavior of the system. Secondly the place where the RDG is connected to the system is different for the two cases. Consequently the settings of the VSC are different.

For the simulations so far an oversized VSC converter is used for the connection of the wind farm to the system. This was done in order to compare the results of the wind farm with fluctuating wind speed with the case were a constant power supplying RDG is connected via a VSC to the power system. The oversizing of the converter allows some extra voltage support. The 50 % oversizing is, however, considerable. Note furthermore that the current limitation of 1.1 pu already allows some reactive power support. In table 4.10 the result is shown for the simulations where the VSC is not oversized. So the nominal power of the VSC equals the nominal power of the wind farm. As can be seen, in this case a smaller MVA rating is required to prevent voltage instability. Voltage collapse can be avoided if the total RDG capacity in the load area’s is about 3.5 % (240 MVA) of the load. Voltage instability can be prevented if the total RDG capacity in the load area’s is about 6.0 % of the load (400 MVA). This difference shows the importance of active power over reactive power in solving voltage instability.

To compare the results of this section with the results of section 4.2.5 it should be noted that the sizes in this former section should be multiplied by two, because two aggregated RDGs were connected to the load buses 9 and 10 and in the case of the wind farm just one wind farm is connected to bus 6.
Figure 4.14. Simulation result for a dip in the wind speed for a wind farm of 100 turbines, 250 MW.
4.3.2 Case study 2: Wind farm replaces part of conventional generation

In this subsection the result of the second case study is given. Here the impact of a dip in the wind speed is investigated when the generation capacity of GEN3 is partly replaced by a wind farm at bus 6. Two sizes of wind farms are investigated: a wind farm of 100 turbines and a wind farm of 300 turbines. The MVA rating of the wind farm equals the MW rating of the wind farm, so voltage support should be provided by the 10 % over current that is allowed. The 100 turbine case corresponds to a penetration of 3.6 % of the local load and the 300 turbine case to 11 %.

A dip in wind speed is applied at 5 s. Dips of 25 %, 50 % and 75 % in the wind speed are investigated. The result of the simulations with the small wind farm is shown in figures 4.14 and 4.15. Figure 4.14 shows the bus 6 voltage (first, upper, graph), the bus 9 voltage (second graph), the LTC tap position (third graph), the field current of GEN3 (fourth graph) and the MLI of the transmission corridor between buses 5 and 6 (fifth, lower, graph). Figure 4.15 shows the active (upper graph) and reactive (middle graph) power injections from the VSC to the grid, and the VSC current (lower graph).

The solid lines of figures 4.14 and 4.15 show the result for a dip in wind speed of 25 % at 5 s. The dip in wind speed has almost no impact on the voltage. Furthermore the MLI drops only a little bit. The active power from the VSC drops and the reactive power increases, but they stay within the VSCs limits. So a drop in wind speed of 25 % has no major influence on the voltage stability of the system.

The result of a dip in wind speed of 50 % is shown by the dashed lines. Note that the drop in speed of 50 % results in a drop in active power of about 75 %. This is due to the fact that the output power of a wind turbine is proportional to the cube of the wind speed. Despite this considerable reduction in power of the wind farm, the system remains voltage stable (MLI above one and the voltage within the band of 10 %).
Table 4.11. Simulation results for the impact of a dip in wind speed in a wind farm of 100 turbines on voltage stability. $P_{\text{VSC}}$, $Q_{\text{VSC}}$ and $I_{\text{VSC}}$ are injected to the test system.

| Size dip [\%] | $P_{\text{VSC}}$ [pu] | $Q_{\text{VSC}}$ [pu] | $I_{\text{VSC}}$ [pu] | $\Delta|U_6|$ [\%] | MLI | Margin [\%] |
|----------------|------------------------|------------------------|------------------------|-------------------|------|---------------|
| 25             | 0.63                   | 0.17                   | 0.64                   | -0.1              | 1.8  | 44            | Stable                      |
| 50             | 0.23                   | 0.34                   | 0.41                   | -0.5              | 1.8  | 44            | Stable                      |
| 75             | 0.05                   | 0.46                   | 0.46                   | -0.7              | 1.8  | 44            | Stable                      |

Table 4.12. Simulation results for the impact of a dip in wind speed in a wind farm of 300 turbines on voltage stability. $P_{\text{VSC}}$, $Q_{\text{VSC}}$ and $I_{\text{VSC}}$ are injected to the test system.

| Size dip [\%] | $P_{\text{VSC}}$ [pu] | $Q_{\text{VSC}}$ [pu] | $I_{\text{VSC}}$ [pu] | $\Delta|U_6|$ [\%] | MLI | Margin [\%] |
|----------------|------------------------|------------------------|------------------------|-------------------|------|---------------|
| 25             | 0.64                   | 0.50                   | 0.82                   | -2.5              | 1.7  | 41            | Stable                      |
| 50             | 0.24                   | 0.50                   | 0.60                   | -9.2              | 1.5  | 33            | Stable                      |
| 75             | 0.05                   | 0.50                   | 0.56                   | -10.8             | 1.4  | 29            | Low voltage                 |

The dotted lines show the result for a dip in wind speed of 75 %. In this case the active power output drops to 5 %, which is considerable. Nevertheless, also in this case the system remains voltage stable (examine the MLI and the voltage).

A summary of the results with the small wind farm is given in table 4.11. The result of the simulations with the large wind farm is shown in figures 4.16 and 4.17. The solid lines of figures 4.14 and 4.15 show the result for a dip in wind speed of 25 %. In this case the bus 6 voltage drops with 2.5 %, this is considerable compared to the 0.1 % in the 100 turbine case. The $MLI$ also drops more significantly. Both the LTC and the OXL respond. Note that the LTC is able to keep the bus 9 voltage close to its initial value. Although in the 300 turbine case the impact of the 25 % dip in wind speed is larger than in the 100 turbine case, the system remains voltage stable. Reactive power output of the VSC is at its limit.

The result of a dip in wind speed of 50 % (with corresponding drop in active power of about 75 %) is shown by the dashed lines. The bus 6 voltage and the MLI drop considerably. The combined action of the OXL (at $t \approx 35$ s) and the LTC worsen this. The MLI, however, stays above one. Furthermore the bus 6 voltage stays just within the band of 10 %. So the voltages are still acceptable.

The dotted lines show the result for a dip in wind speed of 75 % (so the output power drops to 5 %). In this case the voltages drop to an unacceptably low value. The OXL and the LTC both contribute to deterioration of the voltage. The $MLI$ drops considerably but stays above one. So a dip in wind speed of 75 % for a wind farm of 300 turbines is problematic for maintaining the voltage stability.

A summary of the results with the large wind farm is given in table 4.12. Altogether it can be concluded that theoretically, when the when conventional generation is replaced with a large wind farm (300 turbines, 750 MW nominal power, this is equivalent to 11 % of the local load), a severe decrease in wind speed (75 % of rated speed) can cause voltage instability. This dip in wind speed is, however, that large that it will not appear in a realistic situation. So, no problems are to be expected.

4.4 Possibilities for Intelligent Control

Based on the simulations in this chapter it can be concluded that three factors are important for the impact a RDG has on voltage stability:

1. Active power support.
2. Reactive power consumption or generation.
3. Voltage support.

The active power support a RDG can provide influences the amount of power that needs to be transferred between a load area and a generation area. This power transfer is of main importance for the voltage
Figure 4.16. Simulation result for a dip in the wind speed for a wind farm of 300 turbines, 750 MW.
4.4 Possibilities for Intelligent Control

Figure 4.17. The VSC’s active and reactive power output and current.
stability problem. If the active power transfer is reduced due to the presence of RDG in the load area, this is beneficial for voltage stability. Note that this immediately acts on the source of voltage instability, which are the load dynamics that try to restore stability beyond the capability of the combined transmission and generation system. An intelligent controller could measure the MLI on transmission corridors and based on this decide on the local power production of the RDGs.

Note that the control of active power is not possible for all types of RDG. For example, in case of wind turbines the active output power depends on the cube of the wind speed. Although the output power of such a turbine can be reduced, it cannot be increased. A decrease in wind speed, and consequently a decrease in active output, has, nevertheless, impact on the voltage stability of the system. The aforementioned reasoning can also be applied to other types of RDG where the prime-mover cannot be controlled like photo-voltaic cells.

Reactive power consumption of the RDGs influences the voltage of the transmission network directly. If a RDG needs reactive power, the power factor influences whether the RDG is beneficial for voltage stability. If the positive impact of the active power supply is larger than the negative impact of the reactive power consumption, the RDG can prevent the system from a collapse. Generally, however, it is advisable to compensate for the reactive power consumption of the RDG. An intelligent controller could control the reactive power compensator. Such an intelligent controller could also determine to lower the power output of a reactive power consuming RDG and subsequently reduce the reactive power consumption.

When the RDG is capable of providing active voltage support this is beneficial for voltage stability. An intelligent controller can be used to control the voltage support of the available RDGs in the most effective way. One important remark should, however, be made here. The voltage support of most RDGs, certainly if they are connected via power electronics, is rather limited. The large amounts of reactive power that are required for preventing the system from a voltage collapse cannot necessarily be supplied by small RDGs unless generated by many units. Furthermore at this moment small RDGs (< 1 MW) are generally not requested to provide voltage support.

Note that this last possibility for control can also be applied for RDGs with uncontrollable prime-mover. The amount of reactive power available for control is, nevertheless, dependent on the actual amount of active power that is generated.

4.5 Discussion

In this section a discussion of the results obtained in this chapter and some remarks regarding the simulations, assumptions and limitations, will be given.

First of all, one of the research questions was to investigate the voltage stability problems that can be expected in grids with a large share of renewable and distributed generation. In this chapter it is, however, proven that RDG is not necessarily a problem for voltage stability but that they can also be used to prevent it. This beneficial impact is also concluded in literature (see [1, [23, 150]). It was, on the other hand, also proven that a severe decrease in wind speed can introduce voltage instability in a grid with a large wind farm. Furthermore in literature also cases are mentioned in which RDG is detrimental for voltage stability (see [5, 21, 25, 51, 73, 78, 87, 103, 123, 124, 142, 175, 211, 215, 241]). So the conclusion is that adding RDG to a power system is beneficial for voltage stability when the RDG is placed close to the load center. In the first part of the research presented in this chapter (section 4.2) generic types of DG were investigated. The power from the prime-mover was assumed to be constant. In reality this power will, however, change with time. For a micro-CHP the output power will, be temperature driven and in case of a wind turbine this output power is proportional to the cube of the wind speed. To investigate the influence of prime-mover fluctuations on the result of the first part of the research, in the second part for a typical type of RG with variable prime mover was investigated. From this it can be seen that the impact of fluctuations in the prime-mover is minor.

For the Induction Generator two types of compensation were investigated: fixed capacitors and Static Var Compensators. The sizes of these compensators were different. In case of the fixed capacitor the compensation was only used to compensate for the reactive power compensation of the induction generators. In case of the SVC the compensation was also used for voltage control. This is actually based on the functional difference between the two types of compensation. Fixed compensation should be chosen in such a
4.6 Conclusion

way that in steady-state acceptable voltages are obtained. Oversizing the capacitors results in over voltages and this is unacceptable. On the other hand SVC is used for voltage control and can be over sized in order to provide emergency control.

Regarding the limitations of the VSC used in this thesis a remark should be made. Three types are distinguished: the current limiter, the limitation on reactive power and the under/over voltage protection. The maximum current is set to 1.1 pu, which is according to [205] a reasonable value. This value is mainly determined by the minimum voltage level at which nominal power should still be supplied. If the reactive power support needs to be increased, the maximum current also should be adjusted. The limitation on reactive power is included to give priority to active power when the converter current is limited. The reactive power to a fixed value of 0.5 pu, which is according to [134] a typical value. This is a rather simple method and in literature more advanced methods can be found (see for instance [205]). It is recommended for future research to extend the study with these more sophisticated control methods. The over/under voltage protection did only disconnect the DG during a collapse. The low voltage bound is pretty low compared to the minimum voltages of the grid code. This is mainly due to the low voltage ride through capability DG should have [58].

The VSC that is used in the first case study for the wind farm, where the wind farm is used in addition to the conventional local generation, was over sized. This was done to be able to compare the results with the ones obtained for the VSC with uncontrolled prime-mover in section 4.2, where the active power was 66 % of the MVA rating of the VSC. In order to determine the influence of this oversizing also simulations were done where the converter was fully utilized.

In this chapter the impact of RDG on voltage stability at the transmission network level has been investigated. Having a large amount of RDG is not necessarily a threat for voltage instability. Based on the simulations it can even be concluded that adding RDG is generally beneficial for the voltage stability of a transmission system.

Two studies were done. In the first study generic types of DG were connected to the load buses in the test system. It is assumed that the prime-mover supplies a constant amount of power. It was investigated for which sizes of the DG the system stays voltage stable after a severe disturbance (trip of one of the transmission lines between the generation and load area). Without DG this severe disturbance initiates a collapse.

In the second study a wind farm is connected in the load area. The wind farm is of the DFIG type and is connected via a HVDC link to the test system. Two cases are distinguished. In the first case the wind farm is used in addition to the conventional local generation. It is determined for which sizes of the wind farm the system stays voltage stable after a severe disturbance (trip of one of the transmission lines). This case is similar to the first study. The main difference is that in this case the produced power varies with the wind speed. In the second case the wind farm replaces part of the local generation. In this case it is investigated for which reductions in wind speed the system becomes voltage unstable.

A summary of the conclusions of the first study and the first case of the second study is given in figure 4.18.

In this figure the required penetration to prevent collapse (black bars) and low voltages (white bars) is given for the different types of RDG. SG is the Synchronous Generator, SG AVR is the Synchronous Generator with AVR, IG fixed C is the Induction Generator with fixed Compensation, IG SVC is the Induction Generator with SVC compensation, VSC is the inverter coupled DG with constant prime-mover, and WF is the Wind Farm with the oversized VSC.

**DGs based on synchronous generators** are generally beneficial for voltage stability. For relatively small sizes of the generators a collapse can be prevented or even unacceptably low voltages can be avoided. A SG with an AVR that controls the DG terminal voltage is favorable over the case of a SG without AVR. **For DGs based on induction generators** can also be beneficial for voltage stability. But, a relatively a higher amount of reactive power compensation is required in that case than what is the case for compensation of an IG during steady state. For voltage stability the IG can best be compensated by means of SVC compared to fixed compensation, because the SVC can also provide voltage control.
Figure 4.18. Summary of the conclusions of this chapter. The black bars correspond to the penetration of RDG required to prevent a collapse and the white bars to the penetration required to prevent unacceptable low voltages.

Table 4.13. Simulation results for the impact of a dip in wind speed in a wind farm on voltage stability.

<table>
<thead>
<tr>
<th>Size dip [%]</th>
<th># Turbines</th>
<th>Voltage Stability</th>
</tr>
</thead>
<tbody>
<tr>
<td>25</td>
<td>100</td>
<td>Stable</td>
</tr>
<tr>
<td></td>
<td>300</td>
<td>Stable</td>
</tr>
<tr>
<td>50</td>
<td>100</td>
<td>Stable</td>
</tr>
<tr>
<td></td>
<td>300</td>
<td>Stable</td>
</tr>
<tr>
<td>75</td>
<td>100</td>
<td>Stable</td>
</tr>
<tr>
<td></td>
<td>300</td>
<td>Low voltage</td>
</tr>
</tbody>
</table>

By means of a VSC interface, a DG can be decoupled from the grid. These VSC-interfaced DGs are generally beneficial for voltage stability. For relatively small sizes of the generators a collapse can be prevented or even unacceptably low voltages can be avoided.

For the wind farm almost similar results are obtained as for the full converter with constant prime-mover. A little higher penetration is necessary in order to prevent unacceptably low voltages and a collapse, but this can also be caused by the fact that the wind farm is placed at a different bus than the general DGs. When the VSC rating is equal to the nominal power of the wind farm a lower MVA rating is required to prevent instability. This can be explained by the fact that more active power support is provided.

The conclusions of the second case of the second study are listed in table 4.13. It can be concluded that for a large wind farm (300 turbines, 750 MW nominal power, this is equivalent to 11% of the local load), a severe decrease in wind speed (75% of rated speed) can cause unacceptably low voltages. By contrast, a severe dip in a small wind farm (100 turbines, 250 MW nominal, this is equivalent to 3.6% of the local load) causes no instability. Note that a significant decrease in wind speed is a less severe disturbance than the trip of the line. This can be explained by the fact that in the case of a trip of a line both active and reactive power transport to the load area are limited. In the case of a dip in wind speed only the active power is limited.

Finally, the simulations show that mainly three factors are important for the impact a RDG has on voltage stability: active power support, reactive power consumption or generation, and voltage support. An intelligent controller can make use of the positive factors (active power support and voltage support) to prevent a system from a voltage unstable situation. Furthermore if a RDG consumes reactive power, an intelligent controller can make sure that the negative impact is limited. Note that whether active power support can be provided is dependent on the prime-mover technology.
Chapter 5

The Concept of Hierarchical Agent Based Voltage Instability Prevention

5.1 Introduction

In this chapter the concept of a Multi-Agent based system to detect and prevent voltage instability will be outlined. In the subsequent chapters this system is further detailed and analyzed. In this section we will give an introduction to Multi-Agent theory as applied to power systems in particular.

The IEEE Power & Energy Society’s Multi-Agent Systems (MAS) Working Group distinguishes between the terms “agent” and “intelligent agent”. An agent is a software (or hardware) entity that is situated in some environment and is able to autonomously react to changes in that environment. So every system that autonomously interacts with its environment, is an agent. Based on this definition a protection relay and an automatic voltage regulator are also agents because they autonomously react to changes in their environment, in this case the power system. An agent is intelligent when besides the reactivity property the agent is also pro-active and has a social ability. This means that the agent has a goal and to reach this goal it actively communicates and negotiates with other entities. “A Multi-Agent based system is simply a system comprising two or more agents or intelligent agents”.

The before mentioned working group distinguishes four broad categories of MAS applications:

- monitoring and diagnostics,
- distributed control,
- modeling and simulation,
- protection.

MAS based monitoring and diagnostic applications are proposed for both: on-line assistance of the power system operator and off-line post-contingency analysis of disturbance events. These applications require a vast amount of data and agent-based systems are suitable to process this. The data can consist of power system states (e.g. voltages and angles), component states (e.g. transformers oil temperature or partial discharge rates) and data from digital fault recorders (appliances that acquire and save data when triggered by certain power system conditions).

According to the overview of research on MAS in power systems provided in, most papers published on this subject are about distributed control (closely followed by modeling and simulation). See for instance. With Multi-Agent based control a coordinated solution can be found without the requirement that the whole system state is known at a central control location. In the deregulated power system, where different parties own different parts of the system, this limited amount of data sharing is advantageous. One of the many techniques that can be found in literature is based on Distributed Constraint Optimization (DCOP).
MAS systems are also used for modeling and simulation. First of all the modeling and computation of power system analysis software can be agent-based [77]. But it is also possible to simulate an electricity market to determine the (economic) dispatch of (distributed) generators [48, 95, 156, 196, 203]. In such a system agents represent different entities that either buy or sell electrical energy (or ancillary services). Each agent has its own goal and by negotiation with other agents it tries to achieve it. A third option for modeling and simulation is to use multi-agent based techniques to solve classical power system problems like the optimal power flow or reactive power dispatch via a distributed computation [7, 176, 182, 240]. MAS is, for instance, used to solve the underlying optimization problems based on particle swarm techniques (e.g. [176]).

The last category defined by the IEEE PES Working Group on MAS is protection. By having agents that represent relays and other power system components, the actions of protection devices can be coordinated. Information of other power system components can be taken into account before implementing a particular action to minimize the duration of a service interruption. In literature several MAS based protection schemes can be found [15, 43, 224, 238].

Voltage control is most effective when performed locally. Furthermore, voltage instability problems start locally before they become system-wide. This makes agents particularly suited to solve voltage problems. In literature several agent-based systems are proposed. In the case of static voltage control, methods for modeling and simulation [240] and for distributed control [9, 56, 79, 127, 163, 225] can be found. In the case of emergency control for voltage instability, methods for modeling and simulation [7, 176], distributed control [31, 52, 118, 126, 143, 236] and monitoring and diagnostics [172, 173] are proposed.

The focus of this thesis is on agent-based distributed control to alleviate voltage instability problems. The remainder of this section focuses on this type of control.

In [118, 126] model predictive control strategies for voltage control are proposed to coordinate preventive control actions of multiple actuators. With this type of control high accuracies can be obtained. Model predictive control, however, requires detailed models which might be hard to obtain.

The method proposed in [52] has local control agents that immediately react to instability. Based on fast communication, neighboring local agents determine whether they will assist or not. A higher layer establishes coordination in the longer term. This coordination is based on slower communication.

Smart-grids, micro-grids and active distribution networks are often controlled by MAS. In emergency situations it might be required to separate one or more of these local grids from the main grid in order to prevent an emerging collapse. During grid connection the local grid should be controlled in order to assist the main grid and during isolation the goal is to maintain the local voltage and frequency [31].

In [143] a MAS is proposed to coordinate two different types of actuators for preventing voltage instability: load shedding and reactive power control of local generators. The agents controlling the individual devices have two goals: a local goal and a global goal. The local goal is to operate the local system within the normal power system constraints. The global goal is to prevent voltage collapse.

An important problem when implementing a MAS is that it may exhibit chaotic behavior. Communication amongst agents introduces delays and the power system state as assumed by a local agent may be inaccurate. In [236] a method is proposed to deal with this chaotic behavior. In this thesis communication delays will be ignored.

In this chapter a new control strategy and multi-agent structure is proposed. This system is called the Hierarchical Agent Based Voltage Instability Prevention (HABVIP) controller. The HABVIP controller uses four different types of actuators. In this chapter the control strategy and structure of the system are outlined. The control of two of the four actuators is also discussed. Subsequently in chapters 6 and 7 the detailed control of respectively the Load Tap Changer and the Decentralized Generators will be given because the contribution is significant in this thesis for these two types of actuators.

The chapter starts with explaining the control strategy in section 5.2. As stated before, this control strategy integrates the use of different actuators. Coordination among these actuators is discussed in section 5.3. In section 5.4 the MAS based structure will be outlined. Section 5.5 follows with a description of the control strategy for two of the actuator classes. Subsequently in section 5.6 the application of the proposed control structure to meshed systems will be discussed. In section 5.7 a qualitative discussion of the system is given and finally in section 5.8 the conclusions of the chapter are presented.
5.2 Control Strategy

The general description of the controller is based on the system of figure 5.1. In this figure a simple, radial, equivalent of a larger power system is shown. Bus 2 represents an area with mainly loads and some local (distributed) generation. This load area is connected via a transmission corridor to the rest of the system. Note that generators and loads may comprise the aggregated loads and generators in an area.

The emergency control method follows the general idea of restoring stability by moving the unstable operating point within the feasible control space [202]. The difference with the method described in [202] is that our approach is an on-line controller for decentralized multi-agent implementation instead of a system to assist decision making of the human operator.

As discussed in chapter 3, using the MLI the active power reduction and reactive power compensation required to restore the operating point to one within a certain margin to the point of maximum power transfer can be determined [212]. Figure 5.2 illustrates this for the simple system of figure 5.1. This can be generalized to any pair of nodes that are directly connected in a meshed network, as long as the receiving end is identified. The difference between the current value of the MLI and its reference value MLI_{ref} is used as basis for the control signal. MLI_{ref} is chosen such that the system is operated within a margin to the point of maximum power transfer. The control signal is non-zero only when this margin is violated:

\[
\Delta MLI = \begin{cases} 
- (MLI - MLI_{ref}) & MLI < MLI_{ref} \\
0 & MLI \geq MLI_{ref} 
\end{cases}
\]

In this equation \(\Delta MLI\) is the control signal, MLI is the Maximum Loadability Index [212] and MLI_{ref} the desired value the MLI should have in order to operate within a minimum margin to the point of maximum power transfer. A discussion for choosing MLI_{ref} is given later in chapter 8.
To cancel out any offset error and to fixate the control signal when the controller restores stability, a PI-action is added:

$$\Delta MLI_{PI} = \left( k_P + k_I \frac{1}{p} \right) \cdot \Delta MLI$$  \hspace{1cm} (5.2)

In this equation $k_P$ is the parameter for proportional action, $k_I$ the parameter for integral action and symbol $1/p$ the integral operator in Laplace domain. The calculation of the $MLI$ and the determination of the control signal are updated continuously.

The controller resets when the $MLI$ has a safe value (larger than $MLI_{ref}$) for a certain period of time.

Based on the control signal determined with equation (5.2) the active power load relief and the reactive power compensation required to restore the margin of the operating point, can be calculated:

$$\Delta P_{MLI} = P \cdot \Delta MLI_{PI}$$  \hspace{1cm} (5.3)

$$\Delta Q_{MLI} = -Q \cdot \Delta MLI_{PI}$$  \hspace{1cm} (5.4)

Where $P$ is the MW loading and $Q$ the MVar loading at the receiving end of the transmission corridor.

Four types of actuators are used simultaneously: local generators, load tap changers, controllable loads and reactive power compensating devices. Coordination among these actuators is further discussed in section 5.3. With the local generators the active receiving-end power is reduced. The central generators will respond to this via speed-droop control of the speed governors. With the LTC and controllable loads both active and reactive power are controlled at the same time. The control of these actuators focuses on active power; the effect on reactive power is measured and taken into account when determining the control signal for the reactive power compensating device.

The active power control can be used without the reactive power control and vice versa. The control signal will, in that case, be larger than in the case both active and reactive power are adjusted. This is automatically established by the PI-loop.

### 5.3 Coordination of Control Actions

The control strategy as proposed in the former section needs coordination of control actions at three different levels. First of all there is coordination between active power load relief and reactive power compensation. For the reactive power control only one actuator group is specifically defined \(^1\) for the active power control three. For these active power control actions the control signal should be divided among the different actuator classes. The final level of coordination is the coordination among actuators within the same actuator class. In this section the three different levels of coordination will be discussed.

#### 5.3.1 Coordination between active and reactive power control

The coordination between active and reactive power control actions is established by the power factor of the measured receiving-end complex power: this determines the ratio between $\Delta P_{MLI}$ and $\Delta Q_{MLI}$. When only one of the two control types is available, the PI-loop (equation (5.2)) ensures that the control signal becomes large enough to prevent the voltage collapse.

Load control and LTC control influence both the active and reactive power. Load control is applied while maintaining a constant power factor and a change in tap position of the LTC influences both the active and reactive power components of voltage-dependent loads. Because there is only one degree of freedom, the control strategy for these actuator classes is based on active power reduction only. To take into account that reactive power consumption is also reduced by smart load control and LTC control, at actuator level the change in reactive power is determined via measurements:

$$\Delta Q_{\text{done}} = Q(0) - Q(t)$$  \hspace{1cm} (5.5)

---

\(^1\)Note that more could be defined.
In this equation \( Q(0) \) is the measured reactive power consumption before the control action and \( Q(t) \) the reactive power consumption after the load and LTC control action. \( \Delta Q_{\text{done}} \) is used in the control strategy to determine the control signal for the reactive power control action.

The scheme for determining the reactive power control action is given in figure 5.3. In this figure \( \Delta Q_{\text{in}} \) is the required reactive power compensation to prevent the voltage collapse determined with equation (5.4). \( \Delta Q_{\text{max}} \) is the maximum amount of reactive power injection all reactive power actuators can provide together. \( \Delta Q_{\text{done}} \) is the decrease in reactive power compensation obtained by the load and LTC control (equation (5.5)) and \( \Delta Q_{\text{out}} \) the necessary reactive power compensation signal sent to the reactive power actuators.

The output to the reactive power controllers \( \Delta Q_{\text{out}} \) is thus the amount of reactive power compensation determined from equation (5.4) minus the amount of reactive power injection (or reduction of consumption) obtained by load control and LTC control. When this is larger than the amount the reactive power actuators can provide, \( \Delta Q_{\text{out}} \) is limited to this maximum value \( \Delta Q_{\text{max}} \). The PI-loop ensures in that case that the active power control action will increase.

### 5.3.2 Coordination among active power actuator groups

Three types of active power actuators are distinguished: generation control, LTC control and load control. Actuators of the same type are grouped in one class. The required amount of load relief calculated with equation (5.3) is divided over the three defined actuator classes.

Coordination between the different active power actuator classes is based on a preference list: local generation, LTC control, and load control are employed in this order of preference (see figure 5.4). The details of the generator block and the LTC block are shown in figure 5.5 and the load control block is depicted in figure 5.6. In these figures \( \Delta P_{\text{in}} \) is the required load relief from the actuator class, \( \Delta P_{\text{out}} \) is the output of the actuator class, \( \Delta P_{\text{done}} \) is the actual obtained load relief from the actuator class and \( \Delta P_{\text{next}} \) is the amount of load relief that is sent to the next actuator class.

When possible, \( \Delta P \) should be supplied by local generation. If more load relief is necessary than what can be supplied, the remaining part is asked to be provided by LTC control. When the LTC control is also exhausted, the rest of the required load relief is provided via load control. To ensure smooth operation, the control scheme of the LTC and of the local generator (figure 5.5) have a time constant \( T \).

Figure 5.5 implements the aforementioned control coordination of the generator and LTC. The lower right part of this figure sends the difference between the input signal and the output signal after time delay ((\( \Delta P_{\text{in}} - \Delta P_{\text{out}} \))) plus the difference between the requested load relief and the actually obtained load relief ((\( \Delta P_{\text{out}} - \Delta P_{\text{done}} \))) to the next control level. The decomposition is made to keep the discussion transparent, effectively this part of the control reduces into \( \Delta P_{\text{next}} = \Delta P_{\text{in}} - \Delta P_{\text{done}} \).
5.3.3 Coordination of actuators within same group

When two (or more) actuators in the same class can provide load relief, it should be determined which one provides what amount. To keep the relative control space for all actuators the same, giving each actuator equal opportunity to react to an additional event, this coordination is done based on weights determined by the power available for active power load relief:

\[ \Delta P_j = \frac{\Delta P_{j,\text{max}}}{\Delta P_{\text{max}}} \cdot \Delta P_{\text{out}} \]  \hspace{1cm} (5.7)

where \( \Delta P_{j,\text{max}} \) is the amount of active power load relief the \( j \)-th actuator can provide, \( \Delta P_{\text{max}} \) the total amount of load relief that can be provided by the actuator class and \( \Delta P_{\text{out}} \) the load relief required from that actuator class.
A similar equation is used to divide the reactive power control action among the various reactive power actuators:

\[ \Delta Q_j = \frac{\Delta Q_{j,\text{max}}}{\Delta Q_{\text{max}}} \cdot \Delta Q_{\text{out}} \]  

(5.8)

where \( \Delta Q_{j,\text{max}} \) is the amount of reactive power load relief the \( j \)-th actuator can provide, \( \Delta Q_{\text{max}} \) the total amount of load relief that can be provided by the actuator class and \( \Delta Q_{\text{out}} \) the load relief required from that actuator class.

### 5.4 Hierarchical Agent Based Voltage Instability Prevention

The control strategy described in the previous sections is implemented in an agent-based system which is called the Hierarchical Agent Based Voltage Instability Prevention system. In this system each substation is controlled by a substation agent and every actuator is controlled by a so-called actor agent. In this section an overview of the HABVIP agent framework is given.

#### 5.4.1 Hierarchy

Among the agents of the HAVIP system there is a hierarchical structure: actor agents are supervised by substation agents and between the substation agents the classical power system hierarchy, based on voltage levels, is being followed.

Consider the simple network of figure 5.7. Note that this system is not meant to represent a typical power system, but for illustration purposes. It consists of seven substations (A to G) at different voltage levels. The substations are controlled by corresponding substation agents. Based on this simple system the hierarchy and information flow will be explained.

The agent representing substation A is higher in hierarchy than agents of substation B and C because A is at a higher voltage level. Following the same reasoning agents B and C are higher in hierarchy than substations D, E, F and G.

A higher level substation agent is able to communicate with a lower level substation agent when they are electrically connected to each other. A higher level substation is also able to communicate with a lower level substation agent that is indirectly fed by the higher level substation (in figure 5.7 substation E is indirectly fed by B). So the agent representing substation A is able to communicate with substations B and C. Agent B in its turn is able to communicate with agents A, D, E and F. And agent C is able to communicate with agents A and G. These agents exchange local voltage and current phasor measurements.
Furthermore in the case the higher level agent detects voltage instability, it requests load relief $\Delta P_j$ from lower level agents. The lower level agents provide to the higher level agent information about the available ($\Delta P_{\text{max},j}$) and realized ($\Delta P_{\text{done},j}$) amount of load relief. Agents representing electrically interconnected substations at the same voltage level, are also able to communicate. They exchange information about local voltage and current measurements only. So agents D and E as well as agents E and F are able to exchange these local measurements.

Note that there is no direct communication between substation agent A and agents D, E, F and G. The intermediate substation agents B and C aggregate information available at these lower level substations and communicate this to A. Vice versa a request from substation A will be divided by substations B and C among the lower level substations.

Determination of the $MLI$ is done by all agents of receiving-end substations based on the local measurements and the measurements received from neighboring substations. As soon as voltage instability is foreseen, all substation agents detecting it will cooperate. This cooperation is supervised by the substation agent highest in hierarchy sensing the problem: the supervisory agent. It depends on the particular agents that detect the instability which agent becomes the supervisory one. When agent B detects voltage instability and agent A not, agent B becomes the supervisory agent. When the supervisory agent requests control from lower level agents, these lower level agents know automatically that a higher level agent is the supervisory agent.

The supervisory agent determines the amount of load relief necessary to obtain voltage stability. The lower level agents are requested to aggregate the amount of load relief they can provide divided per actuator class and communicate this to the supervisory agent. This division per actuator class is required by the supervisory agent for coordination purposes.

The supervisory agent calculates the amount of load relief each actuator class should provide. The lower level agents subsequently divide this signal among their actuators and the substations one level lower in hierarchy.

A lower level substation agent can overrule the supervisory agent when this is required to solve the local problem. The lower level substation agent compares the higher level control signal with what is required to solve its own local problem and implements the largest signal. When this occurs, the feedback loop of the supervisory agent balances the control signal from other connections.

5.4.2 Substation agent

The block scheme of a substation agent is shown in figure 5.8. In this subsection an outline will be given.

Communication Higher Level Substations

The *Communication Higher Level Substations* block establishes communication with higher level substation agents. From these higher level substation agents it receives: voltage and current measurements and, occasionally a control signal from the higher level substation agents. The control signal is subdivided into $\Delta P_{\text{gen},A+1}$, $\Delta P_{\text{LTC},A+1}$, $\Delta P_{\text{load},A+1}$ and $\Delta Q_{A+1}$. The subscript $A+1$ denotes that the signal is determined one agent higher in hierarchy. The substation agent sends to the higher level substation agents the voltage and current measurements; the amount of control action it has available for each actuator class ($\Delta P_{\text{gen,max},A}$, $\Delta P_{\text{LTC,max},A}$, $\Delta P_{\text{load,max},A}$ and $\Delta Q_{\text{max},A}$); and the amount of control action that is actually implemented ($\Delta P_{\text{gen,done},A}$, $\Delta P_{\text{LTC,done},A}$, $\Delta P_{\text{load,done},A}$ and $\Delta Q_{\text{done},A}$). The subscript $A$ denotes that the signal is determined at the local substation.

In case the HABVIP controller is implemented in a meshed system it may happen that a local substation agent has two supervisory agents that both request load relief. In this case the local agent should add the control signal of both higher level agents.

The available amount of load relief that is sent to the two higher level agents depends on whether load relief is requested. If only one of these agents requests load relief, the full amount of power available for load relief should be sent to that agent only. If both higher level agents request load relief, half of

\[\text{ii} \text{Note that when agent C detects voltage instability as well, both agents will solve their own local problem with the help of the lower level agents.}\]
Figure 5.8. General implementation of the substation agent.
the available amount of load relief should be send to each. The corresponding equation for the generator control becomes:

\[
\begin{bmatrix}
\Delta P_{\text{gen,max},A,1} \\
\Delta P_{\text{gen,max},A,2}
\end{bmatrix} = \begin{cases}
\begin{bmatrix}
\Delta P_{\text{gen,max},A} \\
0
\end{bmatrix} & \Delta P_{\text{gen},A+1,1} > 0 \text{ AND } \Delta P_{\text{gen},A+1,2} = 0 \\
\begin{bmatrix}
0 \\
\Delta P_{\text{gen,max},A}
\end{bmatrix} & \Delta P_{\text{gen},A+1,1} = 0 \text{ AND } \Delta P_{\text{gen},A+1,2} > 0 \\
\begin{bmatrix}
\frac{1}{2} \Delta P_{\text{gen,max},A} \\
\frac{1}{2} \Delta P_{\text{gen,max},A}
\end{bmatrix} & \text{else}
\end{cases}
\]

(5.9)

Note that for load control, LTC control and reactive power control similar equations apply.

For the actual amount of load relief obtained sent to the two higher level substation agents a similar equation can be formulated:

\[
\begin{bmatrix}
\Delta P_{\text{gen,done},A,1} \\
\Delta P_{\text{gen,done},A,2}
\end{bmatrix} = \begin{cases}
\begin{bmatrix}
\Delta P_{\text{gen,done},A} \\
0
\end{bmatrix} & \Delta P_{\text{gen},A+1,1} > 0 \text{ AND } \Delta P_{\text{gen},A+1,2} = 0 \\
\begin{bmatrix}
0 \\
\Delta P_{\text{gen,done},A}
\end{bmatrix} & \Delta P_{\text{gen},A+1,1} = 0 \text{ AND } \Delta P_{\text{gen},A+1,2} > 0 \\
\begin{bmatrix}
\frac{1}{2} \Delta P_{\text{gen,done},A} \\
\frac{1}{2} \Delta P_{\text{gen,done},A}
\end{bmatrix} & \text{else}
\end{cases}
\]

(5.10)

Also in this case similar equations apply for load control, LTC control and reactive power control.

**Phasor Measurement Unit**

The *Phasor Measurement Unit* measures the voltage and current phasors at the local substation, based on the standards in [85].

**Communication Same Level Substations**

The *Communication Same Level Substations* block establishes communication with agents representing substations at the same voltage level which are electrically connected to the local substation. From the neighboring substation agents the agent receives voltage and current measurements. The substation agent sends to the neighboring substation agents the voltage and current measurements from its local PMU.

**Detection**

The *Detection* block determines the *MLI* for all connections with neighboring substations for which the local substation is the receiving-end substation. The calculation of the *MLI* is based on the method described in chapter [3]. When the substation is not at the receiving-end of the connection (this can be determined based on the angle between the voltage and current phasor), the *MLI* has no meaning, and the value of the corresponding connection is rejected. Note that the value of the locally rejected *MLI* will be determined again at a lower substation agent at the receiving-end and implementing a control action makes more sense at this substation.

**MLI-control**

The *MLI-control* block determines for each connection $k$, for which the power flows into the substation, the required control signal $\Delta MLI_{PL,k}$ based on equations (5.11) and (5.2).
P-control

The P-control block determines for each connection with a $MLI < MLI_{ref}$ the required active power load relief $\Delta P_{MLI,k}$ based on equation (5.3). It also determines the sum of these control signals:

$$\Delta P_{MLI,\text{tot}} = \sum_{k=1}^{m} \Delta P_{MLI,k}$$  \hspace{1cm} (5.11)

Where $m$ is the total number of connections. This control signal is the aggregated amount of active power load relief required to restore stability on all connections into the local substation.

Q-control

The Q-control block determines for each connection with a $MLI < MLI_{ref}$ the required reactive power compensation $\Delta Q_{MLI,k}$ based on equation (5.4). It also determines the sum of these control signals:

$$\Delta Q_{MLI,\text{tot}} = \sum_{k=1}^{m} \Delta Q_{MLI,k}$$  \hspace{1cm} (5.12)

Where $m$ is the total number of connections. This control signal is the aggregated amount of reactive power compensation required to restore stability on all connections into the local substation.

Lower DG

Lower DG is a special block introduced for completeness. It reduces the local generation of a connection for which the power flow is from a lower level substation to a higher level substation and where the $MLI$ indicates instability. This control signal is determined by applying equation (5.3) to the particular connection. Note that this control signal is applied irrespective whether the substation agent is a supervisory agent or not, because increasing the local generation from that connection will only worsen the situation.

Agent Coordination

The Agent Coordination block bypasses a part of the local substation agent control in case a higher level substation agent demands more load relief than the local substation agent does. In that case the required amount of load relief is determined by the higher level substation agent. The logic is based on the apparent power load relief, which can be determined with:

$$|\Delta S_{MLI}| = \sqrt{(\Delta P_{MLI})^2 + (\Delta Q_{MLI})^2}$$  \hspace{1cm} (5.13)

The real power load relief demand of a higher level substation $\Delta P_{MLI,A+1}$ is reconstructed from the parts required by load control, LTC control and generator control:

$$\Delta P_{MLI,A+1} = \Delta P_{\text{gen,A+1}} + \Delta P_{\text{LTC,A+1}} + \Delta P_{\text{load,A+1}}$$  \hspace{1cm} (5.14)

Where the additional subscript A+1 denotes a substation agent one level higher in hierarchy. $\Delta Q_{MLI}$ is the reactive power load relief demanded from shunt compensation devices.

The logic for the Agent Coordination block becomes:

$$AC = \begin{cases} 
1 & \text{if } |\Delta S_{MLI,A}| > |\Delta S_{MLI,A+1}| \\
0 & \text{if } |\Delta S_{MLI,A}| \leq |\Delta S_{MLI,A+1}| 
\end{cases}$$  \hspace{1cm} (5.15)

Where AC is an internal signal which determines whether the control of the local substation agent is active, $|\Delta S_{MLI,A}|$ is the apparent power control signal of the local substation agent and $|\Delta S_{MLI,A+1}|$ the apparent power control signal of the substation one level higher in hierarchy.

With the proposed agent coordination based on the control signal, no additional communication is required among the substation agents. With the given implementation the supervisory agent can also be overruled.
in the case when at a lower substation a larger amount of load relief is required. In that case \( \Delta P_{\text{done}} \) that is sent to the higher level substation agent, is larger than the required one. The higher level agent will subsequently lower the control signal for the other substation agents below in the hierarchy. The feedback loop takes care of this.

Coordination Actuators P-control

In the Coordination Actuators P-control block, the control signal \( \Delta P_{\text{MLI, tot}} \) is divided among the actuator classes local generation, LTC and load. This is based on the control diagram of figures 5.4, 5.5 and 5.6. The output signals are \( \Delta P_{\text{gen}}, \Delta P_{\text{LTC}} \) and \( \Delta P_{\text{load}} \). Note that at this level all actuators of the same class are aggregated and no decision is made about individual actuators.

Coordination Actuators Q-control

In the Coordination Actuators Q-control block, the total amount of reactive power compensation obtained by LTC and load control \( \Delta Q_{\text{done, tot}} \) is subtracted from the control signal \( \Delta Q_{\text{MLI, tot}} \) and limited to the maximum amount of compensation \( Q_{\text{max}} \) based on the control diagram of 5.3. The output signal is \( \Delta Q \).

Aggregation

In the Aggregation block the power available for load relief of all actuators and lower level agents in the same class are added:

\[
\begin{align*}
\Delta P_{\text{gen, max, tot}} &= \sum_{j=1}^{m} \Delta P_{\text{gen, max, } j} \\
\Delta P_{\text{LTC, max, tot}} &= \sum_{j=1}^{m} \Delta P_{\text{LTC, max, } j} \\
\Delta P_{\text{load, max, tot}} &= \sum_{j=1}^{m} \Delta P_{\text{load, max, } j} \\
\Delta Q_{\text{max, tot}} &= \sum_{j=1}^{m} \Delta Q_{\text{max, } j}
\end{align*}
\]  

(5.16)

Where \( m \) are the total number of actuators in the class.

Coordination Gen control

In the Coordination Gen control block the control signal for the local generation class \( \Delta P_{\text{gen}} \) is subdivided among the actuators connected to the local substation and all substations one level lower in hierarchy based on equation (5.7). The output signals are: \( \Delta P_{\text{gen, } 1}, \Delta P_{\text{gen, } 2}, \ldots \Delta P_{\text{gen, } j} \). Note that the control signals that are sent to lower level substations are subdivided further by the lower level substation agent.

Coordination LTC control

In the Coordination LTC control block the control signal for the LTC class \( \Delta P_{\text{LTC}} \) is subdivided among the actuators connected to the substation and all substations one level lower in hierarchy based on equation (5.7). The output signals are: \( \Delta P_{\text{LTC, } 1}, \Delta P_{\text{LTC, } 2}, \ldots \Delta P_{\text{LTC, } j} \). Note that the control signals that are sent to lower level substations are subdivided further by the lower level substation agent.
5.4 Hierarchical Agent Based Voltage Instability Prevention

Coordination Load control

In the Coordination Load control block the control signal for the load control class $\Delta P_{\text{load}}$ is subdivided among the actuators connected to the substation and all substations one level lower in hierarchy based on equation (5.7). The output signals are: $\Delta P_{\text{load,1}}, \Delta P_{\text{load,2}}, ..., \Delta P_{\text{load,j}}$. Note that the control signals that are sent to lower level substations are subdivided further by the lower level substation agent.

Coordination Q-control

In the Coordination Q-control block the control signal for the reactive power compensation class $\Delta Q$ is subdivided among the actuators connected to the substation and all substations one level lower in hierarchy based on equation (5.8). The output signals are: $\Delta Q_1, \Delta Q_2, ..., \Delta Q_j$. Note that the control signals that are sent to lower level substations are subdivided further by the lower level substation agent.

Actuator Exclusion

The Actuator Exclusion block determines based on the signals $\Delta MLI_{\text{gen},k}$ of the individual connections $k$, whether the actuators connected via this connection can be used for control action. When the connection is close to voltage instability and the power flow is into the substation (so $\Delta MLI_{\text{gen},k} > 0$ and $P_k > 0$) actuators connected via that connection cannot be used because this will worsen the situation. The control action will increase the power flow on the connection and it will be operated closer to, or even beyond the point of maximum power transfer.

In the Actuator Exclusion block the power available for load relief of these overloaded incoming connections is set to zero:

$$
\begin{bmatrix}
\Delta P_{\text{gen,max,k, out}} \\
\Delta P_{\text{TC,max,k, out}} \\
\Delta P_{\text{load,max,k, out}} \\
\Delta Q_{\text{max,k, out}}
\end{bmatrix}
= 
\begin{cases}
0 \\
0 \\
0 \\
0
\end{cases}
$$

If $\Delta MLI_{\text{gen},k} > 0$ and $P_k > 0$

$$
\begin{cases}
\Delta P_{\text{gen,max,k,in}} \\
\Delta P_{\text{TC,max,k,in}} \\
\Delta P_{\text{load,max,k,in}} \\
\Delta Q_{\text{max,k,in}}
\end{cases}
$$

else

Where $\Delta P_{\text{gen,max,k, out}}$, $\Delta P_{\text{TC,max,k, out}}$, $\Delta P_{\text{load,max,k, out}}$ and $\Delta Q_{\text{max,k, out}}$ is the power available for the connection $k$ for the four actuator classes taking into account the loading of the connection; $\Delta P_{\text{gen,max,k,in}}$, $\Delta P_{\text{TC,max,k,in}}$, $\Delta P_{\text{load,max,k,in}}$ and $\Delta Q_{\text{max,k,in}}$ is the power available for the connection $k$ for the four actuator classes without taking into account the loading of the connection.

Note that for actuators directly connected to the substation it is assumed that the connection is not overloaded.

Communication Lower Level Substations & Actuators

The block Communication Lower Level Substations & Actuators establishes communication with substation agents one level lower in hierarchy and actor agents that represent actuators which are electrically connected to the substations. The substation agent receives voltage and current measurements, the amount of active power load relief ($\Delta P_{\text{gen,max,A-1}}$, $\Delta P_{\text{TC,max,A-1}}$ and $\Delta P_{\text{load,max,A-1}}$) and reactive power compensation ($\Delta Q_{A-1}$) the actuators and substations can provide, and the amount of control action that is actually established ($\Delta P_{\text{gen,done,A-1}}$, $\Delta P_{\text{TC,done,A-1}}$, $\Delta P_{\text{load,done,A-1}}$ and $\Delta Q_{\text{done,A-1}}$). The substation agent sends out voltage and current measurements and the required control signal ($\Delta P_{\text{gen,A}}$, $\Delta P_{\text{TC,A}}$, $\Delta P_{\text{load,A}}$ and $\Delta Q_{A}$).

5.4.3 Actuator agent

The goal of the actuator agent is to implement the control action requested by the substation agent, offering a certain amount of active or reactive power load relief, and to provide the substation agent with information
to decide on the control action that should be implemented. The block scheme of the actuator agent is shown in figure 5.9.

The substation agent has three tasks:

1. To convert the required amount of active or reactive power load relief in a control action for that particular actuator.

2. To determine the amount of power the actuator has available for load relief. This depends on physical limitations of the actuator (e.g., maximum tap position of LTC or capability diagram of the synchronous generator) and minimum allowed voltages.

3. To determine the amount of active and reactive power load relief already implemented.

In section 5.6 the control strategy for load control and reactive power control will be discussed. In chapters 6 and 7 a detailed discussion will be given about respectively the LTC control and the local generator control.

5.5 HABVIP applied to meshed systems

The operation of the HABVIP controller in radial systems is straightforward. The system works, however, for meshed systems as well. In this section the application of the HABVIP controller in meshed systems will be discussed based on two examples.

5.5.1 Voltage Instability Prevention in Meshed Transmission Systems

Consider the meshed system of figure 5.10. This system consists of three substations (A to C) at the same voltage level. The arrows in the figure indicate the direction of the power flow.

Because the substations are at the same voltage level, they only exchange the voltage and current phasors. So no load relief is demanded by one substation agent from another substation agent at the same level.

In the case all three connections between the substations are overloaded, the following will happen. Substation B has two incoming connections which are overloaded. In order to restore stability, the total control signal is determined (equations 5.11 and 5.12) to bring back the $M LI$ of both connections. Substation B requests an amount of load relief from the substations at lower voltages connected to it only.

Substation C has only one incoming connection that is overloaded. The agent from this substation determines the amount of load relief required to solve the voltage instability problem. This load relief is solely requested from the lower level substations connected at substation C.
So both substations B and C solve ‘their own’ voltage instability problems. The load relief applied at substation B might, however, also influence the loading of the line A-C. In this case the load relief of the total system is larger than what is required. In that case substation C will notice that the $MLI$ of connection A-C becomes larger than its threshold. The corresponding agent will, based on that, decrease the requested load relief. In this way the control among the substations at the same voltage level will be coordinated.

### 5.5.2 Voltage Instability Prevention in Meshed Distribution Systems

The discussion will be based on the distribution system of figure 5.11. Note that this system is not meant to represent a typical power system, but for illustration purposes. It consists of four substations at different voltage levels. A is the highest substation and D the lowest in hierarchy. From A to D the power flow is via two paths: via substation B and via substation C.

Assume that both connections: A-B and A-C are voltage unstable. In that case both substations, B and C, will request load relief from substation D. Substation D will add the load relief required from the two higher level substations and implement this control. For determination of the amount of load relief available and the amount of actually implemented load relief respectively equations (5.9) and (5.10) are used.

### 5.6 Control of Actuators

Four types of actuators are controlled with the HABVIP controller: local generators, LTCs, loads and reactive power compensating devices. In chapter 6 the control of the LTC will be outlined and in chapter 7 the detailed control of the local generators will be described.
In this section the control of the loads and the reactive power compensating devices will be briefly given.

### 5.6.1 Smart Load Control

Load shedding controlled by under-voltage and under-frequency relays is a classic and effective countermeasure to avoid instability. For consumers the impact of this classic form of load-shedding is considerable, because the supply of the customers in a specific area is interrupted. In future, loads will be intelligent and able to participate in demand response programs [96, 110, 114, 147, 228]. An example of such intelligent loads is the charging of an electric car that can be temporarily paused. For small amounts of load reduction, the reduction can be divided over time amongst customers (load idling).

Intelligent loads should be equipped with a mechanism to inform the substation agent about the amount of load relief they are able to provide. This intelligent form of load control differs from classical, relay triggered load shedding, because the reduction is temporary, and buys in fact time till other actuators can become active.

The above-described controllable loads and the required smart-metering infrastructure are not everywhere available at the moment of writing this thesis and the HABVIP controller should (partly) rely on a more classical way of load control. In this classical method load feeders are simply disconnected from the substation. By monitoring the load power the impact of decoupling a particular feeder is known beforehand and the amount of load that is disconnected can be minimized. In the simulations in this thesis it is assumed that smart load control does exist and is part of an aggregated load model.

For modeling of intelligent load control it is assumed that the load follows a constant power model. Furthermore it is assumed that on an aggregated level the load can be controlled continuously.

In case \( \Delta P_{\text{load}} \) needs to be shed from the controllable loads, the reference for the active power from the dynamic load model becomes:

\[
P_{\text{load,ref}} = P(0) - \Delta P_{\text{load}}
\]  
(5.18)

Where \( P(0) \) is the load consumption before the control action is applied.

It is assumed that active and reactive power are controlled in such a way that the power factor remains constant. The reference for the reactive power consumption becomes:

\[
Q_{\text{load,ref}} = Q(0) \left(1 - \frac{\Delta P_{\text{load}}}{P(0)}\right)
\]  
(5.19)

The amount of active power available for load relief is:

\[
\Delta P_{\text{load,max}} = P(0) - P_{\text{load,min}}
\]  
(5.20)

Where \( P_{\text{load,min}} \) represents the amount of active load power that cannot be controlled.

### 5.6.2 Reactive power compensating devices

In this thesis a Static Var Compensator with modified control is used as reactive power compensating device. An SVC is a shunt compensator that is voltage controlled [200].

In the altered control scheme for the HABVIP control the reactive power is controlled instead of the voltage (see chapter 2). The control scheme for the SVC susceptance under HABVIP control is:

\[
B_{\text{svc}} = (Q_{\text{ref}} - Q) \left( k_P + k_I \frac{1}{P} \right)
\]  
(5.21)

\( B_{\text{svc}} \) is subject to:

\[
P_{\text{min}} \leq B_{\text{svc}} \leq P_{\text{max}}
\]  
(5.22)

The reference for the controller, \( Q_{\text{ref}} \), can be determined from:

**(Note that although connection and disconnection of individual loads is a discrete process, at an aggregated level with a sufficiently large number of devices, it appears to be continuous.**

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Note that although connection and disconnection of individual loads is a discrete process, at an aggregated level with a sufficiently large number of devices, it appears to be continuous.
5.7 Qualitative Discussion

\[ Q_{\text{ref}} = Q(0) + \Delta Q \]  

(5.23)

Where \( Q(0) \) is the reactive power supplied by the SVC before the HABVIP controller starts to act and \( \Delta Q \) is the amount of reactive power load relief asked from the SVC.

The SVC should distinguish two control modes: normal control and emergency control. In the case no load relief is asked from the SVC it should be in voltage droop control mode. In the case reactive power load relief is asked from the SVC it should supply the requested amount of reactive power. The control strategy becomes:

\[
B_{\text{svc}} = \begin{cases} 
\frac{|U_{\text{ref}}| - |U|}{X_{\text{svc}} |U|} & \text{if } \Delta Q = 0 \\
(Q_{\text{ref}} - Q) \left( k_p + k_i \frac{1}{p} \right) & \text{else}
\end{cases}
\]  

(5.24)

subject to:

\[ B_{\text{min}} \leq B_{\text{svc}} \leq B_{\text{max}} \]  

(5.25)

In this equation \( U \) is the voltage that is regulated by the SVC, \( U_{\text{ref}} \) is the voltage reference, \( X_{\text{svc}} \) is the droop of the SVC characteristic in regulating mode, \( B_{\text{svc}} \) the SVC susceptance, \( B_{\text{min}} \) and \( B_{\text{max}} \) are the limits of the SVC susceptance, and \( K_p + K_i / p \) is a PI control action.

The amount of reactive power the SVC has available for load relief can be determined from:

\[ \Delta Q_{\text{max}} = B_{\text{max}} |U|^2 - Q(0) \]  

(5.26)

5.7 Qualitative Discussion

In this section some qualitative points regarding the HABVIP controller will be discussed. The system will be described further in the subsequent chapters.

In the introduction of this chapter the distinction was made between an agent and an intelligent agent [111, 112]. An agent is an entity that is able to interact with its environment and an intelligent agent is an entity that has besides this reactivity the ability to interact with other entities in a pro-active mode. The substation agents and actor agents fit easily within the rather broad definition of an agent. Substation agents and actor agents interact with their environment and with each other. The definition for an intelligent agent is more strict. To be an intelligent agent, the actuator agents and substation agents should be pro-active and have a social ability (e.g. negotiation in order to obtain the local goal). The substation agents are pro-active. They anticipate to an emerging instability and adapt the control when necessary. The actor agents are not really pro-active. When requested by the substation agent, they just perform their task.

Substation agents communicate with each other. There is also communication between substation agents and actor agents. They do not really negotiate, but they exchange more information than just measurements. Altogether substation agents can be classified as intelligent agents. Actor agents can only be classified as normal agents. The HABVIP controller is thus a Multi-Agent System that consist of both intelligent and normal agents.

A second point is whether a MAS is appropriate for the problems solved with a HABVIP controller? According to [111] a MAS is appropriate for applications that have at least one of the following characteristics:

- requirement for interaction between entities;
- large number of interacting entities;
- locally enough information available;
- implementation within existing plant items and control items;
- requirement for continued extension.
The first characteristic is that: "There is a requirement for interaction between distinct conceptual entities, such as different control subsystems and plant items, e.g., controlling a micro-grid while taking account of thermal constraints, voltage control, and renewable energy sources." The HABVIP controller contains two distinct conceptual entities: substation agents and actor agents. The substation agents determine on a higher level what the control action should be. The actor agents implement the control actions and provide the substation agents with information about the capability of the actuators. The actor agents take into account the different constraints of the actuator like field-current or tap ratio limitations of local generators. The substation agents cannot determine the control action without knowing the capability of the actuators and the actor agents are unable to establish an action without the control signal from the substation agents. So there is a clear need for communication between distinct conceptual entities.

The second characteristic is that: "A very large number of entities must interact, where it would be impossible to explicitly model overall system behavior, e.g., simulation of an energy marketplace where each individual generator, independent system operator, and customer is modeled." The HABVIP controller involves all substations and actuators available in the system. Some of these entities may be owned by different parties. The LTC belongs, for instance, to the system operator and DG to market parties. None of these parties has access to all the information required for centralized control. In the HABVIP controller this problem is circumvented because agents only have to send aggregated information to the higher level agents. These higher level agents do not need more information about the lower level system behavior.

The third characteristic is that: "There is enough data/information available locally to undertake an analysis/decision without the need for communication with a central point, e.g., substations-based diagnostics from transformer, switchgear, and protection analysis systems." Voltage stability starts locally and spreads system-wide when it is not timely solved. The detection method based on the MLI requires only voltage and current phasors of the local and neighboring substations. Furthermore, only the agents at substations that sense the problem communicate to devise control actions.

The fourth characteristic is that: "New functions need to be implemented within existing plant items and control systems, e.g., extending substations-based condition monitoring systems by adding data interpretation functions." The proposed hierarchical structure of the HABVIP controller can be extended to include more functions than voltage instability prevention only. Existing protection devices should be incorporated in the system, the frequency and rotor angle stability problems could also be solved with this architecture and during steady-state a market environment like the PowerMatcher should be used. The fact that only a limited, aggregated, amount of data is exchanged makes the HABVIP structure particularly suitable for implementation in the deregulated power system.

The fifth characteristic is that: "Over time, there is a requirement for functionality to be continually added or extended, e.g., asset management through the use of real-time condition monitoring on multiple plant items." The electricity network changes over time: the number of households keeps increasing, new neighborhoods are build and thus new distribution substations are necessary. Also at higher voltage level extension will remain necessary. Load demand changes and new (renewable) generation units will be build. Consequently, the HABVIP controller should be continuously extended and adapted. It is easy to add new devices to the HABVIP controller because the data that needs to be exchanged is well defined and consistent, and the architecture is modular.

So from the analysis given above it can be concluded that a MAS is appropriate for the problems solved with the HABVIP controller.

5.8 Conclusion

In this chapter the control strategy and architecture for the Hierarchical Agent Based Voltage Instability Prevention system (HABVIP) are given. The control strategy uses the MLI to detect voltage instability and quantify the amount of load relief required to restore voltage stability. The control architecture is an agent-based system where each substation is controlled by a substation agent and every actuator is controlled by a so-called actor agent. Among the agents there is a hierarchical structure. The load relief is obtained by: increase of local generation, indirect load shedding with LTC action, smart load control and the increase of the reactive power compensation with Static Var Compensators. The chapter discusses the coordination among these different control actions. The control of the SVC and the load is briefly described.
in the chapter. The control of the LTC and the local generation will be described in chapters 6 and 7. A verification of the HABVIP controller will be given in chapters 8 and 9.
Chapter 6

Control Strategy for Load Tap Changers

6.1 Introduction

As outlined in section 2.3.3.2, Load Tap Changers (LTCs) are used to control the voltage at the transformer substations connecting transmission to distribution grids, or distribution grids to low voltage grids. Under normal operating conditions the objective is to keep these voltages close to their nominal value or, when line-drop compensation is used, a little higher than that to account for the voltage drops in underlying distribution feeders. For voltage dependent loads this means that the LTC is capable of restoring the load: a drop in the voltage results for these loads in a decrease in load consumption, the LTC will try to increase the secondary voltage by adjusting its tap ratio and with that it attempts to restore the load power of the mentioned types of loads. Under normal operating conditions the LTC’s voltage regulating property is beneficial for the power system. When the system is, however, close to voltage instability, the load restoring property can be detrimental to the power system and might even contribute to a voltage collapse [185, 200]. To prevent the load restoring behavior of the LTC during these emergency situations, several emergency controls have been proposed in the literature and are compared in [201, 218]:

- tap blocking;
- tap locking;
- tap reversing;
- voltage set-point reduction.

With LTC tap blocking, as soon as voltage instability is detected, the tap changer is blocked. This method is proposed in [198, 217]. In the method of [198], all LTCs are blocked upon voltage instability detection. To be able to restore the voltage to some extent, the LTCs with the smallest impact are later released. In [217] a method is proposed where the voltage instability detection method determines the appropriate LTCs which should be blocked.

Tap locking is a special form of tap blocking. In the case of locking, when voltage instability is detected, the LTC first brings its tap to a target position and then blocks [201, 218].

With the tap-reversing method, the LTC starts to control the primary (high-voltage side) voltage instead of the secondary voltage. The logic of the LTC is reversed in this case. This method is proposed in [138]. If voltage set-point reduction is applied, the reference voltage of the LTC at the distribution voltage side is lowered. For voltage sensitive loads, this subsequently lowers the load. In [129] a method is introduced where the voltage set-point is lowered to a fixed minimum value. In [219] a method is introduced where, upon detection of a low secondary voltage, the voltage reference is reduced by 5%. In addition to this, the tap position is increased by two steps at a time to speed up the regulation process. This process is repeated if the voltage stays too low.
The emergency controls of the LTC can be combined with other countermeasures for voltage instability such as generator voltage control and load shedding. Examples can be found in [38, 72, 102, 104, 139, 156, 160]. The focus in these papers is the coordination of the different control actions. The main difference between the HABVIP controller and the coordination methods proposed in the cited literature is that the HABVIP controller is a decentralized control system and the other methods require centralized control.

The control strategy for the LTC that is proposed in this chapter requires the calculation of a new voltage reference that corresponds to the amount of load relief that is required from the LTC. The method uses the reverse of the load restoring property of the LTC: where for voltage sensitive loads a higher voltage leads to a higher load, a lower voltage leads to a lower load. The benefit of this proposed method compared to the existing voltage set-point reduction methods [129, 219] is that the effect of a given control action can be evaluated ahead of time.

As discussed in chapter 5, the focus of the LTC control is to lower the active power. As positive side-effect the reactive power is also reduced. This reduction in reactive power will be measured and sent to the substation agent.

The proposed method will be implemented in a HABVIP actor agent controlling the LTC. In chapter 5 it was outlined that these actor agents should:

1. Convert the requested amount of load relief to an action of the actuator.
2. Determine the amount of load relief the actuator has available for load relief.
3. Measure the actually established amount of active and reactive power load relief as a result of the action implemented by the actor agent.

The established active and reactive power load relief is determined with the following equations:

$$\Delta P_{LTC, done} = P_{load}(0) - P_{load}(t) \quad (6.1)$$

$$\Delta Q_{LTC, done} = Q_{load}(0) - Q_{load}(t) \quad (6.2)$$

Where $P_{load}(0)$ and $Q_{load}(0)$ are the initial active and reactive power consumption of the aggregated load behind the LTC and $P_{load}(t)$ and $Q_{load}(t)$ the active and reactive power load after the control action is established.

The method to convert the requested amount of load relief to an action that can be used by the LTC is outlined in section 6.2. This method assumes some knowledge about the dependency between voltage and load consumption. In the section a proof of concept is given and a sensitivity analysis is done to determine the influence of the different parameters. In section 6.3, the method to determine the available power for load relief is discussed. Also for this method a proof of concept and a sensitivity analysis is given. Section 6.4 provides a discussion of the method that is developed. Finally in section 6.5, the conclusions are given.

6.2 Indirect load shedding

The actor agent controlling the LTC has two control modes:

- Normal control.
- Emergency control.

In the normal control mode no load relief is required from the LTC. The voltage reference is the normal one, for instance determined by an optimal power flow program (with e.g. as goal the minimization of generation cost or the active power losses in the system [171]). In the emergency control mode the LTC control is used to obtain a requested amount of load relief. The voltage reference is determined based on the method that will be introduced in this section.

Switching between normal control and emergency control is based on the load relief requested from the LTC ($\Delta P_{LTC}$), which is received from the substation agent (see chapter 5). When this control signal is zero, the normal control mode is used. When this signal has another value than zero, emergency control is applied.
6.2 Indirect load shedding

6.2.1 Method for indirect load shedding

With the proposed control scheme load is indirectly shed by lowering the secondary voltage of the load tap changer by an amount that results in the requested amount of load relief (which is decided in coordination with the other available control actions). When the amount of load relief required from the LTC ($\Delta P_{\text{LTC}}$) and the analytical expression of the voltage dependency for the load supplied by the LTC are known, the voltage set-point of the load tap-changer ($|U_{\text{ref}}|$) can be calculated. In the proposed method a static ZIP-model for the load is assumed (see chapter 2). For convenience the model is repeated here:

$$P_{\text{load}} = P_0 \left( a_P \left( \frac{|U|}{|U_0|} \right)^2 + b_P \left( \frac{|U|}{|U_0|} \right) + c_P \right)$$  \hspace{1cm} (6.3)

$$Q_{\text{load}} = Q_0 \left( a_Q \left( \frac{|U|}{|U_0|} \right)^2 + b_Q \left( \frac{|U|}{|U_0|} \right) + c_Q \right)$$  \hspace{1cm} (6.4)

In this equation $P_{\text{load}}$ and $Q_{\text{load}}$ are the active and reactive power consumed by the load; $P_0$ and $Q_0$ the real and reactive power consumed at nominal voltage $U_0$; $a_P$, $b_P$ and $c_P$ the fractions of the real power for respectively the constant impedance, constant current and constant power parts of the load; $a_Q$, $b_Q$, and $c_Q$ the fractions for the reactive power for respectively the constant impedance, constant current and constant power parts; and $U$ the actual voltage. For the parameters it should hold that: $a_P + b_P + c_P = \alpha_Q + b_Q + c_Q = 1$.

To estimate the load model parameters from measurements, several methods are proposed in literature. For instance in [168] a method is outlined based on least squares optimization and in [13] a method is introduced based on a hybrid learning algorithm. These methods can in principle be applied periodically to update the parameters as the composition of the load changes. In this thesis such a method is implicitly assumed.

As stated before for the LTC control we will only concentrate on the active power reduction. If the amount of load that should be indirectly shed by the LTC is $\Delta P_{\text{LTC}}$, the reference for the power can be calculated with:

$$P_{\text{ref}} = P_{\text{load}(0)} - \Delta P_{\text{LTC}}$$  \hspace{1cm} (6.5)

In this equation $P_{\text{load}(0)}$ is the initial load consumption.

For obtaining the set-point for the voltage $|U_{\text{ref}}|$, $P_{\text{ref}}$ are substituted for $|U|$ and $P_{\text{load}}$ in equation (6.3). This equation can be rewritten as:

$$a_P \left( \frac{|U_{\text{ref}}|}{|U_0|} \right)^2 + b_P \left( \frac{|U_{\text{ref}}|}{|U_0|} \right) + c_P - \frac{P_{\text{ref}}}{P_0} = 0$$  \hspace{1cm} (6.6)

Solving for $|U_{\text{ref}}|$ gives two solutions:

$$|U_{\text{ref},1}, U_{\text{ref},2}| = |U_0| \pm \frac{b_P \pm \sqrt{b_P^2 - 4a_P \left( c_P - \frac{2a_P}{2a_P} \right)}}{2a_P}$$  \hspace{1cm} (6.7)

Note that this works only when $a_P \neq 0$, so when some portion of the load is constant impedance. From these two solutions the highest voltage value should be taken as reference voltage because it corresponds to the desirable operating point (see chapter 2):

$$|U_{\text{ref}}| = \max \{|U_{\text{ref},1}, |U_{\text{ref},2}|\}$$  \hspace{1cm} (6.8)

If the secondary voltage of the LTC has to stay within certain limits, this can be taken into account. If the voltage is only allowed to deviate by $\Delta |U_{\text{max}}|$ lower than the nominal voltage, the new reference value for the voltage becomes:

$$|U_{\text{ref,lim}}| = \begin{cases} |U_{\text{ref}}| & |U_0| - |U_{\text{ref}}| \leq \Delta |U_{\text{max}}| \\ |U_0| - \Delta |U_{\text{max}}| & |U_0| - |U_{\text{ref}}| > \Delta |U_{\text{max}}| \end{cases}$$  \hspace{1cm} (6.9)
6.2.2 Proof of concept with radial load connection to the grid

A proof of concept of the control method of the LTC is given in this subsection based on the test circuit of figure 6.1. In this simulation realistic line parameters are used and a load with a power factor 0.96 lagging is assumed. The circuit data is given in appendix E.1. The LTC is controlled with the proposed new extension for indirect load shedding control. This controller will be assigned to a certain amount of load relief and it will be determined whether or not the required amount of load relief is actually provided. The proof of concept is given based on simulations in Matlab/Simulink with the SimPowerSystems toolbox [80].

For the proof of concept it is assumed that the parameters of the (active power) load model used for determining the voltage reference (equation (6.7)) are equal to the actual load parameters. For the test circuit this means: \( a_P = 0.5 \), \( b_P = 0 \), \( c_P = 0.5 \), \( P_0 = 3384 \) MW and \( |U_0| = 1.00152 \) pu. The simulation is initialized such that \( P_{load}(0) = P_0 \). At \( t = 50 \) s, 4 \(^\circ\) (135 MW, or 0.04 pu) of the load needs to be indirectly shed. The result is shown in figure 6.2.

In the upper graph of 6.2 the LTC’s primary voltage (solid line), secondary voltage (dashed line) and the reference for the secondary voltage (dotted line) are given. Before \( t = 50 \) s no load relief is requested from the LTC. The primary voltage is lower than one per unit because of line drop losses. The reference for the secondary voltage equals one. The actual secondary voltage is somewhat higher due to the deadband introduced by the discrete control of the tap positions. In the load model used in the LTCs indirect load shedding method this higher \(|U_0|\) is taken into account.

After \( t = 50 \) s the indirect load shedding is started. The reference of the secondary voltage drops immediately. The actual secondary voltage is lowered in steps every 5 s until at \( t = 85 \) s the LTC has the tap at a position where the voltage is within the LTCs deadband. The final secondary voltage is a slightly (less than 0.03 \(^\circ\)) too high. During the time period \( 50 \leq t \leq 85 \) s the primary voltage increases due to the fact that with lowering the secondary voltage, the required current is also lowered and subsequently the voltage drop across the line. Note that this increase in primary voltage partly counteracts the indirect load shedding process.

In the middle graph of figure 6.2 the tap position of the LTC is shown. To lower the secondary voltage the tap position increases as expected.

In the lower graph of figure 6.2 the power consumption of the load is shown. From this graph the step-wise indirect load shedding behavior of the LTC is clearly visible. The load that is finally indirectly shed is 0.04 pu. This is exactly the amount that should be indirectly shed.

The simulation shows that when, for the circuit used, 0.04 pu load relief is requested from the LTC, the actual load that is indirectly shed is equals the required amount. In order to investigate whether the requested amount of load relief is always obtained with the proposed method in figure 6.3 the error of the actual load that is indirectly shed is given as function of the amount of load that needs to be indirectly shed (solid line). The figure also includes the theoretical maximum error (dashed line) and the LTC’s limits (dotted vertical lines). An explanation follows.
Figure 6.2. Voltages (upper graph), tap setting (middle graph) and load power (lower graph) for ideal operation of method if at $t = 50$ seconds the control signal is given to shed indirectly 4% of the load.
The relative error (solid line) is calculated with:

$$\varepsilon_{\Delta P_{\text{LTC,done}}} (\Delta P_{\text{LTC}}) = \frac{\Delta P_{\text{LTC,done}} - \Delta P_{\text{LTC}}}{\Delta P_{\text{LTC}}} \cdot 100\% \quad (6.10)$$

Where $\Delta P_{\text{LTC,done}}$ is the amount of power that is actually indirectly shed and $\Delta P_{\text{LTC}}$ is the amount of load relief that is requested.

The theoretical maximum error (dashed line) is the error introduced by the deadband in the LTC voltage control. This deadband in the voltage will appear as a deadband in the obtained indirectly shed power. The voltage magnitude deviates due to this by at most: $\frac{1}{2} \Delta |U_{\text{DB}}|$. Differentiating the load model equation (equation (6.3)) and substituting the maximum voltage deviation gives the theoretical maximum error in the voltage:

$$\varepsilon_{P_{\text{LTC,done}}} (\Delta |U_{\text{DB}}|) = \frac{1}{2} \Delta |U_{\text{DB}}| \cdot P_0 \cdot \left( \frac{|U|}{|U_0|} \right) + b_p \cdot 100\% \quad (6.11)$$

Figure 6.3 shows that the error in the amount of obtained indirect load shedding is highly dependent on the amount of load relief that is requested. So the fact that with the simulations of figure 6.2 exactly the amount of load relief is obtained as what is requested, cannot be generalized to all cases.

As can be seen from figure 6.3 the error in the amount of load that is indirectly shed is restricted by the theoretical maximum error whenever the LTC operates within its limits. From this it can be concluded that the error is determined by the deadband of the LTC. As can be expected the error is lower than the maximum error most of the time. This is because the deviation in the secondary voltage does not always reach its maximum value.

The minimum and maximum limits of the LTC tap ratio (vertical dotted lines) limit the region for which the LTC can provide load relief. The minimum limit in the power that can be indirectly shed is related to the amount of power that can be indirectly shed by one tap change. The maximum limit is introduced by the maximum tap position. LTC indirect load shedding control is only feasible within this region. If larger amounts of load need to be indirectly shed than what is possible with the LTC at its maximum position, the error will increase and exceed the theoretical maximum error.

For the simulations under consideration the error is negative due to the choice of the deadband and the voltage step of the LTC. This is illustrated in figure 6.4. In this figure the small vertical lines illustrate voltage reference ($|U_{\text{ref}}|$) and each subsequent 'virtual' reference which is an increase of this reference with an integer times the deadband ($|U_{\text{ref}}| + N \cdot \Delta |U_{\text{DB}}|$). The longer vertical lines illustrate the deadband around the reference and the subsequent 'virtual' references. The dots and the dashed lines with arrows show the tap changing when load is virtually shedded with the proposed method. Two cases are shown: one when
the indirect load shedding starts with an initial voltage that is higher than the 'virtual' reference and one when the initial voltage is lower than this 'virtual' reference. The tap position is changed when the difference between the voltage $|U|$ and the reference voltage is larger than half the deadband ($|U| - |U_{ref}| \geq \frac{1}{2} |U_{DB}|$). For these simulations the deadband $|U_{DB}|$ is chosen to be twice the voltage step per tap $\Delta|U_{tap}|$, which is according to [200] a typical value. In the indirect load shedding procedure the tap is controlled from a lower tap position to a higher one (which means from a higher voltage to a lower voltage). Because $|U_{DB}| = 2 \cdot |U_{tap}|$ this implies that the voltage will never end in the lower part of the deadband. If, of course, a different relation between $|U_{DB}|$ and $|U_{tap}|$ is chosen, this error can also become positive. The relative error is large when small amounts of power have to be indirectly shed. This is because $\varepsilon_{\Delta P_{LTC,done}}$ is relative to the amount of load that needs to be indirectly shed. If the error is in the order of magnitude of $\Delta P_{LTC}$, the relative error will be large.

6.2.3 Sensitivity analysis

In the previous subsection the concept of the indirect load shedding control method for the LTC is proven and the error between the amount of load that needs to be indirectly shed and the amount that is actually obtained, is discussed. In this subsection the sensitivity of the indirect load shedding method to the different load model parameters is studied. In this way the impact of an inaccuracy in the load model can be investigated. Simulations are done with the circuit of figure 6.1 with varying load model parameters $a_P$, $b_P$, $c_P$, $P_0$ and $|U_0|$ (the parameters as known by the controller are varied). Furthermore simulations are carried out with varying values for the maximum allowed voltage deviation $\Delta|U_{max}|$. The parameters for the test system are given in appendix E.1.

In the previous sections it was shown that the deadband of the LTC is of major importance for the error between the requested load relief and the load that is actually indirectly shed. This error has a sawtooth shape as is shown in figure 6.3. To take into account this error, three amounts of load to be indirectly shed are compared based on the range of errors available from figure 6.3:

1. 0.0400 pu, which gives in the ideal case an error close to zero;
2. 0.0425 pu, which gives in the ideal case an error halfway between zero and the theoretical maximum;
3. 0.0450 pu, which gives in the ideal case an error close to the theoretical maximum.

The actual amount of load that is indirectly shed is determined and the error between what is actually obtained relative to the amount that is requested (equation (6.10)) is determined. The theoretical maximum error introduced by the deadband (equation (6.11)) is approximately 14 % for about 4 % of requested load relief. Note that as long the error due to an inaccuracy in the load model parameters does not exceed this error due to the deadband, the influence of the inaccuracy is not significant.

The result for the sensitivity analysis is given in figure 6.5.

The left hand side graphs give the sensitivity of the method for load model parameters $a_P$, $b_P$ and $c_P$. For these parameters it is required that: $a_P + b_P + c_P = 1$. In this sensitivity study this requirement is

\[\text{Note that for the same choice of } |U_{DB}| \text{ and } \Delta|U_{tap}| \text{ the reverse is true if the secondary voltage needs to be increased.}\]
Figure 6.5. Sensitivity analysis of the indirect load shedding method to the different load model parameters used by the method. Three levels of load to be indirectly shed are used: 0.0400 pu (solid line), 0.0425 pu (dashed line) and 0.0450 pu (dotted line). Negative deviation means less load is indirectly shed than requested.
fulfilled because otherwise the total amount of load in the model would be influenced. This means that an increase in one parameter is compensated by a decrease in another, such that the total sum remains 1. The cases investigated are \( a_P \) compensated by \( c_P \) (upper left hand graph), \( a_P \) compensated by \( b_P \) (middle left hand graph) and \( c_P \) compensated by \( b_P \) (lower left hand graph). The relation between these parameters are respectively:

\[
\begin{align*}
    c_P &= 1 - a_P, \\
    b_P &= 0.5 - a_P, \\
    a_P &= 0.5 - c_P.
\end{align*}
\]

For the case \( a_P \) compensated by \( c_P \) (upper left hand graph) it can be seen that when the deviation in \( a_P \) is positive the LTC actor agent ‘thinks’ that the load has a larger share of constant impedance load than it actually has. \( c_P \) is on the contrary larger than expected implying that the constant power part of the load is larger than expected. This means that the voltage reference that is calculated is too high and subsequently not enough load is indirectly shed. Of course the opposite is also true: when the deviation in \( a_P \) is negative the LTC actor agent expects a load with a smaller constant impedance part and the voltage set-point that is calculated is too low. In this case more load is indirectly shed than necessary.

For the cases \( a_P \) compensated by \( b_P \) (middle left hand graph) and \( c_P \) compensated by \( b_P \) (lower left hand graph) a similar effect can be seen. In these cases because \( b_P \) is involved, \( a_P \) and \( c_P \) can only be reduced because \( b_P \) is zero in the load under consideration. The increase in error between the amount of load that is actually indirectly shed is smaller for these two cases than it was for the case that \( a_P \) is compensated by \( c_P \).

This is because for these two cases the LTC actor agent expects respectively a larger constant impedance part but has a larger constant current part (middle left hand graph) and expects a larger constant power part but has a larger constant current part (lower graph). The voltage dependence of a constant impedance load is quadratic, the voltage dependence of a constant current load is linear and a constant power load is not dependent on the voltage. From this it can be seen that the voltage dependence of a constant impedance load and a constant current load or a constant current load and a constant power load are more comparable than the voltage dependency of a constant impedance load and a constant power load.

The right hand graphs give the sensitivity of the method to the load model parameters \( P_0 \) (upper right hand graph) and \( |U_0| \) (middle right hand graph); and the constraint \( \Delta|U_{\text{max}}| \) (lower right hand graph). It can be seen that the indirect load shedding method is rather sensitive for deviations in both parameter \( P_0 \) and \( U_0 \). So these parameters should be known accurately by the controller.

The lower right hand graph shows the dependency of the method on the constraint \( \Delta|U_{\text{max}}| \). It can be seen that as long as \( \Delta|U_{\text{max}}| > 0.04 \text{pu} \), the fact that the maximum voltage deviation is limited does not introduce an extra error. The maximum allowable voltage deviation of 10% as requested in the Dutch grid code (see [57]) will thus not introduce an extra error in the method.

In figure 6.5 the discrete behavior of the LTC can be noticed for all cases: the deviation in the parameter does not influence the relative error in the amount of load to be indirectly shed as long as the deviation does not induce a step in the tap setting. Furthermore due to the fact that in the ideal case not enough power is indirectly shed, a deviation in a parameter which results in that less power is indirectly being shed, is more detrimental than when the opposite occurs. A deviation in a parameter which makes that more power is indirectly shed can even be advantageous.

Generally it can be concluded from the sensitivity analysis that a deviation in a load model parameter does not influence the relative error in the amount of load to be indirectly shed as long as the deviation does not result in a step in the tap setting. This highlights that the error due to the deadband is more important than an inaccuracy in the model.

### 6.3 Available power for control action

For determining the optimal control strategy it is necessary that the amount of load that can be indirectly shed by the load tap changer is known. In subsection 6.3.1 the method to determine this will be introduced. In subsection 6.3.2 this method will be tested. Finally in subsection 6.3.3 a sensitivity analysis of the proposed method is given.

#### 6.3.1 Method for determining the power available for control action

The amount of power the LTC has available for load relief is dependent on the number of tap changes from the initial tap position \( r(0) \) to the maximum tap position \( r_{\text{max}} \) (assuming tap moves in the direction...
lowering the secondary voltage) and the voltage step per tap $\Delta|U_{\text{tap}}|$. From this the maximum step in the secondary voltage can be calculated:

$$\Delta|U| = (r_{\text{max}} - r(0)) \cdot \Delta|U_{\text{tap}}|$$

(6.12)

If the secondary voltage of the LTC has to stay within certain limits, this can be taken into account. If the voltage is only allowed to deviate $\Delta|U_{\text{max}}|$ from the nominal voltage, the total voltage step becomes:

$$\Delta|U_{\text{lim}}| = \begin{cases} 
\Delta|U| & \Delta|U| \leq \Delta|U_{\text{max}}| \\
\Delta|U_{\text{max}}| & \Delta|U| > \Delta|U_{\text{max}}| 
\end{cases}$$

(6.13)

From this the minimum secondary voltage of the LTC can be found:

$$|U_{\text{min}}| = |U(0)| - \Delta|U_{\text{lim}}|$$

(6.14)

In this equation $U(0)$ is the initial secondary voltage (which is not necessarily the same as $|U_0|$). Note that in the calculation above, only the dynamics of the load tap changer are included and that the result obtained can only be an approximation.

The value found for $|U_{\text{min}}|$ with equation (6.14) substituted for $|U|$ in equation (6.3) gives the power consumed by the load at minimum voltage $P_{\text{min}}$. From this the available power for indirect load shedding by means of the LTC can be calculated:

$$\Delta P_{\text{LTC,max}} = P_{\text{load}}(0) - P_{\text{min}}$$

(6.15)

Note that $r(0)$ and $|U(0)|$ are dependent on the current state of the system and they should be re-evaluated each time the emergency control is activated.

### 6.3.2 Proof of concept

A proof of concept of the method to determine the amount of load that can indirectly be shed by the LTC is given in this subsection based on the test circuit of figure 6.1. In this simulation realistic line parameters are used and a load with a power factor 0.96 lagging is assumed. The circuit data is given in appendix E.1. For the simulations it is assumed that the parameters of the (active power) load model used for determining the power available for load relief are equal to the actual load parameters. For the test circuit this means: $a_P = 0.5$, $b_P = 0$, $c_P = 0.5$, $P_0 = 3384$ MW, and $|U_0| = 1.00152$ pu. Furthermore $r_{\text{max}} = 8$, $r(0) = -2$ and $\Delta|U_{\text{up}}| = 0.00625$ pu. $\Delta|U_{\text{max}}|$ is neglected. The simulation is initialized such that $P_{\text{load}}(0) = P_0$ and $|U(0)| = |U_0|$. During the simulations the power available for load relief is determined based on the method introduced in section 6.3.1.

In figure 6.6 the simulation is given for the case when at $t = 50$ s 0.04 pu load relief is requested from the LTC. This simulation corresponds to the simulation in section 6.2.2. The upper graph of figure 6.6 gives the tap position and the lower graph the power available for indirect load shedding. Because of the fact that $P_{\text{LTC,max}}$ is calculated with the initial values $|U(0)|$ and $r(0)$ this measure stays constant at the initial value.
6.3 Available power for control action

Figure 6.6. Tap position (upper graph) and power available for indirect load shedding (lower graph) when $0.04\,\text{pu}$ load should be indirectly shed.

6.3.3 Sensitivity analysis

In the foregoing two subsections the calculation method to determine the amount of power available for the LTC’s indirect load shedding was demonstrated. In this subsection the sensitivity of this calculation method for the different load models and LTC model parameters is studied. The load model parameters $a_P$, $b_P$, $c_P$, $P_0$ and $|U_0|$; the LTC model parameters $r_{\text{max}}$, $r(0)$ and $\Delta|U_{\text{tap}}|$ and furthermore $\Delta|U_{\text{max}}|$ are varied. In this section it is determined what the influence of the variation of the parameters would be on the calculation of the power available for indirect load shedding. The new obtained amount is compared with a base case. Note that in this section the deviations in the model parameters of the model used for control are investigated.

As base case the simulation of section 6.3.2 is taken. The power initially available for indirect load shedding from this simulation ($0.0836\,\text{pu}$) is compared with the amount calculated based on a deviated parameter. This deviation is calculated as percentage of this initial amount of power available for indirect load shedding.

The results for the sensitivity analysis are given in figures 6.7 and 6.8.

The left hand side graphs of figure 6.7 gives the sensitivity of the method to the load model parameters $a_P$, $b_P$ and $c_P$. For these parameters it is required that: $a_P + b_P + c_P = 1$. As for the sensitivity study of the indirect load shedding method (section 6.2.3), to fulfill this requirement, an increase in one parameter is compensated by a decrease in another, such that the total remains 1. The cases investigated are: $a_P$ compensated by $c_P$ (upper left hand graph), $a_P$ compensated by $b_P$ (middle left hand graph) and $c_P$ compensated by $b_P$ (lower left hand graph). The relations between these parameters are respectively: $c_P = 1 - a_P$, $b_P = 0.5 - a_P$ and $b_P = 0.5 - c_P$.

For the case $a_P$ compensated by $c_P$ (upper left hand graph) a positive deviation in $a_P$ means that the LTC actor agent ‘thinks’ that the load has a larger share of constant impedance load than it actually has while the constant power part of the load is larger than expected. Consequently for a positive deviation in $a_P$, the actor agent ‘thinks’ that it has more load to be indirectly shed than it actually has. Of course the opposite is also true: when the deviation in $a_P$ is negative, the LTC actor agents expects a load with a smaller constant impedance part and the agent ‘thinks’ that less power can be indirectly shed than it actually can. Note that
Figure 6.7. Sensitivity analysis of the power available for indirect load shedding to the load model parameters $a_P$, $b_P$, $c_P$, $P_0$ and $|U_0|$; and the constraint $\Delta |U_{max}|$ as used by the method.
Figure 6.8. Sensitivity analysis of the power available for indirect load shedding to the LTC model parameters $r_{\text{max}}$, $r(0)$ and $\Delta|U_{\text{tap}}|$ as used by the method.
this effect is the opposite as found for the control strategy itself (see section 6.2.3).

For the cases $a_P$ compensated by $b_P$ (middle left hand graph) and $c_P$ compensated by $b_P$ (lower left hand graph) a similar effect can be seen. In these cases, because of the fact that $b_P$ is involved, the deviation in $a_P$ respectively $c_P$ can only be negative because $b_P$ is zero for the actual load. The slope of the relative error in the calculated load available for indirect load shedding is smaller for these two cases than it was for the case that $a_P$ is compensated by $c_P$. As discussed in section 6.2.3, this has to do with the fact that the voltage dependency of a constant impedance load and a constant current load or a constant power load are more comparable than the voltage dependency of a constant impedance load and a constant power load.

Compared to figure 6.5, the sensitivities for the indirect load shedding method and the method for determining the power available for load relief are a little bit lower in magnitude and opposite in sign for the parameters $a_P$, $b_P$ and $c_P$. If, due to an error in the model, the actor agent 'thinks' that it has more power available to be indirectly shed than it actually has, less power will be indirectly shed and vice versa. Note that these errors cannot cancel each other.

The right hand graphs give the sensitivity of the method to the load model parameters $P_0$ (upper right hand graph) and $|U_0|$ (middle right hand graph), and the constraint $|U_{\text{max}}|$ (lower right hand graph). As for the indirect load shedding method itself the calculation method for the power available for indirect load shedding is very sensitive to the parameters $P_0$ and $|U_0|$. This again highlights the importance for the accuracy in these measures.

The lower right graph shows the dependence of the method on the constraint $|U_{\text{max}}|$. It can be seen that as long as $\Delta|U_{\text{max}}| > 0.09$ pu, the fact that the maximum voltage deviation is limited does not introduce an extra error. The maximum allowable voltage deviation of 10% given by the Dutch grid code (see [57]) will thus not introduce an extra error in the method.

In figure 6.8, the sensitivity of the method to the maximum tap position $r_{\text{max}}$ (upper graph), the initial tap position $r(0)$ (middle graph) and the voltage difference per tap $\Delta|U_{\text{tap}}|$ are given. As can be expected from equation 6.12, the sensitivities for $r$ and $r_{\text{max}}$ are opposite to each other. An inaccuracy in these measures is, however, not very realistic.

As can be seen from the lower graph of figure 6.8, the calculation method for determining the power available for load relief is very sensitive to a deviation in $|U_{\text{tap}}|$. It will be important that this measure is accurately tuned for the LTC which uses the indirect load shedding method.

### 6.4 Discussion

In this section some points regarding the LTC’s indirect load shedding method and the determination of the amount of load relief available for load relief will be discussed.

The LTC changes its tap position in discrete steps. The voltage control is thus also in discrete steps and has a deadband. The impact of this deadband on the indirect load shedding is shown in figure 6.3. It can be seen that the deadband of the LTC introduces an error between the requested amount of load relief and the actually obtained amount of load relief. It has been theoretically proven that with the proposed method always less power is indirectly shed. The exact error is dependent on the current state of the system and the amount of load relief that is requested, but is bounded by a theoretical maximum.

Because the LTC control method is used in emergency situations, the fact that most of the time less power is indirectly shed than what is requested, can be detrimental for the system. One solution to this problem can be to make sure that when the LTC is in emergency control it always takes one tap position higher than required from the calculation method. In the HABVIP controller, however, the error in the deadband will be counteracted by the integral action of the PI-controller in the MLI control loop and the feedback of the actual amount of load relief to the coordination. So no extra measures are required.

The proposed method relies on a load model. When this load model is not known accurately enough, an extra error could be introduced between the requested amount of load relief and the actual obtained amount. By means of a sensitivity analysis it was shown that the error introduced by an inaccuracy in the load model will only have an impact when due to this error a different tap position is chosen than the one that would have been established without the inaccuracy. This highlights that the error due to the deadband...
is more important than an inaccuracy in the model. Note furthermore that such an inaccuracy will also be counteracted by the feedback loop and the PI-controller.
If, due to an inaccuracy in the load model, an extra step is introduced, the influence is highly dependent on the direction of the error. Because the error due to the deadband of the LTC is always negative, implying that less load is indirectly shed than required, an error in a load model parameter which results in more power being indirectly shed can be beneficial. On the contrary an error in a load model parameter which results in less power being indirectly shed is detrimental.
A final remark that should be made is regarding the fact that a change in tap position has an effect on the primary side of the transformer as well. For normal conditions this is discussed in chapter 2: a low voltage problem is transferred from the secondary side of the transformer to the primary side and the LTC can only effectively control the voltage when the positive impact on the secondary voltage is larger than the negative impact on the primary voltage. In case of the proposed emergency control the opposite is true: this emergency control will only lower the load at the secondary side of the transformer when the change in tap position has a larger impact on the secondary side of the transformer than on the primary side. Otherwise the lowering of the secondary voltage might be counteracted by the increase in primary voltage. This problem can mainly be expected in weak grids. In weak grids the voltage support of the sending-end is limited and they are often formed by long feeders.
The above described effect is in principal beneficial for voltage stability. It interferes, however, with the correct operation of the HABVIP controller. Further research to this potential problem should be done.

6.5 Conclusion

In this chapter a new emergency control strategy is introduced for the Load Tap Changer. This control strategy is implemented in actor agents which control the LTCs as part of the Hierarchical Agent Based Voltage Instability Prevention system. This actor agent should: convert a control requested by the substation agent (an amount of load relief) to an action of the actuator and determine the amount of load relief the LTC has available.
The emergency control strategy for the load changer is based on the fact that the secondary voltage of a load tap changer is controlled by adjusting the tap ratio. Normally the LTC tries to keep the voltage near nominal value. When the voltage is, however, reduced, constant impedance and constant current parts of the load will also be lowered. In this way it is possible to shed load indirectly by lowering the secondary voltage. A voltage set-point for the secondary voltage is calculated to obtain a certain amount of indirect load shedding based on a ZIP load model.
It is shown that the proposed method works properly. An error in the power that is actually shed indirectly is, however, introduced due to the fact that the LTC controls its tap setting in discrete steps. The magnitude of this error is highly dependent on the position of the voltage magnitude within the deadband. The voltage set-point is calculated based on a load model. The accuracy of the parameters of this load model determine the accuracy of the indirect load shedding method. In this chapter a sensitivity study is done for the different load model parameters. Generally it can be concluded that the deviation in the parameter does not influence the relative error in the amount of load to be indirectly shed as long as the deviation does not introduce a step in the tap setting. This highlights that the error due to the deadband is more important than an inaccuracy in the model. Note furthermore that such an inaccuracy will be counteracted by the feedback loops in the HABVIP controller.
Chapter 7

Control Strategy for CHP-based Local and Distributed Generation

7.1 Introduction

Combined Heat and Power (CHP) units are expected to play an increasingly important role in the electricity production capacity at all voltage levels in the power system. In order to increase overall energy efficiency, in greenhouses the conventional heating equipment is replaced by CHP units. A similar trend is expected for households where the central heating system can be replaced by micro-CHP. This would mean that in the future a large share of the production capacity is (micro-)CHP.

With the expected penetration, (micro-)CHP units have to be included in smart-grid control strategies. Besides that, these units are often installed in load areas which makes them in particular suitable to be applied as actuators in the HABVIP controller.

In this chapter the HABVIP control strategy for (micro-)CHP units is outlined. For this type of DG the HABVIP controller controls the active power. As discussed in chapter 5, the control consist of three modules: the part which controls the actuator in such a way that the requested amount of load relief is obtained; the part which determines the amount of load relief that can be provided by the actuator; and the part which determines the amount of load relief that was actually provided.

To start with the last task. The amount of load relief that is actually provided by an individual CHP unit can be determined from:

\[ \Delta P_{\text{CHP,done}} = P_{\text{CHP}}(t) - P_{\text{e,ref}}(0) \] (7.1)

Where \( P_{\text{CHP}}(t) \) is the generator power after control action and \( P_{\text{e,ref}}(0) \) the measured initial electrical output power. Note the differences between this equation and the one given for the LTC in chapter 6.

In this chapter two types of (micro-)CHP units are considered. The control of the thermostatically controlled unit is given in section 7.2. Subsequently in section 7.3 the control of the continuously controlled unit is outlined. Finally in sections 7.4 and 7.5 a discussion and conclusions related to the proposed methods will be given.

7.2 Thermostatically controlled CHP unit

Micro-CHP units for households currently in use are often thermostatically controlled. A challenge for this type of CHP unit is that due to constraints related to its heating schedule it either produces power or not. They turn on at the moment the room temperature becomes lower than: \( T_{\text{ref}} - \frac{1}{2} \Delta T \) and turn off at the moment this temperature becomes higher than \( T_{\text{ref}} + \frac{1}{2} \Delta T \). In these expressions \( T_{\text{ref}} \) is the reference temperature and \( \frac{1}{2} \Delta T \) the maximum absolute value the temperature is allowed to deviate from this reference. So from electrical perspective the thermostatically controlled units are either on or off and for a single unit only the average power over a period can be controlled by controlling the on/off...
time interval. The control of a single unit is proposed in subsection 7.2.1. For the HABVIP control it is, however, necessary that the increase in output power of the micro-CHP can be continuously supplied. This is achieved by considering multiple micro-CHP units aggregated as a Virtual Power Plant (VPP). The required coordinated controller is described in subsection 7.2.2.

7.2.1 Control of one unit

The electricity production of a micro-CHP is coupled to its heat production. So when the HABVIP controller increases the electrical output power of such a unit, it also increases the average room temperature. In the proposed controller the consumers can set the temperature to a desired reference $T_{\text{ref}}$. Under normal operating conditions the unit is controlled in such a way that the average room temperature is regulated to this value. In addition the consumers may set a maximum room temperature $T_{\text{max}}$ as well. Under emergency control conditions the average room temperature is allowed to increase to this value.

The thermal system of a typical household micro-CHP and the space it is heating is modeled with the electrical equivalent of Fig. 7.1. Examples of this type of models for the thermal system can be found in literature (e.g., [46, 113]). In this model $T_{s}$ is the temperature of the heat source, $T_{0}$ the outside temperature, $T$ the room temperature, $C$ the thermal capacity of the dwelling, $R_{l}$ the thermal resistance (efficiency) from the heating system to the dwelling and $R_{o}$ the thermal resistance (insulation) to the outside environment. These parameters can be determined during operation from the response of the system (see for instance [46, 113]). The switch closes as soon as the room temperature gets lower than $T_{\text{ref}} - \frac{1}{2} \Delta T$ and opens if the temperature becomes higher than $T_{\text{ref}} + \frac{1}{2} \Delta T$ (with $\Delta T$ the controller deadband).

The thermostatically controlled CHP prime-mover (usually a gas-fired turbine) is not able to turn on and off instantaneously. The unit has to ramp-up and ramp-down and this takes some time. It is assumed that during ramping-up and ramping-down the output power of the thermostatically controlled CHP unit increases/decreases linearly. This is illustrated in figure 7.2a for ramping-up and in figure 7.2b for ramping-down. In these figures $\Delta t_{\text{ru}}$ is the time for ramping-up from zero to nominal output power and $\Delta t_{\text{rd}}$ is the time for ramping-down from nominal output power to zero. In the remainder of this section it is assumed that $\Delta t_{\text{ru}} = \Delta t_{\text{rd}}$. A typical value for these times is 3 minutes.

7.2.1.1 Control strategy

The time period that the micro-CHP is on can be determined based on the electrical equivalent in figure 7.1.
The average output power of the micro-CHP changes by:

\[ \Delta P_{\text{av}} = \frac{C \Delta T}{\frac{1}{R_l} + \frac{1}{R_{eq}} - \frac{1}{R_{eq_{\text{eq}}}}} \]  \hspace{1cm} (7.2)

Where \( R_{eq} = (R_l R_{eqe})/(R_l + R_{eq}) \).

The time period that the micro-CHP is off can be determined in a similar way:

\[ \Delta t_{\text{off}} = \frac{C \Delta T}{\frac{1}{R_{eq}} - \frac{1}{R_l}} \]  \hspace{1cm} (7.3)

Based on this, the average output power of the micro-CHP can be calculated with:

\[ P_{\text{av}} = \frac{\Delta t_{\text{on}} P_0}{\Delta t_{\text{on}} + \Delta t_{\text{off}}} = \frac{-P_0 R_{eq} R_l (T_0 - T_{\text{ref}})}{R_{eq} R_l T_{\text{ref}} + R_{eq} R_o T_s - R_l R_{eq} T_{\text{ref}}} \]  \hspace{1cm} (7.4)

Where \( P_0 \) is the unit’s nominal electrical output power. Note that the assumption that \( \Delta t_{\text{on}} = \Delta t_{\text{off}} \) makes that these ramping-up and ramping-down times have no influence on the average power output.

When the reference for the room temperature changes from its initial reference \( T_{\text{ref,0}} \) to a new value \( T_{\text{ref,t}} \), the average output power of the micro-CHP changes by:

\[ \Delta P_{\text{av}} = P_{\text{av}}(T_{\text{ref,t}}) - P_{\text{av}}(T_{\text{ref,0}}) \]  \hspace{1cm} (7.5)

Where \( P_{\text{av}}(T_{\text{ref,0}}) \) and \( P_{\text{av}}(T_{\text{ref,t}}) \) are obtained by respectively substituting \( T_{\text{ref,0}} \) and \( T_{\text{ref,t}} \) in equation (7.4).

Rewriting equation (7.5) to:

\[ P_{\text{av}}(T_{\text{ref,t}}) - P_{\text{av}}(T_{\text{ref,0}}) - \Delta P_{\text{av}} = 0 \]  \hspace{1cm} (7.6)

And solving for \( T_{\text{ref,0}} \) gives the reference value for the temperature for a requested increase in the average power of \( \Delta P_{\text{av}} \).

### 7.2.1.2 Available power for load relief

The agent controlling the micro-CHP should also determine the amount by which the average output power can increase. The relative maximum increase in average output power is:

\[ \Delta P_{\text{av,max}} = \frac{P_{\text{av}}(T_{\text{max}}) - P_{\text{av}}(T_{\text{ref,0}})}{P_{\text{av}}(T_{\text{ref,0}})} \]  \hspace{1cm} (7.7)

Where \( P_{\text{av}}(T_{\text{ref,0}}) \) and \( P_{\text{av}}(T_{\text{max}}) \) are obtained by respectively substituting \( T_{\text{ref,0}} \) and \( T_{\text{max}} \) in equation (7.4).

This gives, using equation (7.7):

\[ \Delta P_{\text{av,max},t} = \frac{(T_{\text{ref,0}} - T_{\text{ref,t}})(R_{eq} R_l T_0 - R_l R_o T_0 + R_{eq} R_o T_s)}{(T_0 - T_{\text{ref,0}})(R_{eq} R_l T_{\text{ref,t}} + R_{eq} R_o T_s - R_l R_{eq} T_{\text{ref,t}})} \]  \hspace{1cm} (7.8)

The maximum average power increase of the micro-CHP unit is now calculated based on the relative maximum increase in equation (7.8):

\[ \Delta P_{\text{av,max}} = \Delta P_{\text{av,max},t} \cdot P_{\text{av}}(T_{\text{ref,0}}) \]  \hspace{1cm} (7.9)

### 7.2.1.3 Proof of Concept

A proof of concept of the proposed control strategy for the thermostatically controlled (micro-)CHP unit is given based on the simulation of a small unit (1 kW). The data for this unit is given in appendix E.1. The data are not specific for a particular type or brand of micro-CHP, but are used to demonstrate the proposed concepts. A ramp-up and ramp-down time of 3 minutes is assumed. The initial average power production is 0.2 kW.

During the simulations it is calculated that the unit has 0.1846 kW average power available for load relief. In that case the temperature rises from \( T_{\text{ref,0}} = 18^\circ\text{C} \) to \( T_{\text{ref,t}} = 20^\circ\text{C} \). At \( t = 4000 \) s it is requested to increase the average power generation with 0.150 kW. The result is shown in figure 7.3.
The upper graph of figure 7.3 shows the output power of the unit. The solid line shows the instantaneous output power and the dashed line the average output power. For both measures the increase is clearly shown: the average power increases to 0.350 kW and the on-time of the instantaneous power becomes larger. So with the proposed method the (micro-)CHP’s electrical power can be increased with the requested amount while still respecting the constraint of the maximum temperature.

The lower graph of figure 7.3 shows the room temperature. The solid line shows the instantaneous temperature and the dashed line the average temperature. Note that from the moment the increase in output power is requested, the average room temperature increases from $18^\circ$C to $19.7^\circ$C. So the average room temperature is still lower than the maximum of $20^\circ$C.

### 7.2.2 Aggregated Virtual Power Plant control

The method described in the previous subsection controls the reference temperature of a thermostatically controlled (micro-)CHP unit in such a way that the average output power of the unit increases by a requested amount. The unit is, however, either on or off (see figure 7.3). The HABVIP controller, nevertheless, requires a continuous supply of power. To this end, multiple units should cooperate and work together as if they are one Virtual Power Plant (VPP). So for the thermostatically controlled CHP units two levels of actor agents are required: each individual unit contains an agent that controls the unit, and each VPP contains an agent that coordinates among multiple units. It is only this VPP agent that communicates with the substation agent.

In literature several VPP control methods are proposed for different purposes [75, 86, 148, 157, 230]. The goal of the VPP designed for the HABVIP controller is to obtain a nearly constant output power. To do this, micro-CHP units should start one after the other in a predetermined sequence. This can be achieved by applying a method based on the token-ring approach known from communication technology [206]. The idea is that for each group of micro-CHPs the VPP agent releases a number of tokens (a token is a virtual object that gives permission to units to act). When a micro-CHP receives a token it keeps the token and starts generating. As soon as the room temperature reaches its upper limit $T_{\text{ref}} + \frac{1}{2} \Delta T$ the micro-CHP turns off and passes the token to the next unit. This strategy requires communication among micro-CHPs.
and between micro-CHPs and the VPP agent (the communication technology is outside the scope of the thesis).

The number of tokens that should circulate dependents on the total average power generated by the micro-CHPs, \(\sum_{i=1}^{m} P_{av,i}\), and the nominal output power for a single unit \(P_0\):

\[
\text{# tokens} = \frac{\sum_{i=1}^{m} P_{av,i}}{P_0}
\]  
(7.10)

Where \(P_{av,i}\) is the average power generated by an individual unit \(i\) and \(m\) is the total number of units that are coordinated by the VPP.

In the case this equation gives a non-integer result, the number of tokens is floored and an extra, special, token is released. If a micro-CHP receives this special token, it is only allowed to start in the case the temperature is below its minimum reference \(T_{ref} - \frac{1}{2} \Delta T\). This special token is necessary to meet the exact temperature demand.

An illustration of this token based VPP control is given in figure 7.4. Note that all micro-CHPs contain their own agent. The VPP agent determines the required number of tokens and releases them. After a token passed all CHP agents, the VPP agent determines whether the token should make another round or vanish.

### 7.2.2.1 Control strategy

In case a substation agent requests a certain amount of load relief \(\Delta P_{\text{CHP}}\) from the VPP, the aggregation agent should do two things. First of all \(\Delta P_{\text{CHP}}\) should be converted to an increase in the average power of each individual unit. In order to do so, the required increase for the VPP is determined with:

\[
\Delta P_{\text{VPP}} = \begin{cases} 
P_0 \left( \frac{\Delta P_{\text{CHP}}}{P_0} - P_{\text{res}} \right) & \text{if } P_{\text{res}} > 0, \\
\frac{\Delta P_{\text{CHP}}}{P_0} & \text{else} 
\end{cases}
\]  
(7.11)

Where \(P_{\text{res}} = \sum_{i=1}^{m} P_{av,i} - P_0 \left( \sum_{i=1}^{m} \frac{P_{av,i}}{P_0} \right)\), \(i\) is the unit’s index, \(m\) the total number of units. \([\cdot]\) and \([\cdot]\) symbolize respectively the floor and ceiling operators.

Two things can be noted from this equation. Firstly, \(\left[\frac{\Delta P_{\text{CHP}}}{P_0}\right]\) is introduced because the increase in power is done in steps of \(P_0\). Secondly, the term \(\left( \frac{\Delta P_{\text{CHP}}}{P_0} - P_{\text{res}} \right)\) is introduced to convert a special token to a full token, assuring that the power profile is flat from the moment the HABVIP controller demands load relief.

From the total required increase in generation by the VPP the increment in average power for each individual unit is determined:
\[ \Delta P_{av,k} = \frac{\Delta P_{av,max,k}}{\sum_{i=1}^{m} \Delta P_{av,max,i}} \cdot \Delta P_{VPP} \] (7.12)

Where \( k \) is the index of the individual unit. The VPP agent determines an updated required number of tokens:

\[ \#\text{tokens} = \frac{\sum_{i=1}^{m} P_{av,i} + \Delta P_{VPP}}{P_0} \] (7.13)

Note that due to the ceiling and floor actions in equation (7.11) the number of tokens is an integer.

7.2.2.2 Available power for load relief

As outlined before, the aggregation agent should also determine the total, continuously available, increase in output power. This can be determined from:

\[ \Delta P_{VPP,max} = \left( \left[ \frac{\sum_{i=1}^{m} P_{av,i} + \sum_{i=1}^{m} \Delta P_{av,max,i}}{P_0} \right] - \left[ \frac{\sum_{i=1}^{m} P_{av,i}}{P_0} \right] \right) P_0 \] (7.14)

Where \( \Delta P_{av,max,i} \) is defined for the individual units by equation (7.9). 

7.2.2.3 Actual obtained load relief

The actual obtained load relief for the total VPP is calculated with:

\[ \Delta P_{VPP,done} = \sum_{i=1}^{m} \Delta P_{CHP,done,i} \] (7.15)

Where \( \Delta P_{CHP,done,i} \) is the obtained load relief by the individual CHP units as determined with equation (7.1). Note that for the thermostatically controlled unit \( \Delta P_{CHP,done,i} \) is intermittent, but because of the VPP control strategy its sum is continuous.

7.2.2.4 Proof of Concept

In this section a proof of concept of the VPP control will be given. The aggregated behavior of 10 micro-CHP units is simulated. The individual micro-CHPs are controlled with the method of section 7.2.1, and the aggregated control introduced in sections 7.2.2.1 - 7.2.2.3 is used for VPP control. For reasons of transparency it is assumed that all CHPs have the same settings. These data are given in appendix F.1.

The following stages can be identified in the simulation:

- For \( 0 \leq t < 10.000 \) s no additional load relief is requested.
- For \( 10.000 \leq t < 20.000 \) s a total load relief is requested of 1 kW.
- For \( 20.000 \leq t < 30.000 \) s a total load relief is requested of 3 kW.

The result of the simulation is shown in figure 7.5. The first graph shows the aggregated output power of the micro-CHPs, the second graph shows the actual obtained amount of load relief, the third graph shows the number of tokens that are circulating in the network, the fourth graph shows the room temperatures and the fifth graph the temperature reference. The calculated power available for load relief is 3 kW. 

During the first time interval of the simulation (\( 0 \leq t < 10.000 \) s) no additional load relief is requested. The VPP coordination determines the number of tokens that are required to maintain the requested average room temperatures by the consumers (18\(^\circ\) C) and at the same time assures a power output profile that is
Figure 7.5. Simulation of the aggregated behavior of 10 micro-CHP units with VPP control.
as smooth as possible. Two normal tokens and one special token are required for this. Due to this special token in the first time interval the aggregated output power switches between 2 kW and 3 kW. Note that the HABVIP controller can only rely on 2 kW continuously supplied power. During the second time interval (10.000 \( \leq t < 20.000 \) s) a load relief of 1 kW is requested. As outlined, the VPP will in this case first change the special token to a normal token, so that the HABVIP controller can rely on 3 kW. The normal token is provided immediately. The special token can, however, only be removed from the circulation at the moment it passes through the aggregation agent (see figure 7.4). Because of this the aggregated output power is temporarily increased to 4 kW. Note that with the increase in requested load relief also the reference room temperature increases. During the last time interval (20.000 \( \leq t < 30.000 \) s) a total load relief of 3 kW is requested. This is the maximum amount of load relief that can be obtained with the VPP. The number of tokens increases from 3 to 5 and the aggregated output power from 3 kW to 5 kW. The reference temperature becomes 20°C, which is the maximum that is allowed by the consumer (see appendix 7.4). The calculated power available for load relief was thus correctly determined with the proposed method. Note that in the aggregated output power some glitches appear. These coincide with the take-over in power generation among different micro-CHP units. A more accurate coordination during the take-over process could solve this problem. Furthermore by increasing the number of micro-CHP units that are controlled by the VPP, the relative size of the glitches will become smaller. Altogether it can be concluded that the aggregated VPP control for the HABVIP controller works properly. With the proposed method the aggregated output power can be assumed to remain constant. Furthermore for the higher level HABVIP agents the power available for load relief can be determined accurately. And if a certain amount of load relief is requested, the VPP aggregation agent makes sure that the requested increase in output power is continuously provided.

### 7.3 Continuously controlled CHP unit

The continuously controlled CHP unit continuously supplies power and heat. This type is common in greenhouse CHP units. It is expected that in the future this type will also become common for household micro-CHP units. There is a significant difference between the HABVIP control of the continuously controlled CHP unit and the thermostatically controlled CHP unit. In case of the thermostatically controlled unit the average electrical power is increased by increasing the duty-cycle. The control does not depend on the electrical generator technology being used. In case of the continuously controlled CHP unit, however, an increase in electrical power is obtained by increasing the mechanical power. This requires a different control for each electrical generator type. For that reason, in this section a separation is made between the heat control and the electrical generator control. Note that both are necessary for the control of the (continuously controlled) CHP unit and that they are interdependent.

The heat control is discussed in subsection 7.3.1. In subsection 7.3.2 the control is extended to the induction generator and in section 7.3.3 to the synchronous generator.

#### 7.3.1 Heat control

The thermal model of the continuously controlled CHP is given in figure 7.6 where the difference with figure 7.1 is the absence of the switch. The continuous supply means that the temperature of the source \( T_s \) is controlled to obtain the required room temperature \( T_{ref} \):

\[
T_s,c = \left(1 + \frac{R_l}{R_o}\right) T_{ref} - \frac{R_l}{R_o} T_0 \tag{7.16}
\]

#### 7.3.1.1 Control strategy

For the continuously controlled CHP unit the required increase in electrical output power \( \Delta P_{CHP} \) should first be converted to a required increase in mechanical output power \( \Delta P_{CHP,mech} \):
7.3 Continuously controlled CHP unit

\[ \Delta P_{\text{CHP,mech}} = f(\Delta P_{\text{CHP}}) \]  

(7.17)

The exact form of \( f(\Delta P_{\text{CHP}}) \) depends on the generator that is used. In subsections 7.3.2 and 7.3.3 for respectively the induction and synchronous generator \( f(\Delta P_{\text{CHP}}) \) will be given.

Based on \( \Delta P_{\text{CHP,mech}} \), a new reference for the room temperature is determined. It is assumed that the relation between the thermal power supply and the mechanical power supply is linear. Given this assumption, based on the thermal power that flows in the circuit of figure 7.6, the relative increase in mechanical power for a temperature increase from \( T_{\text{ref,0}} \) to \( T_{\text{ref,t}} \) becomes:

\[ \Delta P_{\text{CHP,mech,r}} = \frac{(T_0 - T_{\text{ref,t}})}{(T_0 - T_{\text{ref,0}})} \left( \frac{T_{\text{ref,t}}}{R_l R_o + 1} - \frac{T_0}{R_l R_o} \right) - 1 \]  

(7.18)

When the mechanical output power of the CHP unit has to increase from a certain (measured) initial reference \( P_{\text{mech,ref}} \) with the amount determined from equation (7.17) it should hold that:

\[ \Delta P_{\text{CHP,mech,r}} \cdot P_{\text{mech,ref}} = \Delta P_{\text{CHP}} = 0 \]  

(7.19)

Substituting equation (7.18) for \( \Delta P_{\text{CHP,mech,r}} \) and solving for \( T_{\text{ref,t}} \) gives the reference for the room-temperature that coincides with the required mechanical power increase \( \Delta P_{\text{CHP,mech}} \) and subsequently the required electrical power increase \( \Delta P_{\text{CHP}} \).

7.3.1.2 Available power for load relief

The power available for load relief depends on the average room-temperature that is not allowed to exceed the maximum value \( T_{\text{max}} \) set by the consumer. Based on this the relative maximum increase in mechanical output power can be determined with:

\[ \Delta P_{\text{c,mech,max},r} = \frac{(T_0 - T_{\text{ref,0}})}{(T_0 - T_{\text{ref,0}})} \left( \frac{T_{\text{max}}}{R_l R_o + 1} - \frac{T_0}{R_l R_o} \right) - 1 \]  

(7.20)

Multiplying this with the initial mechanical power \( P_{\text{mech,ref}(0)} \) gives the maximum mechanical power the CHP unit has available for load relief:

\[ \Delta P_{\text{c,mech,max}} = \Delta P_{\text{c,mech,max},r} \cdot P_{\text{mech,ref}(0)} \]  

(7.21)

Where the subscript \( c \) stands for continuous. Based on this, the maximum electrical power from the thermal point of view is determined:

\[ \Delta P_{\text{CHP, max, th}} = g(\Delta P_{\text{c,mech, max}}) \]  

(7.22)

The exact form of \( g(\Delta P_{\text{c,mech, max}}) \) depends on the generator that is used (synchronous or induction). In subsections 7.3.2 and 7.3.3 for respectively the induction and synchronous generator \( g(\Delta P_{\text{c,mech, max}}) \) will be given.
7.3.2 Induction generator

The electrical model on which the Induction Generator (IG) control is based, is given in Fig. 7.7. Generator convention is used. It is assumed that all quantities are in per unit. For the control of the IG two basic equations are of importance. The first equation gives the electrical power output as function of the slip $s$ (see equation (2.23) for the definition of slip) and the terminal voltage $U_t$ [99]:

$$P_{IG,e} = \Re \left( -\frac{|U_t|^2}{R_s + j X_s + j X_m} \right)$$  \hspace{1cm} (7.23)

The second equation gives the electromagnetic torque as function of the slip and the Thévenin equivalent voltage:

$$T_e = -\frac{R_t}{s} \frac{|U_{th}|^2}{(R_{th} + \frac{R_t}{s})^2 + (X_{th} + X_m)^2}$$  \hspace{1cm} (7.24)

The Thévenin equivalent voltage as function of the terminal voltage is given by $|U_{th}| = \frac{X_m}{\sqrt{(R_t + (X_s + X_m)^2)}} |U_t|$ and the Thévenin equivalent impedance of the IG is $R_{th} + j X_{th} = \frac{j X_m (R_s + j X_s)}{R_t + j (X_s + X_m)}$. Based on these two equations the torque-slip and the power-slip characteristic (generator operation, i.e. $s < 0$) for a specific value of $|U_t|$ are given in Fig. 7.8.
7.3 Continuously controlled CHP unit

7.3.2.1 Control strategy

The actor agent controlling the IG should determine the mechanical power (or torque) that is required to supply the requested increase in generation. When the electric output power has to increase from an initial amount $P_{IG,e}(0)$ with a certain amount $\Delta P_{IG,e}$, the required output power from the generator becomes:

$$P_{IG,e,\text{ref}} = P_{IG,e}(0) + \Delta P_{IG,e}.$$  

As can be seen from Fig. 7.8 $P_{IG,e,\text{ref}}$ is related to a certain value for the slip $s_{\text{ref}}$. This reference for the slip can be found by solving equation (7.23) for $P_{IG,e,\text{ref}}$ and the measured terminal voltage. Two values for the slip will result, from which the lowest value is related with the stable operation of the induction generator.

$s_{\text{ref}}$ substituted for $s$ in equation (7.24) gives the electromechanical torque $T_{IG,e,\text{ref}}$ required at the shaft of the induction generator in order to supply the required output power. The mechanical losses at the desired operation point ($(1 - s_{\text{ref}})F$) should be added to this torque to obtain the required mechanical torque:

$$T_{IG,\text{mech,ref}} = T_{IG,e,\text{ref}} + (1 - s_{\text{ref}})F$$  

(7.25)

Where $F$ is the mechanical damping factor. Note that this equation is only valid in per unit.

**Determination of $\Delta P_{\text{CHP,mech}}$**

For the heat control the mechanical power increase $\Delta P_{\text{CHP,mech}}$ that is required by the generator to obtain the required amount of load relief $\Delta P_{\text{CHP}}$ should be determined:

$$\Delta P_{\text{CHP,mech}} = T_{IG,\text{mech,ref}} \cdot \omega_m - P_{IG,\text{mech,ref}}(0)$$  

(7.26)

Where $\omega_m$ is the mechanical rotational speed and $P_{IG,\text{mech,ref}}(0)$ the initial mechanical power.

7.3.2.2 Available power for load relief

Two limitations influence the power the continuously controlled CHP with IG has available for load relief: the maximum electrical power that can be provided by the IG from electrical point of view ($\Delta P_{IG,e,\text{max}}$) and the maximum power the unit has available from room temperature constraints ($\Delta P_{\text{CHP,max,th}}$). The most constraining limitation determines the power the CHP has available for load relief.

$$\Delta P_{\text{CHP,max}} = \min(\Delta P_{\text{CHP,max,th}}, \Delta P_{IG,e,\text{max}})$$  

(7.27)

**Determination of $\Delta P_{IG,e,\text{max}}$**

As can be seen from Fig. 7.8 there is a maximum in the electrical power $P_{IG,e,\text{max}}$ the IG can supply. To determine $P_{IG,e,\text{max}}$ the accompanying value for the slip $s_{\text{opt}}$ has to be determined\(^1\). Note that in a practical situation, however, a margin to this slip should be left for the induction generator to be able to re-accelerate after a fault. In this thesis we will, nevertheless, use $s_{\text{opt}}$.

$s_{\text{opt}}$ is determined based on optimization of the expression in equation (7.23). So $\frac{dP_{\text{ref}}}{ds}$ has to be determined, set to zero and solved. This gives two solutions: a positive one, which comprises the maximum power drawn in motor operation, and a negative one, which comprises the maximum power supplied in generator operation. The negative slip is required and is given by:

$$s_{\text{opt}} = -\frac{R_sX_m - R_sR_r + R_rX_r}{R_sX_m + R_sX_r + X_mX_r + X_mX_s + X_rX_s}$$  

(7.28)

Substituting $s_{\text{opt}}$ in equation (7.23) gives $P_{IG,e,\text{max}}$. For a given initial reference value of the generator $P_{IG,e}(0)$ the power available for load relief is calculated with:

$$\Delta P_{IG,e,\text{max}} = P_{IG,e,\text{max}} - P_{IG,e}(0)$$  

(7.29)

\(^1\)Note that the value for the slip where the power is at its maximum is not equal to the value for the slip at maximum torque.
Determination of $\Delta P_{\text{CHP,max,th}}$

As discussed in section 7.3 for the continuously controlled CHP, without knowing the generator technology, only the available mechanical power from the room temperature limitation can be determined. In the remainder of this subsection the method will be outlined to convert this to the available electrical power from the IG.

First of all the available mechanical power $\Delta P_{\text{c,mech,max}}$ (as calculated from equation (7.21)) should be converted to a required electromagnetic torque for the induction machine (per unit):

$$T_{\text{IG,e,max}} = \frac{\Delta P_{\text{c,mech,max}} + P_{\text{mech,ref}(0)}}{1 - s_{\text{max,th}}} - (1 - s_{\text{max,th}}) \cdot F$$

(7.30)

Where $P_{\text{mech,ref}(0)}$ is the initial mechanical power of the machine $s_{\text{max,th}}$ the slip of the induction generator corresponding to the maximum mechanical power from the prime mover, $F$ is the mechanical damping of the machine and subscript $\text{th}$ stands for thermal. Note that equation (7.30) is only valid under the assumption that all quantities are in per unit.

Both $T_{\text{IG,e,max}}$ and $s_{\text{max,th}}$ are unknown. So an extra equation is required. Equation (7.24) is used with $T_{\text{IG,e,max}}$ substituted for $T_e$ and $s_{\text{max,th}}$ substituted for $s$:

$$T_{\text{IG,e,max}} = -\frac{R_e}{s_{\text{max,th}}} \left( \frac{|U_{\text{th}}|^2}{R_{\text{th}} + \frac{R_e}{s_{\text{max,th}}}^2} + (X_{\text{th}} + X_e)^2 \right)$$

(7.31)

Solving equations (7.30) and (7.31) is done in two steps as illustrated in figure 7.9. First, based on the previous calculation of the slip $s_{\text{max,th}(t-1)}$, the torque for that value of the slip $T_{\text{IG,e,max}(t)}$ is determined from equation (7.30). In the second step the new slip $s_{\text{max,th}(t)}$ is determined by solving equation (7.31). This loop repeats itself and converges to the correct solution.

Subsequently the electric power $P_{\text{IG,e,max}}$ comprising this slip, is determined by substituting $s_{\text{max,th}}$ for $s$ in equation (7.23). From this, the maximum power available for load relief based on the temperature limits of the prime-mover can be determined from:

$$\Delta P_{\text{CHP,max,th}} = P_{\text{IG,e,max}} - P_{\text{e,ref}(0)}$$

(7.32)

Where $P_{\text{e,ref}(0)}$ is the initial electrical power of the generator.

7.3.2.3 Proof of Concept

A proof of concept of the proposed controller for the induction generator is given based on the simple system of figure 7.10. In this system a continuously controlled CHP unit with IG is connected via an
7.3 Continuously controlled CHP unit

Figure 7.10. Circuit used for tests on the continuously controlled CHP unit with induction generator.

impedance to an infinitely strong grid. The data of the simulation model is given in appendix F.2. The initial power supply from this generator is \( P_{IG}(0) = 3.5 \text{ kW (electrical)} \), which corresponds to a room temperature of 18°C. The room temperature is allowed to increase to 20°C during emergencies. During the simulation three situations will occur:

- For \( 0 \leq t < 50 \text{ s} \) no additional load relief is required.
- For \( 50 \leq t < 100 \text{ s} \) a total load relief is requested of 3.5 kW.
- For \( 100 \leq t \leq 150 \text{ s} \) a total load relief is requested that equals the amount that is available from the room temperature limitation.
- For \( 150 \leq t \leq 200 \text{ s} \) a total load relief is requested that equals the amount that is available from the IG’s maximum electrical power limitation.

The result for the simulations is given in figures 7.11 and 7.12. The first (upper) graph of figure 7.11 shows the room temperature. The second graph the active power production of the generator. The third graph gives the reactive power production of the generator (negative production means consumption). The fourth graph depicts the mechanical torque of the generator. Finally, the fifth graph shows the slip of the generator. Figure 7.12 gives the power available for load relief. The upper graph gives this measure for the two IG limitations: the room temperature limitation (solid line) and the IG’s maximum electrical power limitation (dashed line). The lower graph gives the total power the unit has available for load relief, which is the lowest value of the two limitations.

During the first time interval \( (0 \leq t < 50 \text{ s}) \) no load relief is requested and the active power production is 3.5 kW. The room temperature is equal to the reference for normal operation (18°C). The IG consumes reactive power in the order of magnitude of the active power production. In a typical DG this reactive power consumption during nominal power production will be compensated. The slip and the mechanical torque are determined by the proposed controller in order to obtain the requested amount of electrical power. Note from figure 7.12 that the power available for load relief is determined by the room temperature limitation. During the second time interval \( (50 \leq t < 100 \text{ s}) \) a load relief is requested of 3.5 kW. The room temperature increases to 18.8°C. A new value for the slip is determined and based on this the mechanical torque is adapted. The electrical output power becomes 7.0 kW, so the requested power increase is obtained. Furthermore the increase in active output power coincides with an increase in reactive power consumption. The increase in power production does not influence the power available for load relief (figure 7.12).

During the third time interval \( (100 \leq t \leq 150 \text{ s}) \) the requested amount of load relief equals the amount that is available from the room temperature limitation (8.73 kW). The room temperature increases to 20°C and the active output power to 12.2 kW. Based on the requested load relief a new reference is determined for the slip and the mechanical torque is adapted. The reactive power consumption of the generator increases significantly.

During the last time interval \( (150 \leq t \leq 200 \text{ s}) \) the requested amount of load relief equals the amount that is available from the IG’s maximum electrical power limitation (18.25 kW). The room temperature increases to 22.8°C and exceeds consequently its limitation. The active power production increases to 21.8 kW and the reactive power consumption of the generator increases significantly.

Based on the simulations given in this section, it can be concluded that the proposed control strategy for the continuously controlled CHP unit with induction generator works correctly.
Figure 7.11. Simulation of a continuously controlled CHP unit with induction generator.
7.3 Continuously controlled CHP unit

7.3.3 Synchronous generator

The control strategy described in this subsection is first of all designed for a CHP’s Synchronous Generator. The proposed strategy can, however, be used to control a large synchronous generator of a conventional power plant as well.

For the description of the control the model of figure 7.13 is used. Furthermore it is assumed that the voltage of the generator is controlled by means of an exciter equipped with AVR and OveReXcitation Limiter (OXL). Note that these last two types of controls influence $E$ in figure 7.13.

7.3.3.1 Control strategy

The actuator agent of the synchronous generator adapts the reference power of the speed governor in such a way that, after all transients have damped, the output power of the generator is increased with the amount that is asked by the substation agent subject to limitations as detailed in the next subsection. This implies that the standard speed governor is used to take care of the speed-droop control.

The reference in electrical power $P_{SG,ref}$ and the demanded increase $\Delta P_{SG}$ are converted to a mechanical reference, taking into account the losses in the generator:
Figure 7.14. Capability curve of the synchronous generator [171]. \(P_e\) and \(Q_e\) are the real and reactive power production, \(U_t\) is the terminal voltage and \(X_s\) the stator reactance.

\[
P_{SG,\text{ref,mech}} = P_{SG,\text{ref,e}} + \Delta P_{SG} + R_s I_s^2 + F \omega_{\text{mech}}^2
\]  
(7.33)

In this equation \(R_s I_s^2\) comprises the electrical losses in the stator and \(F \omega_{\text{mech}}^2\) the mechanical losses due to the rotation. \(P_{SG,\text{ref,mech}}\) will be used as input for the speed governor.

**Determination of \(\Delta P_{CHP,\text{mech}}\)**

For the continuous controlled CHP unit with synchronous generator, a similar equation as \((7.33)\) can be used to determine \(f(\Delta P_{CHP})\) in equation \((7.17)\):

\[
\Delta P_{CHP,\text{mech}} = \Delta P_{CHP} + R_s I_s^2 + F \omega_{\text{mech}}^2
\]  
(7.34)

### 7.3.3.2 Available power for load relief

The power available for load relief depends on the capability of the synchronous generator. An illustration of the capability curve is shown in figure [7.14]. During voltage instability the local generator works in overexcitation mode [185,200], so only the upper part of the capability diagram is important. In this mode of operation three limitations should be taken into account for determining the power available for load relief: the field-current limit \((\Delta P_{SG,fd,max})\), the armature-current limit \((\Delta P_{SG,s,max})\) and the prime-mover limit which is determined by the room temperature restriction \((\Delta P_{CHP,max,th})\). The most constraining limitation determines the power available from the continuously controlled CHP unit:

\[
\Delta P_{CHP,max} = \min(\Delta P_{CHP,max,th}, \Delta P_{SG,fd,max}, \Delta P_{SG,s,max})
\]  
(7.35)

**Determination of \(\Delta P_{SG,fd,max}\)**

To prevent the field current from exceeding the field-heating limit an Overexcitation Limiter (OXL) limits the field current to a maximum value \((I_{fd,max})\). This current determines the maximum value of the internal voltage \((E_{\text{max}})\). Applying Pythagorean’s theorem to figure [7.14] given a certain supply of reactive power \(Q_{SG,e}\), the maximum active power which can be supplied by the generator becomes:

\[
P_{SG,fd,max} = \sqrt{\left(\frac{|U_t||E_{\text{max}}|}{X_s}\right)^2 - \left(\frac{|U_t|^2}{X_s} + \frac{|Q_{SG,e}|}{X_s}\right)^2}
\]  
(7.36)
Under the assumption that all values are in per unit the maximum internal voltage equals the maximum field current ($|E_{\text{max}}| = |I_{\text{fd,\text{max}}}| [\text{pu}]$). In order to minimize an error in the determination of $P_{\text{SG,fd,\text{max}}}$ introduced by the stator resistance which is neglected, a slightly lower value for $|I_{\text{fd,\text{max}}}|$ should be used than what is used for the OXL.

The power that is available for load relief from the field current limitation’s perspective is:

$$\Delta P_{\text{SG,fd,\text{max}}} = P_{\text{SG,fd,\text{max}}} - P_{\text{SG,e,\text{ref}}}$$  \text{(7.37)}

Where $P_{\text{SG,e,\text{ref}}}$ is the initial reference value of the electrical power.

### Determination of $\Delta P_{\text{SG,s,\text{max}}}$

The armature current $|I_s|$ is not allowed to exceed a certain maximum value $|I_{s,\text{max}}|$. From this, the maximum apparent power the generator can supply becomes:

$$|S_{\text{SG,s,\text{max}}}| = |U_t||I_{s,\text{max}}|$$  \text{(7.38)}

Applying Pythagoreans theorem to Fig. 7.14 given a certain supply of reactive power $Q_{\text{SG,e}}$, gives the maximum active power which can be supplied by the generator:

$$P_{\text{SG,s,\text{max}}} = \sqrt{(|U_t||I_{s,\text{max}}|)^2 - Q_{\text{SG,e}}^2}$$  \text{(7.39)}

For a given initial reference value of the generator $P_{\text{SG,e,\text{ref}}}$ the power available for load relief from armature current point of view can be calculated with:

$$\Delta P_{\text{SG,s,\text{max}}} = P_{\text{SG,s,\text{max}}} - P_{\text{SG,e,\text{ref}}}$$  \text{(7.40)}

Where $P_{\text{SG,e,\text{ref}}}$ is the initial reference value of the electrical power.

### Determination of $\Delta P_{\text{CHP,max,th}}$

The power available from the prime-mover limitation is dependent on the room temperature limits. As discussed in section 7.3 to obtain the power available from the room temperature constraint, the type of electrical generator should be known. Without this, only the available mechanical power $\Delta P_{\text{c,mech,\text{max}}}$ could be determined (equation (7.21)). For the SG the available mechanical power can be converted to electrical power with:

$$\Delta P_{\text{CHP,max,th}} = \Delta P_{\text{c,mech,\text{max}}} + P_{\text{SG,ref,mech}} - P_{\text{SG,e,\text{ref}}} - R_s|I_s|^2 - F\omega_{\text{mech}}$$  \text{(7.41)}

In this equation $\Delta P_{\text{c,mech,\text{max}}}$ is the mechanical power available from the CHP prime-mover, $P_{\text{SG,ref,mech}}$ is the initial mechanical power (input) of the prime-mover, $P_{\text{SG,e,\text{ref}}}$ is the initial electrical power production of the generator, $R_s|I_s|^2$ are the electrical loses in the generator and $F\omega_{\text{mech}}^2$ are the mechanical loses in the generator. Note that in equation (7.41) the magnetic saturation is neglected, this simplification will result in an inaccuracy in the determined value of $\Delta P_{\text{CHP,max,th}}$.

#### 7.3.3.3 Proof of Concept

A proof of concept will be given based on the simple circuit of figure 7.15. In this circuit a continuously controlled CHP with a synchronous generator is connected to an infinitely strong grid via an impedance. Parallel to the transformer is a purely resistive load connected. The data of the test system are given in appendix F.3.

The CHP is controlled with the proposed HABVIP controller. Note that this controller consist of the heat control of subsection 7.3.1 and the generator control of subsection 7.3.3. The average room temperature is allowed to increase from 18°C, during normal operation, to 20°C, during emergencies. The maximum
field-current is assumed to be 3.25 pu and the maximum armature-current 1.5 pu. For the field current a safety margin of 0.02 pu is taken into account.

In order to demonstrate some aspects of the control, the limitations are allowed to be exceeded in the simulations of this subsection. In the real implementation (e.g. chapter) the armature-current limiter and OXL will not allow the generator to exceed these limitations.

In the simulations four stages are distinguished:

- For $0 \leq t < 10000$ s no load relief is required.
- For $10000 \leq t < 20000$ s a load relief is requested which equals the amount that is available from the prime-mover limitation.
- For $20000 \leq t \leq 30000$ s a load relief is requested which equals the amount that is available from the field-current limitation.
- For $30000 \leq t \leq 40000$ s a load relief is requested which equals the amount that is available from the armature-current limitation.

The exact values of the requested load relief cannot be given beforehand, because the actual amount available depends on the current operation point.

The results of the simulations are given in figures 7.16 and 7.17. The first (upper) graph of figure 7.16 gives the room temperature’s reference. The second graph gives the active power produced by the generator. Subsequently the third graph shows the reactive power production of the generator. The field-current is given in the fourth graph and the armature-current in the fifth graph. Figure 7.17 shows the power the generator has available for load relief. The first (upper) graph gives this measure for the different limitation of the generator. The solid line is for the room temperature heating limitation, the dashed line is for the field winding limitation and the dotted line for the armature winding limitation. Subsequently the second graph of figure 7.17 gives the power the CHP unit has available for load relief: which is determined by the most constraining limitation of the unit.

During the first time interval $0 \leq t < 10000$ s no additional load relief is requested. The room temperature reference is equal to $18^\circ$C and electrical output power is 450 MW. Both the field-current and the armature current are below their limits.

During the second time interval $10000 \leq t < 20000$ s a total load relief is requested that equals the amount that is available based on the room temperature limitation. The temperature reference increases to the maximum allowed value of $20^\circ$C and the electrical output power becomes 1580 MW. The reactive power production decreases because the increase in active power production leads to a voltage rise. Consequently less reactive power is required for voltage control. Both the field-current and the armature-current stay below their respective limits. The power available for load relief in figure 7.17 adjusts according to the new operating point.

During the third time interval $20000 \leq t < 30000$ s a total load relief is requested that equals the amount that is available based on the field-current limitation. The room temperature increases to $20.8^\circ$C and is thus above its limitation. The electrical output power becomes 2135 MW. The field-current increases to 3.23 pu, which is the limit when we take into account a safety margin of 0.02 pu.

These values are chosen to demonstrate the operation and not to represent a generator of a specific brand.
Figure 7.16. Simulation of a continuously controlled CHP unit with synchronous generator.
Finally during the last time interval $30000 \leq t \leq 40000$ s a total load relief is requested that equals the amount that is available based on the armature-current point of view. The temperature reference increases to $20.9^\circ\text{C}$ and the electrical output power becomes $2165$ MW. The armature current increases to $1.5$ pu, which equals the maximum that is set for this parameter. Note that both the temperature reference and the field current exceed their limitation under these conditions and as can be seen from figure 7.17 the room temperature limitation is the most limiting one.

Based on the simulations of this subsection it can be concluded that the proposed controller for the continuously controlled CHP unit with synchronous generator works properly. Furthermore the power available for control for the different limitations of the generator is determined correctly.

7.4 Discussion

In this section a discussion of the proposed CHP control, its assumptions and limitations, will be given. First of all the CHP control proposed in this paper is used in addition to existing classical power system controls. The proposed control strategies are thus not meant to replace standard governing and excitation systems, but they will coexist with them. Note that the exciter will play an important role during voltage instability because it determines the reactive power supply of synchronous generators.

Secondly it is assumed that it is allowed to increase the average room temperature of households and greenhouses. The required increase in average temperature is, however, small (one or two degrees). This will, most probably, not be a problem for customers (temperature in greenhouses is in fact determined by energy price). Customers should nevertheless be compensated for any discomfort and increased fuel costs.

In the aggregated output power of the VPP some glitches appear. These coincide with the take-over in power generation between different micro-CHP units. The size of the glitches is at maximum $17\%$. The simulation shown in the proof of concept is, however, a worst case situation where a small number of units (10) are shown. The larger the number of thermostatically controlled CHPs a VPP controls, the more this effect will level out. So in a real-life system it is expected that these glitches will not play an important role.
Furthermore, for the ramping-up and ramping-down of the thermostatically controlled CHP it is assumed that the ramping-up and ramping-down down is linear and that the time both processes take are equal. It is also assumed that the units controlled by a VPP agent are identical and have the same settings and parameters. When these assumptions are not true for a certain system, the output power profile of the VPP are expected to contain more glitches. Note, however, that with a large number of CHPs controlled by one VPP, this effect will level out.

The models that are used for the CHP prime-mover are rather simple models mainly used to represent the time constants of these units. In a future study more accurate models could be used and the simple models of this thesis could be verified. Note that in this case the basics of the control will stay the same. Only for the Synchronous Generator the stator current limit is taken into account. For the Induction Generator this limitation could, however, be implemented in the same way as it is done for the SG.

The system requires communication at a low level in the power system. It is assumed that for instance micro-CHP units are connected to each other via a communication network. Furthermore these units should be able to communicate to a VPP aggregation agent. It is assumed that in the future smart-grid this type of communication is widely available. Note that through the Internet this communication is already available. Furthermore in future Smart-Metering communication networks will be established especially for power system purposes.

7.5 Conclusion

In this chapter the control strategy was proposed for Combined Heat and Power based local and distributed generators. The decentralized and local nature of these generators make them especially suitable to be used as actuator in the proposed HABVIP control. For the CHP-based DG the active power is controlled. The increase in output power of a CHP results in an increase in temperature of the space that is heated. In the controller customers can set a maximum rise in average temperature.

Two types of CHP units are discussed: the thermostatically controlled unit and the continuously controlled unit. In case of the thermostatically controlled unit the average output power is controlled by adjusting the duty-cycle. The unit either supplies nominal power or nothing. The HABVIP controller, however, should rely on continuous power production. In the chapter it is shown that with a proper Virtual Power Plant coordination of the micro-CHPs, constant power supply can be assumed on an aggregated level.

In case of the continuously controlled unit the electrical output power is increased by adjusting the mechanical power of the prime-mover. The control differs for each type of electrical generator. Two types are distinguished in this thesis: the synchronous generator and the induction generator. The control of continuously controlled CHP units with both types of generators are discussed.

The proposed control is verified by means of simulations and it works as expected.
Chapter 8

Proof of Concept of the HABVIP controller based on Simulations

8.1 Introduction

In chapter 5 the Hierarchical Agent Based Voltage Instability Prevention controller was proposed as a solution for voltage instability problems in a grid with a large share of renewable and distributed generation. In addition, the control of two types of actuators: smart loads and reactive power compensating devices, were outlined. Subsequently in chapters 6 and 7 a detailed discussion was given about the control of two other types of actuators: the Load Tap Changer (LTC) and Combined Heat and Power (CHP) based distributed generators.

In the current chapter a proof of concept of the HABVIP controller will be given. This is based on simulations in Matlab/Simulink with the SimPowerSystems toolbox [80]. A typical test system is used that can become voltage unstable under certain conditions. This test system was already used in the previous chapters to introduce voltage instability (chapter 2), present the voltage instability detection method (chapter 3) and to investigate the impact of DG on Voltage Stability (chapter 4). In this chapter some modifications are made to this test system in order to increase the control and disturbance possibilities and the HABVIP controller is implemented. The merit of the proposed control system is evaluated based on off-line simulations.

In section 8.2 the modifications made to the test system will be discussed. Subsequently in section 8.3 the implementation of the HABVIP control in this test system will be outlined. Section 8.4 follows with the obtained results. Multiple simulation cases are discussed. The HABVIP controller relies on a certain number of control parameters. The influence of these parameters is studied in section 8.5. Subsequently in section 8.6 the proposed HABVIP controller is compared with the conventional emergency control. A discussion of the results is given in section 8.7. Finally, in section 8.8 the conclusion of this chapter is given.

8.2 Simulation Model

The circuit of figure 8.1 is used as a test system. This system is a modified version of the system proposed in [99][135]. Note that the system without modifications was already used in previous chapters and the reader is referred to section 2.4.1 for a detailed discussion of the model.

The modifications to the original model are:

1. The line between buses 7 and 8 is changed to a double circuit allowing for separate switching of each single circuit. The impedance of each line of this double circuit is twice the impedance of the original single circuit. Thus the equivalent parallel impedance of the double circuit is equal to the impedance of the original single circuit.
2. A Virtual Power Plant of 100,000 gas-fired micro-CHP units is connected to bus 9. The micro-CHPs are thermostatically controlled and are equipped with induction generators to convert the mechanical power into electrical power. The reactive power consumption of this generator is compensated for with a fixed capacitor so that at rated power $\cos \phi = 1$. The nominal power of each unit is 1 kW. To save computational time, the behavior of the 100,000 is emulated by 10 units with an nominal output power of 10 MW each.

3. A Static Var Compensator of 200 MVar is connected to bus 6. This SVC is in addition to the fixed capacitor compensation that was already present. The SVC’s minimum and maximum compensation is $200/ -200$ MVar (both in the capacitive and inductive range).

4. Generator GEN3 is assumed to be a large greenhouse CHP unit (or equivalently the aggregated model of multiple of these units). The prime-mover is continuously controlled and the conversion from mechanical to electrical power is done by means of a synchronous generator. The synchronous generator’s field winding is protected by means of an overexcitation limiter of which the current limit is set to $|I_{fd,max}| = 3.25$ pu.

The data of the modified simulation model is given in appendix G.

8.2.1 Simulation results for modified system without control

The simulation result of the modified system of figure 8.1 for a trip of one of the five transmission lines of the transmission corridor between buses 5 and 6 is given in figures 8.2, 8.3, 8.4, 8.5 and 8.6. During this simulation no HABVIP control was available. The simulations in this subsection are used as a base case when evaluating the HABVIP controller.

In figure 8.2 the voltage magnitudes at all buses in the system are given. The bus voltages are grouped per bus type: the upper (first) graph shows the voltages at generator buses, the second graph the voltages for buses at transmission level, the third graph the voltages for buses at sub-transmission level and the lower (fourth) graph gives the voltages at load buses.

Figures 8.3, 8.4 and 8.5 show the Maximum Loadability Index ($MLI$) (upper graphs) and the power transfer (lower graphs) for the three connections in the radial system (4-5, 5-6 and 7-8). The power flows are measured from left to right in figure 8.1. As can be seen, all power flows are positive in this direction and consequently only the $MLI$ values $MLI_{4,5}$, $MLI_{5,6}$ and $MLI_{7,8}$ are meaningful (see section 3.6).
Figure 8.2. Voltages at all buses in the system for simulations without HABVIP control for a trip of a line between buses 5 and 6.
Figure 8.3. The MLI s (upper graph) and the power transfer for the line between buses 4 and 5 for a trip of a line between buses 5 and 6. The power transfer is measured from bus 4 to bus 5.

Figure 8.4. The MLI s (upper graph) and the power transfer for the transmission corridor between buses 5 and 6 for a trip of a line between buses 5 and 6. The power transfer is measured from bus 5 to bus 6.
8.2 Simulation Model

Finally figure 8.5 gives the LTC’s tap position (first graph), the SVC’s reactive power production and susceptance (second graph), the power production of the micro-CHPs (third graph) and GEN3’s field current (fourth graph). Note that in the second graph two y-axis scales are used: the reactive power is measured on the left y-axis and the value of the equivalent susceptance on the right y-axis. The spikes in the power production of the VPP are due to the LTC tap action.

Note first of all the differences between the results obtained in this section and the results obtained in section 2.4.1. During the simulations in this former section the deterioration of the system resulted in a collapse of the bus voltages. In the current section, on the contrary, no collapse occurs but the voltages in the load area are at a low value. This difference is caused by the modifications to the system: the active power production from the micro-CHPs connected at bus 9 and the reactive power compensation of the SVC at bus 6 provide enough relief to prevent the collapse even without the coordinated control benefits of the HABVIP controller.

Following the trip of one of the lines between buses 5 and 6 at $t = 10$ s, the voltages in the load area drop. The voltage drop is counteracted in three ways: GEN3 increases its reactive power production, the SVC increases its reactive power compensation level and the LTC tries to restore the bus 9 voltage by changing its tap position. The increase in reactive power from GEN3 is obtained by applying a larger field current. The field current reaches a level above its thermal limit, which is temporarily allowed (see section 2.3.1). The reactive power support from GEN3 and the SVC make that the LTC’s tap changing has the desired impact: a decrease in tap position results in an increase in secondary (bus 9) voltage.

At $t \approx 60$ s, however, the OXL begins to limit the field current. The SVC increases its reactive power production and is soon operated at its maximum output, where it behaves like a fixed capacitor. The LTC tries to restore its secondary voltage, but due to the limited reactive power support, the tap changing has the opposite effect: a decrease in tap position leads to a decrease in secondary voltage. A clear voltage unstable process can be seen from the voltage profile. The deterioration of the voltages stops at the moment the LTC hits its lowest tap position.

To compare the simulations in this chapter, five performance indices will be used: the load power not supplied ($P_{NS}$), the final value of the $MLI$ between buses 5 and 6 ($MLI_{5-6}$), the deviation in bus 6

![Figure 8.5. The MLI's (upper graph) and the power transfer for the transmission corridor between buses 7 and 8 for a trip of a line between buses 5 and 6. The power transfer is measured from bus 7 to bus 8.](image)
Figure 8.6. The LTC’s tap position (first graph), SVC’s reactive power production and susceptance (second graph) the power production of the micro-CHPs (third graph) and GEN3’s field current (fourth graph) for a trip of a line between buses 5 and 6. Note that in the second figure different y-axis scales are used and negative reactive power implies that the SVC operates in capacitive mode.
8.3 Implementation of HABVIP controller

Table 8.1. Performance indices simulations without HABVIP control.

| $P_{NS}$ [MW] | $ML/\Delta_{-6}$ | $\Delta|U_6|$ [%] | $\Delta|U_9|$ [%] | $|I_{fd}|$ [pu] |
|---------------|------------------|----------------|----------------|----------------|
| 393.6         | 1.25             | -12.43         | -10.34         | 3.25           |

voltage with respect to the initial operating point in per cent ($\Delta|U_6|$), the deviation in bus 9 voltage with respect to the initial operating point in per cent ($\Delta|U_9|$) and the field current of generator 3 ($|I_{fd}|$). The performance indices for the simulations in this section are given in table [8.1]: $P_{NS}$ is calculated from the power consumption of the two load buses before and after the disturbance:

$$P_{NS} = (P_{load, 9}(0) - P_{load, 9}(t)) + (P_{load, 10}(0) - P_{load, 10}(t))$$

(8.1)

Where $P_{load, 9}(0)$ is the bus 9 load before the disturbance, $P_{load, 9}(t)$ the bus 9 load after the control restored steady-state, and $P_{load, 10}(0)$ and $P_{load, 10}(t)$ are the same parameters for bus 10.

From the indices it becomes clear that about 400 MW of load power is not supplied due to the voltage instability and the deviation in voltages exceeds the 10 % bound and these are thus unacceptably low.

8.3 Implementation of HABVIP controller

The HABVIP controller is implemented for the test power system of figure [8.1]. The system has four substations and to each of these substations a substation agent has been assigned (see figure [8.7]):

- substation agent A4 controls the substation that consists of buses 1 and 4;
- substation agent A5 controls the substation that consists of buses 2 and 5;
- substation agent A6 controls the substation that consists of buses 3, 6, 7 and 10;
- substation agent A9 controls the substation that consists of buses 8 and 9.

The HABVIP controller can control five actuators:

- GEN3, which is a large scale greenhouse-CHP;
- the load at bus 10;
- the SVC connected to bus 6;
- the LTC between buses 8 and 9;
- the VPP consisting of 100,000 micro-CHP units connected to bus 9.

These actuators are controlled by there respective actor agents. The agents of GEN3, the SVC and the controllable load are supervised by substation agent A6. The agents of the LTC and the VPP are supervised by substation agent A9.

The structure of the HABVIP controller as implemented in Matlab/Simulink is given in figure [8.8]. An overview of the functions implemented per substation agent is given in table [8.2]. As can be seen, not all functions that were defined in chapter 5 (see figure [5.8]) are implemented.

From the simulations of section 2.4.1 it is known that the voltage instability problem starts in the load area. Substation agents A6 and A9 are thus expected to play a major role in the emergency control. With the implementation of the HABVIP controller in simulation, this knowledge is used for simplification. First of all only actuators located in the load area will be used. Furthermore as substation agents A4 and A5 are not expected to play a role, they are only able to decide whether they should take a control action. Another class of simplifications is that for substation agents A6 and A9 only the control blocks are implemented that are needed for the particular substation. Substation agent A6 has, for instance, no higher substation agent and subsequently no “Communication Higher Level Substations” is required. Furthermore the load at bus 9 (3722.4 MW) is much larger than the maximum power production of the VPP (100 MW)
Figure 8.7. Implementation HABVIP control in modified simulation model.

Figure 8.8. Overview of the implementation of the agent control scheme for the power system of figure 8.7.
Table 8.2. Implemented functions per substation agent.

<table>
<thead>
<tr>
<th>Function</th>
<th>A4</th>
<th>A5</th>
<th>A6</th>
<th>A9</th>
</tr>
</thead>
<tbody>
<tr>
<td>Communication Higher Level Substations</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phasor Measurement Unit</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Communication Neighboring Substations</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Detection</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>MLI-control</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>P-control</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Q-control</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Lower DG</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Agent Coordination</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Coordination Actuators P-control</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coordination Actuators Q-control</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aggregation</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Coordination gen control</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Coordination LTC control</td>
<td></td>
<td></td>
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<tr>
<td>Coordination Load control</td>
<td></td>
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<tr>
<td>Coordination Q-control</td>
<td></td>
<td></td>
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<tr>
<td>Actuator Exclusion</td>
<td></td>
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<tr>
<td>Communication Lower Level Substations &amp; Actuators</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

and hence the power flow is always from bus 7 to bus 8. So the situation that the DG should be lowered to prevent an in feeding overload, will not occur for this test system. And finally, there is only one LTC, one controllable load and one controllable SVC in the system, so no coordination among units from the same class is required for these actuator types. Note that these simplifications do not influence the generality of the method.

Table 8.3 lists the data that is used for the controller parameters for each of the substation agents. The value for $MLI_{ref}$ is chosen above one to provide some safety margin to instability. Note that there is a significant difference between the values for $T_{gen}$ in case of A6 and of A9. This is because the type of generator the agents can control is different. It is assumed that it will take longer to control a large synchronous generator than multiple small micro-CHPs. In section 8.5 the settings of these parameters will be evaluated by means of a sensitivity analysis. The data used in the different actor agents is given in appendix G.
8.4 Results

In this section the results of a number of simulation scenarios will be given. In subsection 8.4.1 the operation of the HABVIP controller will be evaluated based on a typical single contingency scenario: the trip of one of the lines between buses 5 and 6. Subsequently in subsection 8.4.2 the result for a contingency in addition to the trip of the line between buses 5 and 6, the trip of one of the lines between buses 7 and 8, will be investigated. In subsection 8.4.3 the influence of the different actuator classes on the system performance will be studied. Furthermore in subsection 8.4.4 the influence of communication delays between the agents will be investigated (it is assumed that communication within a substation is so fast that it is instantaneous). And finally in subsection 8.4.5 the behavior of the HABVIP controller when there are multiple LTCs at different voltage levels is tested.

8.4.1 Result for a trip of a line between buses 5 and 6

In this section simulation results are given for the test circuit of figure 8.1 with HABVIP control. The contingency is the trip of one of the five parallel transmission lines between buses 5 and 6. The result is given in figures 8.9, 8.10, 8.11, 8.12, 8.13, 8.14, 8.15, 8.16 and 8.17. In figure 8.9 the system voltages are given for all buses in the system. The graphs are grouped per bus type: generator voltages, transmission voltages, sub-transmission voltages and load voltages.

In figures 8.10, 8.11 and 8.12, for each substation agent the $MLI$ for each incoming connection (here connection is defined as the parallel equivalent of the physical lines directly connecting two substations) and the corresponding control signal (equation 5.2), and for all lines connecting to the substation the power flow are given. Note that the $MLI$ and the PI-control signal are given in one figure with two y-axis scales: the left scale is for the $MLI$ and the right scale for the control signal. In the case of the power flow, a positive flow means flow into the substation. For example, for substation agent A4 (figure 8.10) the power flow between buses 5 and 4 is negative and thus out of the substation. The $MLI$ of this connection is consequently disregarded by the controller because it has no meaning (see section 3.6).

The $MLI$ of all connections is larger than the reference value (1.6), except for two: the one of connection 5-6 and the one of connection 6-5 (see figures 8.11 and 8.12). In the case of connection 5-6, for which the value of the $MLI$ is determined by substation agent A5, the power flow is negative. So agent A5 does not activate the emergency control. For the connection 5-6, for which the value of the $MLI$ is determined by agent A6, the power flow is positive. Agent A6 activates, based on the $MLI$ value, its control. A6 becomes the supervisory agent and demands load relief from its lower level agents. These lower level agents are located in the load area and thus the simplifications adopted for the agents in the generation area do not influence the result.

In figure 8.14 the internal signal Agent Coordination (AC) (upper graph) and the control signal for the active power and reactive power load relief (lower graph) as determined by substation agent A6 are given. Subsequently in figure 8.15 the control signal (solid lines), the power available for load relief (dashed lines) and the actually obtained amount of load relief (dotted lines) are given for the active power actuators (generator, LTC and smart load control). In the upper graph of figure 8.16 the same figures are given for the SVC and in the lower graph of this figure the amount of reactive power load relief obtained from the LTC and smart load control are given.

Finally figure 8.17 shows the LTC’s reference voltage and tap position (first graph), the SVC’s reactive power production and susceptance (second graph) the power available from local generator GEN3’s different limitations (third graph) and GEN3’s field current (fourth graph). Note again that in the first two figures two y-axis scales are used.

Following the trip of the line at $t = 10$ s substation agent A6 detects an emerging voltage instability and starts its emergency control (see figure 8.14). This substation agent demands load relief from its lower level substation agent A9 and the actor agents which are directly under its control. Because it takes some time for the control action of the generator and the LTC to take effect, during the first period of time the demanded load relief is obtained by load control. This load control is, in due course, taken over by the generator control and LTC control and at $t \approx 75$ s no control action from the load control is required anymore (see figure 8.15). Note that this effect is also visible in the reactive power control: in the beginning a major part of the reactive power load relief is provided by load control, but as less active power is necessary from load...
control, also less reactive power load relief is provided by this control class. The required reactive power load relief is provided by LTC control and SVC control (see figure 8.16).

The performance indices for the simulations of this subsection are given in table 8.4. Some load power is not supplied, but compared to the simulations without HABVIP control this is decreased by about 80%.

The smallest $MLI$ in the system is above its threshold. From figure 8.10 it can be seen that the bus 6 voltage is close to its initial value, in fact it is even a little bit higher. The bus 9 voltage is decreased by about 2%. Note that this decrease is much smaller than in the case without emergency control.

So altogether it can be concluded that the proposed HABVIP emergency controller works properly. Voltage instability can be prevented and the system voltages are restored to acceptable values. Although the controller influences the customer loads by smart load control and voltage reduction, the load power not supplied is much less than in the case without emergency control.

### Table 8.4

| $P_{ss}$ [MW] | $MLI_{5-6}$ | $\Delta|U_6|$ [%] | $\Delta|U_9|$ [%] | $|I_d|$ [pu] |
|---------------|-------------|------------------|------------------|-------------|
| 83.5          | 1.62        | 0.11             | -2.11            | 3.15        |
Figure 8.9. Voltages at all buses in the system for simulations with HABVIP control for a trip of a line between buses 5 and 6.
Figure 8.10. The MLI and the control signals for both connections to substation 4 and the power flow for these connections for a trip of a line between buses 5 and 6. Note that the MLI and control signals are given in one figure, with two y-scales.
Figure 8.11. The MLI and the control signals for both connections to substation 5 and the power flow for these connections for a trip of a line between buses 5 and 6. Note that the MLI and control signals are given in one figure, with two y-scales.
8.4 Results

Figure 8.12. The MLI and the control signals for both connections to substation 6 and the power flow for these connections for a trip of a line between buses 5 and 6. Note that the MLI and control signals are given in one figure, with two y-scales.
Figure 8.13. The MLI and the control signals for both connections to substation 9 and the power flow for these connections for a trip of a line between buses 5 and 6. Note that the MLI and control signals are given in one figure, with two y-scales.

Figure 8.14. The internal coordination signal AC and the load relief requested as determined by substation agent A6 for a trip of a line between buses 5 and 6.
Figure 8.15. Control actions (control), power available for load relief (space) and obtained amount of load relief (done) from the active power actuators for a trip of a line between buses 5 and 6.
Figure 8.16. Control action (control), power available for load relief (space) and obtained amount of load relief (done) from the SVC (upper graph) and the amount of reactive power load relief obtained by the LTC and load control (lower graph) for a trip of a line between buses 5 and 6.
Figure 8.17. LTC’s reference voltage and tap position (first graph), SVC’s reactive power production and value of the equivalent susceptance (second graph) the power available from GEN3’s different limitations (third graph) and GEN3’s field current (fourth graph). Note that in the first two figures two y-axis scales are used for a trip of a line between buses 5 and 6.
8.4.2 Result for an additional trip of a line between buses 7 and 8

In this section the coordination between agents is investigated. In addition to the trip of one of the transmission lines between buses 5 and 6, one of the two lines between buses 7 and 8 trips. This additional trip of the line occurs at the moment that a steady-state is reached after the trip event between buses 5 and 6, so the simulations in this section continue the simulations of the previous section (i.e. timescale begins at 200 s).

The result of this simulation is given in figures 8.18, 8.19, 8.20, 8.21 and 8.22. Only figures for the two substation agents in the load area (A6 and A9) are given. In figure 8.18 the bus voltages divided per bus type are given. Subsequently in figure 8.19 the MLI for the critical connections 5-6 and 7-8 (first graph), the active and reactive power control signal from substation agent A6 (second graph), the active power control signal from substation agent A9 (third graph) and the internal coordination signal AC for both substation agents (fourth graph) are given. Note that substation agent A9 has only active power actuators available and consequently only the active power control signal is determined. In figures 8.20 and 8.21 the control signals from the active power actuators and the reactive power actuators are shown. Note that the transients as result of the second trip of the line cause transients in the control signal for the micro-CHPs (third graph, figure 8.20). These transients have a higher impact on this control signal than on the other ones because it is relatively small (compared to the other signals). Finally, figure 8.22 contains the LTC’s tap position (upper graph) and generator GEN3’s field current (lower graph).

The additional trip of the line results in a decrease in the bus 7, bus 8 and bus 9 voltages. This leads to a decrease in load power at bus 9 which is beneficial for the MLI of the connection between buses 5 and 6. This MLI increases a little bit (see upper graph figure 8.19). On the contrary, the MLI of the connection between buses 7 and 8 decreases below the threshold of 1.6 and substation agent A9 starts to determine the required control signal to restore the MLI. This signal soon exceeds the amount A6 requests from A9 and the internal coordination signal AC from A9 becomes one. So A9 starts to implement its own control signal (figure 8.19, bottom graph).

From figure 8.20 it can be seen that the control possibilities of A9 are limited. The micro-CHPs are already exploited to their full extent and the LTC can only perform one tap change before it reaches its limitation. Note that the control signal for the LTC after the trip of the second line takes into account the load reduction due to the trip of that line: the initial power and voltage are updated by the controller and the measures for the LTC in figure 8.20 are in addition to the load relief obtained by the trip of the line. Due to the limited control space of A9 not all load relief required to restore the MLI can be implemented. MLI7−8 stays below the reference value of 1.6. Furthermore the integrator in A9 stays integrating what explains the increasing control signal (figure 8.19, third graph from top). Substation agent A6 does not release its control because the MLI of connection 5-6 does not restore to a value above 1.7 (the reference plus 0.1).

It can be seen that the voltage drop of bus 9 is larger than 10% (figure 8.18, third graph from top) and the bus 9 voltage is thus unacceptably low. Note that, nevertheless, the higher level voltage of bus 6 is acceptable. Despite the fact that insufficient control was available to restore all voltages to above 10% from their original steady-state, from the simulations the correct agent coordination is demonstrated. Substation agent A9 starts to implement its own control action from the moment the locally determined control signal becomes greater than the control signal determined at a higher level. This is noticed by the higher level agent A6 and this agent balances the control it requests from the actuators at a higher level (figure 8.19, second graph from top).
Figure 8.18. Voltages at all buses in the system for simulations with HABVIP control (lines 5-6 and 7-8 trip).
Figure 8.19. The MLI (first graph), the active and reactive power control signals of substation agent A6 (second graph), the active power control signal of substation agent A9 (third graph) and the internal signal AC for both substation agents (fourth graph) (lines 5-6 and 7-8 trip).
Figure 8.20. Control actions (control), power available for load relief (space) and obtained amount of load relief (done) from the active power actuators (lines 5-6 and 7-8 trip). Note that GEN3 and the controllable load are directly connected to A6 and the LTC and the micro-CHPs are directly connected to A9.
Figure 8.21. Control action (control), power available for load relief (space) and obtained amount of load relief (done) from the SVC (upper graph) and the amount of reactive power load relief obtained by the LTC and load control (lower graph) (lines 5-6 and 7-8 trip). Note that the SVC and controllable load are directly connected to A6 and the LTC is directly connected to A9.

Figure 8.22. LTC’s tap position (upper graph) and GEN3’s field current (fourth graph) (lines 5-6 and 7-8 trip).
8.4.3 Influence of Actuator Types

In this section the influence of the different actuator classes on the performance of the HABVIP controller is investigated. Simulations are performed with the test circuit of figure 8.1 with the HABVIP emergency control turned on. The event triggering the (potential) voltage instability is the trip of one of the transmission lines between buses 5 and 6 (see section 8.2.1 for the result without HABVIP control). Several studies are performed where each time one actuator class of the HABVIP controller is turned off. The performance indices for these studies are shown in Table 8.5. The first row gives the simulation result in case all actuator classes are used. The second row gives the result for the case when generators active power control are not used in the HABVIP controller. The third row gives the result for the case the LTC is not used in the control. The fourth row gives the result for the case that the smart loads are not used in the emergency control and the fifth and sixth rows give the results for the case the SVC is not used. For the SVC two cases are distinguished: the case where the SVC is not activated directly by the HABVIP controller but where it provides some assistance via voltage droop control (fifth row) and the case where the SVC is not available at all (sixth row). The last row gives, for comparison, the result when no HABVIP controller is available at all (see Table 8.1).

The control of the local generators is very important for the HABVIP controller. The load power not supplied increases dramatically when this actuator class is unavailable for emergency control, in fact it increases above the amount of load power not supplied in the case without emergency control (last row of the table). Note that this does not lead to the conclusion that the result without HABVIP control is better than the case of the HABVIP controller without generator control. Even without the generators the HABVIP controller restores the voltages with a maximum deviation of $2.5\%$. Note furthermore that the MLI indicates that the system is operated with a considerable margin to the point of maximum power transfer.

The HABVIP controller without LTC control seems to perform better than the system that has the LTC as actuator. A smaller amount of load power is not supplied in the case without LTC control than in the case with LTC control. The load power that is not supplied is from loads behind the LTC, and consequently correlated with a lower secondary voltage (this load is not directly controlled).

The unexpected behavior of the LTC control seems to contradict with the assumption on which the coordination scheme is based that slightly lower voltages at the customer side are less severe than smart load control. In order to investigate the unexpected behavior, in Table 8.6 the result is given for simulations where the control signal for the LTC is not prevented to decrease when the generator reaches its field current limitation. This adaptation was introduced to prevent the hunting between the LTC control and generator control. Note that this hunting does not appear in the simulations of this subsection because some smart load control is requested (see Chapter 8 for a more thorough discussion). It can be seen that the load power not supplied is considerably smaller for the case $\Delta |I_{fd,lim}| = 0$ than for the case $\Delta |I_{fd,lim}| = 0.13$. Also in this case the load power not supplied is the load behind the LTC. The optimal setting of parameter $|I_{fd,lim}|$ will be further investigated in the sensitivity analysis in Section 8.5.

So the main cause of the higher load power not supplied with the LTC participating in the HABVIP controller is the fact that the LTC control signal is blocked when the field current of the local generators

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Table 8.5. Impact of different types of Actuators (with $\Delta |I_{fd,lim}| = 0.13$).

| Gen. | LTC | Load | SVC     | $P_{NS}$ [MW] | $M L I_{5-6}$ | $\Delta |U_6|$ [%] | $\Delta |U_9|$ [%] | $|I_9|$ [pu] |
|------|-----|------|---------|--------------|--------------|-------------|-------------|-----------|
| 1    | 1   | 1    | 1       | 83.5         | 1.62         | 0.11        | -2.11       | 3.15      |
| 0    | 1   | 1    | 1       | 543.1        | 1.61         | 0.24        | -2.53       | 2.84      |
| 1    | 0   | 1    | 1       | 33.1         | 1.60         | -0.07       | -0.07       | 3.23      |
| 1    | 0   | 0    | 1       | 101.2        | 1.63         | 0.20        | -2.55       | 3.04      |
| 1    | 1   | 1    | 0 (Droop Control) | 163.1 | 1.60 | -0.15 | -2.95 | 3.24 |
| 1    | 1   | 0    | (No SVC) | 182.4 | 1.60 | -0.15 | -2.95 | 3.24 |
| 0    | 0   | 0    | 0       | 393.6        | 1.25         | -12.43      | -10.34      | 3.25      |

---

Note that the LTC is still in the test circuit, but it is not used in the emergency controller.
Table 8.6. Simulations without blocking LTC signal ($\Delta |I_{fd,lim}|$).

| Gen. | LTC | Load | SVC | $P_{NS}$ [MW] | $ML|I_{5-6}$ | $\Delta |U_9|$ [%] | $\Delta |U_6|$ [%] | $|I_6|$ [pu] |
|------|-----|------|-----|--------------|-------------|-------------|-------------|-------------|
| 1    | 1   | 1    | 1   | 46.5         | 1.61        | -0.04       | -1.16       | 3.20        |

approach their limitation. The load power not supplied without this blocking is, however, still a little bit larger than for the case without LTC control. This is due to the discrete tap changing of the LTC: the voltage decreases with fixed tap sizes and this introduces a deadband. The maximum error in load power due to this deadband is 20 MW. In the case of load control it is assumed that the control can be performed continuously.

The load control is also important for the HABVIP controller, but the influence is smaller than that of the generator control. In the case no load control is available the load power not supplied increases. So the performance of the HABVIP controller is better in the case this controller is able to lower loads directly than when this is not possible. Note that without load control, nevertheless, the system is still capable to restore the voltages and to keep a margin to the point of maximum power transfer.

The reactive power compensation controlled by the HABVIP controller is also important for the system performance. Without this actuator class, the load power not supplied increases significantly. The difference between the case of the system with voltage droop controlled SVC and no SVC at all is small. Note that also in the case without reactive power control the voltage drop is acceptable and the HABVIP controller is able to restore operation before the point of maximum power transfer is reached.

8.4.4 Influence of Communication Delays

The HABVIP controller requires communication. Substation agents exchange local measurements and communicate with the supervisory agent in order to determine the control action. Furthermore substation agents and actor agents of actuators connected to the substation communicate. Note that it is only required for agents to have a communication link when the substations and/or actuators which they represent are electrically connected.

It is assumed that in the future power system this communication is available [59]. It is likely that a mix of different technologies will be used. Direct connections between substations can be made via optic fiber, ethernet or power line communication. This is mainly expected to be used at higher hierarchical levels in the HABVIP controller as these direct connections are more expensive. At lower levels the existing infrastructure as the Internet could be used. Furthermore within a substation wireless technologies can be used. The connections should be redundant: a direct connection between higher level substations should have as back-up for instance the Internet.

In addition to the technology, a communication protocol should be chosen. Several protocols are proposed for different purposes. The IEC 61850 and 61850-90 protocols are specially designed for substation automation and inter-substation communication [81, 82]. Furthermore the IEEE defined a 2030 protocol for Smart Grid interoperability [83]. At the low voltage customer side also protocols are defined like the ZigBee to establish communication among loads and the smart meter [44].

In this thesis no choice has been made for a particular communication technology or protocol. It is, however, expected that the communication will influence the performance of the HABVIP controller as it introduces delays. The measurements at bus 9 are, for instance, not instantaneously known at substation agent A6. Communication can be further delayed when the data needs to be transmitted through multiple substation levels.

In this section the consequences of the communication delays on the performance of the HABVIP controller will be investigated. In order to do so, delays are added to the connections between the agents (see figure 8.3). These delays are modeled with the Transport Delay block of Matlab/Simulink. It is assumed that, when required, actuators perform bus voltage and current measurements locally for which no delay is assumed.

Simulations are performed for the single contingency case study (loss of line in transmission corridor 5-6) for different delay times. The result is shown in table 8.7. A discussion of the range of communication delays is given in section 8.7. Note that the delays given in this table are for communication between two
8.4 Results

Table 8.7. Impact of communication delay on performance of the HABVIP controller.

| $\Delta t_{\text{com}}$ [s] | $P_{\text{NS}}$ [MW] | $MLI_{5-6}$ | $\Delta |U_6|$ [%] | $\Delta |U_9|$ [%] | $|I_9|$ [pu] | $t_{\text{set}}$ [s] |
|----------------|----------------|-------------|---------------|---------------|-------------|------------|
| 0              | 83.5           | 1.62        | 0.11          | -2.11         | 3.15        | 134        |
| 0.01           | 86.7           | 1.62        | 0.04          | -2.19         | 3.15        | 134        |
| 0.05           | 86.6           | 1.62        | 0.04          | -2.18         | 3.15        | 136        |
| 0.1            | 86.8           | 1.62        | 0.04          | -2.19         | 3.15        | 140        |
| 0.15           | 86.7           | 1.62        | 0.04          | -2.18         | 3.15        | 140        |
| 0.2            | 86.7           | 1.62        | 0.04          | -2.18         | 3.15        | 140        |

directly connected entities only. So a control signal from A6 to the LTC is first send to substation agent A9 and after that to the LTC and has thus a delay of $2 \cdot \Delta t_{\text{com}}$. In addition to the previously defined performance indices, the settling time ($t_{\text{set}}$) is used as a parameter to investigate the system behavior. The first row of table 8.7 gives the result for the case when there is no communication delay. This is the result obtained in table 8.4. The next five rows show the result for a communication delay of 10 ms, 50 ms, 100 ms, 150 ms and 200 ms.

From the table it can be concluded that the communication delay has no significant impact on the final performance of the HABVIP controller, as given by the previously defined performance indices.

8.4.5 Influence of Multiple LTC levels

In the simulations so far there is one LTC (LTC 3, between buses 8 and 9). This LTC is located at HV/MV side and it feeds the load directly. In a typical power system, however, multiple LTCs can be present and some of these LTCs might be in cascade. In [200] it is shown that two or more LTCs in cascade can exhibit an oscillatory behavior when the time delays among their actions are not properly tuned. In this section the influence of multiple LTCs on the performance of the HABVIP controller is investigated.

In the study of this section two regular transformers are replaced by LTCs: the transformer between buses 6 and 7 (LTC 2) and the transformer between buses 6 and 10 (LTC 1). So two LTCs are in cascade (LTC 2 and LTC 3). The settings of the LTCs are given in appendix G.3. Note that the LTC between buses 8 and 9 is made slower in order to prevent oscillatory behavior. The two extra LTCs are not controlled by the HABVIP controller and use their normal LTC voltage control. The main question to be answered is whether this normal control will interfere with the HABVIP controller.

The simulation result is given in figure 8.23. The upper graph shows the bus 6 (solid line) and bus 9 (dashed line) voltages. The middle graph shows the $MLI$ of the connection between buses 5 and 6 and the lower graph gives the tap position of the LTCs. Note that the graphs of the tap positions of LTC 1 and LTC 2 coincide and remain at zero. The initiating event is a trip of one of the transmission lines between buses 5 and 6.

It can be seen that also in this multiple LTC case the HABVIP controller is capable to restore the system state. The system voltage does not drop below the 10 % bound and the $MLI$ indicates a margin to the point of maximum power transfer. LTC 1 and LTC 2 do not change their tap position: the tap stays at the initial position. This means that the HABVIP controller is able to restore the voltages at buses 7 and 10 fast enough so that it is not necessary for the voltage control of LTC 1 and LTC 3 come into action.

The performance indices are given in table 8.8. The first row gives these indices for the case only one LTC is present (LTC 3, which is controlled by the HABVIP controller). The second row gives the result when three LTCs are present of which two are not controlled by the HABVIP controller (LTC 1 and LTC 2). There is no significant difference between the performance indices of the two cases. So having LTCs that are not controlled by the HABVIP controller is no problem as long as this controller reacts faster than the LTCs.

Typically the lower level LTC should be 20 - 40 s slower than the higher level LTC [200]. In the simulations of this subsection LTC3 is 30 s slower than LTC 2.
Figure 8.23. Bus 6 and bus 9 voltage (upper graph), the MLI of the connection between buses 5 and 6 (middle graph) and the tap position of the LTCs (lower graph) for simulations with three LTCs. The HABVIP controller is turned on. Note that due to the fast response of the HABVIP controller, LTC1 and LTC2 are not activated.

Table 8.8. The performance indices for simulations with one LTC and with three LTCs.

|        | $P_{\text{NS}}$ [MW] | $MLI_{5-6}$ | $\Delta |U_6|$ [%] | $\Delta |U_9|$ [%] | $|I_{fd}|$ [pu] |
|--------|-----------------------|-------------|-------------|-------------|-------------|
| One LTC | 83.5                  | 1.62        | 0.11        | -2.11       | 3.15        |
| Three LTCs | 86.4                | 1.62        | 0.04        | -2.18       | 3.15        |
Table 8.9. Sensitivity analysis for parameter $T_{gen}$.

| $T_{gen}$ [s] | $P_{NS}$ [MW] | $MLI_{5-6}$ | $\Delta U_{6}$ [%] | $\Delta U_{9}$ [%] | $|I_{fd}|$ [pu] |
|--------------|--------------|------------|------------------|------------------|--------------|
| 1            | 83.8         | 1.62       | 0.11             | -2.11            | 3.15         |
| 10           | 83.5         | 1.62       | 0.11             | -2.11            | 3.15         |
| 20           | 83.5         | 1.62       | 0.11             | -2.11            | 3.15         |
| 25           | 103.4        | 1.62       | 0.15             | -2.61            | 3.13         |
| 35           | 103.3        | 1.62       | 0.14             | -2.61            | 3.13         |

Table 8.10. Sensitivity analysis for parameter $T_{LTC}$.

| $T_{LTC}$ [s] | $P_{NS}$ [MW] | $MLI_{5-6}$ | $\Delta U_{6}$ [%] | $\Delta U_{9}$ [%] | $|I_{fd}|$ [pu] |
|--------------|--------------|------------|------------------|------------------|--------------|
| 20           | 103.5        | 1.62       | 0.15             | -2.61            | 3.12         |
| 30           | 83.5         | 1.62       | 0.11             | -2.11            | 3.15         |
| 40           | 63.3         | 1.61       | 0.07             | -1.59            | 3.18         |
| 50           | 63.6         | 1.61       | 0.07             | -1.59            | 3.18         |
| 60           | 42.9         | 1.61       | 0.04             | -1.08            | 3.20         |
| 70           | 43.2         | 1.61       | 0.03             | -1.08            | 3.20         |

8.5 Sensitivity Analysis

The HABVIP controller relies on multiple parameters. It is to be expected that the settings of these parameters are of influence on the system performance. It was, for instance, shown in section 8.4.3 that the parameter $\Delta |I_{fd,lim}|$ has a significant influence on the load power not supplied and the bus 9 voltage. In this section the influence of the parameters is investigated by means of a sensitivity analysis.

Simulations are done with the test system of figure 8.1. Communication delays are not taken into account. The triggering event is the trip of one of the transmission lines between buses 5 and 6. Because substation agent A6 is the supervisory agent, only the influence of the parameters of this agent are investigated. Furthermore the influence of the proportional and integral gain ($k_P$ and $k_I$) of the SVC controller, and the field current safety margin $\Delta |I_{fd,lim}|$ is investigated. The simulations are evaluated based on the performance indices: load power not supplied ($P_{NS}$), the $MLI$ of the connection between buses 5 and 6 ($MLI_{5-6}$), the voltage deviation at buses 6 and 9 ($\Delta |U_6|$ and $\Delta |U_9|$) and the final field current of GEN3 ($|I_{fd}|$).

In table 8.9 the results for varying values of the time constant for generator control ($T_{gen}$) are given. The bold line highlights the base case result: the settings as used in section 8.4. As it becomes clear from this table, the parameter $T_{gen}$ has no significant influence on the performance of the HABVIP controller as long as $T_{gen} \leq 20$ s. When this parameter becomes larger than 20 s the load power not supplied increases and the bus 9 voltage decreases. The value of 10 s, as determined by intuitive reasoning, seems reasonable.

The next parameter that is investigated is the time delay in LTC control ($T_{LTC}$). The result is given in table 8.10. The base case scenario is, again, highlighted in bold. It can be seen that this parameter has a larger impact on the performance. Up and until $T_{LTC} = 60$ s an increase in this parameter comes with a decrease in both the load power not supplied and the drop in bus 9 voltage at the cost of a higher field current. An increase beyond 60 s does not result in any further significant change of the performance indices. So the value for $T_{LTC}$ as determined by intuitive reasoning (30 s) does not lead to the optimal result, as it is better to choose a higher value (e.g. 60 s).

The result of the sensitivity analysis for the proportional and integral gain ($k_P$ and $k_I$) of the coordinated controller are given in table 8.11. The table is divided into four compartments. In the first compartment (the first row) the base case scenario is given. In the next compartment (the next three rows) the result is given when the settings for $k_P$ and $k_I$ are chosen such that $k_P + k_I = 1$, which results in a less reactive response of the PI-controller. The third compartment subsequently gives the results for a variation in $k_P$ only. The fourth compartment gives the result for a variation in $k_I$ only. The values of the parameters in these last two compartments are chosen intentionally in a different range than of the former compartments. From this analysis it can be seen that in the case parameter $k_P$ is made larger, the performance does not change. If, on the other hand, $k_I$ is made larger, the performance deteriorates: the load power not supplied increases and the bus 9 voltage drops compared to the base case.

The next control parameter taken into consideration is the reference value for the $MLI$ ($MLI_{ref}$). The
results of this study are shown in table 8.12. Note again that the boldface character gives the result of the the base case scenario. $MLI_{ref}$ has a significant impact on the system performance. In terms of the load power not supplied, the chosen value of 1.6 results in an optimum. For both the bus 9 voltage and the field current of GEN3 a larger value of $MLI_{ref}$ seems positive because both performance indices decrease in magnitude. The bus 6 voltage increases when $MLI_{ref}$ increases. Because the load power not supplied is considered as one of the most important performance indices $MLI_{ref} = 1.6$ is considered as optimum from that standpoint.

Note that when a small value of $MLI_{ref}$ is chosen, the controller will react late to an emerging voltage instability. If a too small value is chosen, the possibility exists that the instability cannot be prevented at all. If, on the contrary, $MLI_{ref}$ is too large, it may occur that the controller starts to act when the system is not in danger at all. For the system under consideration this happens for $MLI_{ref} = 1.8$. In that case the HABVIP controller starts before the initiating event even occurred, unnecessarily lowering the bus voltages and hence resulting in a large value for $P_{NS}$.

The sensitivity analysis to the parameters $k_P$ and $k_I$ of the SVC control is given in table 8.13. The table is divided into two compartments. The first compartment gives the result for a variation in $k_P$. The second compartment gives the result for a variation in $k_I$. The influence of these parameters is not significant.

The importance of the parameter field current safety margin ($\Delta|I_{fd,lim}|$) became already clear from section 8.4.3. The blocking of the decrease in control signal for the LTC that is a result of this parameter setting, makes that the load power not supplied increases. A more thorough investigation of this parameter is given in table 8.14. From this table it becomes clear that the negative influence of this blocking mechanism vanishes when $\Delta|I_{fd,lim}| \leq 0.1$ pu. So $\Delta|I_{fd,lim}| = 0.1$ gives an optimum: the negative influence on

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### Table 8.11. Sensitivity analysis for parameters $k_P$ and $k_I$ of coordinated controller of A6.

| $k_P$ | $k_I$ | $P_{NS}$ [MW] | $MLI_{ref}$ | $\Delta|U_6|$ [%] | $\Delta|U_9|$ [%] | $|I_6|$ [pu] |
|------|------|-------------|------------|--------------|--------------|----------|
| 0.4  | 0.6  | 83.5        | 1.62       | 0.11         | -2.11        | 3.15     |
| 0.25 | 0.75 | 83.7        | 1.62       | 0.11         | -2.10        | 3.15     |
| 0.5  | 0.5  | 83.6        | 1.62       | 0.11         | -2.11        | 3.15     |
| 0.75 | 0.25 | 83.5        | 1.62       | 0.11         | -2.11        | 3.15     |
| 25   | 0.6  | 83.5        | 1.62       | 0.11         | -2.10        | 3.15     |
| 75   | 0.6  | 83.5        | 1.62       | 0.11         | -2.10        | 3.15     |
| 125  | 0.6  | 83.1        | 1.62       | 0.12         | -2.10        | 3.15     |
| 0.4  | 25   | 135.1       | 1.63       | 0.26         | -2.48        | 3.04     |
| 0.4  | 50   | 127.9       | 1.63       | 0.24         | -2.50        | 3.05     |
| 0.4  | 75   | 118.1       | 1.63       | 0.23         | -2.52        | 3.07     |

### Table 8.12. Sensitivity analysis for parameter $MLI_{ref}$.

| $MLI_{ref}$ | $P_{NS}$ [MW] | $MLI_{ref}$ | $\Delta|U_6|$ [%] | $\Delta|U_9|$ [%] | $|I_6|$ [pu] |
|-------------|---------------|-------------|----------------|----------------|----------|
| 1.5         | 254.1         | 1.54        | -0.22          | -3.04          | 3.24     |
| 1.55        | 163.0         | 1.55        | -0.18          | -2.98          | 3.24     |
| **1.6**     | **83.5**      | **1.62**    | **0.11**       | **-2.11**      | **3.15** |
| 1.65        | 197.9         | 1.65        | 0.39           | -2.33          | 2.95     |
| 1.7         | 613.3         | 1.79        | 1.16           | -1.45          | 2.42     |
| 1.8         | 826.7         | 1.87        | 1.46           | -1.14          | 2.15     |

### Table 8.13. Sensitivity analysis for parameters $k_P$ and $k_I$ of SVC.

| $k_P$ | $k_I$ | $P_{NS}$ [MW] | $MLI_{ref}$ | $\Delta|U_6|$ [%] | $\Delta|U_9|$ [%] | $|I_6|$ [pu] |
|------|------|-------------|------------|--------------|--------------|----------|
| 100  | 50   | 83.4        | 1.62       | 0.11         | -2.10        | 3.15     |
| **300** | **50** | **83.5**    | **1.62**   | **0.11**     | **-2.11**   | **3.15** |
| 500  | 50   | 84.0        | 1.62       | 0.11         | -2.11        | 3.15     |
| 300  | 25   | 83.2        | 1.62       | 0.11         | -2.10        | 3.15     |
| **300** | **50** | **83.5**    | **1.62**   | **0.11**     | **-2.11**   | **3.15** |
| 300  | 75   | 87.4        | 1.62       | 0.03         | -2.19        | 3.15     |

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Proof of Concept of the HABVIP controller based on Simulations
8.6 Comparison with Conventional Control Strategies

Table 8.14. Sensitivity analysis for parameter $\Delta |I_{fd,lim}|$.

| $\Delta |I_{fd,lim}|$ [pu] | $P_{NS}$ [MW] | $MLI_{5-6}$ | $\Delta |U_6|$ [%] | $\Delta |U_9|$ [%] | $|I_{fd}|$ [pu] |
|-------------------------|--------------|-------------|-------------|-------------|----------------|
| 0                       | 43.2         | 1.61        | 0.03        | -1.08       | 3.20           |
| 0.05                    | 43.0         | 1.61        | 0.04        | -1.08       | 3.20           |
| 0.1                     | 43.2         | 1.61        | 0.03        | -1.08       | 3.20           |
| 0.13                    | 83.5         | 1.62        | 0.11        | -2.11       | 3.15           |
| 0.15                    | 83.6         | 1.62        | 0.11        | -2.11       | 3.15           |

Table 8.15. Near optimum settings for the parameters of the HABVIP controller of A6.

| $t_{gen}$ [s] | $T_{LTC}$ [s] | $k_p$ | $k_i$ | $MLI_{ref}$ | $\Delta |I_{fd,lim}|$ [pu] | $P_{NS}$ [MW] | $MLI_{5-6}$ | $\Delta |U_6|$ [%] | $\Delta |U_9|$ [%] | $|I_{fd}|$ [pu] |
|--------------|-------------|------|------|-------------|----------------|--------------|-------------|-------------|-------------|-------------|
| 10           | 60          | 0.4  | 0.6  | 1.6         | 0.05           | 300          | 50          | 42.8        | 1.61        | 0.04        | -1.08       | 3.20 |

the load power not supplied is at its minimum while the hunting of the LTC control is actively prevented. Finally in table 8.15 the simulation result is given with the optimal values for all parameters investigated above. Note that taking the optimum values obtained by the optimization of the individual parameters does not necessarily result in an optimization of the system as a whole. As can be seen the system performance of this ‘optimal’ system is close to the performance of the system with only $T_{LTC}$ or $\Delta |I_{fd,lim}|$ optimized. This once more illustrates the impact of the deadband in the LTC control. Altogether it can be concluded that the tuning of the following three parameters is of major importance for the performance of the HABVIP controller: the time delay of the LTC control ($T_{LTC}$), the reference value of the MLI ($MLI_{ref}$) and the field current safety margin ($\Delta |I_{fd,lim}|$).

8.6 Comparison with Conventional Control Strategies

In this section the HABVIP controller is compared with two types of classical voltage instability emergency control presented in the literature: Under Voltage Load Shedding (UVLS) [184] and tap blocking of the LTC [201]. Note that these methods were also used in section 2.5.2. Simulations are done with the test system of figure 8.1. The triggering event is, again, the trip of one of the transmission lines between buses 5 and 6. For the HABVIP controller the non-optimized controller is used with parameters given in table 8.3. Communication delays are ignored. The comparison is based on the performance indices: load power not supplied ($P_{NS}$), the MLI of the connection between buses 5 and 6 ($MLI_{5-6}$), the voltage deviation at buses 6 and 9 ($\Delta |U_6|$ and $\Delta |U_9|$) and the field current of GEN3 ($|I_{fd}|$).

For UVLS the method proposed in [184], which is designed for the same test circuit, is used. Load shedding is applied to the load at bus 10. The following heuristic rule describes the control:

If the voltage stays below 0.90 pu for 1.5 s: shed 5 % of the area load.

This load shedding can be repeated two times. In case of the LTC tap blocking the method is applied to the LTC between buses 8 and 9. The control is given by the following heuristic rule [201]:

If the primary voltage stays below 0.90 pu for 4 s: block the LTC.

The results are shown in table 8.16. The first row gives for reasons of comparison the result for the case without emergency control (see section 8.2.1). The second row shows the result with UVLS control. The third row shows the result with LTC tap blocking as emergency control. The fourth row gives the result with the HABVIP controller. The fifth row shows the result with HABVIP controller but with the local generator control blocked (see subsection 8.4.3).
Table 8.16. Comparison of proposed control with conventional control.

|                      | $P_{NS}$ [MW] | $MLI_{5-6}$ | $\Delta |U_6| [%]$ | $\Delta |U_9| [%]$ | $|I_{fd}|$ [pu] |
|----------------------|---------------|-------------|-------------|-------------|--------------|
| No control           | 393.6         | 1.25        | -12.43      | -10.34      | 3.25         |
| UVLS                 | 380.9         | 1.56        | -0.21       | 0.90        | 3.17         |
| Tap blocking         | 165.2         | 1.38        | -5.31       | -4.20       | 3.25         |
| HABVIP control       | 83.5          | 1.62        | 0.11        | -2.11       | 3.15         |
| HABVIP w/o generator control | 543.1  | 1.61        | 0.24        | -2.53       | 2.84         |

In the case of UVLS the $MLI$ is close to 1.6 and both voltages are restored close to their initial values. GEN3 has some margin (0.08 pu) in the field current before the OXL acts. When only these four indices are taken into consideration UVLS performs better than the HABVIP controller: the bus 9 voltage is restored closer to its initial value and the other three indices have comparable values. The load power not supplied is, however, much larger in the case of UVLS than in the case of the HABVIP controller. Note that the reason for this is that it uses local generation as actuator (see the last row of table 8.16).

In the case of tap blocking the load power not supplied is much smaller than in the case of UVLS. It is, nevertheless, still two times the amount that is not served in the case of the HABVIP controller. The $MLI$ indicates that although the system is operated with a margin to the point of maximum power transfer, this margin is reduced. Furthermore, the decrease in bus 6 and bus 9 voltages is significant. Their values stay, however, within the band of 10%. Furthermore, GEN3 is operated with its field current at the maximum limit, this indicates that with this control strategy the OXL limit must intervene to the reactive power production. Note again that the performance of the HABVIP controller is mainly determined by the capability to control the local generator.

One might argue that the classical controls are not completely optimized for this test system. It is, however, questionable whether settings can be found for the voltage level and time delays that are optimal under all emergency conditions. This is different for the proposed controller: for each individual case the best control strategy is determined based on the momentary needs and capabilities of the agents. Note furthermore that the parameters of the HABVIP were not optimized for the simulations.

### 8.7 Discussion

In this chapter a verification of the proposed HABVIP controller was given based on simulations in Matlab/Simulink. The results obtained will be discussed in this section. The points under discussion can be divided into two parts. First of all, the simulation itself can influence the results and the conclusions. So the first points that will be mentioned are related to the method of investigation itself. Secondly, the HABVIP controller itself and its performance should be discussed.

Simulations are performed with the ode23tb solver. The absolute and relative tolerances are generally set to $1 \cdot 10^{-3}$ (typical values are $1 \cdot 10^{-5}$ for the relative tolerance and $1 \cdot 10^{-6}$ for the absolute tolerance [174]). Experience with the simulation model have shown that this gives in most cases a sufficiently accurate result and the time required for a typical simulation is reasonable. The simulation time is especially important for the sensitivity analysis, because a lot of simulations are involved.

In the case of numerical problems the absolute and relative tolerances are varied between $2.5 \cdot 10^{-2}$ and $1 \cdot 10^{-5}$ to search for settings where the simulations could proceed. In these cases the result is carefully evaluated to determine whether dynamics are not neglected: for large tolerances the time step may become too large during steady state and the token passing in the VPP is not handled correctly.

A second point that influences the accuracy is the initial state of the system. If possible, the same initial state is used for the different simulation cases. Nevertheless, in some cases the simulation model had to be re-initialized because of modifications to the model. The small differences in the initial states result in small differences in the simulation result. For the load power not supplied the introduced error due to different initializations is about 4%.

Although not explicitly stated during the evaluation of the results, the settings of the tolerances and the influence of the initial state are taken into account. Conclusions regarding differences between cases are only drawn when these differences are significant.
8.7 Discussion

Table 8.17. Average response time of sending the ping command to servers located in different countries.

<table>
<thead>
<tr>
<th>Country</th>
<th>Via university network</th>
<th>Via ADSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Netherlands</td>
<td>2 ms</td>
<td>18 ms</td>
</tr>
<tr>
<td>Germany</td>
<td>18 ms</td>
<td>33 ms</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>39 ms</td>
<td>47 ms</td>
</tr>
</tbody>
</table>

The simulation results are mainly evaluated based on five performance indices: the load power not supplied ($P_{NS}$), the $MLI$ of the connection between buses 5 and 6 ($MLI_{5\rightarrow6}$) the deviations in bus 6 and bus 9 voltages ($\Delta|U_6|$ and $\Delta|U_9|$) and the field current of generator 3 ($|I_{fd}|$). The choice of these performance indices will, obviously, influence the results. When other parameters would have been chosen the conclusions could change. The choice for the particular indices was made because of the following reasons.

$P_{NS}$ and $\Delta|U_9|$ are directly related to the consequences for the customers. Note that the voltage of bus 10, to which industrial customers are connected, can be evaluated based on the bus 6 voltage because there is only a transformer with fixed tap ratio between them. So $P_{NS}$, $\Delta|U_6|$ and $\Delta|U_9|$ give a rather complete picture of the consequences for customers.

$MLI_{5\rightarrow6}$ is the parameter that is used as reference in the HABVIP controller. This parameter is used as performance index to determine whether the controller’s goal is reached. Finally $|I_{fd}|$ is a measure that indicates whether the power system dynamics are stabilized. When this measure is larger than the field current limitation of the OXL (in this case 3.25 pu), this protection device is likely to operate in the future and the simulations should run longer to investigate the effect of the OXL action.

An important aspect that is noticed from the simulations, is the influence the actuators have on the performance (see section 8.4.3). As can be expected, the generators play an important role and are one of the major contributors to system performance. Counterintuitive is, however, that the result obtained without the LTC control was better than with this type of control. It was shown that the main reason for this was the combination of the blocking of the decrease in the LTC control signal and the deadband of the LTC controller. To diminish the negative side effect of the LTC control, the value for the field current of GEN3 for which the LTC is blocked can be made smaller. The sensitivity analysis has proven that the negative impact can be minimized while still meeting the goal of the blocking (see section 8.5). Another solution could be to swap the priority between the LTC control and the load control. Note, however, that during the simulations it was assumed that the load can be controlled continuously. This is, of course, not possible in real life, and the load control will have a deadband too. It depends on the exact sizes of the deadband in LTC and load control whether swapping the order of LTC and load control makes sense.

The coordination among the different agents works properly (see sections 8.4.1 and 8.4.2). Only substations agents that notice a problem take part in the control. In the case of a higher level and lower level problem the lower level agent is able to decide on its own to implement a larger control action, in the case the lower level problem requires this. Note that in the simulations the lower level problem could, however, not be solved completely because at the lower level not enough power was available for control.

It was shown that small communication delays have no influence on the performance of the HABVIP controller (section 8.4.4). The values for the communication delay that are used in the study vary from 10 ms to 200 ms. In order to investigate whether these values are typical, a little experiment is performed in which the ping command is used to send 32 bytes to servers located in different countries. The result is shown in table 8.17. In this table the results are given for the experiment executed from the university network and from a home PC via an Asynchronous Digital Subscriber Line (ADSL). Although the experiment is rather simple, it shows that typical values for a communication channel via the Internet (a public network) is within the range of communication delays that has been investigated.

Note that during the simulations with communication delay no special measures were taken to compensate for the fact that the local measurements are known before measurements from neighboring substations are known. So the results are pessimistic.

A sensitivity analysis is performed to investigate the impact of the parameters of the HABVIP controller (section 8.5). From this it was concluded that the time delay of the LTC control ($t_{LTC}$), reference value of the $MLI$ ($MLI_{ref}$) and the field current safety margin ($\Delta|I_{fd,lim}|$) need to be tuned carefully:
Proof of Concept of the HABVIP controller based on Simulations

- $T_{\text{LTC}}$ should be chosen larger (about two times) than the time constant of the LTC.
- $MLI_{\text{ref}}$ should be determined based on simulations of the particular system to which the HABVIP controller is implemented.
- $\Delta|I_{\text{fd,lim}}|$ should also be determined based on simulations.

The other parameters can be tuned based on intuitive reasoning:

- $T_{\text{gen}}$ should be chosen in the order of magnitude of the speed governor’s time constant.
- $k_P$ and $k_I$ of the PI-loop should be chosen such that $k_P + k_I = 1$ to have a non-aggressive controller.
- $k_P$ and $k_I$ of the SVC can be chosen in the order of magnitude of classical voltage droop controllers of SVCs.

Based on the sensitivity analysis optimal settings have been defined for the parameters. These settings are used in a final simulation. This simulation is considered as an ‘optimum’. It is, however, possible that this ‘optimum’ is not the real optimum.

During the sensitivity analysis only the influence of the parameters of substation agent A6 were taken into consideration. It is to be expected that for substation agent A9, for a similar single contingency case, similar results can be obtained. However, in the case a lower level agent takes over the control of a higher level agent (see section 8.4.2) the time constants $T_{\text{gen}}$ and $T_{\text{LTC}}$ should be chosen differently. The cause for this is that before the control is taken over by the lower level agent, a control signal has already been applied by a higher level agent. When the lower level agent takes over the control, the time constants make that the control signals applied to the actuators become lower for a short time and increase afterwards. So the time constants should be made adaptive:

- if no emergency control is demanded from the local agent by a higher level agent the time constants should be chosen ‘normally’,
- if, on the other hand, a higher level agent already demands load relief from the local agent, the time constants should be chosen as small as possible.

During the simulations with a second contingency (section 8.4.2) the knowledge that the contingency between buses 7 and 8 was a second contingency was used and the time constant of the generator control was already chosen as small (see bullet two).

The performance of the HABVIP controller is finally compared to traditional voltage instability controllers: Under Voltage Load Shedding and LTC tap blocking (section 8.6). For this comparison the non-optimized system was used. It can be concluded from these simulations that the HABVIP controller performs better than these traditional controllers. Note that the reason for this is that the HABVIP controller can control local generation. An interesting additional research would be to compare the HABVIP controller with a traditional voltage instability emergency control that also performs generator re-scheduling. This is, however, beyond the scope of this thesis.

One might argue that the classical controls are not completely optimized for the test system. It is, however, questionable whether settings can be found for the voltage and time delay that are optimal under all emergency conditions. This is different for the proposed controller: for each individual case the control strategy is determined based on the momentary needs and capabilities of the agents. Note furthermore that the parameters of the HABVIP control could also be further optimized.

8.8 Conclusion

In this chapter a verification of the performance of the HABVIP controller was given based on simulations in Matlab/Simulink. It was investigated which actuators play a major role in this control system. Subsequently the influence of communication delays and having multiple LTCs that are not controlled by the HABVIP controller have been investigated. By means of a sensitivity analysis it was determined which
parameters of the HABVIP controller are important to tune to obtain an optimal result. Furthermore this system was compared to two traditional controllers: Under Voltage Load Shedding and LTC tap blocking. It can be concluded that the HABVIP controller works properly: voltage instability can be prevented with the proposed control system and coordination between agents works as expected. The local generator actuator class is the main contributor to the good performance. Communication delays and uncontrolled LTCs have no major impact on the system performance. The sensitivity analysis showed that the tuning of three parameters is of major importance for the HABVIP controller: the time constant of the LTC control ($T_{\text{LTC}}$), the reference value of the MLI ($MLI_{\text{ref}}$) and the field current safety margin ($\Delta |I_{\text{fd,lim}}|$). The other parameters can be chosen by intuitive reasoning. Last but not least the HABVIP controller performs better than traditional controllers.
Proof of Concept of the HABVIP controller based on Simulations
Chapter 9

Real-time Demonstration of the HABVIP controller

9.1 Introduction

Three categories of smart grid architecture validation can be distinguished:

1. off-line simulation,
2. Hardware-In-the-Loop (HIL) simulation,
3. tests in a pilot set-up.

Performing off-line simulations, as done in chapter 8, is a convenient and often-used method to validate new smart grid control concepts [9, 209, 238] and power system control in general [204, 210, 214]. Matlab/Simulink with the SimPowerSystems toolbox [80] is just one of the programs that can be used. The main advantages of these off-line simulations are that: they often can run on a desktop computer, simulation models can be quickly adapted so different cases can be verified with only a little effort, and there are no consequences for customers when a test would result in a service disruption. Besides these advantages, off-line simulations also have their drawbacks. First off all simulations rely on models. These models are always a simplification of the real world. Secondly the control itself is tested within the simulation environment. In this way it is not possible to verify in detail whether a hardware implementation is feasible or to identify and solve hardware implementation problems.

This second drawback can be solved by performing real-time Hardware-In-the-Loop simulations [31, 63, 91, 107, 98, 106, 109, 145, 233]. In this type of simulation, hardware is directly connected to a real-time computer simulating the test system. The full hardware implementation for the control concepts can be tested in this way. For this type of testing the computer running the test system should be fast enough to reproduce the power system behavior in real-time. Different systems are on the market as such as those from RTDS Technologies [167] and OPAL-RT [137]. The system of OPAL-RT uses off-the-shelf computer components and the system can be applied in different fields as electrical and power systems, aerospace, defense and automotive. The system of RTDS Technologies is specially dedicated for power system studies. This system uses specially dedicated processor- and interface cards. Note that the first drawback of simulations, the dependence on models, is not solved with Hardware-In-the-Loop testing since the hardware being tested only reflects the control architecture.

The icing on the cake is implementation of smart grid control in a pilot set-up for doing tests in a small-scale laboratory set-up or for demonstration at field sites. World-wide several sites for this exist [55, 117, 169, 181] and they are commissioned in the Netherlands as well [22, 37, 127, 159, 178, 208]. These sites can either emulate the power flows in a small scale network, as is for instance done in the DENlab [159, 208] or it can be a real network with smart residential consumers, as is for instance done in the Netherlands at different

1Although in principle all models could be used that are written in C-code.
sites of the Smart Energy Collective [178] and at the Danish island Bornholm in the EcoGrid project [55]. In a pilot set-up, smart grid control can be tested with real power flows. When the network is real and not emulated, there are no models involved, so no chance for any inaccuracy in the models. This type of testing is, however, less flexible than the other options in terms of allowing change of configuration. Furthermore, in pilot set-ups with real customers involved an error during the testing could have a major influence on the customers.

In this chapter the Hardware-In-the-Loop approach is used to validate the HABVIP controller. This approach goes one step further than the off-line simulations performed in chapter 8 because the control system is implemented in real hardware and interfacing between the different distributed entities is required. In this way it can be determined whether a hardware implementation is feasible for industry and possible bottlenecks in such an implementation can be investigated and solved. Note that in the set-up the phasor measurement units remain virtual and a simple form of inter-agent communication is used.

The next step could be the implementation of the HABVIP controller in a pilot set-up. This is, however, out of the scope of this thesis.

In section 9.2 a detailed description of the test set-up is given. Subsequently in section 9.3 the results that are obtained with this system are discussed. Section 9.4 follows with a discussion. Finally in section 9.5 the main conclusions are drawn.

### 9.2 Test set-up

The test set-up that is used for real-time demonstration of the HABVIP concept is built around a Real-Time Digital Simulator (RTDS) [27] that is used to simulate the same power system as in chapter 8 and the real-time industrial target-PCs of experimental Triphase converters [194] for the agent implementation. A schematic overview of this demonstration set-up is given in figure 9.1.

In this section a detailed description of this test set-up will be given. In subsection 9.2.1 the implementation of the test power system in the RTDS will be discussed. Subsequently in subsection 9.2.2 a description...
follows of the implementation of a HABVIP 2-agent controller in the Triphase industrial computers. Finally, in section 9.2.3 the interfacing between the two devices is discussed.

9.2.1 RTDS

The Real-Time Digital Simulator is a multi-processor based machine specially dedicated for real-time power system studies of electromagnetic transients. With the RTDS, Hardware-In-the-Loop simulations can be performed for testing protection and control equipment. In order to realize this, the RTDS has multiple interfacing possibilities such as analogue and digital inputs and outputs. For smart-grid control, cards are available to communicate with models of power system components within the RTDS via the IEC 61850 and IEEE C37.118 protocols. However these are not used in the present set-up, where interfacing is achieved via analogue signals.

9.2.1.1 RTDS Hardware and Software

In this subsection an overview is given of the components of the RTDS system owned by the Delft University of Technology (TU Delft) that are relevant to the demonstrator. More details of this particular RTDS are given in appendix H and a detailed description of the RTDS in general can be found at the website [167] or in the manual [166].

As stated before the RTDS is a multi-processor simulation tool. These processors are mounted on cards. The processor cards form modular building blocks which can be individually replaced when necessary. This modularity makes the RTDS flexible and future-proof: when new processor cards are developed, these new cards can be added to an existing configuration.

The RTDS of the Intelligent Electrical Power Grids group of the TU Delft contains two types of processor cards: triple Processor Cards (3PCs) and RISC Processor Cards (RPCs). The 3PCs have three ADSP-21062 Digital Signal Processors (DSPs) which require 25 ns per instruction cycle. On the 3PCs there are direct analogue and digital interface possibilities for the connection of external hardware.

The RPCs contain two IBM PPC750CXe PowerPC processors. These processors are faster than the ones of the 3PCs: they need only 1.67 ns per instruction cycle. RPCs have, however, no direct interface possibilities.

The processor cards are assembled in racks. Within one rack the processor cards communicate via a backplane. In addition to the processor cards a rack contains communication and interface cards.

Each RTDS rack at the TU Delft contains two communication cards: one Inter-Rack Communications card (IRC) and one Workstation InterFace card (WIF).

The IRC establishes bi-directional communication with (a maximum of) six other racks. In this way multiple racks can be used to simulate a large grid. This use of multiple racks has, however, a limitation: inter-rack communication takes 50 µs. The traveling time of the electromagnetic transients between two substations should be equal or larger than these 50 µs. In practice this means that when the two subsystems are interconnected via an overhead line, the distance between these subsystems should be at least 15 km. In case of a cable this distance is shorter because of the larger capacitance.

The WIF establishes communication between a rack and a workstation. The workstation is a normal Personal Computer (PC) containing the RSCAD program. In the DRAFT module of this software a power system can be assembled based on blocks in a library containing power system components and control blocks. If required, custom components can be developed in the C-language. The DRAFT module compiles the network so that it can be used by the processor cards. During compilation the assignment of processors can be done manually, but this can also be left to the compiler.

In the RUNTIME module of the software, the compiled system can be sent to the RTDS and the simulation is started. This module of the software uses the WIF. In runtime, interaction with the RTDS is possible: reading of graphs and meters can be performed in real-time, settings can be adjusted and circuit breakers can be operated.

In addition to communication with the workstation the WIF takes care of synchronization. This synchronization is required when data is exchanged between racks and when data from multiple racks is plotted in
one graph. A fiber optic link between the WIFs interconnected via a Global Bus HUB (GBH) takes care of this when the two racks are not directly interconnected.

The RTDS racks are placed in cubicles. A cubicle can contain one or more racks and an RTDS system can be built up of multiples of these cubicles. The full RTDS system can be used to simulate one large power system, but all racks can also be used individually for the study of smaller systems. The RTDS system is thus highly flexible.

For interfacing, the RTDS has several possibilities additional to the ones directly available at the processor cards. For the demonstration set-up DDACs and OADCs are used. The DDAC is a 12 channel Digital-to-Analogue converter (input) and the OADC is a 6 channel Analogue-to-Digital converter (output). Both cards can be connected to a processor card via a fiber optic link and are assigned to a specific processor.

The RTDS of the TU Delft consists of 8 racks divided over 4 cubicles. An overview of the complete system is given in appendix H. With this RTDS configuration it is possible to simulate a power system up to 144 three phase nodes in real-time.

9.2.1.2 Network implementation

As test system the system of figure 9.2 is used. This system is a slightly modified version of the system proposed in [99, 185]. Note that the system is also used in the previous chapters.

The basic RTDS model of this system was provided by the support team of RTDS Technologies. There are two important differences between this model and the model used in the previous chapters:

1. The data of the test system are as provided by RTDS Technologies. This data is given in appendix I. Because the goal of the real-time demonstration model is to prove that the HABVIP controller can be used in a real-time environment, and not to compare simulation results in Matlab/Simulink and RTDS, no effort was put into making the models identical. The maximum field current is, for instance, limited in this model to 3.02 pu.

2. The line between buses 7 and 8 is converted into a double circuit. The impedance of each line of this double circuit is twice the impedance of the original single circuit. So the equivalent impedance ($R_{eq} + jX_{eq}$) of the double circuit is equal to the impedance of the original single circuit.

Note that the double circuit line was also used in the proof of concept of chapter 8. In the demonstrator, however, no VPP and SVC are present. The models as used in this chapter and the model used in chapter 8 should thus be considered as separate models.

Interfacing between the RTDS and the control system is done via the DDAC and OADC cards using analogue signals. A more detailed discussion about the interfacing will be given in section 9.2.3. The number of analogue inputs and outputs is limited. For that reason the test system is divided among two racks: racks 7 and 8.

The split is made between buses 5 and 6. The transmission line between these two buses is 200 km so the 50 $\mu$s communication delay is no problem. Rack 7 contains the system at the right side of the transmission corridor and rack 8 contains the system at the left side of the transmission corridor.

For demonstration purposes in two other racks (5 and 6) the test system is duplicated, but no HABVIP control is connected to this system. In this way the HABVIP controller can simultaneously be compared with the case without emergency control. The reference system could have been implemented in one rack only. This would, however, cause some timing errors for the command signal to trip a line. This timing in the reference system would be different from the one in the system with HABVIP control resulting in a small deviation in performance, therefore it was decided to split the implementation of the system without HABVIP control over two racks as well.

9.2.2 Triphase machines

The Triphase systems are flexible power converters especially designed for rapid prototyping of motor drives, power amplifiers, micro grids etc. [108]. Furthermore off-the-shelf modules can be bought that can be used for all kinds of digital and analogue interfacing. The modular design makes it possible to add or remove components easily (both power electronics and interfacing modules).
9.2 Test set-up

9.2.2.1 Triphase Hardware and Software

This subsection contains a description of the relevant aspects of the Triphase converter system. More information is given in appendix [11] or can be found at the Triphase company website [194] or in the tutorial [193].

A schematic overview of a Triphase converter system is given in figure 9.3. The system consists of one real-time target PC and one or more power electronic converters. In addition, digital and analog input/output (I/O) devices can be connected to the system.

The target PC is an industrial computer with Linux as operating system. It executes all control loops. The target PC communicates with the power electronic converters via an internal fieldbus and with the external I/O devices via an EtherCAT fieldbus. The control algorithm itself is built in Matlab/Simulink and converted to C-code via Matlab’s Real-Time Workshop [190]. This program runs on a separate workstation and the C-code program is sent via Ethernet to the target PC. Via this workstation it is also possible to interact with the control loop in real-time.

The Triphase machines at TU Delft contain two types of input devices, the Beckhoff EL3102 and EL3104, and one type of output device, the Beckhoff EL4132. These devices are respectively Analogue-to-Digital

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**Figure 9.2.** Modified simulation model as used for the proof of concept. Source original model: [99, 185].

**Figure 9.3.** Schematic overview Triphase converter system.
converters and Digital-to-Analogue converters. The reason for having two different types of input devices lies in the fact that the devices were bought in different stages of the set-up development.

TU Delft owns two Triphase converter systems. One is referred to as 'Nexcom' and the other one is referred to as 'Babelehr'. The number of I/O devices connected to each machine is customized for the application.

### 9.2.2.2 HABVIP controller Implementation

The HABVIP control for the test power system of figure 9.2 that is implemented in this real-time demonstration set-up has three actuators which can be controlled:

- The active power of GEN3.
- The load at bus 10.
- The LTC between buses 8 and 9.

The control as implemented in the demonstration set-up is thus a simplified version of the one that was used in the proof of concept of chapter 8. The target PCs of the Triphase machines are used to emulate the HABVIP control. In 'Nexcom' the substation agent controlling the substation consisting of buses 3, 6, 7 and 10 is implemented. As discussed in chapter 8 this agent is called A6. In addition to this, the actor agent control of GEN3 and the load control of the load at bus 10 are implemented in 'Nexcom'. The Matlab/Simulink block scheme of this control is given in figure 9.4. Note that in this scheme also substation agent A5 is shown. In the hardware implementation A5 is only used to perform phasor measurements.

In 'Babelehr' the substation agent controlling the substation consisting of buses 8 and 9 is implemented. As discussed before this agent is called A9. In addition to this, the actor agent control of the LTC is implemented in 'Babelehr'. The Matlab/Simulink block scheme of this control is given in figure 9.5. Substation agents A6 and A9 are the only substation agents that are implemented in hardware. Based on the extensive simulations of chapter 8 it is known that the other substation agents will not act for the specific disturbance simulated. Furthermore the resources to implement these agents were limited as there are only two real-time target PCs available.

An overview of the control functions implemented per substation agent is given in table 9.1. As discussed in chapter 8 not all functions that were defined for the substation agents are implemented (see figure 5.8) and only the control blocks that are needed for the particular substation are implemented.
Figure 9.5. Schematic overview of the control implementation in Babelehr (agent A9).

Table 9.1. Implemented substation control blocks per substation.

<table>
<thead>
<tr>
<th></th>
<th>A6</th>
<th>A9</th>
</tr>
</thead>
<tbody>
<tr>
<td>Communication Higher Level Substations</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Phasor Measurement Unit</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Communication Neighboring Substations</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Detection</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>MLI-control</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>P-control</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Q-control</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lower DG</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Agent Coordination</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Coordination Actuators P-control</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Coordination Actuators Q-control</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aggregation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coordination gen control</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coordination LTC control</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coordination Load control</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coordination Q-control</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Actuator Exclusion</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Communication Lower Level Substations &amp; Actuators</td>
<td>X</td>
<td>X</td>
</tr>
</tbody>
</table>
Table 9.2. Parameters for the substation agents of the HABVIP controller.

<table>
<thead>
<tr>
<th></th>
<th>A6</th>
<th>A9</th>
</tr>
</thead>
<tbody>
<tr>
<td>$MLI_{ref}$</td>
<td>1.58</td>
<td>1.58</td>
</tr>
<tr>
<td>$k_p$</td>
<td>0.8</td>
<td>0.97</td>
</tr>
<tr>
<td>$k_l$</td>
<td>0.2</td>
<td>0.03</td>
</tr>
<tr>
<td>$T_{gen}$</td>
<td>10 s</td>
<td>N/A</td>
</tr>
<tr>
<td>$T_{LTC}$</td>
<td>5 s</td>
<td>N/A</td>
</tr>
<tr>
<td>$\Delta</td>
<td>I_{ld,lim}</td>
<td>$</td>
</tr>
<tr>
<td>$MLI_{reset}$</td>
<td>1.68</td>
<td>1.68</td>
</tr>
<tr>
<td>$T_{reset}$</td>
<td>30 s</td>
<td>30 s</td>
</tr>
</tbody>
</table>

Table 9.2 lists the parameter data that is used for the controllers in the substation agents. Note that because the test system differs from what is used in chapter 8 there are also differences in the parameters adopted of the controllers. Apart from some small differences, which are due to some minor fine-tuning, the differences are:

- The time constant of the LTC control ($T_{LTC}$) is adapted to match the time constant of the LTC that is used.
- Because substation agent A9 can only control the LTC, the time constants $T_{gen}$ and $T_{LTC}$ are not used as they do not serve their purpose. Furthermore, to prevent unnecessary integration during the delay in LTC operation, $k_p$ and $k_l$ of A9 are tuned in such way that the integral action becomes smaller.
- The $k_p$ and $k_l$ of A6 are chosen in such way that the integral action is smaller, preventing the controller to become reactive.

In appendix I the data of the actuator agents is given.

9.2.3 Interfacing

The RTDS and both Triphase target PCs exchange information. This signal exchange is done via an analogue interface. The main reason for this is that both, the RTDS and the Triphase systems at TU Delft, have no suitable digital communication cards. Note that for the interface between the RTDS and the Triphase machines the use of analogue signals is realistic because these signals will in reality be obtained via measurements. A detailed overview of the signals that are exchanged is given in figure 9.6.

For the output signals of the RTDS the DDAC cards are used. Both racks that are used (racks 7 and 8) have one such a card. So the number of analogue outputs is limited to 12 per rack. For the input signals into the RTDS the OADC card is used. Only rack 7 has such a card. For that reason the load area of the test circuit is modeled in this rack. As shown in chapter 8 this part of the system is the only one that requires inputs from the control system. The number of inputs is limited to six.

For the output signals of the Triphase machines, Beckhoff EL4132 devices are used. Both machines have three of these devices and can consequently send 6 signals each. As input devices the machines have a combination of Beckhoff EL3102 and EL3104 devices. With the given configuration ‘Nexcom’ has 16 inputs and ‘Babelehr’ has 8 inputs. Via an Unshielded Twisted Pair (UTP) cable the devices are connected to the rest of the Triphase equipment.

The analogue channels are suitable for signals of $\pm 10$ V, so the signals that are exchanged between the different devices should be properly scaled. For this scaling the signal-to-noise ratio was kept as large as possible. However, some measures can be either small or large. In these cases the scaling could not be chosen for an optimal signal-to-noise ratio and the scaling had to be adapted to cover the largest possible value of the signal. The scaling of the different signals is summarized in table 9.3.

For voltages and currents, the instantaneous value of one phase is sent to an analogue output. This instantaneous value is converted within the substation agents to a phasor with the help of a phase locked loop. The reason for doing this, instead of sending the magnitude and phase angle of the phasor directly, is that
Figure 9.6. Signal exchange in the RTDS-Triphase demonstrator. In this figure $U$ and $I$ are the bus voltages and currents; $I_{fd}$, $\omega_{mech}$, and $T_{\text{ref}}$ are GEN3’s field current, rotor angular frequency and torque reference; $P_{\text{ref}}$ is the reference for the load power; $U_{\text{ref}}$ is the LTC’s voltage reference; and Control, Space, and Done are the control signals that are exchanged between the agents.

Table 9.3. Scaling of the different signals that are exchanged. These scaling factors define for each signal to which value 1 V at the interface corresponds to.

<table>
<thead>
<tr>
<th>Signal</th>
<th>Scaling factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>BUS 3 $U$</td>
<td>2.64 $\sqrt{2/3}$ kV</td>
</tr>
<tr>
<td>BUS 3 $I$</td>
<td>20 kA</td>
</tr>
<tr>
<td>BUS 5 $U$</td>
<td>100 $\sqrt{2/3}$ kV</td>
</tr>
<tr>
<td>BUS 5 $I_{5-6}$</td>
<td>2 kA</td>
</tr>
<tr>
<td>BUS 6 $U$</td>
<td>100 $\sqrt{2/3}$ kV</td>
</tr>
<tr>
<td>BUS 6 $I_{5-6}$</td>
<td>2 kA</td>
</tr>
<tr>
<td>BUS 7 $U$</td>
<td>23 $\sqrt{2/3}$ kV</td>
</tr>
<tr>
<td>BUS 7 $I_{7-8}$</td>
<td>20 kA</td>
</tr>
<tr>
<td>BUS 8 $U$</td>
<td>23 $\sqrt{2/3}$ kV</td>
</tr>
<tr>
<td>BUS 9 $U$</td>
<td>2.76 $\sqrt{2/3}$ kV</td>
</tr>
<tr>
<td>GEN3 $I_{fd}$</td>
<td>0.4 pu</td>
</tr>
<tr>
<td>GEN3 $\omega_{mech}$</td>
<td>0.2 pu</td>
</tr>
<tr>
<td>A6 Control</td>
<td>20 MW</td>
</tr>
<tr>
<td>A9 Space</td>
<td>60 MW</td>
</tr>
<tr>
<td>A9 Done</td>
<td>60 MW</td>
</tr>
<tr>
<td>GEN3 $T_{\text{ref}}$</td>
<td>0.2 pu</td>
</tr>
<tr>
<td>LTC $U_{\text{ref}}$</td>
<td>0.2 pu</td>
</tr>
<tr>
<td>Load $P_{\text{ref}}$</td>
<td>7.5 MVA</td>
</tr>
</tbody>
</table>
the latter would require two signals per voltage (or current) instead of one and the maximum number of input and output signals would be exceeded. As voltage stability problems are typically balanced problems, using one phase instead of three in the calculations will not influence the results.

All wires used for the analogue signals are twisted with a different number of twists to prevent electromagnetic coupling between the wires. The 60 Hz signals that correspond to the voltages and currents could otherwise interfere with other signals.

The limited number of inputs and outputs has forced another simplification: voltages and currents at neighboring substations are measured directly instead of received from the substation agent controlling the particular substation. Furthermore the current of line 7-8 is measured at one end of the line because the measurement from the other end of the line will be identical.

Two final remarks should be made about the data acquisition of the control system. First of all this data acquisition is real-time. It may happen due to various reasons that one capture of the signals is missed. In Nexcom this problem occurred several times due to the large number of signals that are measured. In order to prevent problems initiated by this, critical signals are rate-limited. In the case of MLI for instance, the slew rate is set to $+0.5$ s$^{-1}$. This prevents a sudden change in the control signal when a capture is lost.

The second remark concerns the fact that analogue communication is used. There is always some noise in the channels. The control signal to the LTC is influenced by this. Even when no control signal is required, there is some signal present due to noise. This is solved by applying a deadband to the signal. Only signals that are larger than 0.5 MW are sent through.

### 9.3 Results

With the real-time demonstration model two tests are performed. In the first test one of the lines between buses 5 and 6 trips (see figure 9.2). The results of the system with and without the proposed emergency control are compared.

The second test continues where the first test stops, so initially one of the lines between buses 5 and 6 is out of service. In this test it is investigated what happens when subsequently also a line between buses 7 and 8 trips. This additional event was introduced to highlight the coordination function among agents.

Note that the disturbance tests with the real-time demonstration model are the same as the tests applied in chapter 8. Despite the small differences in the data of the simulation model, a similar result is expected. The added value of the tests in this chapter is that the agent-based control is implemented in an external piece of hardware.

#### 9.3.1 Result for a trip of a line between buses 5 and 6

The result of the first case study, where at $t = 10$ s one of the five parallel transmission lines of corridor 5-6 trips, is shown in figures 9.7, 9.8, 9.9 and 9.10. Figure 9.7 gives the bus 6 and 9 voltages for the system without and with HABVIP control (note that in the case without HABVIP control the normal local controllers, like generator AVR and LTC voltage control, are available). Figure 9.8 shows the MLI, the local coordination signal (AC) and the required amount of load relief determined by the agents A6 and A9. Figure 9.9 gives an overview of the power available for load relief and the amount of load relief requested per actuator group. Because the amount of load relief requested from the LTC and the load at bus 10 is very small compared to the power available for load relief from these two actuators, in figure 9.10 a detailed view is given.

Following the trip of the line the bus 6 and 9 voltages drop (figure 9.7). The MLIs of both transmission corridors drop as well (upper graph figure 9.8). The decrease in the MLI of the corridor 5-6 is more severe than the drop in MLI for the corridor 7-8. Both values stay, however, above the threshold value of 1.58.

The LTC restores its secondary voltage (bus 9, lower graph figure 9.7). This is at the cost of the primary voltage and with each change in LTC tap position, the value of the MLIs reduce (upper graph figure 9.8). Each change in tap position also has its impact on the amount of load relief the generator has available for control (upper graph figure 9.9). This is because with each change in tap position the field-current of the generator increases and is operated closer to its maximum current limit.
Figure 9.7. Bus 6 voltage (upper graph) and bus 9 voltage (lower graph) for the case without (dashed lines) and with (solid lines) the HABVIP controller.

At $t \approx 65$ the $MLI$ of corridor 5-6 drops below the threshold. This triggers the control activation of agent A6 (middle graph figure 9.8). At this point the behavior of the system with and without HABVIP control start to differ.

For the system with HABVIP control A6 determines the amount of load relief that is required to restore stability (lower graph figure [9.8]) and divides this among the three actuator groups (figures 9.9 and 9.10). Because load relief is also requested from the LTC, this transformer stops with the restoration of the secondary voltage. In the reference system the LTC keeps trying to restore the secondary voltage. For every change in tap position, a larger amount of field current is required from GEN3. At $t \approx 170$ the Overexcitation Limiter (OXL) of GEN3 limits the field current and the system starts to deteriorate in the case without HABVIP control.

In the case of the system with HABVIP control, it takes some time for the generator control and LTC control to become effective. Hence, in the beginning, load control is applied for about 20 s (figure 9.10). After the generator and LTC have implemented their control, load control is reduced and approaches zero from about 90 s.

In conclusion the tests in this subsection show that with the proposed HABVIP controller voltage instability can be prevented and a real-time hardware implementation is feasible. Whereas in a system without HABVIP control the trip of one of the lines between buses 5 and 6 results in unacceptably low voltages, the control actions undertaken by the HABVIP controller make the voltages recover to acceptable values.
Figure 9.8. The MLI of two relevant corridors (upper graph), internal signal Agent Coordination (AC) (middle graph) and the total control signal (lower graph) as determined by agent A6 (solid lines) and agent A9 (dashed lines). The fluctuations in the control signal are due to noise in the measurements that determine this signal.
9.3 Results

Figure 9.9. The control signal (control, solid lines) and the power available for load relief (space, dashed lines) for GEN3 (upper graph), the LTC (middle graph) and the load at bus 10 (lower graph).

Figure 9.10. Detailed view of the control signal for the LTC (solid line) and the load (dashed line). The fluctuations in the control signal are due to noise in the measurements that determine the control signals.
9.3.2 Result for an additional trip of a line between buses 7 and 8

The second case study begins where the first case study ends. At $t = 210$ s (thus after stabilization of the voltage profiles following the first trip) also one of the lines between buses 7 and 8 trips. This additional event was introduced to highlight the coordination function among agents as implemented in this hardware set-up.

The result of this second case study is shown in figures 9.11, 9.12 and 9.13. Figure 9.11 gives the bus 6 and 9 voltages for the system without and with HABVIP control. Figure 9.12 shows the MLI, the local coordination signal (AC) and the required amount of load relief determined by agents A6 and A9. Figure 9.13 gives an overview of the power available for (virtual) load relief and the amount of load relief requested per actuator group.

As can be expected, the additional trip of the line results in a significant drop in bus 9 voltage (lower graph figure 9.11). As a consequence the voltage sensitive portion of the load at bus 9 reduces. This is positive for the problem between buses 5 and 6 because less load power needs to be transfered. This becomes clear from the bus 6 voltage of the reference system and the $MLI_{5-6}$ of the system with control (upper graph figure 9.12) as they both increase.

The trip of the line between buses 7 and 8 leads to a significant reduction of the $MLI$ of this connection (upper graph figure 9.12). This triggers the control of agent A9 (lower graph figure 9.12). The control signal that is required to solve this local voltage instability problem is larger than what is required to solve the problem between buses 5 and 6 and the internal Agent Coordination (AC) signal of substation agent A9 goes from zero to one. So A9 implements the locally determined control action (middle graph figure 9.12). Note that the signal AC of A6 is also still one and this agent requests load relief from A9. Because the amount of load relief that is required to solve the voltage instability problem of A9 is larger than the amount that is requested by A6, A9 ignores the request of A6.

Substation agent A9 has only the LTC as actuator. Because this LTC operates with a time delay (of 5 s in this case) it takes some time before the control action can take effect. Due to this, there is initially an overshoot in the control signal as the PI-loop keeps integrating while the $MLI$ is not brought back to a safe value (lower graph figure 9.12). When the LTC starts changing its tap position, the control signal is partly
Figure 9.12. The MLI (upper graph), internal signal Agent Coordination (AC) (middle graph) and the total control signal (lower graph) as determined by agent A6 (solid lines) and agent A9 (dashed lines). Note that because the control signal has a much larger value than was the case in figure 9.8, the signal-to-noise ratio is much better and no noise is observed.
Figure 9.13. The control signal (control, solid lines) and the power available for load relief (space, dashed lines) for GEN3 (upper graph), the LTC (middle graph) and the load at bus 10 (lower graph). Note that no load relief is requested from the smart loads.
released.

The increase in load relief from the LTC makes that the the field current of GEN3 reduces and the amount of power available for load relief from GEN3 increases (upper graph figure 9.13). It makes, however, no sense for the controller to use this extra available control because the main problem is now located between buses 7 and 8.

The control action of A9 and the load reduction due to the fact that the power transfer through the transmission corridor between buses 7 and 8 is limited, makes that the \textit{MLI} between buses 5 and 6 becomes larger than 1.68 (upper graph figure 9.12). As a consequence 30 s after its \textit{MLI} became ‘healthy’ A6 releases its control. The internal Agent Coordination signal AC becomes zero and no load relief is requested from GEN3 and the load at bus 10 (see figure 9.13). For substation agent A9 it is still required to request load relief and the AC signal of this agent stays one.

In conclusion the tests in this subsection show that the coordination among multiple substation agents works as expected. If at a lower level voltage instability is detected, the lower level agent implements the largest of two control actions. The PI-loop ensures that if at a lower level a larger control action is implemented than requested at a higher level, then the control at the higher level is balanced (i.e. accordingly reduced).
9.4 Discussion

In this chapter the proposed HABVIP controller is implemented in a real-time demonstration set-up. The tests show that a hardware implementation of the HABVIP controller is feasible and during the implementation no major bottlenecks have been noticed. There are, however, some points for discussion.

First of all the signal exchange between the RTDS and the target PCs is done by means of analogue signals. Furthermore the communication between substation agents is also performed with analogue signals. The scaling of the signals is chosen in such a way that the signal-to-noise ratios are as good as possible. An important limitation is, however, that the signal should stay within ±10 V under all conditions. This limitation prevents in some cases the use of an optimal signal-to-noise ratio: this 10 V should correspond with the largest possible signal, but this largest possible signal may deviate from the signal levels that are commonly in use. This problem can be partly solved by applying a digital filter.

The analogue interface could also be replaced in a new version of the demonstrator. The communication between the target PCs could be established by a proxy fieldbus which uses an Ethernet connection (a special license is required for this). Furthermore the interfacing with the RTDS could be established via Giga-Transceiver Network Communication Cards which support the IEC 61850 and IEEE C37.118 protocols. It is recommended to first investigate how the target PCs can communicate with these cards before purchasing them.

An important remark regarding the control has to do with the overshoot in the control signal for the second case study. The LTC needs some time before a requested control signal is implemented. Because of this, the initial deviation between the MLI and its reference is integrated by the PI-loop. After some time (5 s in this case) the LTC starts changing its tap position and the MLI comes closer to the reference and the overshoot in the control signal reduces. Finally, the control signal stabilizes to a value that corresponds to a value of the MLI that is only a little bit higher than the reference. With multiple actuators this overshoot will probably be reduced.

A future step could be to integrate the real-time demonstration model with the DENlab [159, 208]. In this set-up the RTDS is still used for simulating the higher level network. The DENlab can be used to emulate the low voltage network. The agent control can still be performed by the target PCs of the Triphase converters. For this it is necessary that a connection between DENlab and the RTDS is established.

One final more general remark about voltage instability should be made. This type of instability is often seen as a system-wide problem. In this thesis, nevertheless, a local approach is taken. The simulations of chapter 8 and the tests in the current chapter show that the voltage instability problem starts locally and when it is detected in time it can also be solved locally. In the tests with the additional trip of a line between buses 7 and 8 (section 9.3.2) it is also shown that the initiation of a potential second voltage instability problem can be beneficial for a first voltage instability problem is a large component of the load is voltage-sensitive.

9.5 Conclusion

In this chapter the proposed HABVIP controller is implemented in a real-time demonstration set-up consisting of a Real-Time Digital Simulator that is used for emulating the test system and the real-time industrial computers of a Triphase converter system that are used to implement the agent control. This approach goes one step further than the off-line simulations performed in chapter 8 because the control system is implemented in real hardware and interfacing between the different distributed entities is required. In this way it can be determined whether a hardware implementation is feasible for industry and possible bottlenecks in such an implementation can be investigated and solved. The next step could be the implementation of the HABVIP controller in a pilot set-up. This is, however, out of the scope of this thesis.

The tests with the demonstrator show that a hardware implementation of the HABVIP controller and that with the system voltage instability can be prevented. Based on the tests it can be concluded that there are no important bottlenecks for industrial implementation. Whereas in a system without HABVIP a trip of a transmission line initiates a deterioration process that leads to unacceptably low voltages, the control actions undertaken by the HABVIP controller make voltages restore to acceptable values. The coordination
among substation agents is highlighted. The local character of the agent control and the possibility of cooperation make that local voltage problems are solved locally before they spread.
Chapter 10

Conclusion and Recommendations

In this chapter the main conclusions of the work performed for this thesis are given (section 10.1) and recommendations are given for future research and implementation of the HABVIP controller (section 10.2).

10.1 Conclusion

Blackouts have a significant influence on society and the objective of power system planning and operation is to prevent them. Because voltage instability is one of the power system dynamic phenomena that may result in a system-wide blackout, this type of stability problems have been an important research topic for many years. Voltage stability problems appeared in the 1970s in large interconnected power systems for the first time. The main cause of this type of instability is the load dynamics that try to restore the power consumption beyond the capabilities of the combined transmission and generation system. Grid developments, like the increase of Renewable and Distributed Generation (DG) and the impact of deregulation, in combination with the steadily increasing electricity demand, will continue to influence the flow of electricity in the power system which has its impact on the power system’s voltage stability. On the other hand, developments in power system monitoring and control such as the use of accurate Phasor Measurement Units and the development of Smart Grid control concepts, introduce new possibilities for voltage instability prevention. The objective of this thesis was:

To develop a new control strategy to prevent voltage instability in a power system by making effective use of decentralized control possibilities, accurate phasor measurements and renewable and distributed generation.

To reach this goal, two preparation steps are taken: a method to detect voltage instability is chosen and the impact of DG on voltage instability is investigated.

Voltage Instability Detection

In chapter 3 two voltage instability indicators are chosen that are used in this thesis. The first indicator is used for off-line evaluation of the post-fault steady-state. It is based on the bus voltage magnitude and corresponds to the first definition of voltage stability which states that the system is voltage stable when all voltages in the system are steady and acceptable during normal operation and after being subjected to a disturbance [99]. Voltage magnitudes are related to the effect of voltage instability. For on-line detection and control the indicator is, however, less suitable. In a highly compensated system the voltages can still be acceptable when the system is actually operated close to the point of collapse. The second indicator is the Maximum Loadability Index (MLI) [212]. This indicator is a measure for the distance of the current operating point to the point of maximum power transfer. This indicator follows the second definition of voltage (in)stability which states that voltage instability stems from the attempt of load dynamics to restore power consumption beyond the capability of the combined transmission-
Conclusion and Recommendations

The indicator is based on the cause of instability and suitable for on-line detection and control, because from the MLI a direct control measure can be derived. In order to make the MLI more generally applicable, in chapter 3 an extension for the standard MLI is proposed, which includes an on-line parameter estimation method based on PMU-measurements. The method determines the equivalent line parameters of a connection between two adjacent buses. With this extension the MLI can be determined for each connection between two adjacent buses, and topology changes are immediately followed.

The MLI is based on a simplified transmission line (or cable) model and neglects line shunt capacitances. It is theoretically derived what the influence of these measures is on the estimated parameters. Furthermore it is proven that in the MLI computation these influences cancel, so ignoring shunt capacitances has no effect on the accuracy of the MLI.

Simulations show that both indicators are able to detect voltage (in)stability in a power system. The extension to the MLI works properly. The error that is measured in this estimation method equals the theoretical error introduced by neglecting the shunt capacitances. These simulations furthermore prove that the determination of the MLI should be conditional: the direction of the power-flow should be determined first and based on this the sending-end and receiving-ends are established.

Since the MLI computation only needs information from local measurements and neighboring buses, it fits well in the HABVIP controller that was proposed in chapter 5.

Impact of DG integration on Voltage Stability

Based on the detection methods, in chapter 4 the impact of DG on voltage stability at transmission network level has been investigated. Two studies are done. In the first study generic types of DG are connected to load buses. It is assumed that the prime-mover supplies a constant amount of power. It is investigated for which percentages of DG penetration the system stays voltage stable after a severe disturbance (trip of one of the transmission lines between the generation and load area). Without DG this severe disturbance initiates a collapse.

The conclusions of the first case study can be summarized as follows:

- **DGs based on Synchronous Generators (SG)** are generally beneficial for voltage stability. For relatively small sizes of the generators a collapse can be prevented and unacceptable low voltages can be avoided. A SG with an Automatic Voltage Regulator (AVR) is favorable over the case of a SG without AVR.

- For **DGs based on directly connected Induction Generators (IG)** the merit for voltage stability is highly dependent on the reactive power compensation. A relatively higher amount of reactive power compensation is required in the case the IG should prevent voltage instability than what is required during steady state. For voltage stability the IG can best be compensated by means of a Static Var Compensator (SVC), because the SVC can provide variable reactance and hence voltage control via closed-loop feedback.

- By means of a **Voltage Source Converter (VSC)** interface, a DG can be decoupled from the grid. These VSC interfaced DGs are generally beneficial for voltage stability. For relatively small sizes of the generator a collapse can be prevented and unacceptable low voltages can be avoided.

In the second study a wind farm was connected in the load area. The wind farm contains turbines of the Doubly-Fed Induction Generator (DFIG) type and is connected via an High-Voltage Direct Current (HVDC) link to the test system. Two cases are distinguished. In the first case the wind farm is used in addition to the conventional local generation. It is determined for which rated power of the wind farm the power system stays voltage stable after a severe disturbance (trip of a transmission line). This case is similar to the first study. The main difference is that the produced power varies with the wind speed. In the second case the wind farm replaces part of the local generation. It is investigated for which reductions in wind speed the system becomes voltage unstable. The conclusions of the second case study are:
• For wind farm in addition to the local generation only a little higher penetration is required than in the case of the full converter with constant prime-mover (mentioned above in third bullet) to prevent voltage collapse and unacceptable low voltages.

• Unacceptably low voltages can in a theoretical case be introduced by a dip in wind speed of 75%. Such a dip in wind speed is, however, unrealistic.

Three factors are of most importance for the impact a DG can have on voltage stability: active power support, reactive power consumption, and voltage support. An intelligent controller can make use of the positive factors (active power and voltage support) to prevent a system from reaching a voltage unstable situation. Furthermore if a DG consumes reactive power, an intelligent controller can reduce the negative impact by providing adequate compensation. Note that whether active power support can be provided when requested is dependent on the prime-mover technology.

Hierarchical Agent-Based Voltage Instability Prevention

Based on the results of chapter 4 a controller is designed. The control strategy and architecture are proposed in chapter 5. The emergency control method uses the MLI to detect voltage instability and quantify the amount of load relief required to restore stability with a certain margin to instability. The load relief is obtained by: increase of local generation, indirect load shedding with LTC action, smart load control and the increase of the reactive power compensation with Static Var Compensators.

The control strategy requires coordination of control actions at three different levels. First of all there is coordination among active power load relief and reactive power compensation. Coordination at this level is established by the power factor of the transferred complex power. For the active power control actions the control signal should be divided among different actuator classes. This is done based on priority levels: local generation, LTC control, and load control are employed, in this order. For the reactive power control only one actuator group is defined in this thesis. The final level of coordination is the coordination of actuators within the same actuator class. To keep the relative control space for all actuators the same, this coordination is done based on weights determined by the power available for load relief.

The control strategy is implemented in an agent-based system which was called the Hierarchical Agent Based Voltage Instability Prevention (HABVIP) controller. In this system each substation is controlled by a substation agent and every actuator is controlled by a so-called actor agent. Among the agents there is a hierarchical structure: actor agents are supervised by substation agents and between the substation agents the classical power system hierarchy, based on voltage levels, is being followed. Determination of the MLI's is done by all substation agents based on the local measurements and the measurements received from neighboring substations. As soon as voltage instability is foreseen, all substation agents detecting this, will cooperate. This cooperation is supervised by the substation agent highest in hierarchy sensing the problem: the so-called supervisory agent.

The supervisory agent determines the amount of load relief necessary to obtain voltage stability. The lower level agents are requested to aggregate the amount of load relief they can provide divided per actuator class and communicate this to the supervisory agent. The supervisory agent subsequently calculates the amount of load relief each actuator class should provide. The lower level agents then divide this signal among their actuators and the substations one level lower in hierarchy.

The control of the SVC and the smart (flexible) load is briefly described in chapter 5 when introducing the HABVIP controller. The control of the LTC and the local generation is described in more detail in two separate chapters.

In chapter 5 the control strategy for the Load Tap Changer is introduced and implemented in an actor agent. The control consists of three parts: the part that controls the device in order to obtain the required amount of load relief; the part that determines the power the device has available for indirect load relief; and the part that calculates the actual obtained amount of indirect load relief.

The control strategy for the LTC is based on the fact that its secondary voltage is controllable. Normally the LTC tries to keep the voltage near nominal value. When the voltage is, however, reduced, voltage sensitive loads will also be lowered. In this way it is possible to shed load indirectly by lowering the secondary voltage. For doing this, based on a ZIP (constant impedance, constant current and constant power) load
model a new voltage set-point for the secondary voltage is calculated to obtain a certain amount of indirect load shedding. It is shown, based on simulations, that the proposed method works properly. An error in the actual power that is indirectly shed is, however, introduced due to the fact that the LTC controls its tap setting in discrete steps. The magnitude of this error is highly dependent on the position of the set-point voltage within the deadband: if the set-point voltage is at a level where the tap just does not change, the error is large; if the set-point voltage is at a level where the tap just changes the error is small. The error is limited by a theoretical maximum and can be diminished with appropriate settings in the PI-loop of the HABVIP controller.

The control of the LTC is based on a load model. The accuracy of the parameters of this load model determine the accuracy of the indirect load shedding method. A sensitivity study is done for the different load model parameters. Generally it can be concluded that the deviation in any parameter does not influence a relative error in the amount of load to be shed as long as the deviation does not introduce a step in the tap setting. This highlights the importance of the error due to the LTC’s discrete behavior.

In chapter 7 the control strategy is proposed for Combined Heat and Power (CHP) based local and decentralized generators. The decentralized and local nature of these generators make them especially suitable to be used as actuator in the proposed HABVIP control. For the CHP-based DG the active power is controlled. The increase in output power of a CHP results in an increase in temperature of the space that is heated. In the controller customers can set a maximum rise in average temperature.

Two types of CHP units are discussed: the thermostatically controlled unit and the continuously controlled unit. In case of the thermostatically controlled unit the average output power is controlled by adjusting the duty-cycle. The unit either supplies nominal power or nothing. The HABVIP controller, however, should rely on continuous power production. In the chapter it is shown that with a proper Virtual Power Plant coordination of the micro-CHPs, constant power supply can be assumed on an aggregated level.

In case of the continuously controlled unit the electrical output power is increased by adjusting the mechanical power of the prime-mover. The control per electrical generator type differs. Two types are distinguished in this thesis: the synchronous generator and the induction generator. The control of continuously controlled CHP units with both types of generators are discussed.

The proposed DG-control was verified by means of simulations and it was concluded that it works as expected.

Proof of Concept via Simulations and Hardware-In-the-Loop demonstration

In chapter 8 a verification of the performance of the HABVIP controller was given based on simulations in Matlab/Simulink. It was investigated which actuators play a major role in this system. Subsequently the influence of communication delays and having multiple LTCs that are not all controlled by the HABVIP controller have been investigated. By means of a sensitivity analysis it was determined which parameters of this HABVIP controller are important to tune to obtain an optimal result. Furthermore this system was compared to two traditional voltage instability controllers: Under Voltage Load Shedding and LTC tap blocking.

It can be concluded that the HABVIP controller works properly: voltage instability can be prevented with the system and coordination between agents works as expected. The local generator actuator class is the main contributor to the good performance of the system.

Communication delays and uncontrolled LTCs have no major impact on the system performance. The sensitivity analysis showed that the tuning of three parameters is of major importance for the HABVIP controller: the time delay in LTC control ($T_{LTC}$), the reference value of the $MLI$ ($MLI_{ref}$) and the safety margin of the generator’s field current ($\Delta I_{fd,lim}$). The other parameters can be chosen by intuitive reasoning. Furthermore, it is shown that the HABVIP controller performs better than the two traditional controllers.

In chapter 9 the HABVIP controller is implemented in a real-time demonstration set-up consisting of a Real-Time Digital Simulator that is used for emulating the test power system and the real-time industrial computers of a Triphase converter system that are used to implement the agent-based control. The tests with the demonstrator model show that a hardware implementation of the HABVIP controller is feasible and that with the system voltage instability can be prevented. During building the demonstrator set-up no
important bottlenecks for industrial implementation were discovered. Whereas in a system without HAB-VIP a trip of transmission lines initiates a deterioration process that leads to unacceptably low voltages, the control actions undertaken by the HABVIP controller make voltages restore to acceptable values. The local character of the agent-based control and the capability of cooperation make that local voltage problems are solved locally before they spread.

10.2 Recommendations

Despite the 205 pages of the thesis, at the moment one comes at the end of a PhD-project and reflects on the research, one actually feels that they are still at the beginning. You made choices and are wondering what would happen if you had made different decisions; the scope of the thesis is limited and you actually would like to pay attention to some questions that are out of this scope; new research questions and points of view come up; and finally there are some practical points regarding the implementation of the research which you would like to pay attention to. What is now left for the researcher is to formulate some recommendations regarding these points. The most important ones of this thesis are given in this section.

Integral approach for implementation

The HABVIP controller is designed especially to prevent voltage instability. The system should, however, when implemented, be part of a larger power system monitoring, control and protection system. Examples of additional functionality for such a system include:

- Rotor-angle instability detection and control. For instance the method of [60] could be included.
- Frequency stability control.
- Power system protection. For instance the algorithms of [238] could be included.

The agent framework of the HABVIP controller can serve as basis for this integral system and future research should focus on how these functions can be included in the proposed control framework.

Tests on larger systems

The proof of concept based on simulations and the tests with the real-time demonstration model have given a lot of information about the behavior of the HABVIP controller. Both tests are, however, based on a small network. The reason for choosing this simple system is that it is well-known and transparent. An important recommendation for further research is to do simulations or perform real-time testing with a larger test network. These extra tests should determine how the system performance is affected when a large number of agents have to cooperate. When choosing a network it is especially important that the transmission, sub-transmission and distribution grids are all modeled. When this aspect is neglected the extra information the tests can provide about the interaction of a large number of agents will be limited. Another option could be to integrate the real-time demonstration model with the DENlab. In this proposed future system the RTDS is still used for simulating the higher voltage network. The DENlab can be used to emulate the low voltage network. The agent control can still be performed by the target PCs of the Triphase converters, but implementation in PCs with data-acquisition cards or in an opal-rt system is also an option. For this it is important that a connection between DENlab and the RTDS is established.

Comparison local control to ‘optimal’ system-wide approach

In the thesis a comparison is made between the proposed HABVIP controller and the classical local control strategies Under Voltage Load Shedding and LTC tap blocking. It would be interesting to make an extra comparison between the HABVIP controller and fully centralized control. This centralized controller should have all data available to provide an optimal control. The comparison in this case will be between the HABVIP controller with partial knowledge of the system and the case of an optimal controller.
An important remark should be made regarding the ‘optimal centralized’ control. This control has as major drawback that it requires information from the total power system. Subsystems of the power system are owned by different parties who most probably do not want to share too much confidential information. In the case of the HABVIP controller only a limited amount of data is transferred between entities and the data that is exchanged is standardized for every party. In addition a localized approach has the advantage that it limits the information any given agent has to manage; the centralized approach would result in a data explosion.

Security aspects

A very important aspect that should get more attention before implementing the HABVIP controller is security. First of all, in the proposed system a lot of entities exchange data. Dependent on the communication channel that is used (e.g. power line communication, an optic fiber connection, a wireless technology or the Internet) the data transfer is more or less vulnerable to cyber-attacks. In the best case these attacks just reveal confidential information, but in the worst case the operation of the system is influenced and e.g. load relief is requested while it is not required. This is not only an issue for the HABVIP controller, but for all smart grid control and wide area monitoring and control systems.

Both, power system engineers and computer engineers, have an important task in securing power system control. Power system engineers should design their controllers in such a way that the impact of a cyber attack is limited. Computer engineers should design algorithms and hardware to secure the data connection. Another security aspect is that because the HABVIP controller automatically decreases the risk for voltage instability, parties might become reckless. To prevent this, appeal of the prevention system by one of the parties should be charged. Because the HABVIP accurately identifies the location of a problem, logs of this system can help to determine what the source that triggered the operation of the HABVIP controller was and who has to pay. Note, however, that some may argue that the Transmission System Operator (TSO) should be charged for decreasing power quality by lowering voltage levels at the consumer nodes.

Interests of stakeholders for the HABVIP controller implementation

For the HABVIP controller there are several stakeholders with different interests. The most important ones will be producers, grid operators and consumers. Due to the envisioned large amount of DG that will be implemented in the future grid, the consumers will not only consume electric power but may also supply power. Some recommendations regarding the interests of the aforementioned stakeholders are given below. First of all, for all three the stakeholders it is important that a blackout is prevented. The choice between implementation of a control action or doing nothing is likely the choice between maintaining stability, with some discomfort due to the control action, or a blackout. So it is of interest to all parties that a control signal demanded by the HABVIP controller is implemented. It is, however, also important that the discomfort such a control action may cause is divided equally among parties.

An important share of the control actions will have impact on the consumers. DG owned by consumers should be controlled, their voltages can be lowered and even loads might be temporarily interrupted by the system. This will have an important impact because it means that they change from passive to active consumers (also known as prosumers). A different mindset is required and implementation of the HABVIP controller should provide a seamless transition. It should be prevented that consumers get a "big brother is watching you" idea. So consumers should be able to opt out (temporary) of the HABVIP control, as is the case in the proposed micro-CHP control. Furthermore it should be financially beneficial to participate in the HABVIP controller by for instance a discount in the electricity price for stand-by and a compensation each time the control is requested.

A large part of the HABVIP controller has to be implemented by grid operators. This is also the party responsible for the largest investments. As noted before, it is important that the the HABVIP controller should be integrated in a system with more functionality than voltage instability prevention only. So the investments should also be seen in a larger perspective. For this party the HABVIP controller is a tool for emergency control. With this tool it is also possible to identify the source of the problem after emergency control was addressed.
The last group of stakeholders for the HABVIP controller are the producers. These parties produce and sell electrical energy that is transported via the grid. This group of stakeholders have mainly the same interests as the consumers: they should be paid for stand-by and should be compensated each time the control is requested.

**Fundamental smart grid control research**

The research in this thesis is based on power system engineering knowledge. The HABVIP controller is developed based on knowledge of typical voltage instability scenarios. For a future research project on smart grid control it would be interesting to take a more fundamental approach based on distributed control system theory as for instance provided in [207] and apply it to the power system. This research could, potentially, lead to a basic theory for smart grid design.
Appendix A

Simulation Model Typical Voltage Instability Scenario

The diagram of the system used for simulation is given in figure 2.23. The sources of this system are the textbooks [99, 185]. The base values of the line-to-line voltages of the buses correspond to [185].

| Bus 1: 13.2 kV |
| Bus 2: 13.2 kV |
| Bus 3: 13.2 kV |
| Bus 4: 500 kV |
| Bus 5: 500 kV |
| Bus 6: 500 kV |
| Bus 7: 115 kV |
| Bus 8: 115 kV |
| Bus 9: 13.8 kV |
| Bus 10: 13.8 kV |

The base frequency of the system is 60 Hz. The system is modeled with the SimPowerSystems toolbox of Matlab/Simulink [80]. The original modeling was done in Release 2007b. The simulations with this model were done in release 2009b (except for the simulations in chapter 4).

Generators

The data of the generators is given in tables A.1 and A.2. In the subsequent subsections for each generator the model is described.

Generator 1

In accordance to [99,185], generator 1 represents the rest of the grid. The generator is modeled as an infinite bus. The Three-Phase Programmable Voltage Source is used. The variation is disabled. Parallel to Generator 1 a resistive load is connected. For this parallel load the Three-Phase Parallel RLC load model is used. Data is determined so that the load consumes about 10% of the generator power.

Generator 2

Generator 2 is modeled as a synchronous machine with speed governor and excitation system with Automatic Voltage Regulator and Power System Stabilizer.
Table A.1. Data generators.

<table>
<thead>
<tr>
<th>Source</th>
<th>Generator 1</th>
<th>Generator 2</th>
<th>Generator 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connected to bus:</td>
<td>1</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>[ U_{01} ] [kV]</td>
<td>13.2</td>
<td>13.2</td>
<td>13.2</td>
</tr>
<tr>
<td>[ S_{01} ] [MVA]</td>
<td>-</td>
<td>2200</td>
<td>1400</td>
</tr>
<tr>
<td>Synchronous machine</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>[ X_d, X'_d, X''_d ] [pu]</td>
<td>-</td>
<td>[2.07, 0.28, 0.215]</td>
<td>[2.07, 0.28, 0.215]</td>
</tr>
<tr>
<td>[ X_q, X'_q, X''_q ] [pu]</td>
<td>-</td>
<td>[1.99, 0.49, 0.215]</td>
<td>[1.99, 0.49, 0.215]</td>
</tr>
<tr>
<td>[ T_{do}, T'<em>{do}, T''</em>{do}, T_{qo}, T'<em>{qo}, T''</em>{qo} ] [s]</td>
<td>-</td>
<td>[4.1, 0.033, 0.56, 0.062]</td>
<td>[4.1, 0.033, 0.56, 0.062]</td>
</tr>
<tr>
<td>[ R_i ] [pu]</td>
<td>-</td>
<td>0.0046</td>
<td>0.0046</td>
</tr>
<tr>
<td>[ H ] [s]</td>
<td>-</td>
<td>2.09</td>
<td>2.33</td>
</tr>
<tr>
<td>[ F ]</td>
<td>-</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>[ p ]</td>
<td>-</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>speed governor</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>[ T_{ref} ] [pu]</td>
<td>-</td>
<td>0.789091</td>
<td>0.8283</td>
</tr>
<tr>
<td>[ \omega_{ref} ] [pu]</td>
<td>-</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>[ K_p ]</td>
<td>-</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>[ R ] [pu]</td>
<td>-</td>
<td>0.05</td>
<td>0.05</td>
</tr>
<tr>
<td>Dead zone [pu]</td>
<td>-</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>[ T_i ] [s]</td>
<td>-</td>
<td>0.001</td>
<td>0.001</td>
</tr>
<tr>
<td>[ T_m ] [s]</td>
<td>-</td>
<td>0.15</td>
<td>0.15</td>
</tr>
<tr>
<td>Gate opening speed limits [pu/s]</td>
<td>-</td>
<td>[-0.1, 0.1]</td>
<td>[-0.1, 0.1]</td>
</tr>
<tr>
<td>Gate opening limits [pu]</td>
<td>-</td>
<td>[0, 4.496]</td>
<td>[0, 4.496]</td>
</tr>
<tr>
<td>Nominal speed [rpm]</td>
<td>-</td>
<td>3600</td>
<td>3600</td>
</tr>
<tr>
<td>[ T_2, T_3, T_4, T_5 ] [s]</td>
<td>-</td>
<td>[0, 10, 3.3, 0.5]</td>
<td>[0, 10, 3.3, 0.5]</td>
</tr>
<tr>
<td>Torque fractions</td>
<td>-</td>
<td>[0.5, 0.5, 0, 0]</td>
<td>[0.5, 0.5, 0, 0]</td>
</tr>
</tbody>
</table>

Table A.2. Data generators continued.

<table>
<thead>
<tr>
<th>Generator 1</th>
<th>Generator 2</th>
<th>Generator 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Exciter with AVR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>[ U_{ref} ] [pu]</td>
<td>-</td>
<td>0.9646</td>
</tr>
<tr>
<td>Low pass filter time constant [s]</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>Exciter gain and time constant [1, s]</td>
<td>-</td>
<td>[200, 0.3575]</td>
</tr>
<tr>
<td>Regulator gain and time constant [1, s]</td>
<td>-</td>
<td>[1, 0]</td>
</tr>
<tr>
<td>Transient gain reduction [s]</td>
<td>-</td>
<td>[0, 0]</td>
</tr>
<tr>
<td>Damping filter gain and time constant [1, s]</td>
<td>-</td>
<td>[0.0529, 1]</td>
</tr>
<tr>
<td>[ K_p ]</td>
<td>-</td>
<td>0.05</td>
</tr>
<tr>
<td>[ K_i ]</td>
<td>-</td>
<td>1</td>
</tr>
<tr>
<td>[ p ]</td>
<td>-</td>
<td>1</td>
</tr>
<tr>
<td>Power System Stabilizer</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sensor time constant [s]</td>
<td>-</td>
<td>30 \cdot 10^{-3}</td>
</tr>
<tr>
<td>[ K ]</td>
<td>-</td>
<td>20</td>
</tr>
<tr>
<td>Wash-out time constant [s]</td>
<td>-</td>
<td>2</td>
</tr>
<tr>
<td>Lead-lag #1 [ T_{num}, T_{den} ] [ms]</td>
<td>-</td>
<td>[50, 20]</td>
</tr>
<tr>
<td>Lead-lag #2 [ T_{num}, T_{den} ] [s]</td>
<td>-</td>
<td>[3, 5.4]</td>
</tr>
<tr>
<td>[ U_{PSS,min}, U_{PSS,max} ] [pu]</td>
<td>-</td>
<td>[-5.73, 5.73]</td>
</tr>
</tbody>
</table>

Over excitation limiter | | |
| \[ I_{th,min} \] [pu] | - | - | 3.06 |
| \[ S_1, S_2 \] | - | - | 1.2 |
| \[ \alpha_{min}, \alpha_{max} \] | - | - | [-20, 0.1] |
| \[ K \] | - | - | 1 |
| \[ K_i \] | - | - | 0.1 |
| Parallel load | | |
| Configuration | Y (grounded) | Y (grounded) | |
| \[ P \] [MW] | 500 | 150 | 110 |
| \[ Q_L \] [Mvar] | 0 | 0 | 0 |
| \[ Q_L \] [Mvar] | 0 | 0 | 0 |
Parallel to Generator 2 a resistive load is connected. The synchronous machine of SimPowerSystems is modeled as a controlled current source [80]. The parallel resistor is to prevent that a current source is connected in series with an inductor (the transformer.) For the parallel load the Three-Phase Parallel RLC load model is used. Data is determined so that the load consumes about 10% of the generator power.

For the synchronous machine of generator 2 the Synchronous Machine pu Standard model is used. The round rotor type is taken. Unless specified otherwise the data of unit F18 described in [8] is used.

For the speed governor of Generator 2 the Steam Turbine and Governor model is used. The Tandem-compound (single mass) type is taken. Because the standard model differs from the model described in [8] the default settings of the SimPowerSystems model are taken unless specified otherwise.

For the exciter with AVR of Generator 2 the Excitation System model is used. Unless specified otherwise, the data of unit F18 described in [8] is used.

For the Power System Stabilizer of Generator 2 the Generic Power System Stabilizer model is used. Because the standard model differs from the model described in [8] the default settings of the SimPowerSystems model are taken.

Generator 3

Generator 3 is modeled as a synchronous machine with speed governor, excitation system with Automatic Voltage Regulator, Power System Stabilizer and overexcitation limiter.

Parallel to Generator 3 a resistive load is connected. The synchronous machine SimPowerSystems is modeled as a controlled current source [80]. The parallel resistor is to prevent that a current source is connected in series with an inductor (the transformer.) For the parallel load generator 3 the Three-Phase Parallel RLC load model is used. Data is determined so that the load consumes about 10% of the generator power.

For the synchronous machine of generator 3 the Synchronous Machine pu Standard model is used. The round rotor type is taken. Unless specified otherwise the data of unit F18 described in [8] is used.

For the speed governor of Generator 3 the Steam Turbine and Governor model is used. The Tandem-compound (single mass) type is taken. Because the standard model differs from the model described in [8] the default settings of the SimPowerSystems model is taken unless specified otherwise.

For the exciter with AVR of Generator 3 the Excitation System model is used. Unless specified otherwise, the data of unit F18 described in [8] is used.

For the Power System Stabilizer of Generator 3 the Generic Power System Stabilizer model is used. Because the standard model differs from the model described in [8] the default settings of the SimPowerSystems model are taken.

For the overexcitation limiter of Generator 3 the OXL with integral control of field current model described in [200] is used. The block diagram is given in figure 2.5.

Transformers

The data of the transformers is given in tables A.3. In the subsequent subsections for each transformer the model is described.

Transformer 1

For transformer 1 the Three-Phase Transformer (Two Windings) model is used. Unless specified otherwise the data given in [185] is used. The core is unsaturable.

Transformer 2

For transformer 2 the Three-Phase Transformer (Two Windings) model is used. Unless specified otherwise the data given in [185] is used. The core is unsaturable.
### Table A.3. Data transformers.

<table>
<thead>
<tr>
<th>General</th>
<th>Trafo 1</th>
<th>Trafo 2</th>
<th>Trafo 3</th>
<th>Trafo 4</th>
<th>Trafo 5</th>
<th>Trafo 6</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connected to buses</td>
<td>6-10</td>
<td>6-7</td>
<td>8-9</td>
<td>1-4</td>
<td>2-5</td>
<td>3-6</td>
<td></td>
</tr>
<tr>
<td>Type</td>
<td>Regular</td>
<td>Regular</td>
<td>LTC</td>
<td>Regular</td>
<td>Regular</td>
<td>Regular</td>
<td></td>
</tr>
<tr>
<td>$</td>
<td>S_p</td>
<td>[MVA]$</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
</tbody>
</table>

#### Transformer

<table>
<thead>
<tr>
<th>Winding 1</th>
<th>Yg</th>
<th>Yg</th>
<th>-</th>
<th>Yg</th>
<th>Yg</th>
<th>Yg</th>
</tr>
</thead>
<tbody>
<tr>
<td>$U_1$ [pu]</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>$L_1$ [pu]</td>
<td>1.5 $\cdot 10^{-3}$</td>
<td>1.3 $\cdot 10^{-3}$</td>
<td>0.5 $\cdot 10^{-3}$</td>
<td>1 $\cdot 10^{-3}$</td>
<td>2.25 $\cdot 10^{-3}$</td>
<td>0.625 $\cdot 10^{-3}$</td>
</tr>
<tr>
<td>$R_1$ [pu]</td>
<td>13.8</td>
<td>115</td>
<td>13.8</td>
<td>540</td>
<td>540</td>
<td>530</td>
</tr>
<tr>
<td>$R_2$ [pu]</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>$L_2$ [pu]</td>
<td>1.5 $\cdot 10^{-3}$</td>
<td>1.3 $\cdot 10^{-3}$</td>
<td>0.5 $\cdot 10^{-3}$</td>
<td>1 $\cdot 10^{-3}$</td>
<td>2.25 $\cdot 10^{-3}$</td>
<td>0.625 $\cdot 10^{-3}$</td>
</tr>
<tr>
<td>$R_s$ [pu]</td>
<td>500</td>
<td>500</td>
<td>300</td>
<td>500</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>$L_m$ [pu]</td>
<td>500</td>
<td>500</td>
<td>300</td>
<td>500</td>
<td>500</td>
<td>500</td>
</tr>
</tbody>
</table>

#### Tap changer

| $R_{tap}$ [pu] | - | - | 0.003 | - | - | - | default |
| $X_{tap}$ [pu] | - | - | 0.09 | - | - | - | default |
| $\Delta U_{tap}$ [pu] | - | - | 0.00625 | - | - | - | default |
| Selection time [s] | - | - | 10 | - | - | - | empirical |
| Transition time [s] | - | - | 0 | - | - | - | empirical |
| $R_{transfer}$ [$\Omega$] | - | - | 5 | - | - | - | default |
| $|U_{ref}|$ [pu] | - | - | 0.929448 | - | - | - | empirical |
| $\Delta |U_{min}|$ [pu] | - | - | 0.0125 | - | - | - | empirical |
| Delays [s] | - | - | 20 | - | - | - | empirical |

**Transformer 3 (Load Tap Changer)**

For transformer 2 the Three-Phase OLTC Regulating Transformer model is used. The tap range of this model is $+/−8$. Operation mode is voltage regulation. Unless specified otherwise the data given in [185] is used. The core is unsaturable.

**Transformer 4**

For transformer 4 the Three-Phase Transformer (Two Windings) model is used. Unless specified otherwise the data given in [185] is used. The core is unsaturable.

**Transformer 5**

For transformer 5 the Three-Phase Transformer (Two Windings) model is used. Unless specified otherwise the data given in [185] is used. The core is unsaturable.

**Transformer 6**

For transformer 6 the Three-Phase Transformer (Two Windings) model is used. Unless specified otherwise the data given in [185] is used. The core is unsaturable.

**Branches**

**Branch 1**

For branch 1 the Three-Phase Series RLC Branch model is used. The branch type is L. The reactance is chosen 10 times smaller than as given in [99]: $X = 0.00040$ pu. The nominal power is 100 MVA. The inductance is calculated in Henri with:
\[ L = 0.0004 \cdot \frac{(500 \cdot 10^3)^2}{100 \cdot 10^4 \cdot 2 \cdot \pi \cdot 60} \]  
(A.1)

**Branch 2**

For branch 2 the Three-Phase Series RLC Branch model is used. The branch type is RL. The data given in [99] is used: \( X = 0.003 \) pu and \( R = 0.001 \) pu. The nominal power is 100 MVA. The inductance (in Henri) and the resistance (in \( \Omega \)) is calculated with:

\[ L = 0.003 \cdot \frac{(115 \cdot 10^3)^2}{100 \cdot 10^6 \cdot 2 \cdot \pi \cdot 60} \]
\[ R = 0.001 \cdot \frac{(115 \cdot 10^3)^2}{100 \cdot 10^6} \]  
(A.2)

**Transmission Line**

All five parallel transmission lines have the same parameters. Each line is modeled by it’s pi-equivalent. For the RL series branch the Three-Phase Series RLC Branch model is used (type RL). For the line capacitance two grounded Three-Phase Series RLC Branch models are used (type C.) The data given in [99] is used: \( X = 0.0288 \) pu, \( R = 0.0015 \) pu and \( B = 1.173 \) pu. The nominal power is 100 MVA. The inductance (in Henri), the resistance (in \( \Omega \)) and the capacitance (in Farad) is calculated with:

\[ R = 0.0015 \cdot \frac{(500 \cdot 10^3)^2}{100 \cdot 10^6} \]
\[ L = 0.0288 \cdot \frac{(500 \cdot 10^3)^2}{100 \cdot 10^6 \cdot 2 \cdot \pi \cdot 60} \]
\[ C = 1.173 \cdot \frac{(500 \cdot 10^3)^2}{100 \cdot 10^6 \cdot 2 \cdot \pi \cdot 60} \]  
(A.3)

**Loads**

The data of the loads is given in table A.4. In the subsequent subsections for each load the model is described.

**Industrial Load (bus 10)**

For the industrial load (bus 10) the Three-Phase Dynamic Load model (in constant power mode) is used. Unless specified otherwise the data given in [99] is used.

**Residential and Commercial load(bus 9)**

For the Residential and Commercial load (bus 9) two parallel Three-Phase Dynamic Load models are used. One of these models is in constant power mode and the other in constant impedance mode. Unless specified otherwise the data given in [99] is used. Parallel the Residential and Commercial load a resistive load is connected. The dynamic load model of SimPowerSystems is modeled as a controlled current source [80]. The parallel resistor is to prevent that a current source is connected in series with an inductor (the transformer.)

**Shunt compensation**

The data of the shunt compensation is given in table A.5. In the subsequent subsections for each device the model is described.
### Table A.4. Data loads.

<table>
<thead>
<tr>
<th></th>
<th>Commercial and Residential</th>
<th>Industrial</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>General</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Connected to bus</td>
<td>9</td>
<td>10</td>
<td></td>
</tr>
<tr>
<td>$</td>
<td>U_0</td>
<td>[kV]$</td>
<td>13.8</td>
</tr>
<tr>
<td><strong>Constant Impedance</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$P_0$ [MW]</td>
<td>1692</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>$Q_0$ [Mvar]</td>
<td>485.5</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>$</td>
<td>U_0</td>
<td>[pu]$</td>
<td>0.929448</td>
</tr>
<tr>
<td>$\alpha_P$</td>
<td>2</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>$\alpha_Q$</td>
<td>2</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>$[T_{P,1}, T_{P,2}, T_{Q,1}, T_{Q,2}]$ [s]</td>
<td>[0.1, 0.01, 0.1, 0.01]</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>$</td>
<td>U_{th}</td>
<td>[pu]$</td>
<td>0.2</td>
</tr>
<tr>
<td><strong>Constant Power</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$P_0$ [MW]</td>
<td>1692</td>
<td>3271</td>
<td></td>
</tr>
<tr>
<td>$Q_0$ [Mvar]</td>
<td>485.5</td>
<td>1015</td>
<td></td>
</tr>
<tr>
<td>$</td>
<td>U_0</td>
<td>[pu]$</td>
<td>0.929448</td>
</tr>
<tr>
<td>$\alpha_P$</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>$\alpha_Q$</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>$[T_{P,1}, T_{P,2}, T_{Q,1}, T_{Q,2}]$ [s]</td>
<td>[0.1, 0.01, 0.1, 0.01]</td>
<td>[0.1, 0.01, 0.1, 0.01]</td>
<td></td>
</tr>
<tr>
<td>$</td>
<td>U_{th}</td>
<td>[pu]$</td>
<td>0.2</td>
</tr>
<tr>
<td><strong>Parallel resistive load</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$P^*$ [MW]</td>
<td>338.4</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>$Q_L$ [Mvar]</td>
<td>0</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>$Q_c$ [Mvar]</td>
<td>0</td>
<td>-</td>
<td></td>
</tr>
</tbody>
</table>

### Table A.5. Data shunt compensation.

<table>
<thead>
<tr>
<th></th>
<th>Compensation 1</th>
<th>Compensation 2</th>
<th>Compensation 3</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>General</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Connected to bus</td>
<td>6</td>
<td>7</td>
<td>10</td>
<td></td>
</tr>
<tr>
<td>Configuration</td>
<td>Y (grounded)</td>
<td>Y (grounded)</td>
<td>Y (grounded)</td>
<td></td>
</tr>
<tr>
<td>$</td>
<td>U_0</td>
<td>[kV]$</td>
<td>530</td>
<td>115</td>
</tr>
<tr>
<td><strong>Compensation</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$P$ [MW]</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>$Q_Z$ [Mvar]</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>$Q_L$ [Mvar]</td>
<td>763</td>
<td>1710</td>
<td>600</td>
<td></td>
</tr>
</tbody>
</table>
Table A.6. Data Circuit Breakers.

<table>
<thead>
<tr>
<th>Initial status</th>
<th>Closed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Switching of</td>
<td>Phase A, B and C</td>
</tr>
<tr>
<td>Breaker Resistance [Ω]</td>
<td>0.001</td>
</tr>
<tr>
<td>Snubber Resistance [Ω]</td>
<td>1 \cdot 10^6</td>
</tr>
<tr>
<td>Snubber Capacitance [F]</td>
<td>∞</td>
</tr>
</tbody>
</table>

Compensation 1 (bus 6)
For compensation 1 (bus 6) the Three-Phase Parallel RLC load model is used. Unless specified otherwise the data given in [99] is used.

Compensation 2 (bus 7)
For compensation 2 (bus 7) the Three-Phase Parallel RLC load model is used. Unless specified otherwise the data given in [99] is used.

Compensation 3 (bus 10)
For compensation 3 (bus 10) the Three-Phase Parallel RLC load model is used. Unless specified otherwise the data given in [99] is used.

Circuit Breakers
The data of the circuit breakers is given in table A.6. For both circuit breakers, the one of the line between buses 5 and 6 and the one of the line between buses 7 and 8, the same model and the same data is used. The model that is used is the Three-Phase Breaker model.
Simulation Model Typical Voltage Instability Scenario
Appendix B

Data Simulation Model Impact Distributed Generation

B.1 Data Simulation Model simulations general types of DG

Simulations are performed with the SimPowerSystems toolbox of Matlab/Simulink release 2007b [80]. For the test circuit the data as given in appendix A are used apart for the following:

- For each type and size of DG new load flow is executed. The DG’s power production is subtracted from GEN3’s power reference. So the reference power of GEN 3 is different per simulation case. Furthermore the initial voltage of the loads was set by the load flow tool and are different from the values given in appendix A.

- The reference voltage of the LTC is set to 0.93 pu. Furthermore the tap selection time is set to 4 s and the delay to 1 s to speed up the simulation.

The models for the DG are as follows:

Synchronous Machine

For the synchronous machine the Synchronous Machine pu Standard model is used with the following data:

| \(|U_0| = 13.8 \text{kV}\) | \(X''_d = 0.252\) pu | \(T''_{do} = 4.49\) s | \(H = 3.7\) s |
| \(f_0 = 60\) Hz | \(X_q = 0.474\) pu | \(T''_{dq} = 0.0681\) s | \(p = 0\) pu |
| \(X_d = 1.305\) pu | \(X''_q = 0.243\) pu | \(T''_{dq} = 0.0513\) s | \(p = 20\) |
| \(X''_d = 0.296\) pu | \(X_f = 0.18\) pu | \(R_c = 0.003\) pu |

AVR

For the exciter with AVR the Excitation System model is used with the following data:

| Low pass filter time constant: 20 ms | Damping filter gain and time constant \([1, s]\): [0.001, 0.1] |
| Regulator gain and time constant \([1, s]\): [300, 0.001] | \([|E_{lim}|, |E_{lim}|] [\text{pu}]: [11.5, 11.5] [\text{pu}]| |
| Exciter gain and time constant \([1, s]\): [1, 0] | \(K_p = 0\) pu |
| Transient gain reduction \([s]\): [0, 0] |

Induction generator

For the induction generator the Asynchronous Machine pu Units model is used with the following data:

| Rotor type: Squirrel-cage | \(f_0 = 60\) Hz | \(R''_r = 0.01969\) pu | \(H = 0.09526\) s |
| \(R''_r = 0.01969\) pu | \(L''_r = 0.0397\) pu | \(F = 0.05479\) pu |
| \(|U_0| = 13.8\) kV | \(L''_d = 0.0397\) pu | \(L''_m = 1.354\) pu | \(p = 2\) |
Table B.1. Data used for grid connected Voltage Source Converter.

<table>
<thead>
<tr>
<th>$U_0$</th>
<th>$I_{\text{max}}$</th>
<th>$U_{\text{min}}$</th>
<th>$I_{\text{max}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>500 kV</td>
<td>1.1 pu</td>
<td>0.3 pu</td>
<td>1.2 pu</td>
</tr>
<tr>
<td>$K_V$</td>
<td>$Q_{\text{max}}$</td>
<td>$T_{\text{min}}$</td>
<td></td>
</tr>
<tr>
<td>50</td>
<td>0.5 pu</td>
<td>0.2 s</td>
<td></td>
</tr>
<tr>
<td>$T_V$</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.5 s</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Fixed compensation induction generator

For the fixed compensation the Three-Phase Parallel RLC Load model is used with the following data:

<table>
<thead>
<tr>
<th>$U_0$</th>
<th>$P$</th>
<th>$Q_L$</th>
</tr>
</thead>
<tbody>
<tr>
<td>13.8 kV</td>
<td>0 W</td>
<td>0 Var</td>
</tr>
<tr>
<td>$f_0$</td>
<td>$\lambda_{\text{svc}}$</td>
<td>$K_p$</td>
</tr>
<tr>
<td>60 Hz</td>
<td>0.03 pu/MVA</td>
<td>0 puMpuV</td>
</tr>
</tbody>
</table>

SVC induction generator

For the Static Var Compensator the Static Var Compensator (Phasor Type) model is used with the following data:

<table>
<thead>
<tr>
<th>$U_0$</th>
<th>$P$</th>
<th>$Q_L$</th>
</tr>
</thead>
<tbody>
<tr>
<td>13.8 kV</td>
<td>0 W</td>
<td>0 Var</td>
</tr>
<tr>
<td>$f_0$</td>
<td>$K_p$</td>
<td></td>
</tr>
<tr>
<td>60 Hz</td>
<td>0 puMpuV</td>
<td></td>
</tr>
<tr>
<td>$T$</td>
<td>$\lambda_{\text{svc}}$</td>
<td>$K_i$</td>
</tr>
<tr>
<td>4 ms</td>
<td>0.03 pu/MVA</td>
<td>300 puMpuV/s</td>
</tr>
</tbody>
</table>

Voltage Source Converter

For the Voltage Source Converter the model of appendix [C] is used with the following parameters:

<table>
<thead>
<tr>
<th>$U_0$</th>
<th>$I_{\text{max}}$</th>
<th>$U_{\text{min}}$</th>
<th>$I_{\text{max}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>13.8 kV</td>
<td>1.1 pu</td>
<td>0.3 pu</td>
<td>1.2 pu</td>
</tr>
<tr>
<td>$K_V$</td>
<td>$Q_{\text{max}}$</td>
<td></td>
<td></td>
</tr>
<tr>
<td>50</td>
<td>0.5 pu</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

B.2 Data Simulation Model simulations Wind Farm: wind farm in addition to GEN3

Simulations are performed with the SimPowerSystems toolbox of Matlab/Simulink release 2009b [80]. For the test circuit the data as given in appendix [A] are used apart for the following:

- The initial voltage of the loads and the power of GEN 3 were set by the load flow tool and are slightly different from the values given in appendix [A].

- The reference voltage of the LTC is set to 0.93 pu. Furthermore the tap selection time is set to 4 s and the delay to 1 s to speed up the simulation.

- For the grid-side VSC the data of table B.1 is used.

B.3 Data Simulation Model simulations Wind Farm: wind farm replaces part of GEN3

Simulations are performed with the SimPowerSystems toolbox of Matlab/Simulink release 2009b [80]. For the test circuit the data as given in appendix [A] are used apart for the following:

- The wind farm replaces a part of generator GEN3. GEN3 is reduced by the nominal power rating of the wind farm. The settings for the voltage references of GEN3, the VSC and the LTC are chosen in such a way that the generator field-current and the VSC's reactive power output are below their limits. The voltage reference for the LTC is 0.9 pu and for the VSC 1.02 pu. The voltage reference of GEN3 is lowered because of the lower power rating (for the 100 turbine case this reference is 1.03 pu and for the 300 turbine case 1.015 pu).
The initial voltage of the loads were set by the load flow tool and are slightly different from the values given in appendix A.

The tap selection time is set to 4 s and the delay to 1 s to speed up the simulation.

For the grid-side VSC the data of table B.1 is used.
Appendix C

Model Voltage Source Converter connected DG

Generally two types of DGs coupled via a Voltage Source Converter can be distinguished: a DC source (e.g., a PV-array) coupled via a DC/AC-converter or an AC source (e.g., a constant speed wind turbine) coupled via a back-to-back converter (AC-DC-DC-AC). For both types, under normal conditions, the grid side is decoupled from the DG side. Voltage and active power can be controlled independently \[122\]. If no energy storage is available, the active power from the DG equals the grid side active power.

In this thesis for the DG coupled via a VSC the average model is used \[76, 177, 204, 205\]. This model is valid under the following assumptions \[177\]:

- The parameters of the machine are known.
- The controllers are operated in their linear region.
- The modulation scheme of the converters is vector modulation.
- The grid side voltage is close to the nominal value.

For the first two assumptions data provided by the manufacturer can be used. The third assumption is implicitly often the case in voltage source converters \[177\]. The last assumption is met by the fact that converters are often disconnected from the grid at low voltages \[177\]. In the average model only the grid side DC/AC-converter needs to be modeled \[177\]. The power available at the DC-bus \(P_{DC}\) is the power supplied by the DG \(P_{DG}\):

\[
P_{DC} = P_{DG}
\]  \hspace{1cm} (C.1)

If required the dynamics of the power production of the prime mover of the DG can be taken into account as in example is done for wind turbines in \[76, 177, 204, 205\].

The block diagram of the DG connected via a VSC as used in the simulations in this thesis is given in figure C.1. The VSC is modeled as a controllable current source. The current that is injected to the power system is determined from the power available at the DC-side of the converter \(P_{DC}\) and a voltage controller.

The controller works based on positive sequence components in per unit. With the model only simulations on the balanced system will be done.

In the following sections the different blocks in the model will be outlined.

Voltage Controller

The voltage controller determines the reactive power that needs to be supplied to the grid based on the measurement of the magnitude of the grid side voltage. The controller is as described in \[177\] and is given in figure C.2. The maximum amount of reactive power is limited to \(Q_{max}\).
Model for the VSC connected DG.
Power Controller

The Power Controller determines, based on the available DC-bus power \( P_{DC} \) and the required reactive power for voltage control \( Q \), the three phase complex power \( S_{3\Phi,ref} \) that should be supplied by the VSC. For the active power it is required that the power at the DC side of the converter and the power at the AC side of the converter are in balance:

\[
P_{AC} = P_{DC}
\]  
(C.2)

The three phase complex power that should be supplied by the VSC is determined by:

\[
S_{3\Phi,ref} = P_{AC} + jQ
\]  
(C.3)

Current Controller

In the current controller the required three phase complex power \( S_{3\Phi,ref} \) is converted to the required positive sequence current \( I_{\text{ref,1}}^{(1)} \). Due to the fact that the model is in the per unit system it holds that \( S_{3\Phi,ref} = \frac{U_{\text{ref,1}}^{(1)} I_{\text{ref,1}}^{(1)*}}{U_{r}^{(1)}} \), independent if the power variant or power invariant form of the symmetrical components is used \((140)\). The required positive sequence current is determined with:

\[
I_{\text{ref,1}}^{(1)} = \left( \frac{S_{3\Phi,ref}}{U_{r}^{(1)}} \right)^* 
\]  
(C.4)

Memory

The Memory block is to break the algebraic loop that exists because the voltage and current in the electrical system are related to each other. With the memory block the output signal is delayed with one computational cycle.

Current Limiter

The current limiter limits the magnitude of the required positive sequence current. For the output current of this limiter it holds that:

\[
|I_{\text{ref,1}}^{(1)}| \leq |I_{\text{max}}|
\]  
(C.5)

Note that this current limiter will limit both: the active and reactive power output of the VSC. This is only possible if physically \( P_{DC} \) can be adjusted. This is possible if the output power of the DG \( P_{DG} \) can be controlled or at the DC link an energy storage or a dump load is available.
Under/Over Voltage Protection

With the Under/Over Voltage Protection the VSC is disconnected from the grid during low and high voltages. The block diagram of this Under/Over Voltage Protection is shown in figure C.3. For low voltages it is possible to set a maximum time ($\Delta t_{\max}$) the VSC must be stay connected to the grid during low voltages ($<|U_{\min}|$). This is a simplification of the Voltage Ride Through Capability most grid codes require [195]. If the low voltage condition holds on for a period of time longer than $\Delta t_{\max}$ the VSC is disconnected from the grid, implying that the output current becomes zero. For the high voltage condition $|U_{\max}|$ the VSC is immediately disconnected from the grid.

Limitations of model

The model used during the simulations has the following limitations:

- Due to the fact that only the positive sequence voltages and currents are used in the control, the model is only valid for balanced systems. For the simulations in this thesis this is true and does not form a problem.

- The current limiter limits both the output active and reactive power. This is only possible if physically $P_{DC}$ can be adjusted. This is possible if the output power of the DG $P_{DG}$ can be controlled or at the DC link an energy storage or a dump load is available.

Validation of Model

The model is implemented and validated with the simPowerSystems toolbox of Matlab/Simulink [80]. The test circuit for this validation is given in figure C.4. In table C.1 the simulation data used is given. The current injection is simulated with a current source. Two types of tests are performed: a steady state test and a dynamic state test. In the following subsections these tests and their results will be discussed.

Steady State Behavior

For the steady state test $P_{DG} = 1.0$ pu and the grid voltage is $|U_{\text{grid}}| = 1.0$ pu. Both signals are not varied. The Grid bus voltage and the VSC bus voltage are shown in figure C.5. The power that according to the controller should be supplied by the VSC and the power injected by the VSC is shown in figure C.6.

1Note that a current source with zero output current is equivalent to an open circuit.
Table C.1. Data test circuit VSC.

<table>
<thead>
<tr>
<th>General:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(</td>
<td>U_0</td>
</tr>
<tr>
<td>(</td>
<td>S_0</td>
</tr>
<tr>
<td>(f_0 = 60 \text{ Hz})</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Voltage Source Converter:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(</td>
<td>U_{\text{ref}}</td>
</tr>
<tr>
<td>(K_V = 50)</td>
<td></td>
</tr>
<tr>
<td>(T_V = 0.5 \text{ s})</td>
<td></td>
</tr>
<tr>
<td>(</td>
<td>I_{\text{max}}</td>
</tr>
<tr>
<td>(</td>
<td>U_{\text{min}}</td>
</tr>
<tr>
<td>(T_{\text{min}} = 0.2 \text{ s})</td>
<td></td>
</tr>
<tr>
<td>(</td>
<td>U_{\text{max}}</td>
</tr>
<tr>
<td>(Q_{\text{max}} = 0.5 \text{ pu})</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Load:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Purely resistive</td>
<td></td>
</tr>
<tr>
<td>At nominal voltage (P = 230 \text{ W})</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Line:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(R = 0.6585 \Omega) ([49])</td>
<td></td>
</tr>
<tr>
<td>(L = 66.3 \text{ mH}) ([49])</td>
<td></td>
</tr>
</tbody>
</table>

Figure C.4. Test circuit for testing VSC model.
Due to the fact that the resistive load power that is required at the VSC is smaller than the power generated by the VSC, power needs to be transported from the VSC to the grid. This explains the angle from the VSC bus voltage.

As can be seen the VSC controls the VSC bus voltage magnitude to be the reference value (1 pu). Because in this simulation the limiters does not react, the required power equals the injected power.

**Dynamic Behavior**

**Varying grid voltage**

For the dynamic behavior test with varying grid voltage $P_{DG} = 1.0$ pu, and this is not varied. The grid bus voltage is varied in magnitude. The variation is shown in the upper graph of figure C.7. The Grid bus voltage and the VSC bus voltage are shown in figure C.7. The power that according to the controller should be supplied by the VSC and the power injected by the VSC is shown in figure C.8. The positive sequence current calculated by the controller before and after the current limiter is shown in figure C.9.

For $0 \leq t < 5$ s the simulation equals the steady state test. The results are the same for this period of time as with the steady state test.

For $5 \leq t < 10$ s the voltage is VSC bus voltage is 0.9. As can be seen in the lower graph of figure C.7 the VSC bus voltage also initially drops. The VSC counteracts this drop. The current required to fully compensate for the drop is, however, higher than the VSC can handle. The current is limited (see figure C.9) and the voltage does not reach the reference value.

For $10 \leq t < 15$ s the grid bus voltage is at steady state level again. It takes some time for the VSC to restore the steady state.

For $15 \leq t < 20$ s the grid bus voltage drops to 0.25 pu. During the first 200 ms the VSC tries to restore the VSC bus voltage. Due to the current and reactive power limitations this action is, however, limited. After 200 ms the VSC is disconnected from the grid due to the low voltage.
For $20 \leq t < 25$ s the grid bus voltage is at steady state level again. The VSC reconnects to the grid. It takes some time for the VSC to restore the steady state.

For $25 \leq t < 30$ s the grid bus voltage increases to $1.1$ pu. The VSC tries to decrease the VSC bus voltage. Due to the settings of the voltage controller there is an offset between the reference voltage and the VSC bus voltage.

For $30 \leq t < 40$ s the grid bus voltage is at steady state level again. It takes some time for the VSC to restore the steady state.

**Varying DG power voltage**

For the dynamic behavior test with varying $P_{DG}$ the grid voltage is $1.0$ pu, and this is not varied. $P_{DG}$ is varied in magnitude. The variation is:

- $0 \leq t < 5$
- $5 \leq t < 10$
- $10 \leq t < 15$

The Grid bus voltage and the VSC bus voltage are shown in figure C.10. The power that according to the controller should be supplied by the VSC and the power injected by the VSC is shown in figure C.11. The positive sequence current calculated by the controller before and after the current limiter is shown in figure C.12.

or $0 \leq t < 5$ s the VSC operates clearly within its limits. The VSC power equals its set points.

For $5 \leq t < 10$ s the VSC operates closer to its limits but still stays within it’s limits. This case is the steady state case discussed earlier.

For $10 \leq t < 15$ s the VSC operates at it’s current limit. The output power is lower than the set point.
Figure C.7. Magnitude (in [pu]) and angle (in [rad]) from the grid voltage (upper graph) and the VSC voltage (lower graph).

Figure C.8. Required (upper graph) and realized (lower graph) power.
Figure C.9. Current before and after the current limiter.

Figure C.10. Magnitude (in [pu]) and angle (in [rad]) from the grid voltage (upper graph) and the VSC voltage (lower graph).
Figure C.11. Required (upper graph) and realized (lower graph) power.

Figure C.12. Current before and after the current limiter.
Appendix D

Wind Farm Model

For the wind farm the aggregated model proposed in [191, 192] is used of which a description follows. This model represents the behavior of $N$ identical turbines. It approximates qualitatively the power fluctuations produced by a wind farm. The fluctuations from each turbine are partially incoherent and therefore cancel each other. Such a smoothing effect can be properly described by rescaling the output (the real power) of a single turbine model. Assuming that the wind speeds acting on the different turbines of the wind farm are incoherent, the aggregated model is based on the following function:

$$P_a(t) = \sqrt{N} \left( P(t)|_{w(t)} - \tilde{\mu}_P \right) + N \cdot \tilde{\mu}_P$$  \hspace{1cm} (D.1)

where $P(t)|_{w(t)}$ is the output of a single turbine model produced by the wind speed $w(t)$ and $\tilde{\mu}_P$ is an estimation of the statistical mean of the produced power from one turbine $\mu_P = E \left[ P(t)|_{w(t)} \right]$. It can be proven that the statistical mean, variance, and autocorrelation of the aggregated power $P_a(t)$ equal those of the full model:

$$P_{tot}(t) = \sum_{i=1}^{N} P_i(t)|_{w_i(t)} = P_a(t)$$  \hspace{1cm} (D.2)

provided that $\tilde{\mu}_P = \mu_P$. The exact calculation of $\mu_P$ is difficult, but a suitable estimate $\tilde{\mu}_P$ can be easily calculated by making two approximations:

- the dynamic model of the turbine is approximated with a steady state model (power curve);
- the wind speed can be described by means of a Gaussian probability density function $f_w(v) = \frac{1}{\sqrt{2\pi}\sigma} e^{-\frac{(v-w_0)^2}{2\sigma^2}}$ [64]. Where $\sigma$ is the standard deviation and $w_0$ the mean.

Under these assumptions the mean output power can be computed by applying the Gaussian filter method [130, 192]:

$$\tilde{\mu}_P(w_0) = \int_{-\infty}^{+\infty} P_{ss}(v) f_w(v) dv$$  \hspace{1cm} (D.3)

The time-series power output of the aggregated wind farm ($P_a(t)$) is calculated based on the method described above and used as a feed-forward input to the grid-side VSC. Because of the decoupling of the relatively fast power fluctuations in the wind farm from the grid through the DC bus and the grid-side VSC, this simplification is allowable.
Appendix E

Data Simulation Models Tests LTC Control

Simulations are performed with the SimPowerSystems toolbox of Matlab/Simulink release 2009b [80].

E.1 Data for Simulation Model used for Proof of Concept

The diagram of the system used for demonstrating theoretical operation of the LTC control method is given in figure 6.1. The simulation data applies for the simulations of sections 6.2.2, 6.2.3 and 6.3.2. The base voltages for each bus are:

<table>
<thead>
<tr>
<th>Bus</th>
<th>Voltage (kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>G</td>
<td>115</td>
</tr>
<tr>
<td>1</td>
<td>115</td>
</tr>
<tr>
<td>2</td>
<td>13.8</td>
</tr>
</tbody>
</table>

The base power for the load is: 3384 MW. The nominal frequency for all components is 60 Hz.

Infinite source

For modeling the infinite source the Three-Phase Programmable Voltage Source is used. The time variation is turned off. The positive sequence parameters are: $|U_0| = 1.0$ pu and $\delta = 0$ rad.

Line

For the line the Three-Phase Series RLC Branch model is used. The following parameters are used: $X = 0.001$ pu and $R = 0.00033$ pu. The nominal power is 100 MVA. The inductance (in Henri) and the resistance (in Ω) are calculated with:

$$
L = 0.001 \cdot \frac{(115 \cdot 10^3)^2}{100 \cdot 10^6 \cdot 2 \cdot \pi \cdot 60} \\
R = 0.00033 \cdot \frac{(115 \cdot 10^3)^2}{100 \cdot 10^6} 
$$

LTC

For the LTC the Three-Phase OLTC Regulating Transformer model is used. The tap range of this model is $+/−8$. Operation mode is voltage regulation. The nominal power is 100 MVA. The core is chosen to be not saturable.
Load

The load is modeled as ZIP model. The parameters for the active power load are: \( a_P = 0.5, b_P = 0, \) \( c_P = 0.5, P_0 = 3384 \text{ MW}, |U_0| = 1.00152 \text{ pu} \). The parameters for the reactive power load are: \( a_Q = 0.5, b_Q = 0, c_Q = 0.5, Q_0 = 971 \text{ Mvar}, |U_0| = 1.00152 \).

To obtain this ZIP load in simPowerSystems a Three-Phase Dynamic Load set as constant impedance load (\( \alpha_P = \alpha_Q = 2 \)), a Three-Phase Dynamic Load set as constant power load (\( \alpha_P = \alpha_Q = 0 \)) and a Three-Phase Parallel RLC Load are connected in parallel.

The data for the Three-Phase Dynamic Load is:

<table>
<thead>
<tr>
<th>Constant Impedance</th>
<th>Constant Power</th>
</tr>
</thead>
<tbody>
<tr>
<td>( P_0 = 1353.6 \text{ MW} )</td>
<td>( P_0 = 1692 \text{ MW} )</td>
</tr>
<tr>
<td>( Q_0 = 485.5 \text{ Mvar} )</td>
<td>( Q_0 = 485.5 \text{ Mvar} )</td>
</tr>
<tr>
<td>(</td>
<td>U_0</td>
</tr>
<tr>
<td>( \delta = -34.0945 \text{ pu} )</td>
<td>( \delta = -34.0945 \text{ pu} )</td>
</tr>
<tr>
<td>( \alpha_P = 2 )</td>
<td>( \alpha_P = 0 )</td>
</tr>
<tr>
<td>( \alpha_Q = 2 )</td>
<td>( \alpha_Q = 0 )</td>
</tr>
<tr>
<td>( T_{P,1} = 0.1 \text{ s} )</td>
<td>( T_{P,1} = 0.1 \text{ s} )</td>
</tr>
<tr>
<td>( T_{P,2} = 0.01 \text{ s} )</td>
<td>( T_{P,2} = 0.01 \text{ s} )</td>
</tr>
<tr>
<td>( T_{Q,1} = 0.1 \text{ s} )</td>
<td>( T_{Q,1} = 0.1 \text{ s} )</td>
</tr>
<tr>
<td>( T_{Q,2} = 0.01 \text{ s} )</td>
<td>( T_{Q,2} = 0.01 \text{ s} )</td>
</tr>
<tr>
<td>(</td>
<td>U_a</td>
</tr>
</tbody>
</table>

Parameters for the Three-Phase Parallel RLC Load:

<table>
<thead>
<tr>
<th>Configuration: ( Y ) (grounded)</th>
<th>( P = 338.4 \text{ MW} )</th>
<th>( Q_L = 0 \text{ MVar} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>(</td>
<td>U_0</td>
<td>= 1.00152 \text{ pu} )</td>
</tr>
</tbody>
</table>
Appendix F

Data Simulation Models Tests CHP based DG Control

Simulations are performed with the SimPowerSystems toolbox of Matlab/Simulink release 2009b [80].

F.1 Data for demonstrating thermostatically controlled unit and VPP control

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_0$</td>
<td>1 kW</td>
</tr>
<tr>
<td>$T_{ref,0}$</td>
<td>18°C</td>
</tr>
<tr>
<td>$T_1$</td>
<td>35°C</td>
</tr>
<tr>
<td>$T_{ref,1}$</td>
<td>20°C</td>
</tr>
<tr>
<td>$T_0$</td>
<td>15°C</td>
</tr>
<tr>
<td>$\Delta T$</td>
<td>2°C</td>
</tr>
<tr>
<td>$R_l$</td>
<td>300 pu</td>
</tr>
<tr>
<td>$C$</td>
<td>8 pu</td>
</tr>
</tbody>
</table>

F.2 Data for proof of concept IG control

For the infinite bus the Three-Phase Programmable Voltage Source is used. The variation is disabled. The phase to phase rms voltage is 460 V and the phase angle is 0. The internal source connection is Yg. The line is modeled with the internal impedance of the Three-Phase Programmable Voltage Source. The resistance is 0.01 Ω and is thus purely resistive.

For the induction generator the Asynchronous Machine pu Units model is used. The rotor type is squirrel-cage. The parameters are given in the following table:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_0$</td>
<td>3.73 kW</td>
</tr>
<tr>
<td>$X_s$</td>
<td>0.0397 pu</td>
</tr>
<tr>
<td>$H$</td>
<td>1 s</td>
</tr>
<tr>
<td>$U_{u0}$</td>
<td>460 V</td>
</tr>
<tr>
<td>$R_t$</td>
<td>0.01909 pu</td>
</tr>
<tr>
<td>$f_0$</td>
<td>60 Hz</td>
</tr>
<tr>
<td>$X_r$</td>
<td>0.0397 pu</td>
</tr>
<tr>
<td>$#$ pole pairs</td>
<td>1</td>
</tr>
<tr>
<td>$X_m$</td>
<td>1.454 pu</td>
</tr>
</tbody>
</table>

F.3 Data for proof of concept Continuously controlled CHP with SG

For the infinite bus the Three-Phase Programmable Voltage Source is used. The variation is disabled. The phase to phase rms voltage is 13.2 kV and the phase angle is 0. The internal source connection is Yg. The line is modeled with the internal impedance of the Three-Phase Programmable Voltage Source. The resistance is 0.01 Ω and the inductance is 0.0001 H.
For the synchronous machine the Synchronous Machine pu Standard model is used. For the speed governor the Steam Turbine and Governor model is used. For the exciter with AVR the Excitation System model is used.

Data of the generator, speed governor and exciter used for the Proof of Concept of the Synchronous Generator control:

<table>
<thead>
<tr>
<th>Generator</th>
<th>speed governor</th>
<th>Exciter</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_0 = 1400$ MW</td>
<td>Type: tandem compound multi mass</td>
<td>Low pass filter time const.: $20$ ms</td>
</tr>
<tr>
<td>$[E_{0}] = 13.2$ kV</td>
<td>$K_p = 1$</td>
<td>Regulator gain: $200$</td>
</tr>
<tr>
<td>$f_0 = 60$ Hz</td>
<td>$K = 0.05$ pu</td>
<td>Regulator time const.: $0.3575$ s</td>
</tr>
<tr>
<td>$X_q = 0.0346$ pu</td>
<td>Dead zone: $0$</td>
<td>Exciter gain: $1$</td>
</tr>
<tr>
<td>$X_q = 2.07$ pu</td>
<td>$T_{sw} = 0.001$ s</td>
<td>Exciter time const.: $0$ s</td>
</tr>
<tr>
<td>$X_q = 0.28$ pu</td>
<td>$T_{im} = 0.15$ s</td>
<td>Transient gain reduction [s]: $[0, 0]$</td>
</tr>
<tr>
<td>$X_q = 0.215$ pu</td>
<td>Gate opening speed limits: $[-0.1, 0.1]$ pu/s</td>
<td>Damping filter gain: $0.0529$</td>
</tr>
<tr>
<td>$X_q = 1.99$ pu</td>
<td>Gate opening limits: $[0, 4.496]$ pu</td>
<td>Damping filter time const.: $1$ s</td>
</tr>
<tr>
<td>$X_q = 0.49$ pu</td>
<td>Nominal speed: $3600$ rpm</td>
<td>$[</td>
</tr>
<tr>
<td>$X_q = 0.0315$ pu</td>
<td>$[T_2, T_3, T_4]: [0, 10, 3.3, 0.5]$ s</td>
<td>$K_p = 0$</td>
</tr>
<tr>
<td>$X_q = 0.155$ pu</td>
<td>Torque fractions: $[0.5, 0.5, 0, 0]$</td>
<td>$[U_{ref}] = 1.0$ pu</td>
</tr>
<tr>
<td>$T_{sw} = 4.1$ s</td>
<td>Inertia: $[1.5498, 0.24894, 0.0]$ s</td>
<td>$[\omega] = 0$</td>
</tr>
<tr>
<td>$T_{sw} = 0.033$ s</td>
<td>Stiffness: $[83.47, 42.702, 0.0]$ pu/ rad</td>
<td>Damping: $[2.4832, 0.4, 0, 0]$ pu $T/\omega$</td>
</tr>
<tr>
<td>$T_{sw} = 0.56$ s</td>
<td>Damping: $[2.4832, 0.4, 0, 0]$ pu $T/\omega$</td>
<td></td>
</tr>
<tr>
<td>$T_{sw} = 0.062$ s</td>
<td>Damping: $[2.4832, 0.4, 0, 0]$ pu $T/\omega$</td>
<td></td>
</tr>
<tr>
<td>$H = 2.33$ s</td>
<td>$p = 1$</td>
<td></td>
</tr>
<tr>
<td>$R = 0.5$ pu</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$p = 1$</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The data of the thermal system of the generator is:

$P_0 = 1400$ MW  $T_{set0} = 18^\circ$ C  $R_0 = 300$ pu
$T_0 = 15^\circ$ C  $T_{ref,t} = 20^\circ$ C  $K_0 = 300$ pu

For the local load the Three-Phase Parallel RLC Load model is used (configuration: Y grounded). The load is fully resistive. The nominal voltage is $13.2$ kV, the nominal frequency $60$ Hz and the active power load is $454$ MW.
Appendix G

Simulation Model Proof of Concept

Simulations are performed with the SimPowerSystems toolbox of Matlab/Simulink release 2009b [80].

G.1 Test System

The diagram of the system used for simulation is given in figure 8.1. This system is taken from the books from Taylor [185] and Kundur [99]. The data used for the simulations are as given in appendix A apart from the following:

- The line between buses 7 and 8 is changed to a double circuit. The impedance of each line of this double circuit is twice the impedance of the original single circuit: $R = 0.002$ pu and $L = 0.006$ pu. So the equivalent impedance ($R_{eq} + jX_{eq}$) of the double circuit is equal to the impedance of the original single circuit.

- A Virtual Power Plant (VPP) of 100,000 micro-CHP units is connected to bus 9. The micro-CHPs are thermostatically controlled and have an induction generator to convert the mechanical power to electrical power. The reactive power consumption of this generator is compensated for with a fixed capacitor so that $\cos \phi = 1$. The nominal power of each unit is 1 kW. To save computational time, the behavior of the 100,000 is emulated by 10 units with a nominal output power of 10 MW each. The data of the micro-CHPs is given in table G.1. For the induction generators the Asynchronous Machine pu Units of the simPowerSystems toolbox of Matlab/Simulink is used set as torque controlled squirrel cage induction machine.

- A Static Var Compensator (SVC) of 200 MVAR is connected to bus 6. As model the Static Var Compensator (Phasor Type) of the simPowerSystems toolbox of Matlab/Simulink is used. This model is slightly adapted according to the discussion in section 5.6. The minimum and maximum compensation is $+/- 200$ MVAR. The data for the normal control mode of this SVC is given further on in this appendix.

- Generator GEN3 is assumed to be a large greenhouse CHP unit (or equivalently the aggregated model of multiple of these units). The prime-mover is continuously controlled and the conversion from mechanical to electrical power is done by means of an synchronous generator. The data of the synchronous generator is as given in appendix A except that the field current limit is set to $|I_{fd,max}| = 3.25$ pu. The data of the CHP prime mover is given in table G.2.

- The industrial load at bus 10 is made externally controllable. The reactive power part of this load is set to 971 MVAR.
Table G.1. Data micro-CHPs.

<table>
<thead>
<tr>
<th>General</th>
<th>CHP</th>
<th>Generator</th>
<th>Compensation</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_0 = 10\text{ MW}$</td>
<td>$T_s = 33^{\circ}\text{C}$</td>
<td>$R_s = 0.01965\pu$</td>
<td>$Q_{\text{L}} = 8.6215\text{ Mvar}$</td>
</tr>
<tr>
<td>$</td>
<td>U_0</td>
<td>= 13.8\text{ kV}$</td>
<td>$T_0 = 15^{\circ}\text{C}$</td>
</tr>
<tr>
<td>$T_{\text{ref}} = 18^{\circ}\text{C}$</td>
<td>$R_{r} = 0.01909\pu$</td>
<td>$Q_{\text{C}} = 8.6215\text{ Mvar}$</td>
<td></td>
</tr>
<tr>
<td>$R_0 = 300\pu$</td>
<td>$I_{m} = 1.354\pu$</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$T_0 = 15^{\circ}\text{C}$</td>
<td>$R_s = 0.01965\pu$</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$T_{\text{ref},0} = 18^{\circ}\text{C}$</td>
<td>$R_{r} = 0.01909\pu$</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$\Delta T = 2^{\circ}\text{C}$</td>
<td>$I_{L} = 0.0397\pu$</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$R_0 = 300\pu$</td>
<td>$I_{m} = 1.354\pu$</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table G.2. Data CHP GEN3.

<table>
<thead>
<tr>
<th>General</th>
<th>Normal mode</th>
<th>HABVIP mode</th>
</tr>
</thead>
<tbody>
<tr>
<td>$I_{\text{max}} = 1.5\pu$</td>
<td>$</td>
<td>U_{\text{ref}}</td>
</tr>
<tr>
<td>$I_{\text{max}} = 1.0\pu$</td>
<td>$X_{\text{svc}} = 0.03$</td>
<td>$k_f = 50$</td>
</tr>
</tbody>
</table>

G.2 Actuator Agents

The data of the actor agent controlling GEN3 is given in the following table:

| $I_{\text{max}} = 1.5\pu$ | $|U_{\text{ref}}| = 1.086\pu$ | $k_p = 300$ |
| $I_{\text{max}} = 1.0\pu$ | $X_{\text{svc}} = 0.03$ | $k_f = 50$ |

The data of the actor agent controlling the load is given in the following table:

| $P(0) = 3271\text{ MW}$ | $Q(0) = 971\text{ MW}$ | $P_{\text{load,min}} = 2490\text{ MW}$ |

The data of the actor agent controlling the SVC is given in the following table:

<table>
<thead>
<tr>
<th>General</th>
<th>Normal mode</th>
<th>HABVIP mode</th>
</tr>
</thead>
<tbody>
<tr>
<td>$B_{\text{min}} = 1.0\pu$</td>
<td>$</td>
<td>U_{\text{ref}}</td>
</tr>
<tr>
<td>$B_{\text{max}} = 1.0\pu$</td>
<td>$X_{\text{svc}} = 0.03$</td>
<td>$k_f = 50$</td>
</tr>
</tbody>
</table>

The data of the actor agent controlling the LTC is given the following table. For the simulation for the line trip between buses 5 and 6 different values for $P_{\text{load}}(0)$, $U_{\text{load}}(0)$ and $r = 0$ are used than for the line trip between buses 7 and 8. In the first case the values with subscript 1 are used, in the second case the values with subscript 2.

| $a_p = 0.55$ | $r_{\text{max}} = 8$ | $|U_{\text{load}}(1)\text{pu}| = 0.9248\pu$ |
| $b_p = 0$ | $\Delta|U_{\text{ref}}| = 0.00625\pu$ | $r_2 = 4$ |
| $c_p = 0.45$ | $\Delta|U_{\text{max}}| = \infty$ | $P_{\text{load,2}}(0) = 3250\text{ MW}$ |
| $P_0 = 3772.4\text{ MW}$ | $r_1 = 3$ | $|U_{\text{load}}(2)\text{pu}| = 0.8145\pu$ |
| $|U_0| = 0.929448\pu$ | $P_{\text{load,1}}(0) = 3702.3\text{ MW}$ |  |

The data of the actor agent controlling the VPP is given in the following table:

| $T_s = 33^{\circ}\text{C}$ | $T_{\text{ref}} = 20^{\circ}\text{C}$ | $R_0 = 300\pu$ |
| $R_0 = 15^{\circ}\text{C}$ | $\Delta T = 2^{\circ}\text{C}$ | $C = 5\pu$ |
| $T_{\text{ref},0} = 18^{\circ}\text{C}$ | $R_0 = 300\pu$ |  |

G.3 Data LTC for study impact multiple LTC levels

The LTC data for study of the impact of multiple LTC levels is given in the following table:
### General

<table>
<thead>
<tr>
<th>Description</th>
<th>LTC 1</th>
<th>LTC 2</th>
<th>LTC 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connected to buses:</td>
<td>6-10</td>
<td>6-7</td>
<td>8-9</td>
</tr>
<tr>
<td>$</td>
<td>S_0</td>
<td>$, [MVA]</td>
<td>100</td>
</tr>
</tbody>
</table>

### Transformer

<table>
<thead>
<tr>
<th>Description</th>
<th>LTC 1</th>
<th>LTC 2</th>
<th>LTC 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>$</td>
<td>U_1</td>
<td>$, [kV]</td>
<td>525</td>
</tr>
<tr>
<td>$R_1$, [pu]</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>$X_1$, [pu]</td>
<td>$1.5 \times 10^{-3}$</td>
<td>$1.3 \times 10^{-3}$</td>
<td>$0.5 \times 10^{-3}$</td>
</tr>
<tr>
<td>$</td>
<td>U_2</td>
<td>$, [kV]</td>
<td>13.8</td>
</tr>
<tr>
<td>$R_2$, [pu]</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>$X_2$, [pu]</td>
<td>$1.5 \times 10^{-3}$</td>
<td>$1.3 \times 10^{-3}$</td>
<td>$0.5 \times 10^{-3}$</td>
</tr>
<tr>
<td>$R_m$, [pu]</td>
<td>300</td>
<td>300</td>
<td>300</td>
</tr>
<tr>
<td>$L_m$, [pu]</td>
<td>300</td>
<td>300</td>
<td>300</td>
</tr>
</tbody>
</table>

### Tap Changer

<table>
<thead>
<tr>
<th>Description</th>
<th>LTC 1</th>
<th>LTC 2</th>
<th>LTC 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R_{tap}$, [pu]</td>
<td>$3 \times 10^{-3}$</td>
<td>$3 \times 10^{-3}$</td>
<td>$3 \times 10^{-3}$</td>
</tr>
<tr>
<td>$X_{tap}$, [pu]</td>
<td>0.09</td>
<td>0.09</td>
<td>0.09</td>
</tr>
<tr>
<td>$\Delta</td>
<td>U_{tap}</td>
<td>$, [pu]</td>
<td>$6.25 \times 10^{-3}$</td>
</tr>
<tr>
<td>Tap selection time [s]</td>
<td>10</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Tap transition time [ms]</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Transfer resistance [$\Omega$]</td>
<td>5</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>$</td>
<td>U_{rel}</td>
<td>$, [pu]</td>
<td>1.02</td>
</tr>
<tr>
<td>$\Delta</td>
<td>U_{rel}</td>
<td>$, [pu]</td>
<td>0.0125</td>
</tr>
<tr>
<td>Delays [s]</td>
<td>20</td>
<td>20</td>
<td>50</td>
</tr>
</tbody>
</table>
Appendix H

Additional Information RTDS and Triphase machines

In this appendix additional information about the RTDS and Triphase machines are given.

H.1 RTDS

In this appendix section an overview is given of the RTDS system owned by the Delft University of Technology (TU Delft). A detailed description of the RTDS can be found at the website [167] or in the manual [166] of the RTDS.

The RTDS is a multi-processor simulation tool. These processors are mounted on cards. The processor cards form modular building blocks which can be individually replaced when necessary. This modularity makes the RTDS flexible and future-proof: when new processor cards are developed, these new cards can be added to an existing configuration.

The RTDS of the Intelligent Electrical Power Grids group of the TU Delft contains two types of processor cards: triple Processor Cards (3PCs) and RISC Processor Cards (RPCs). The 3PCs have three ADSP-21062 Digital Signal Processors (DSPs)\(^1\). These processors require 25 ns per instruction cycle. On the 3PCs there are direct analogue and digital interface possibilities for the connection of external hardware.

The RPCs contain two IBM PPC750CXe PowerPC processors. These processors are faster than the ones of the 3PCs: they need only 1.67 ns per instruction cycle. RPCs have, however, no direct interface possibilities.

A relatively new type of processor card is the GIGA Processor Card (GPC). This card is faster than the 3PC and RPC: one instruction cycle requires only 1 ns. With these cards simulation time steps of 2.5 \(\mu\)s can be reached. These small time steps are particularly interesting when studying transients of power electronics components. For voltage stability studies, however, these small time steps are not required and the older 3PCs and RPCs are sufficient. The standard RTDS simulation time step of 50 \(\mu\)s is used.

The processor cards are assembled in racks. Within one rack the processor cards communicate via a backplane. In addition to the processor cards a rack contains communication and interface cards. Each RTDS rack at the TU Delft contains two communication cards: one Inter-Rack Communications card (IRC) and one Workstation InterFace card (WIF).

The IRC establishes bi-directional communication with (a maximum of) six other racks. In this way multiple racks can be used to simulate a large grid. This use of multiple racks has, however, a limitation: inter-rack communication takes 50 \(\mu\)s. The traveling time of the electromagnetic transients between two substations should be equal or larger than these 50 \(\mu\)s. In practice this means that when the two subsystems are interconnected via an overhead line the distance between these subsystems should be at least 15 km. In case of a cable this distance is shorter because of the larger permittivity.

\(^1\)These processors are also called shark processors.
The WIF establishes communication between a rack and a workstation. The workstation is a normal Personal Computer (PC) containing the RSCAD program. In the DRAFT module of this software a power system can be assembled based on blocks in a library containing power system components and control blocks. If required, custom components can be developed in the C-language. The DRAFT module compiles the network so that it can be used by the processor cards. During compilation the assignment of processors can be done manually, but this can also be left to the compiler.

In the RUNTIME module of the software, the compiled system can be sent to the RTDS and the simulation is started. This module of the software uses the WIF. In runtime, interaction with the RTDS is possible: reading of graphs and meters can be performed in real-time, settings can be adjusted and circuit breakers can be operated.

In addition to communication with the workstation the WIF takes care of synchronization. This synchronization is required when data is exchanged between racks and when data from multiple racks is plotted in one graph. A fiber optic link between the WIFs interconnected via a Global Bus HUB (GBH) takes care of this when the two racks are not directly interconnected.

The RTDS racks are placed in cubicles. A cubicle can contain one or more racks and an RTDS system can be built up of multiples of these cubicles. The full RTDS system can be used to simulate one large power system, but all racks can also be used individually for the study of smaller systems. The RTDS system is thus highly flexible.

For interfacing, the RTDS has several possibilities additional to the ones directly available at the processor cards. For analogue signals the RTDS has the DDAC and OADC. The DDAC is a 12 channel Digital-to-Analogue converter (input) and the OADC is a 6 channel Analogue-to-Digital converter (output). Both cards can be connected to a processor card via a fiber optic link and are assigned to a specific processor.

For digital signals the RTDS has DOPTO cards. These cards have 24 digital optical isolated inputs and 24 digital optical isolated outputs. These inputs and outputs can be accessed either via buses on the front of the card, via the DOTPO connector card in the rear of the RTDS cubicle or can be routed via an IMC card.

The IMC card is an interface multiplexer card. With this card routings can be made between the interface panels located at the front and the various digital inputs and outputs. These inputs and outputs can be of the DOPTO cards, but also from the processor cards. The interface panels can be Digital I/O panels, which provides 16 digital inputs and outputs, or the HV panel, which is a switching panel capable to switch signals up to 250 V DC.

Finally the RTDS contains DITS cards. These cards are used as interface between the RTDS and an external controller from, for instance, HVDC or SVC devices. The firing pulses of these devices can be read and the information can be used by the RTDS software.

The RTDS of the TU Delft consists of 8 racks divided over 4 cubicles. An overview of the system is given in table H.1. With this RTDS configuration it is possible to simulate a power system up to 144 three phase nodes in real-time.

<table>
<thead>
<tr>
<th>Cubicle 1</th>
<th>Cubicle 2</th>
<th>Cubicle 3</th>
<th>Cubicle 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rack 1</td>
<td>Rack 2</td>
<td>Rack 3</td>
<td>Rack 4</td>
</tr>
<tr>
<td>3 PCs</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RPCs</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>IRC</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>WIF</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>DDAC</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>OADC</td>
<td>0</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>DOPTO</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>IMC</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Digital I/O Panel</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>HV Panel</td>
<td>0</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>DITS</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
</tbody>
</table>
This appendix section contains a description of the Triphase converter system. More information can be found at the Triphase company website [194] or in the tutorial [193].

The Triphase systems are flexible power converters especially designed for rapid prototyping of motor drives, power amplifiers, micro grids etc. [108]. Furthermore off-the-shelf modules can be bought that can be used for all kinds of digital and analogue interfacing. The modular design makes it possible to add or remove components easily (both power electronics and interfacing modules).

A schematic overview of a Triphase inverter system is given in figure [9.3]. The system consists of one real-time industrial target PC and one or more power electronic converters. In addition, digital and analog input/output (I/O) devices can be connected to the system. The target PC is a controller and has Linux as operating system. It executes all control loops. The target PC communicates with the power electronic converters via an internal fieldbus and with the external I/O devices via an EtherCaT fieldbus. The control algorithm itself is built in Matlab/Simulink and converted to C-code via Matlab’s Real-Time Workshop [190]. This program runs on a separate workstation and the C-code program is sent via Ethernet to the target PC. Via this workstation it is also possible to interact with the control loop in real-time.

The power electronics converters itself contain Field-Programmable Gate Arrays (FPGAs). The FPGA takes care of the measurements, the pulse width modulation, interfacing, inverter switching and hardware protection. Note that the intelligence of the control is fully provided by the target PC and not by the FPGAs. Digital and analogue I/O modules can be connected to the inverter system via a Beckhoff EtherCaT fieldbus. The Triphase machines at TU Delft contain two types of input devices, the Beckhoff EL3102 and EL3104, and one type of output device, the Beckhoff EL4132. The main specifications are given in table [H.2], the complete data sheets can be found in [17–19]. The reason for having two different types of input devices lies in the fact that the devices were bought in different stages of the set-up development. The Beckhoff devices are placed at the rear of the cubicle that contains racks 7 and 8. Via an Unshielded Twisted Pair (UTP) cable the devices are connected to the rest of the Triphase equipment. In this way the analogue cables where kept as short as possible. The location of the Beckhoff devices and the semi-permanent character of the set-up is also one of the main reasons for using the DDAC and OADC cards of the RTDS.

TU Delft owns two Triphase converter systems. One is referred to as ’Nexcom’ and the other one is referred to as ’Babelehr’. Both machines have a different number of I/O devices connected to it (see table [H.3]).

### Table H.2. Specifications Beckhoff EL3102 and EL3104 input devices and EL4132 output device [17–19].

<table>
<thead>
<tr>
<th></th>
<th>EL3102</th>
<th>EL3104</th>
<th>EL4132</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of inputs</td>
<td>2</td>
<td>4</td>
<td>0</td>
</tr>
<tr>
<td>Number of outputs</td>
<td>0</td>
<td>0</td>
<td>2</td>
</tr>
<tr>
<td>Connection technology</td>
<td>differential</td>
<td>differential</td>
<td>2-wire, single-ended</td>
</tr>
<tr>
<td>Signal voltage</td>
<td>-10...+10 V</td>
<td>-10...+10 V</td>
<td>-10...+10 V</td>
</tr>
</tbody>
</table>

### Table H.3. Input and outputs of the Triphase Machines.

<table>
<thead>
<tr>
<th></th>
<th>Nexcom</th>
<th>Babelehr</th>
</tr>
</thead>
<tbody>
<tr>
<td>EL3102</td>
<td>4</td>
<td>2</td>
</tr>
<tr>
<td>EL3104</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>EL4132</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>Total # of inputs</td>
<td>16</td>
<td>8</td>
</tr>
<tr>
<td>Total # of outputs</td>
<td>6</td>
<td>6</td>
</tr>
</tbody>
</table>
Appendix I

Simulation Model Real-time Demonstrator

The version of the RSCAD software that is used is: 2.025. The release of Matlab/Simulink that is used for the workstations of the Triphase machines is: 2007b.

I.1 Test System

A detailed discussion of the model is given in appendix [X]. In this appendix the data and models used for the RTDS implementation are given. The model corresponds to the one provided by the support of RTDS Technologies [167].

The data that is given in this appendix is the data that can be set. If a chosen option forces other parameter to a certain setting, this parameter is not named in the appendix.

Generators

The data of the generators is given in tables I.1, I.2, I.3 and I.4. In the subsequent subsections for each generator the model is described.

Generator 1

In accordance to [99, 185] generator 1 is modeled as an infinite bus. In RSCAD the If_rtds_sharc_sld_SRC model is used.

Generator 2

Generator 2 is modeled as a synchronous machine with excitation control.

For the synchronous machine the If_rtds_sharc_sld_MACV31 model of RSCAD is used.

For the excitation control of Generator 2 a simple feedback loop is used:

\[ K \cdot (|U_{\text{ref}}| - \frac{G}{1 + pT}|U_{m}|) \]  

(1.1)

Where \( K \) is the proportional gain modelled with the rtds_sharc_ctl_GAIN block, \( U_{\text{ref}} \) is the reference voltage, \( G \) is the gain of the feedback loop, \( T \) the time constant of the feedback loop and \( U_{m} \) is the measured terminal voltage. The feedback loop \( \frac{G}{1 + pT} \) is modeled with the rds_sharc_ctl_REALPL control block.
Table I.1. Data generator 1.

<table>
<thead>
<tr>
<th>Configuration</th>
<th>Generator 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Source Impedance Type</td>
<td>R</td>
</tr>
<tr>
<td>Voltage Input Time Constant [s]</td>
<td>0.05</td>
</tr>
<tr>
<td>Zero Sequence Included</td>
<td>No</td>
</tr>
<tr>
<td>Impedance Data Format</td>
<td>RRL</td>
</tr>
<tr>
<td>Source Wave Type</td>
<td>AC</td>
</tr>
<tr>
<td>Source Control</td>
<td>Run Time</td>
</tr>
<tr>
<td>Preprocessor Source Impedance</td>
<td>No</td>
</tr>
<tr>
<td>Type of Processor Card</td>
<td>3PC</td>
</tr>
<tr>
<td>3PC Configuration</td>
<td></td>
</tr>
<tr>
<td>Requested 3PC Processor</td>
<td>auto</td>
</tr>
<tr>
<td>Positive Sequence RRL</td>
<td></td>
</tr>
<tr>
<td>Resistance (series) [Ω]</td>
<td>1 × 10^-6</td>
</tr>
<tr>
<td>AC Source Initial Values</td>
<td></td>
</tr>
<tr>
<td>Initial Source Mag (L-L) [kV]</td>
<td>13.524</td>
</tr>
<tr>
<td>Initial Frequency [Hz]</td>
<td>60</td>
</tr>
<tr>
<td>Initial Phase [deg]</td>
<td>0</td>
</tr>
<tr>
<td>AC Source Initial Power Output</td>
<td></td>
</tr>
<tr>
<td>Load Flow Result: Real Power [MW]</td>
<td>4213.181364</td>
</tr>
<tr>
<td>Load Flow Result: Reactive Power [MVar]</td>
<td>585.788395</td>
</tr>
<tr>
<td>Specified Initial Real Power [MW]</td>
<td>100</td>
</tr>
<tr>
<td>Specified Initial Reactive Power [MVar]</td>
<td>50</td>
</tr>
<tr>
<td>Monitoring</td>
<td></td>
</tr>
<tr>
<td>Monitoring Real Power</td>
<td>Yes</td>
</tr>
<tr>
<td>Monitoring Reactive Power</td>
<td>Yes</td>
</tr>
<tr>
<td>P &amp; Q Monitoring Location</td>
<td>Terminal</td>
</tr>
<tr>
<td>Time Constant for LP filter [s]</td>
<td>0.0</td>
</tr>
<tr>
<td>Remote Faults</td>
<td></td>
</tr>
<tr>
<td>Fault Duration [s]</td>
<td>0.10</td>
</tr>
<tr>
<td>Source Voltage During Fault [pu]</td>
<td>0.50</td>
</tr>
</tbody>
</table>
### Table I.2. Data synchronous generators 2 and 3.

<table>
<thead>
<tr>
<th>General Model Configuration</th>
<th>Generator 2</th>
<th>Generator 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Format of Machine electrical data input</td>
<td>Generator</td>
<td>Generator</td>
</tr>
<tr>
<td>Number of Q-axis rotor windings</td>
<td>Two</td>
<td>Two</td>
</tr>
<tr>
<td>Is D-axis transfer admittance known?</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Rated MVA of the Machine [MVA]</td>
<td>2200.0</td>
<td>1400.0</td>
</tr>
<tr>
<td>Rated RMS Line-to-Line Voltage [kV]</td>
<td>13.8</td>
<td>13.8</td>
</tr>
<tr>
<td>Base Angular Frequency [Hz]</td>
<td>60</td>
<td>60</td>
</tr>
<tr>
<td>Specification of Mach Saturation Curve</td>
<td>Linear</td>
<td>Linear</td>
</tr>
<tr>
<td>Get Delta Speed (r/s) from CC?</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Initial Speed in the first time step is</td>
<td>Rated</td>
<td>Rated</td>
</tr>
<tr>
<td>Send Elect torque in PU, TE to CC?</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Send Mach Bus V in PU, VMPU to CC?</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Include Optional Y-D Transformer?</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Include Optional Machine Load No. 1?</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Include Optional Machine Load No. 2?</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Solve Model on card type</td>
<td>3PC</td>
<td>3PC</td>
</tr>
</tbody>
</table>

### 3PC Configuration

| Assignment of Model to 3PC Card | Automatic | Automatic |
| If Manual: Request 3PC Card | 1 | 1 |
| If Manual: Start on Processor | A | A |
| Force FP Output to CC to be IEEE | No | No |
| If float input type undefined, receive as | BP_MODE | BP_MODE |

### Mechanical Data and Configuration

| Inertia Constant [MWs/MVA] | 2.09 | 2.33 |
| Synchronous Mechanical Damping [pu/pu] | 0.0 | 0.0 |
| Location of Lock/Free Mode Switch | CC | CC |
| Initial Model of Lock/Free Switch | Lock | Lock |
| CC input for External H: EX | No | No |
| CC in for Extern Damp: EX | W | No |

### Machine Initial Load Flow Data

| Load Flow: Voltage Magn. At t=0- [pu] | 0.9646 | 0.902500 |
| Load Flow: Voltage Phase A sine at t=0- [deg] | -38.225869 | -29.999996 |
| Load Flow: Real P at t=0- [MW] | 1500 | 0 |
| Load Flow React P at t=0- [MVAr] | -150.37489 | 1,885788 |
| Time Constant for Rampung Up [s] | 0.05 | 0.05 |
| Force initial stator currents to zero? | No | No |
| Force all initial currents to zero? | No | No |
| Specified P at Machine Terminal [MW] | 1736 | 1154 |
| Specified Q at Machine Terminal [MVAr] | 0.0 | 0.0 |

### Machine Elect Data: Generator Format

| Stator Leakage Reactance [pu] | 0.155 | 0.155 |
| D-axis: Unsaturated Reactance [pu] | 2.07 | 2.07 |
| D: Unsatureted Transient Reactance [pu] | 0.28 | 0.28 |
| D: Unsatureted Sub-Trans. Reactance [pu] | 0.215 | 0.215 |
| Q-axis Unsatureted Reactance [pu] | 1.99 | 1.99 |
| Q: Unsatureted Transient Reactance [pu] | 0.49 | 0.49 |
| Q: Unsatureted Sub-Trans. Reactance [pu] | 0.215 | 0.215 |
| Stator Resistance [pu] | 0.0046 | 0.0046 |
| D: Unsat. Trans. Open T Const. [s] | 4.10 | 4.10 |
| D: Unstat. Sub-Trans. Open T Const. [s] | 0.033 | 0.033 |
| Q: Unsat. Trans. Open T Const. [s] | 0.56 | 0.56 |
| Q: Unsat. Sub-Trans. Open T Const. [s] | 0.062 | 0.062 |
### Table I.3. Data synchronous generators 2 and 3 (continued).

<table>
<thead>
<tr>
<th>Machine Zero Sequence Impedances</th>
<th>Generator 2</th>
<th>Generator 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Machine Zero Sequence Resistance [pu]</td>
<td>0.002</td>
<td>0.002</td>
</tr>
<tr>
<td>Machine Zero Sequence Reactance [pu]</td>
<td>0.130</td>
<td>0.130</td>
</tr>
<tr>
<td>Natural Series Resistance [pu]</td>
<td>1 \cdot 10^5</td>
<td>1 \cdot 10^5</td>
</tr>
<tr>
<td>Neutral Series Reactance [pu]</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

#### Transformer Parameters

| Transformer Primary L-L RMS Voltage [kV] | 540 | 580 |
| Transformer Secondary L-L RMS Voltage [kV] | 13.2 | 13.2 |
| Delta Leads or Lags Primary 30 Deg. | Lags | Lags |
| Transformer MVA rating [MVA] | 100 | 100 |
| Positive Sequence Resistance [pu] | 0 | 0 |
| Positive Sequence Reactance [pu] | 0.0045 | 0.0125 |
| Is there a TRF zero sequence path | Yes | Yes |
| Zero Sequence Resistance [pu] | 0 | 0 |
| Zero Sequence Reactance [pu] | 0.0045 | 0.0125 |
| Shunt Conductance at TRF Primary [pu] | 0 | 0 |

#### Output Options

| Time Constant of Filter for Powers [s] | 0.02 | 0.02 |
| Time Const of Filter for Max Ph Crt [s] | 0 | 0 |
| One Step lead on Machine Currents | Yes | Yes |
| One Step lead on Machine Voltages | Yes | Yes |
| One Step lead on Neutral V and I | Yes | Yes |
| One Step lead on Transformer Currents | Yes | Yes |

#### Signal Monitoring in RT and CC: MAC

| Monitor P (MW) Out of Machine | Yes | Yes |
| Monitor Q (MVar) Out of Machine | Yes | Yes |
| Monitor Load Angle of Mach, Rad. | No | No |
| Monitor A phase kA Out of Machine | No | Yes |
| Monitor B phase kA Out of Machine | No | No |
| Monitor C phase kA Out of Machine | No | No |
| Monitor Max Mach. Phase Crt kA | No | No |
| Monitor ED Voltage in PU | No | Yes |
| Monitor EQ Voltage in PU | No | No |
| Monitor ID Current in PU | No | No |
| Monitor IQ Current in PU | No | No |
| Monitor Rotor Mechanical Angle, Rad | No | No |
| Monitor Mach Neutral kA | No | No |
| Monitor Mach Neutral kV | No | No |
| Monitor Internal Node A kV | Yes | Yes |
| Monitor Internal Node B kV | Yes | Yes |
| Monitor Internal Node C kV | Yes | Yes |

#### Signal Monitoring in RT and CC: TRF

| Monitoring P (MW) Out of Transformer | No | Yes |
| Monitoring Q (MVar) Out of Transformer | No | Yes |
| Monitor A phase kA Out of Transformer | No | No |
| Monitor B phase kA Out of Transformer | No | No |
| Monitor C phase kA Out of Transformer | No | No |
| Enable D/A Output (MAX=8 Signals): MAC | No | No |
| Enable D/A Output (Continued): TRF | No | No |

#### Internal Bus Parameters

| Initial Bus Voltage [pu] | 0.39646 | 0.9025 |
| Initial Bus Angle [deg] | 0.0 | 0.0 |
| Bus Type | PV BUS | PV BUS |
| Voltage Result (from loadflow) [pu] | 1.0 | 1.0 |
| Angle Result (from loadflow) [deg] | 0.0 | 1.0 |
### Table I.4. Data control of generators 2 and 3.

<table>
<thead>
<tr>
<th></th>
<th>Generator 2</th>
<th>Generator 3</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Excitation control</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Feedback loop</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Time Constant [s]</td>
<td>0.02</td>
<td>0.02</td>
</tr>
<tr>
<td>Gain</td>
<td>1.0</td>
<td>1.0</td>
</tr>
<tr>
<td>Use Extended precision?</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Include input for reset?</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Limits</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Display T &amp; G Values in icon?</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Initial Input</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Initial Output</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Solve Model on card type</td>
<td>3PC</td>
<td>3PC</td>
</tr>
<tr>
<td>Assigned Controls Processor</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Priority Level</td>
<td>18</td>
<td>58</td>
</tr>
<tr>
<td><strong>Gain</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gain</td>
<td>400</td>
<td>400</td>
</tr>
<tr>
<td>Solve Model on card type</td>
<td>3PC</td>
<td>3PC</td>
</tr>
<tr>
<td>Assigned Controls Processor</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Priority Level</td>
<td>20</td>
<td>66</td>
</tr>
<tr>
<td><strong>OXL</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Integral</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Time Constant [s]</td>
<td>-</td>
<td>1.0</td>
</tr>
<tr>
<td>Use extended precision?</td>
<td>-</td>
<td>No</td>
</tr>
<tr>
<td>Include input for reset?</td>
<td>-</td>
<td>No</td>
</tr>
<tr>
<td>Limits</td>
<td>-</td>
<td>Internal</td>
</tr>
<tr>
<td>Initial Input</td>
<td>-</td>
<td>0.0</td>
</tr>
<tr>
<td>Initial Output</td>
<td>-</td>
<td>0.0</td>
</tr>
<tr>
<td>Solve Model on card type</td>
<td>-</td>
<td>3PC</td>
</tr>
<tr>
<td>Assigned Controls Processor</td>
<td>-</td>
<td>1</td>
</tr>
<tr>
<td>Priority Level</td>
<td>-</td>
<td>60</td>
</tr>
<tr>
<td><strong>Gain 1</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gain</td>
<td>-</td>
<td>0.248</td>
</tr>
<tr>
<td>Solve Model on card type</td>
<td>-</td>
<td>3PC</td>
</tr>
<tr>
<td>Assigned Controls Processor</td>
<td>-</td>
<td>1</td>
</tr>
<tr>
<td>Priority Level</td>
<td>-</td>
<td>61</td>
</tr>
<tr>
<td><strong>Gain 2</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gain</td>
<td>-</td>
<td>12.6</td>
</tr>
<tr>
<td>Solve Model on card type</td>
<td>-</td>
<td>3PC</td>
</tr>
<tr>
<td>Assigned Controls Processor</td>
<td>-</td>
<td>1</td>
</tr>
<tr>
<td>Priority Level</td>
<td>-</td>
<td>63</td>
</tr>
<tr>
<td><strong>Limitation</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Integer or Real Function</td>
<td>-</td>
<td>REAL</td>
</tr>
<tr>
<td>Upper Limit</td>
<td>-</td>
<td>20</td>
</tr>
<tr>
<td>Lower Limit</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>Solve Model on card type</td>
<td>-</td>
<td>3PC</td>
</tr>
<tr>
<td>Assigned Controls Processor</td>
<td>-</td>
<td>1</td>
</tr>
<tr>
<td>Priority Level</td>
<td>-</td>
<td>64</td>
</tr>
<tr>
<td><strong>References</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Voltage reference</td>
<td>0.9693</td>
<td>1.046</td>
</tr>
<tr>
<td>Torque reference</td>
<td>0.796</td>
<td>0.831</td>
</tr>
</tbody>
</table>
Generator 3

Generator 3 is modeled as a synchronous machine with excitation control and OXL.
For the synchronous machine the If_rtds_sharc_sld_MACV31 model of RSCAD is used.
For the excitation control the simple feedback loop of equation (I.1) is used. The gain is modeled with the rtds_sharc_ctl_GAIN block. The feedback loop is modeled with the rtds_sharc_ctl_REALPL control block.
For the overexcitation limiter the block diagram as given in figure I.1 is used. For the integral the rtds_sharc_ctl_INTGL control block is used. For both gains the rtds_sharc_ctl_GAIN control block is used. For the output limitation the rtds_sharc_ctl_LIMITS block is used.

Transformers

The transformers 5 (between buses 2 and 5) and 6 (between buses 3 and 6) are modeled within the If_rtds_sharc_sld_MACV31 block. The data can be found in tables I.2, I.3 and I.4.
The data of the other transformers is given in tables I.5 and I.6. In the subsequent subsections for each transformer the model is described.

Transformer 1

Transformer 1 is located between buses 6 and 10. For this transformer the If_rtds_sharc_sld_TRF3P2W model is used.

Transformer 2

Transformer 2 is located between buses 6 and 7. For this transformer the If_rtds_sharc_sld_TRF3P2W model is used.

Transformer 3 (Load Tap Changer)

Transformer 3 is located between buses 8 and 9. For this transformer the If_rtds_sharc_sld_TRF3P2W model is used. This transformer is set to be a tap changing transformer. The control of this tap changer is given in figure I.2. The relevant data is also given in this figure.
A short overview of the blocks used for the LTC control of figure I.2 follows. For the comparison blocks rtds_sharc_ctlCOMPARE control blocks are used. For the switches the rtds_sharc_ctl_SIGSW control blocks are used. For the modulus operator the rtds_sharc_ctl_ABS control blocks are used. For the edge detection the rtds_sharc_ctl_MONO control blocks are used. For the SR Flip Flops the rtds_sharc_ctl_SRFF control blocks are used. For the gains the rtds_sharc_ctl_GAIN control blocks are used. For the integral operators the rtds_sharc_ctl_INTGL control blocks are used. For the logic ports (OR and AND) the rtds_sharc_ctl_LOGIC control blocks are used. The push buttons are the rtds_sharc_ctl_PB control blocks.
Table I.5. Data transformers.

<table>
<thead>
<tr>
<th>General</th>
<th>Trafo 1</th>
<th>Trafo 2</th>
<th>Trafo 3</th>
<th>Trafo 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connected to buses</td>
<td>6-10</td>
<td>6-7</td>
<td>8-9</td>
<td>1-4</td>
</tr>
<tr>
<td>Configuration</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Winding # 1 Connection</td>
<td>Y</td>
<td>Y</td>
<td>Y</td>
<td>Y</td>
</tr>
<tr>
<td>Winding # 2 Connection</td>
<td>Y</td>
<td>Y</td>
<td>Y</td>
<td>Y</td>
</tr>
<tr>
<td>Delta lags or leads Y</td>
<td>Leads</td>
<td>Leads</td>
<td>Leads</td>
<td>Leads</td>
</tr>
<tr>
<td>Transformer Model Type</td>
<td>Ideal</td>
<td>Ideal</td>
<td>Ideal</td>
<td>Ideal</td>
</tr>
<tr>
<td>Tap Changer</td>
<td>No</td>
<td>No</td>
<td>Pos Table</td>
<td>No</td>
</tr>
<tr>
<td>Tap Trigger on</td>
<td>Rising Edge</td>
<td>Rising Edge</td>
<td>Rising Edge</td>
<td>Rising Edge</td>
</tr>
<tr>
<td>Tap Changer Inputs</td>
<td>CC</td>
<td>RunTime</td>
<td>CC</td>
<td>RunTime</td>
</tr>
<tr>
<td>Transformer Rating (3phase) [MVA]</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Base Frequency [Hz]</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
</tr>
<tr>
<td>Leakage Inductance of Tx [pu]</td>
<td>0.003</td>
<td>0.0026</td>
<td>0.001</td>
<td>0.002</td>
</tr>
<tr>
<td>No load losses [pu]</td>
<td>0.001</td>
<td>0.001</td>
<td>0.001</td>
<td>0.001</td>
</tr>
<tr>
<td>No load loss branch type</td>
<td>Winding</td>
<td>Winding</td>
<td>Winding</td>
<td>Winding</td>
</tr>
<tr>
<td>Type of Processor Card</td>
<td>3PC</td>
<td>3PC</td>
<td>3PC</td>
<td>3PC</td>
</tr>
<tr>
<td>Winding #1</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Base primary voltage (L-L RMS) [kV]</td>
<td>533</td>
<td>540</td>
<td>115</td>
<td>13.2</td>
</tr>
<tr>
<td>Winding #2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Base secondary voltage (L-L RMS) [kV]</td>
<td>13.8</td>
<td>115</td>
<td>13.8</td>
<td>540</td>
</tr>
<tr>
<td>Current Monitoring</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Monitor Winding #1 Phase A Current</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Monitor Winding #1 Phase B Current</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Monitor Winding #1 Phase C Current</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Monitor Winding #2 Phase A Current</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Monitor Winding #2 Phase B Current</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Monitor Winding #2 Phase C Current</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Tap Changer A</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of TAP positions</td>
<td>-</td>
<td>-</td>
<td>33</td>
<td>-</td>
</tr>
<tr>
<td>Starting Tap Position</td>
<td>-</td>
<td>-</td>
<td>18</td>
<td>-</td>
</tr>
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</table>
### Table 1.6. Data transformers (continued).

<table>
<thead>
<tr>
<th>Tap Settings</th>
<th>Trafo 1</th>
<th>Trafo 2</th>
<th>Trafo 3</th>
<th>Trafo 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tap Setting for Position # 1 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.909091</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 2 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.914286</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 3 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.91954</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 4 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.924855</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 5 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.930233</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 6 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.935673</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 7 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.941176</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 8 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.946746</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 9 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.952381</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 10 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.958084</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 11 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.963855</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 12 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.969697</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 13 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.97561</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 14 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.981595</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 15 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.987654</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 16 [pu]</td>
<td>-</td>
<td>-</td>
<td>0.993789</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 17 [pu]</td>
<td>-</td>
<td>-</td>
<td>1</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 18 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.006289</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 19 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.012658</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 20 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.019108</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 21 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.025641</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 22 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.032258</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 23 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.038961</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 24 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.045752</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 25 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.052632</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 26 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.059603</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 27 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.066667</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 28 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.073826</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 29 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.081081</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 30 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.088435</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 31 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.095890</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 32 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.103448</td>
<td>-</td>
</tr>
<tr>
<td>Tap Setting for Position # 33 [pu]</td>
<td>-</td>
<td>-</td>
<td>1.111111</td>
<td>-</td>
</tr>
</tbody>
</table>
Figure I.2. Control Tap Changer used in RTDS model.
### Table I.7. Data transmission lines.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of phases</td>
<td>3</td>
</tr>
<tr>
<td>Positive Sequence Series Resistance [Ω/km]</td>
<td>0.01876</td>
</tr>
<tr>
<td>Positive Sequence Series Ind. Reactance [Ω/km]</td>
<td>0.36</td>
</tr>
<tr>
<td>Positive Sequence Shunt Cap. Reactance [MΩ/km]</td>
<td>0.2131287</td>
</tr>
<tr>
<td>Zero Sequence Series Resistance [Ω/km]</td>
<td>0.1875</td>
</tr>
<tr>
<td>Zero Sequence Series Ind. Reactance [Ω/km]</td>
<td>1.08</td>
</tr>
<tr>
<td>Zero Sequence Shunt Cap. Reactance [MΩ/km]</td>
<td>0.31969305</td>
</tr>
<tr>
<td>Line Length [km]</td>
<td>200</td>
</tr>
</tbody>
</table>

**Transformer 4**

Transformer 4 is located between buses 1 and 4. For this transformer the If_rtds_sharc_sld_TRF3P2W model is used.

**Transformer 5**

Transformer 5 is located between buses 2 and 5. This transformer is modeled in with the model of the synchronous generator. The data can be found in tables I.2, I.3 and I.4.

**Transformer 6**

Transformer 6 is located between buses 3 and 6. This transformer is modeled in with the model of the synchronous generator. The data can be found in tables I.2, I.3 and I.4.

**Branches**

**Branch 1**

Branch 1 is located between buses 4 and 5. For this branch the If_rtds_sharc_sld_SERIESIND block is used. The inductance is $L = 0.02652582384$ H. The current is monitored but not send to the analogue output.

**Branch 2**

Branch 2 is located between buses 7 and 8. As discussed, this branch is composed of two equal parallel parts. Each part is modeled with a If_rtds_sharc_sld_SERIESRLC block. In these blocks the series resistance per phase is $0.2645$ Ω, the series inductance per phase is $0.002104824$ H, the series capacitance is $0 \mu$F, the branch current is measured in runtime but not send to the analogue port and the RLC values are displayed in the icon.

**Transmission Line**

For the five parallel transmission lines the If_rtds_sharc_sld_TLINE blocks are used. The transmission line data is defined in a separate file. The data is given in table I.7. Note that the same data is used for all five the transmission lines.

**Loads**

The data of the loads is given in table I.8. In the subsequent subsections for each load the model is described.
### Table I.8. Data loads.

<table>
<thead>
<tr>
<th>Dynamic Load Parameters</th>
<th>Commercial and Residential</th>
<th>Industrial</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type of Load</td>
<td>RL</td>
<td>RL</td>
</tr>
<tr>
<td>R &amp; X in parallel?</td>
<td>R/X</td>
<td>R/X</td>
</tr>
<tr>
<td>P &amp; Q Controlled by</td>
<td>CC</td>
<td>CC</td>
</tr>
<tr>
<td>Rated Line to Line Bus Voltage [kV]</td>
<td>13.8</td>
<td>13.8</td>
</tr>
<tr>
<td>Minimum Bus Voltage [pu]</td>
<td>0.8</td>
<td>0.5</td>
</tr>
<tr>
<td>Base Frequency [Hz]</td>
<td>60</td>
<td>60</td>
</tr>
<tr>
<td>Initial Real Power [MW]</td>
<td>1435</td>
<td>3320</td>
</tr>
<tr>
<td>Minimum Real Power [MW]</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>Maximum Real Power [MW]</td>
<td>10000</td>
<td>10000</td>
</tr>
<tr>
<td>Initial Reactive Power [MVAR]</td>
<td>985</td>
<td>1030</td>
</tr>
<tr>
<td>Minimum Reactive Power [MVAR]</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>Maximum Reactive Power [MVAR]</td>
<td>10000</td>
<td>10000</td>
</tr>
<tr>
<td>Type of Processor Card</td>
<td>3PC</td>
<td>3PC</td>
</tr>
</tbody>
</table>

**Monitoring**

- Monitor measured real power? Yes
- Monitor measured reactive power? Yes
- Time Constant for P & Q meas. [s] 0.01

**ZIP model**

- P, Q Input Source Constant
- Rated Bus Voltage [kV] 13.8
- Bus Voltage Measurement time constant [s] 0.01
- Startup Time [s] 30
- Total Real Power Order [MW] 3779.5
- Total Reactive Power Order [MVAR] 1083.9
- Constant Real Impedance fraction [%] 50
- Constant Real Current fraction [%] 50
- Constant Real MVA fraction [%] 0
- Constant Reactive Impedance fraction [%] 50
- Constant Reactive Current fraction [%] 50
- Constant Reactive MVA fraction [%] 0
- Solve Model on card type 3PC
- Assigned Controls Processor 1
- Priority Level 1
Table I.9. Data shunt compensation.

<table>
<thead>
<tr>
<th></th>
<th>Compensation 1</th>
<th>Compensation 2</th>
<th>Compensation 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Configuration</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shunt Capacitance per phase [µF]</td>
<td>8096</td>
<td>332.98</td>
<td>8357.2</td>
</tr>
<tr>
<td>Connection type</td>
<td>Y</td>
<td>Y</td>
<td>Y</td>
</tr>
<tr>
<td>Include Neutral Connection Point?</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Monitor Branch Current in RunTime?</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Monitor Branch Current at Analogue Output Port?</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>

Table I.10. Data Circuit Breakers.

<table>
<thead>
<tr>
<th></th>
<th>Breakers 5-6</th>
<th>Breakers 7-8</th>
</tr>
</thead>
<tbody>
<tr>
<td>Common Data</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Initial status</td>
<td>Closed</td>
<td>Closed</td>
</tr>
<tr>
<td>Phase Breaker Data</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phase Breaker Closed Resistance [Ω]</td>
<td>0.0001</td>
<td>0.0001</td>
</tr>
<tr>
<td>Extinguish Arc for abs(I) at or below [kA]</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Signal Name to control breaker</td>
<td>BRK10C</td>
<td>BRK78</td>
</tr>
<tr>
<td>Active bit number in Asig to control breaker</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Monitor breaker current</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>

Industrial Load (bus 10)

For the industrial load (bus 10) the rtds_u dc_DYLOAD block is used. The input is a constant power of 3320 MW and 1030 MVAR minus the amount of load shedding required by the HABVIP control.

Residential and Commercial load (bus 9)

For the industrial load (bus 10) the rtds_u dc_DYLOAD block is used. The input comes from a ZIP load modeled with the rtds_sharc_ctl_ZIP block.

Shunt compensation

The data of the shunt compensation is given in table I.9. In the subsequent subsections for each device the model is described.

Compensation 1 (bus 6)

For compensation 1 (bus 6) the If_rtds_sharc_sld_SHUNTCAP block is used.

Compensation 2 (bus 7)

For compensation 2 (bus 7) the If_rtds_sharc_sld_SHUNTCAP block is used.

Compensation 3 (bus 10)

For compensation 3 (bus 10) the If_rtds_sharc_sld_SHUNTCAP block is used.

Circuit Breakers

The data of the circuit breakers is given in table I.10. For both circuit breakers, the one of the line between buses 5 and 6 and the one of the line between buses 7 and 8, the same model and the same data is used. The model that is used is the If_rtds_sharc_sld_BREAKER block.
Table I.11. Data actor agent GEN3.

| $F = 0$ pu | $|I_{fd,max}| = 3.02$ pu | $P_{\text{Stagg.e}} = 0.8154$ pu |
| $R_e = 0.0046$ pu | $I_{\text{max}} = 0.9693$ pu | $|I_{fd,\text{lim}}| = 0.12$ pu |
| $X_s = 2.07$ pu |

Table I.12. Data actor agent load control.

| $P(0) = 3320$ MW | $Q(0) = 1030$ MW | $P_{\text{load,max}} = 2820$ MW |

I.2 Actuator Agents

In the demonstrator three actor agents are used by the HABVIP controller.

The data of the actor agent controlling GEN3 is given in table I.11. The data of the actor agent controlling the load is given in table I.12. The data of the actor agent controlling the LTC is given in table I.13. For the simulation for the line trip between buses 5 and 6 different values for $P_{\text{load}}(0)$, $U_{\text{load}}(0)$ and $r = 0$ are used than for the line trip between buses 7 and 8. In the first case the values with subscript 1 are used, in the second case the values with subscript 2. Note that the value for $\Delta|U_{\text{tap}}|$ is an average value for the difference in voltage per tap position.

Table I.13. Data actor agent LTC.

| $\alpha_p = 0.5$ | $r_{\text{max}} = 24$ | $r_1 = 0$ |
| $b_p = 0.5$ | $\Delta|U_{\text{tap}}| = 0.00625$ pu | $P_{\text{load},2}(0) = 2790$ MW |
| $c_p = 0$ | $\Delta|U_{\text{max}}| = \text{inf}$ | $|U_{\text{load},2}(0)| = 0.8132$ pu |
| $P_0 = 3779.5$ MW | $P_{\text{load},1}(0) = 3186$ MW | $r_2 = 0$ |
| $|U_{0}| = 1.0$ pu | $|U_{\text{load},1}(0)| = 0.9008$ pu |
## Appendix J

### Simulation Software Details

<table>
<thead>
<tr>
<th>Section</th>
<th>Solver</th>
<th>Relative tolerance</th>
<th>Absolute tolerance</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.4.3</td>
<td>ode23tb</td>
<td>auto</td>
<td>auto</td>
</tr>
<tr>
<td>2.5.2</td>
<td>ode23tb</td>
<td>auto</td>
<td>auto</td>
</tr>
<tr>
<td>3.6</td>
<td>ode23tb</td>
<td>auto</td>
<td>auto</td>
</tr>
<tr>
<td>4.2</td>
<td>ode23tb</td>
<td>auto</td>
<td>auto</td>
</tr>
<tr>
<td>4.3</td>
<td>ode23tb</td>
<td>auto</td>
<td>auto</td>
</tr>
<tr>
<td>6.2</td>
<td>ode23tb</td>
<td>$10^{-3}$</td>
<td>auto</td>
</tr>
<tr>
<td>6.3</td>
<td>ode23tb</td>
<td>$10^{-3}$</td>
<td>auto</td>
</tr>
<tr>
<td>7.2</td>
<td>ode23tb</td>
<td>$10^{-5}$</td>
<td>auto</td>
</tr>
<tr>
<td>7.2.2</td>
<td>ode23tb</td>
<td>$10^{-10}$</td>
<td>$10^{-10}$</td>
</tr>
<tr>
<td>7.3</td>
<td>ode23tb</td>
<td>auto</td>
<td>auto</td>
</tr>
<tr>
<td>7.6.2</td>
<td>ode45</td>
<td>auto</td>
<td>auto</td>
</tr>
<tr>
<td>7.6.3</td>
<td>ode23tb</td>
<td>$10^{-4}$</td>
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<td>ode23tb</td>
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<td>8.2.4</td>
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<td>$10^{-3}$</td>
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</table>
## Nomenclature

### Symbols

#### Latin symbols

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a)</td>
<td>ZIP model constant impedance fraction</td>
<td></td>
</tr>
<tr>
<td>(AC)</td>
<td>internal Agent Coordination signal</td>
<td></td>
</tr>
<tr>
<td>(b)</td>
<td>ZIP model constant current fraction</td>
<td></td>
</tr>
<tr>
<td>(B)</td>
<td>suscepcence</td>
<td>([S])</td>
</tr>
<tr>
<td>(c)</td>
<td>ZIP model constant power fraction</td>
<td></td>
</tr>
<tr>
<td>(C)</td>
<td>capacitance, thermal capacitance</td>
<td>([F],[J/K])</td>
</tr>
<tr>
<td>(D)</td>
<td>duty cycle</td>
<td></td>
</tr>
<tr>
<td>(e)</td>
<td>electromotive force, sending-end voltage</td>
<td>([V])</td>
</tr>
<tr>
<td>(f)</td>
<td>frequency</td>
<td>([Hz])</td>
</tr>
<tr>
<td>(f())</td>
<td>function</td>
<td></td>
</tr>
<tr>
<td>(f(v))</td>
<td>Gaussian probability density function</td>
<td>([])</td>
</tr>
<tr>
<td>(g())</td>
<td>function</td>
<td></td>
</tr>
<tr>
<td>(H)</td>
<td>inertia constant</td>
<td>([Ws/VA])</td>
</tr>
<tr>
<td>(i)</td>
<td>current, incremental value in sum</td>
<td>([A],[])</td>
</tr>
<tr>
<td>(j)</td>
<td>number individual unit/actuator</td>
<td></td>
</tr>
<tr>
<td>(J)</td>
<td>Jacobian</td>
<td></td>
</tr>
<tr>
<td>(k)</td>
<td>fractions in PI-controller</td>
<td></td>
</tr>
<tr>
<td>(K)</td>
<td>gain</td>
<td></td>
</tr>
<tr>
<td>(L)</td>
<td>inductance</td>
<td>([H])</td>
</tr>
<tr>
<td>(LI)</td>
<td>leakage inductance</td>
<td>([H])</td>
</tr>
<tr>
<td>(m)</td>
<td>maximum value in sum</td>
<td></td>
</tr>
<tr>
<td>(MLI)</td>
<td>Maximum Loadability Index</td>
<td></td>
</tr>
<tr>
<td>(N)</td>
<td>number of turbines</td>
<td></td>
</tr>
<tr>
<td>(p)</td>
<td>number of pole pairs, Laplace operator</td>
<td></td>
</tr>
<tr>
<td>(P)</td>
<td>active/real power</td>
<td>([W])</td>
</tr>
<tr>
<td>(Q)</td>
<td>reactive power</td>
<td>([VA],[])</td>
</tr>
<tr>
<td>(r)</td>
<td>tap position/ratio</td>
<td></td>
</tr>
<tr>
<td>(R)</td>
<td>resistance, droop</td>
<td>([\Omega])</td>
</tr>
<tr>
<td>(s)</td>
<td>slip</td>
<td></td>
</tr>
<tr>
<td>(S)</td>
<td>complex power, slope</td>
<td>([VA],[])</td>
</tr>
<tr>
<td>(t)</td>
<td>time</td>
<td>([s])</td>
</tr>
<tr>
<td>(T)</td>
<td>torque, time constant, Temperature</td>
<td>([Nm],[s],[^\circ C])</td>
</tr>
<tr>
<td>(u)</td>
<td>voltage</td>
<td>([V])</td>
</tr>
<tr>
<td>(w)</td>
<td>winds speed</td>
<td>([m/s])</td>
</tr>
<tr>
<td>(x)</td>
<td>variable</td>
<td></td>
</tr>
<tr>
<td>(X)</td>
<td>reactance / voltage droop</td>
<td>([\Omega])</td>
</tr>
</tbody>
</table>
Nomenclature

$XI$  leakage reactance  $[\Omega]$
$y$  conditional control gain
$Y'$  admittance  $[S]$
$z$  load demand
$Z$  impedance  $[\Omega]$

Greek symbols

$\alpha$  load characterization
$\Delta$  deviation of a quantity
$\delta$  phase angle of voltage phasor  $[\text{rad}]$
$\varepsilon$  error/deviation  $[%]$  
$\theta$  phase angle of current phasor  $[\text{rad}]$
$\mu$  continuation parameter, mean value
$\omega$  angular frequency  $[\text{rad/s}]$
$\phi$  phase shift between voltage and current, phase angle of impedance  $[\text{rad}]$
$\sigma$  standard deviation

Subscripts

0  nominal, environment
1  primary side transformer, first
2  secondary side transformer, second
1Φ  single phase
3Φ  three phase
a  aggregated
av  average
A  current Agent level
AC  Alternating Current
c  capacitor/capacitive, continue
CHP  CHP
com  communication
d  direct axis
DB  death band
den  denominator
done actual obtained amount (of load relief)
e  electrical
em  electro-magnetic
eq  equivalent
fd  field
gen  generator/generation
grid  grid
in  input
$i$  incremental value in sum
I  Integral
$k$  discrete time instant
k  intermediate quantity, connection number, unit number
lim  limited
loss  loss
Nomenclature

1 source to room
L inductive
line line
load load
LTC Load Tap Changer
m measured quantity, magnetizing, mechanical
max maximum value
mech mechanical
min minimum value
MLI MLI
next next level
NS Not Served
num numerator
o room to environment, open circuit
off off
on on
opt optimum
out output
OXL Over Excitation Limiter
P Proportional
P active power
PI PI action
production production
PSS Power System Stabilizer
q quadrature axis
Q reactive power
r rotor, relative
rd ramping-down
ref reference
res residual
reset reset
ru ramping-up
s stator, source, synchronous
set settling
SG Synchronous Generator
sm servo motor
sr speed relay
svc static var compensator
t terminal, final
tap tap
th Thévenin, threshold, thermal
tot total
transfer transfer
V Voltage controller
VPP Virtual Power Plant
VSC Voltage Source Converter

Superscripts

′ transient
′′ subtransient
(1) positive sequence component
Complex quantities

\[ x \] complex quantity: \( x = \text{Re}(x) + j\text{Im}(x) \)
\[ \text{Re}(x) \] real part of \( x \)
\[ \text{Im}(x) \] imaginary part of \( x \)
\[ |x| \] modulus of \( x \)
\[ \arg x \] argument of \( x \)
\[ x^* \] complex conjugate of \( x \)

Sinusoidal quantities

\[ x(t) \] instantaneous value: \( x(t) = \hat{x}\cos(\omega t + \alpha) = \sqrt{2}|X|\cos(\omega t + \alpha) \)
\[ \hat{x} \] amplitude of \( x(t) \)
\[ \hat{x} \] complex amplitude: \( \hat{x}e^{j\alpha} \)
\[ X \] complex root-mean-square value: \( |X|e^{j\alpha} \)
\[ x \] complex instantaneous value: \( \hat{x}e^{j(\omega t + \alpha)} \)

Phasor representation

In this thesis for the sinusoidal voltages and currents in steady state the phasor representation will be used. The time varying voltage \( u(t) = \sqrt{2} \cdot |U|\sin(\omega t - \delta) \), for example, is written in phasor notation as: \( U = |U|\angle\delta \).

Vector and matrix notation

Vectors are given with a line above the quantity: \( \vec{x} \). Matrices are given as bold quantities \( \mathbf{X} \).
### Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC</td>
<td>Alternating Current</td>
</tr>
<tr>
<td>AVR</td>
<td>Automatic Voltage Regulator</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
</tr>
<tr>
<td>DC</td>
<td>Direct Current</td>
</tr>
<tr>
<td>DCOPO</td>
<td>Distributed Constraint OPtimization</td>
</tr>
<tr>
<td>DEVS</td>
<td>Dynamic state Estimation and Voltage Stability of transmission and distribution grids with a large share of decentralized generation</td>
</tr>
<tr>
<td>DFIG</td>
<td>Doubly Fed Induction Generator</td>
</tr>
<tr>
<td>DG</td>
<td>Distributed Generation</td>
</tr>
<tr>
<td>DSP</td>
<td>Digital Signal Processor</td>
</tr>
<tr>
<td>ENVCi</td>
<td>Equivalent Node Voltage Collapse Index</td>
</tr>
<tr>
<td>EOS-LT</td>
<td>Energie Onderzoek Subsidie Lange Termijn (financial support long term energy research)</td>
</tr>
<tr>
<td>FPGA</td>
<td>Field-Programmable Gate Array</td>
</tr>
<tr>
<td>GBH</td>
<td>Global Bus HUB</td>
</tr>
<tr>
<td>GPC</td>
<td>GIGA Processor Cards</td>
</tr>
<tr>
<td>GPS</td>
<td>Global Positioning System</td>
</tr>
<tr>
<td>HABVIP</td>
<td>Hierarchical Agent-Based Voltage Instability Prevention</td>
</tr>
<tr>
<td>HIL</td>
<td>Hardware-In-the-Loop</td>
</tr>
<tr>
<td>HVDC</td>
<td>High-Voltage Direct Current</td>
</tr>
<tr>
<td>ICT</td>
<td>Information an Communication Technology</td>
</tr>
<tr>
<td>IG</td>
<td>Induction Generator</td>
</tr>
<tr>
<td>I/O</td>
<td>Input/Output</td>
</tr>
<tr>
<td>IRC</td>
<td>Inter-Rack Communication card</td>
</tr>
<tr>
<td>L-L</td>
<td>Line-to-Line</td>
</tr>
<tr>
<td>LTC</td>
<td>Load Tap Changer</td>
</tr>
<tr>
<td>MAS</td>
<td>Multi-Agent System</td>
</tr>
<tr>
<td>micro-CHP</td>
<td>micro Combined Heat and Power</td>
</tr>
<tr>
<td>MLI</td>
<td>Maximum Loadability Limit</td>
</tr>
<tr>
<td>OXL</td>
<td>Overexcitation Limiter</td>
</tr>
<tr>
<td>PC</td>
<td>Personal Computer</td>
</tr>
<tr>
<td>PMU</td>
<td>Phasor Measurement Unit</td>
</tr>
<tr>
<td>pu</td>
<td>per unit</td>
</tr>
<tr>
<td>PV</td>
<td>Photo-Voltaic</td>
</tr>
<tr>
<td>PV-curve</td>
<td>Power-Voltage curve</td>
</tr>
<tr>
<td>RC</td>
<td>Radio Controlled</td>
</tr>
<tr>
<td>RDG</td>
<td>Renewable and Distributed Generation</td>
</tr>
<tr>
<td>RG</td>
<td>Renewable Generation</td>
</tr>
<tr>
<td>RPC</td>
<td>RISC Processor Cards</td>
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<tr>
<td>RTDS</td>
<td>Real-Time Digital Simulator</td>
</tr>
<tr>
<td>SCADA</td>
<td>Supervisory Control And Data Acquisition</td>
</tr>
<tr>
<td>SE</td>
<td>State Estimation</td>
</tr>
<tr>
<td>SG</td>
<td>Synchronous Generator</td>
</tr>
<tr>
<td>SVC</td>
<td>Static Var Compensator</td>
</tr>
<tr>
<td>TCR</td>
<td>Thyristor Controlled Reactor</td>
</tr>
<tr>
<td>TSC</td>
<td>Thyristor Switched Capacitor</td>
</tr>
<tr>
<td>UTP</td>
<td>Unshielded Twisted Pair</td>
</tr>
<tr>
<td>UVLS</td>
<td>Under Voltage Load Shedding</td>
</tr>
<tr>
<td>VPP</td>
<td>Virtual Power Plant</td>
</tr>
<tr>
<td>VSC</td>
<td>Voltage Source Converter</td>
</tr>
<tr>
<td>WF</td>
<td>Wind Farm</td>
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<tr>
<td>WIF</td>
<td>Workstation InterFace card</td>
</tr>
<tr>
<td>WP</td>
<td>Work Package</td>
</tr>
<tr>
<td>WT</td>
<td>Wind Turbine</td>
</tr>
<tr>
<td>ZIP</td>
<td>constant impedance (Z) constant current (I) constant power (P)</td>
</tr>
</tbody>
</table>
Bibliography


[81] Communication networks and networks in substations, IEC Std. 61 850.

[82] Use of IEC 61850 for the communication between substations, IEC Std. 61 850-90.


Publications

Journal Papers


• J. F. Baalbergen, M. Gibescu, L. van der Sluis, ”Coordinated Agent-Based Control for Online Voltage Instability Prevention” accepted for publication in European Transactions on Electrical Power.

Conference Contributions


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Writing a PhD thesis is a lot of work. Luckily I had a lot of support during this process. In this acknowledgment I would like to thank everyone who contributed in one or the other way to my project. In particularly I would like to acknowledge:

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Johan Fredrik (Freek) Baalbergen was born in Heemstede, the Netherlands, on August 11, 1983. He received his B.Sc. degree in Electrical Engineering from Delft University of Technology, the Netherlands, in 2005. The final project was the design of the control for an inverted pendulum on a Radio Controlled (RC) car. He obtained his M.Sc. degree in Electrical Engineering from the Delft University of Technology, in 2007. The specialization was Electrical Power Processing and the final project concerned the design of a hybrid power supply (diesel-battery) of a Gantry Crane. The research was in cooperation with Epyon and Exendis. In 2008 he joined the Electrical Power Systems research group at the Faculty of Electrical Engineering, Mathematics and Computer Science of the Delft University of technology as PhD researcher. The framework is the "Dynamic State-Estimation and Voltage Stability of Transmission and Distribution Grids with a large share of Decentralized Generation Capacity"-project. This project is abbreviated as DEVS-project and is financially supported by AgentschapNL under the EOS-LT program. The thesis work concerns the development of a control system to prevent voltage instability in the transmission and distribution grid with a large share of decentralized generation. In 2012 he joined NedTrain Refurbishment and Overhaul as engineer electrical train systems.
Curriculum Vitae