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HANNU REPONEN

COORDINATED VOLTAGE CONTROL IN REAL TIME SIMULATIONS OF DISTRIBUTION NETWORK WITH DISTRIBUTED ENERGY RESOURCES

Master of Science thesis

Examiner: Prof. Sami Repo
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ABSTRACT

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Voltage rise effect in distribution networks poses challenges in future when increasing amount of Distributed Energy Resources(DERs) are connected to the network, and currently is the limiting factor of the network's DER hosting capacity. Passive approaches reinforce the network to increase the hosting capacity but alternatively coordinated voltage control schemes are capable of utilizing the DERs widely across the network. Using reactive power capability of distributed generators, production curtailment or substation voltage control in coordination, desired network voltages can be achieved and e.g. losses minimized. However, this requires accurate information on the state of the whole network. Distributing the automation and control decision making across network voltage levels reliefs data transfer burden to control centers where the decision making is typically centralized. This allows better utilization of large scale of resources in optimizing the network operation. With Substation Automation Units(SAUs) the above can be realized in distribution networks.

This thesis presents the SAU based architecture, and required algorithms to demonstrate a decentralized automation system and coordinated voltage control in a distribution network. Case study was performed for real LV distribution network in Real-Time Digital Simulator. Main focus was to verify correct operation, and to analyze performance of coordinated voltage control compared to other control schemes under real and artificial network conditions. Under demanding network conditions, coordinated voltage control proved to be superior by avoiding over-voltages and conductor thermal limits. The results validate viability of the automation architecture and effectiveness of the coordinated voltage control scheme. Real network demonstrations are follow-up for this thesis' work.

TIIVISTELMÄ

HANNU REPONEN: Koordinoitu jännitteensäätö hajautettuja energiaresursseja sisältävien jakeluverkkojen reaaliaikasimuloinnissa
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Jännitteennousu on yksi jakeluverkkojen tulevaisuuden haasteista hajautettujen energiaresurssien integroinnin lisääntyessä pien- ja keskijännitejakeluverkoissa. Jännitteennousu liitäntäpisteessä on usein rajoittava tekijä verkkoon liitetylle tuotantokapasiteetille. Verkon vahvistamisinvestoinnit ovat tyypillinen käytäntö liitäntäkapasiteetin kasvattamiseksi, mutta vaihtoehtoisesti koordinoidulla jännitteensäädöllä voidaan hyödyntää näiden resurssien olemassa olevia säätömahdollisuuksia laajemmin. Hajautetun tuotannon loistehokapasiteettia, tehonleikkausta tai sähköaseman jännitteensäätöä yhdistämällä voidaan saavuttaa tavoitellut verkon jännitteet ja minimoida esim. verkon häviöt. Koordinoitu säätö vaatii tarkkaa tietoa verkon nykytilasta, ja siksi automaatio- ja ohjausarkkitehtuurin hajauttaminen myös alemmille jännitetasoille mahdollistaa pienempienkin resurssien hyödyntämisen verkon tilan optimoinnissa. Yllä oleva voidaan toteuttaa tähän tarkoitukseen kehitetyillä automaatioyksiköillä.

Tässä työssä esitellään näihin automaatioyksiköihin pohjautuva säätöarkkitehtuuri, sekä algoritmit joilla kyseinen hajautettu automaatiojärjestelmä ja koordinoitu jännitteensäätö voidaan toteuttaa jakeluverkoissa. Työn testiosuudessa koordinoitua jännitteensäätöä tarkastellaan pienjännitteisen jakeluverkon reaaliaikasimuloinneissa. Simuloinneissa tutkittiin säädön toimintaa ja verrattiin sen tehokkuutta muihin säätömenetelmiin oikeissa ja keinotekoisissa verkon olosuhteissa. Vaativimmissa olosuhteissa koordinoitu jännitteensäätö osoittautui tehokkaimmaksi välttäen ylijännitteet ja johdinten termiset kestävyydet. Tuloksista voidaan todeta arkkitehtuurin toimivuus ja koordinoidun jännitteensäädön suorituskyky, ja siten kyseistä konseptia voidaan demonstroida oikeassa jakeluverkossa.

PREFACE

This Master's thesis was done in the Smart Grid research group at the Department of Electrical Engineering, Tampere University of Technology between Spring 2015 and Spring 2016. The work was done as part of, and received funding from European Union's seventh framework program FP7-SMARTCITIES-2013 under project alias IDE4L - ideal grid for all.

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Last but not least, the thanks go to my family for continuous support in the ups and downs throughout my years of studies.

Tampere, 24.5.2016

Hannu Reponen

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LIST OF ABBREVIATIONS AND SYMBOLS

AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
AVC	Automatic Voltage Controller
AVR	Automatic Voltage Regulator
BOT	Blocking of On-Load Tap Changers of Transformers
CC	Control Center
CIM	Common Information Model
COSEM	Companion Specification for Energy Metering
CVC	Coordinated Voltage Control
DER	Distributed Energy Resource
DLMS	Device Language Message Specification
DMS	Distribution Management System
DR	Demand Response
DSO	Distribution System Operator
DG	Distributed Generation
FACTS	Flexible AC Transmission System
GT	Graded Time
HEMS	Home Energy Management System
IED	Intelligent Electronic Device
KPI	Key Performance Indicator
LDC	Line Drop Compensation
LV	Low Voltage
MINLP	Mixed-Integer Nonlinear Programming
MMS	Manufacturing Message Specification
MV	Medium Voltage
NIS	Network Information System
OLTC	On-Load Tap Changer
OPF	Optimal Power Flow
PC	Power Control algorithm
PSAU	Primary Substation Automation Unit
PV	Photovoltaics
RDBMS	Relational Database Management System
RTDS	Real Time Digital Simulator

SAU	Substation Automation Unit
SCADA	Supervisory Control and Data Acquisition
SE	State Estimation algorithm
SQP	Sequential Quadratic Programming
SSAU	Secondary Substation Automation Unit
STATCOM	Static Synchronous Compensator
SVC	Static VAr Compensator
TSO	Transmission System Operator
WLS	Weighted Least Squares

C_{cur}	Cost of production curtailment
C_{DR}	Cost of demand response actions
C_{losses}	Cost of network losses
C_{tap}	Cost of tap changer operation
C_{Vdiff}	Cost of voltage variation
n_{tap}	Number of tap changer operations
P	Real power
P_{cur}	Curtailed production
P_{DR}	Demand response actions
R	Resistance
Q	Reactive power
V	Voltage
X	Reactance
Z	Impedance
δ	Voltage angle
$cos\varphi$	Power factor

1. INTRODUCTION

European Union's targets to increase the share of energy from renewable sources to 20% by 2020[1] has been followed by increasing amount of distributed generation(DG) connected to distribution networks. Also other distributed energy resources(DERs) have become more common in medium(MV) and low voltage(LV) distribution networks. Controllable loads, electric vehicles and energy storages are immersing with the technology evolving around them.

The traditional power system where the generating units are large and centralized, and the power flow is unidirectional from generation to loads through transmission and distribution networks, is undergoing significant changes due to the growth of DG. DGs and other DERs are more often located far from transmission network and it is often cost-efficient to connect them to the nearest network node, along or at the ends of distribution feeders.[2] The currently passive design and control of existing distribution networks needs re-evaluation with the ongoing changes. The networks are oversized to reliably operate under all possible loading conditions, even if the extreme conditions occur very rarely. In order to mitigate the effects that connecting DGs to the existing networks can cause, utilization of active resources is needed.[3] The main challenges are related to voltage quality, equipment thermal ratings, protection blinding and increased fault currents caused by bidirectional power flows[2].

Connecting a DG unit to a weak distribution network raises the voltage level in the network and highest network voltage can no longer be found at the substation. Usually the voltage rise effect is the limiting factor of the connection capacity of the DG unit.[4] Due to the lack of active voltage control methods in these passive networks, reinforcing the network (i.e. upgrading the conductor size) or building a dedicated feeder have been the traditional practices to overcome the voltage rise problem. Considering the increasing penetration of DGs these practices can cause high costs due to the low utilization of the network assets.[5]

Active voltage control methods introduce alternative means to mitigate the voltage rise problems. When applied to existing distribution networks, active voltage control methods have increased the network's DG hosting capacity, thus reducing the DG connection costs[6]. The methods can be based on local measurements or the control actions can be coordinated somehow. Local control of terminal voltages of DGs by limiting real power output(production curtailment) or by adjusting DG reactive power output using automatic voltage regulator (AVR) are examples of methods that operate based on local measurements. These methods do not necessarily require any data transfer between network nodes which reduces the cost of implementation.[5] As the complexity of the network topology grows with increasing amount of DERs, local measurement based active voltage control can become inadequate. Due to the lack of communication, the local control actions may cause clashes with each other.

In Coordinated Voltage Control (CVC) the active resources are utilized in coordination and the control actions are determined based on more comprehensive information on the state of the distribution network. The actions are executed e.g. by altering target set points of automatic voltage control(AVC) relay controlling on-load tap changer(OLTC) at primary substation and controllers of the DG units simultaneously. In networks with simple topology the coordinated control actions can be determined according to an order of control rules. However, in networks where several controllable components exist, optimizing algorithms should be used to calculate optimal set points values for each individual resource. If the number of resources is large, then some kind of aggregation of the small scale resources is required.[7]

The given problem with reverse power flows applies also to low voltage(LV) distribution networks. Small-scale DG units, photovoltaics(PV) panels particularly, are widely connected to European LV networks. The output of PV units is stochastic due to varying, location specific, weather conditions i.e. solar irradiance and temperature. The aggregated generation amount of PV units can be significant during peak production times, and combined together with low load periods can cause the reverse power flows and have effect on voltage quality. Especially because the load on residential feeders is low when PV generation peaks midday, and the peak load can be found during times of no or low generation.[8, 9] The same active voltage control methods can be applied to LV networks but the efficiency varies due to the difference in characteristics of MV and LV networks, and available resources.

Monitoring and controlling both MV and LV grids efficiently from a control center(CC) is becoming complex to realize as the amount of measurement devices and active resources are increasing in both networks. Distributing the automation burden to lower levels of automation can facilitate this issue. Data transfer across the network will decrease as the information is aggregated closer to field. Only necessary information is sent upwards from the lower levels of automation. This provides means for better utilization of large amounts of small-scale DERs in LV networks.

Within IDE4L project, Substation Automation Units(SAUs) at primary and secondary substations have been designed for monitoring and control purposes at substation level. The SAU collects measurements, runs state estimation and forecasting algorithms, and calculates control actions to optimize the network operation or to solve congestions in the network level it's responsible of. Coordination among CC and the lower level SAUs is required in order to prevent unnecessary control actions. This can be achieved by setting some sort of control hierarchy among the decision making actors.

1.1 Objectives and scope of the thesis

This thesis presents a proof-of-concept of the automation and communication architecture, and performs a case study of CVC scheme on LV distribution network. The decision making is decentralized to secondary substation. State Estimation and Power Control algorithms are introduced and realize the CVC from SAU at the secondary substation.

The objectives of thesis' work are to

1. Verify interoperability of the decentralized automation system and algorithms
2. Verify the correct operation of the coordinated voltage control algorithm in real-time simulations
3. Analyze and compare the performance of coordinated voltage control in real-time congestion management with other control schemes

The simulations are run in Real Time Digital Simulator(RTDS) environment. The simulation network in the real-time environment will resemble a real LV distribution network. Real-time simulations are beneficial as data exchange and communication delays of real network operation are taken into account. Further, external intelligent electronic devices(IEDs) are connected to the simulation environment to measure the model and perform control actions similar to real network operation.

The case study excludes upper level controllers in the future distribution network control hierarchy presented in this thesis. Thus Blocking of On-Load Tap-Changers of Transformers algorithm, which could also be utilized to coordinate operation among SAUs, is not included in the case study, but is presented to provide a complete view of the control architecture.

The tests are conducted as a part of IDE4L project and objectives aim to prepare the presented algorithms for future field demonstrations[10].

1.2 Structure of the thesis

The thesis begins by discussing traditional distribution network design and planning principles in Chapter 2. The chapter then goes on to discuss impacts of DG in MV and LV distribution networks and introduces predominant voltage control principles. Further, the chapter introduces controllable resources that can be utilized in active voltage control. Last topic in the chapter is coordinated voltage control. Possible control architectures and future distribution network control hierarchy are discussed within the subject.

Chapter 3 introduces the aforementioned Substation Automation Unit and what it consists of. SAU interfaces, functions and database are described along with the data models used in modeling different system parts, parameters and attributes. Chapter 4 proceeds to describe algorithms required in realizing a coordinated voltage control scheme. State Estimation, Power Control and Blocking of On-Load Tap Changers of Transformers algorithms are introduced. To further explain how these algorithms work together in real-time, an additional section is added.

Simulation network model and laboratory simulation environment including the IEDs connected to the system are introduced in Chapter 5. Connections and implementation of the operators in the simulation system are also described. The tests consist of different simulation sequences and the test results are evaluated by chosen key performance indicators(KPIs) presented in Chapter 6. Chapter 7 presents calculated KPIs and graphs for each individual simulation sequence under two different network conditions. Chapter 8 summarizes the simulation results and discusses directions for future work. Finally Chapter 9 concludes the contents of the thesis.

2. ACTIVE VOLTAGE CONTROL IN DISTRIBUTION NETWORKS WITH DISTRIBUTED GENERATION

In traditional power system the generating units are large and centralized, and the power flow from generation to loads through transmission and distribution networks is considered unidirectional. In radial distribution networks voltage will gradually decrease along the feeder with highest voltage residing at the substation bay. The voltage drop along the feeder is proportional to varying loading and line length. Therefore the lowest possible network voltage can be traditionally found at the end of the feeders during times of maximum loading. The voltage drop along the feeder has been network dimensioning principle in traditional passive network planning. With correctly chosen MV voltage level, OLTC used to boost MV network voltage at the HV/MV substation has traditionally been sufficient automatic voltage control method in distribution networks. Manually changing tapping of MV/LV transformers off-load has been used to further offset the voltage drop in MV and LV networks to keep customer voltages at acceptable levels.[11]

With increasing amount of DG connected to the distribution networks, the aforementioned assumptions are no longer valid. Therefore, the traditional passive design and control of existing distribution networks needs to face changes. Active voltage control methods have been developed to address these issues by utilizing existing and new passively operated active resources. These often reduce high connection costs of DG units and increase profitability of the investments, in other words increase the network's DER hosting capacity.

This chapter presents challenges that emerge with the increasing level of DG connected to distribution networks, and the required changes to traditional voltage control principles. These may be used to mitigate the negative effects and allow increased DG capacity to be connected. These measures will ensure quality of supply

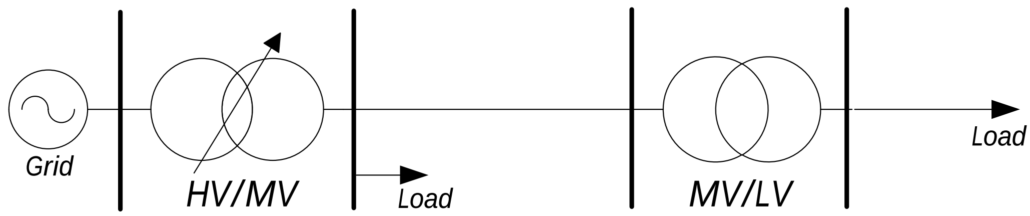

Figure 2.1 *Traditional radial distribution network design*

and operating within allowed network voltage limits while providing cost-savings with better utilization of the resources.

2.1 Design and planning of traditional electricity distribution networks

The original function of distribution networks is to deliver power generated in the transmission network to end customers. The electricity distribution consists of MV and LV networks. The voltage level is adjusted along the path to economically suitable value in HV/MV primary and MV/LV secondary substations considering capacity, operational costs and capital cost. For example, higher voltages increase substation investment costs but result in lower power losses, and longer feeders can be fed with higher voltages as the voltage drop per unit length of the feeder is lower. MV networks supply large customers, such as industrials loads, directly but majority of the customers are connected to LV level and supplied via MV/LV secondary substations and LV networks. The design can vary in different countries. In some countries an additional HV or MV voltage level can be in use, e.g. 33kV to 11kV.[11]

The line types in MV and LV networks vary with the preference by country, environmental surroundings and network location. In rural areas overhead lines are generally in use. Overhead lines can utilize air as insulator and are easier to construct. Underground cables are common in urban areas. Underground cabling improves system reliability but has higher investment cost than overhead lines. Other possible line types are overhead lines with covered conductors and aerial cables.[11]

Distribution networks are operated radially even though they are built in open ring or meshed topology. Design of traditional radial distribution network is illustrated in Figure 2.1. In open ring structure two feeders are connected at the end of the feeders, and an open switch during normal operation separates the feeders. Similarly two substations can be connected via a normally open switch. By closing such switches back-up supply can be activated during network faults or maintenance. The main advantages of radial network design are smaller fault currents and easier implementation of fault isolation, protection and voltage control.[11]

Quality, reliability and safety of supply are of major importance when planning the distribution networks. Utilities search for cost-effective solution in terms of meeting expectations of national regulations, standards and other technical guidelines. The voltage quality experienced by the customers is determined mainly at distribution network level. This is due to use of OLTC in HV/MV primary substation. One limiting factor in network planning is the voltage drop along the feeder from the HV/MV primary substation to the vicinity of the customers. For example, a voltage drop of 5% can be permitted in the whole MV network, and another 5% in LV. In radial network the maximum voltage drop can be calculated during periods of maximum loading at the end of the feeder. Majority of supply interruptions seen by customers are caused by faults in distribution networks. The number and the duration of outages is aimed to be kept within reasonable levels. Radial overhead lines, for example, are prone to environmental conditions, such as snow loads or windy storms. Achieving high levels of reliability can be difficult economically.[11]

Economic consideration is required in capital investments. Cost of losses, expected maintenance costs and outage costs during supply interruptions affect the decision making of Distribution System Operator(DSO). Network reinforcement investments in order to supply more LV network customers are large proportion of the capital investments. Network losses increase power flows through the distribution system and system components. Therefore some component ratings need to be increased to take the losses into account. Losses in LV networks need to be fed from upper voltage levels, and therefore losses in lower voltages are aimed to be minimized. The technical aspects alone do not guarantee optimal solutions for the utility. Economic assessment of costs and return of investments through national regulation is also required.[11]

In general the introduction of DGs and other DERs in the MV and LV distribution networks, and tightening requirements for quality of supply and reliability, e.g. allowed interruption durations, alter many of the traditional planning and design principles and pose challenges for the DSOs. Also during the past ten years a lot has changed in the national regulatory frameworks that affect the DSO's investment decisions. Therefore, for example in Finland the recent investment trend to increase reliability by reducing outage times has been replacing overhead lines entirely with underground cabling in both rural and urban areas.

2.2 Voltage quality requirements in distribution networks

Network users' appliances are designed to tolerate certain voltage levels. Majority of voltage supply conditions fall within these limits, but too large deviations from the nominal voltage can result in malfunction or breaking of the equipment or network components.

European standard EN 50160 defines requirements for voltage characteristics at points of customer connection in distribution networks. The characteristics have a distinction made between continuous phenomena and voltage events. Continuous phenomena include power frequency, supply voltage variations and rapid voltage changes, whereas voltage events include interruptions of the supply and voltage dips. According to the standard, the standard nominal voltage in LV networks U_n is 230 V. The supply voltage variation under normal operating conditions is set to: 95% of the 10 minute mean root mean square(r.m.s.) values should be within $\pm$ 10% of the nominal voltage at the customer connection point. All 10 minute r.m.s. values are required to be within range of U_n+10%/-15%. For special remote network users, the same +10%/-15% limit holds, and the users should be informed about the conditions.[12]

These are used as the minimum requirements as DSOs or national regulation usually sets stricter requirements in different countries. In network planning even stricter requirements for voltage quality are used.

2.3 Impact of distributed generation in distribution networks

Optimal locations for DG units are more often far from transmission network and from the owner point of view it is cost-efficient to connect the units to the nearest network node available. Connecting DG units along or at the ends of distribution feeder will alter the assumption of unidirectional power flows in the distribution network. Voltage profile along the feeder will change with the introduction of reverse

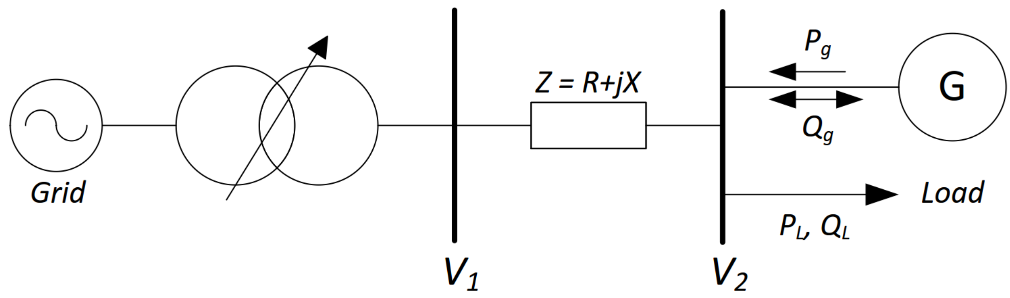

Figure *2.2 Simple radial distribution network with distributed generation*

power flows. The results will have effect on existing voltage control and protection strategies.[4] Protection related issues are out of the scope of this thesis, and the thesis focuses on voltage control and voltage quality.

Voltage rise effect caused by DG is often the factor limiting connection capacity of the DG unit in weak distribution networks[4]. DSOs may set criteria how much the voltage in all buses can rise due to connection of the DG, e.g. 3%. In passive distribution network planning, interconnection studies consider DG as a negative load and the connection capacity is derived from calculations under two extreme loading conditions, where loading is at maximum and generation at minimum, and where loading is at minimum and generation at maximum. The conditions represent the worst case scenarios for voltage quality[6].

2.3.1 Voltage rise effect

To help examine the impact of DG in distribution network voltage, Figure 2.2 presents a simple radial distribution network with a DG unit connected at end of a feeder. V_1 is the primary transformer secondary busbar voltage, Z is the line impedance and V_2 is the voltage at load and DG connection point. The figure illustrates bidirectional power flow and the effect of DG unit to bus voltage at the end of the feeder. The voltage difference between buses 1 and 2 can be calculated from

$$\underline{V}_1 - \underline{V}_2 = (R + jX) * \frac{P - jQ}{\underline{V}_2^*}, \tag{2.1}$$

where $P = P_L - P_g$ and $Q = Q_L \pm Q_g$. With $+Q_g$ the DG consumes reactive power, and with $-Q_g$ the DG unit generates reactive power to the network. If $\underline{V}_2$ angle is set as 0, and it is assumed that the voltage angle between phasors $\underline{V}_1$ and $\underline{V}_2$ in Equation 2.1 is small, the imaginary part in the equation can be neglected. This results in approximation

$$\Delta V = V_1 - V_2 \approx \frac{R(P_L - P_g) + X(Q_L \pm Q_g)}{V_2}. \tag{2.2}$$

Depending on DG real and reactive power production, real and reactive power load, and reactance per resistance(X/R) ratio of the line, Equation 2.2 indicates that DG can either increase or decrease the voltage drop along the feeder[13]. If the DG unit generates reactive power or does not export any reactive power to grid, the voltage drop along the feeder will decrease due to the real power generated, P_g. Furthermore, if the generated real power is larger than the feeder load P_L, the DG connection point voltage V_2 will be greater than substation voltage V_1. The power flow in the feeder will be reversed and will cause a voltage rise at the DG connection point.

In case of lightly loaded distribution network or in worst case loading scenario, where real and reactive power load is zero, the maximum voltage rise effect can be approximated by Equation 2.3. The impact of DG unit on the network voltage depends on the unit's real and reactive power output. The equation presents situation where DG unit generates reactive power.[4]

$$\Delta V \approx \frac{RP_g + XQ_g}{V_2} \tag{2.3}$$

Even if the DG unit would consume reactive power($-Q_g$), the real power output(P_g) of the unit would generally be larger and therefore DG units almost always introduce a voltage rise to the network at their connection points.[4]

2.3.2 Voltage rise mitigation

The DG voltage rise effect falls under continuous phenomena in EN 50160, i.e. it is a long term voltage problem, thus requiring a scheme to alleviate the problem. At present the predominant practices to mitigate the voltage rise effect have been, according to the prevailing passive network planning approach, network reinforcement by increasing the feeder conductor diameter or dedicating a feeder for the DG unit. Upgrading conductor size will significantly reduce resistance of the conductor, and slightly reduce its reactance, and therefore mitigate the voltage rise effect according to the preceding equations. However, with the rising amount of DER connected to distribution networks, proceeding with the passive approach will lead to considerable costs.[4, 5]

Taking active voltage control methods into use, the control capabilities of DERs are used to mitigate the voltage rise effect and to improve voltage quality. In addition to traditional control of the substation voltage with OLTCs, allowing DG units to utilize reactive power capability or to curtail production when necessary, or utilizing reactive power compensation devices in the network, are beneficial in maintaining network voltages within allowed limits. The OLTC control method could be changed from maintaining constant substation target voltage to increasing or decreasing the target voltage based on voltages in the network. Also controllable loads(demand response) and energy storages could be utilized. Simplest active voltage level management methods require only local measurements and no data transfer between network nodes. In these cases, the controllable resources are operated only considering local voltage problems.

Connection of DG, especially PV, in LV networks has recently introduced the voltage rise effect in LV networks[8]. Due to nature and high penetration of PV microgeneration in LV networks, reactive power control may not be sufficient voltage control method. PV based generation peaks during sunniest hours which are often outside of peak demand hours.[14] Also due to lower X/R ratio in LV networks[15], reactive power control is not as efficient according to Equation 2.2. In LV networks the most effective solution is to control tap changer at secondary substation[16]. Application of conventional OLTCs to secondary substation transformers can be expensive but new cheaper technology has been introduced in [17].

Active voltage control based on wider information of the state of the distribution network is referred to coordinated voltage control(CVC). CVC methods are discussed in Section 2.5.

2.4 Controllable resources in active voltage control

Controllable resources can be utilized in active voltage control to keep network voltages within allowed limits and to reduce e.g. network losses. These resources include on-load tap changers of transformers, real and reactive power(power factor) of generation units and controllable loads. Reactive power compensation using power electronics devices can be utilized in control of reactive power flows continuously. Capacitor banks installments in distribution networks manage reactive power flows at primary substations in European type networks. Also energy storages can be charged during times voltage rise needs to be mitigated but are not studied in this thesis. In this section, active resources are introduced in terms of local voltage control. Increasing the utilization of all available DERs and coordinating the operation among them can be advantageous. This is further discussed under coordinated voltage control.

2.4.1 On-Load Tap Changer

Primary substation main transformers are equipped with an OLTC. In passive radial distribution networks OLTC is the key component in voltage control. OLTC alters the transformer winding turns ratio and therefore controls the voltage of the substation secondary side busbar. The operation can be done under load i.e. when the transformer is energized. OLTC is normally operated automatically using AVC relay, but can also be operated manually. The operation is limited by tap changer steps and step size. The step size voltage normally lies between 0.8% and 2.5% of the rated voltage.[18] In Finland HV/MV transformer OLTCs typically have 1.67% step size and e.g. ±9 steps from nominal. Fewer steps have been proposed for MV/LV OLTCs. With 2.5% step size and ±3 steps from the nominal, the voltage range is between 0.925 pu and 1.075 pu, resulting in 15% total control range.

In principle the substation voltage is automatically controlled. AVC relay operating the OLTC aims to maintain constant substation voltage by setting a target voltage and a dead band. The target voltage and the dead band are usually determined by assuming the worst case scenario i.e. winter peak load. Time delay is incorporated before operating the tap changer when transformer secondary voltage differs from the set target voltage more than the dead band value. This limits the number of tap changer actions and prevents unnecessary control actions due to short-term voltage fluctuations.[19]

MV/LV distribution transformers use fixed off-load tap changers as standard. Tap changer operations are done manually in de-energized network. Conventional OLTCs applied to distribution transformers are expensive, can induce hunting behavior and have problems with reverse power flows. Vacuum switch based OLTCs for MV/LV distribution transformers have been recently introduced due to increased amount of DGs connected to LV networks. As a simpler and cheaper alternative the vacuum switch based OLTCs have been successfully used to control LV network voltage as a part of active distribution network management.[17, 20]

Using OLTC as a voltage control resource is advantageous mainly due to couple of reasons. OLTC actions change the voltage in the whole network downstream from the transformer and these actions can either lower or increase the network voltage. Furthermore the actions will not cause increased losses in the network excluding possible losses from the network current change.[21]

The drawback of OLTC voltage control with DG is that when there is DG connected to only one feeder, altering OLTC turns ratio to decrease voltage in that feeder will also change voltages in other feeders. The other feeders may not be experiencing same voltage quality issues as the one with DG so tap changer action can make the situation worse in a healthy feeder.[21] OLTC is also a mechanical component and therefore is subject to wear and requires maintenance. Therefore the number of tap changer actions should be minimized.[18]

An AVC relay is usually provided with Line Drop Compensation(LDC) functionality where a remote bus voltage is aimed to be kept constant instead of the substation voltage. LDC unit uses measured secondary voltage and secondary current multiplied by a line drop impedance to simulate voltage drop across the feeder, and thus to calculate the voltage at the remote control point. This scheme requires no communication link between the remote bus and the transformer. Nevertheless, many OLTCs are operated with the LDC function disabled due to simpler control scheme and prevention of unnecessary errors.[13] An example of LDC error is when DG generation exceeds load, magnitude of reversed current causes voltage rise from the substation to the DG connection point but LDC considers this as a voltage drop and orders OLTC operation to increase transformer secondary busbar voltage.[15] Therefore LDC is not used in this thesis' simulations.

In a scenario where OLTCs across different voltage levels are operated in series, coordination between cascade tap-changers is needed to avoid unnecessary tap changer actions and voltage fluctuation. Problems occur if during upper level voltage deviations lower level OLTC operates before the upper level OLTC and reverting actions are needed at the lower level. The number of unnecessary tap changer operations results in increased required maintenances and reduced OLTC life cycles, and increases voltage out of bounds duration. Graded time(GT) delays are commonly used in cascade OLTC setup. In GT method different time delays are assigned for each cascade OLTC operation. Upper level OLTCs have lower time delay compared to lower level OLTC and therefore the delays ensure that upper level OLTC operates first, as suggested in [22]. The GT delays are set by considering the worst case scenario for voltage restoration at consumption points. Alternatively communication can be used to replace the GT delays with blocking signals. This enables reducing the time delay from worst case correction time to upper level OLTC operation time.[15] Therefore an algorithm to improve OLTC coordination and to reduce delays is introduced in Section 4.3 and could be used with cascade OLTC setup.

However, with increasing amount of DGs it would be beneficial to adjust the OLTC target voltage according to actual network state and the maximum or minimum network node voltage. The node could be located for example at the connection point of one of the DGs in the network. This would require measurements or estimates from critical network nodes and is, in fact, the simplest form of Coordinated Voltage Control as presented in [19].

2.4.2 Real and reactive power of distributed generation

At present DG units connected to distribution networks are considered as passive negative loads with fixed real and reactive power in network planning. The focus in planning is on DG interconnection, and the voltage control principles are not altered.[2] Therefore, most DSOs require DG units to operate in constant power factor mode with unity power factor and thus without DGs taking part in voltage control[23]. However, the real and reactive power control capabilities of the DG units can be used in active voltage level management locally. These capabilities vary with the type of the DG unit. Typical operating modes for DG units are voltage control mode, power factor control mode and VAr control mode with fixed VAr output. In voltage control mode, DG unit controls its reactive power output based on terminal voltage. In power factor mode, the real and reactive power ratio P/Q is kept constant.

Real power generation curtailment can be used to reduce the voltage rise effect. This in current practice would be limited to extreme situations where reactive power consumption is insufficient for maintaining voltage within allowed limits. The probability of these maximum generation and minimum loading situations is low and therefore curtailment can be only profitable if the connection capacity of DG can be increased in return.[24] Intermittent energy sources such as wind and PV are usually operated at maximum available power and therefore their real powers cannot be increased on request. In [25] production curtailment of intermittent wind resources increased the DG hosting capacity in all network nodes with curtailment. Further increased curtailment was found to give diminishing returns i.e. be less attractive. In [26] peak shaving is discussed in terms of DG hosting capacity. By limiting the peak real powers derived from yearly generation curves of intermittent energy sources, considerable higher connection capacities can be allowed with only a small percentage reduce in yearly produced energy i.e. lost income. Limiting the power cut only to necessary locations considering the effect of DG to network voltages is also suggested.

On the other hand, reactive power capability of the DGs can be used to offset the voltage rise locally. In [27] a value for reactive power consumption was calculated to mitigate voltage rise at DG connection point. From DSO's point of view, using this method can represent similar situation as if no DG is connected to the network node. However, consuming reactive power in voltage rise mitigation decreases power factor and increases losses in the network due to increased reactive power flows. Therefore an evaluation of increased losses versus the effectiveness of reactive power control in voltage quality management should be considered in the reactive power control scheme.[6] This may also increase the need of reactive power compensation capacitors at primary substation as reactive power flows from transmission systems are tried to be kept at minimum by DSOs in order to avoid reactive power charges set by transmission system operators(TSOs)[28]. Similarly supplying reactive power in overexcited mode could be used to support local undervoltages.

With synchronous machines the reactive power control is realized by controlling current supplied to machine field winding and is done by automatic voltage regulator (AVR)[29]. New generation AVRs are capable of operating in both voltage control and power factor mode, and switching between the modes if voltages are out of bounds. AVRs are also capable of reactive power sharing for generators connected in parallel.[30] Power electronics interfaced DG such as PV units have varying reactive power capability depending on year, day and weather as the capability is bound to real power output. PV inverters are capable of injecting or consuming reactive power. The capability can be modeled by the rating of the PV inverter S, and the real power output of the PV array P_{pv} as shown in Figure 2.3 [8]. Reactive power limits $\pm Q_g$ are found by projecting P_{pv} intersection points with the S semicircle on Q-axis. The inverter operation allows continuous reactive power support. However, in requirements of IEEE 1547 interconnection standard an unity power factor operation is still a requirement for LV PV inverters. This is expected to be changed to permit injection or consumption of reactive power as the penetration of DER increases.[8, 31] With high penetration levels of PV, the operation of inverters has to be coordinated with other voltage control equipment to fully benefit from the reactive power capabilities of the DG units [8].

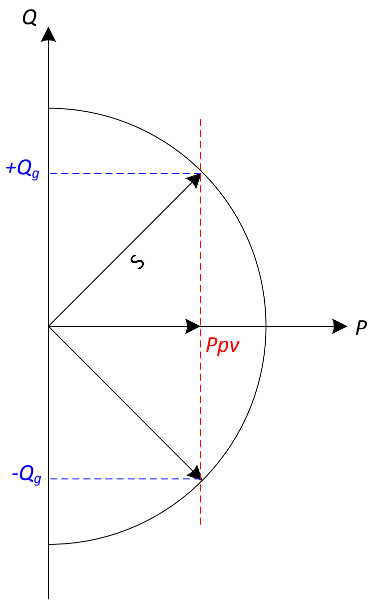

Figure 2.3 *Reactive power capability of a PV inverter*

If the effect of reactive power control is inadequate, increasing inverter rating and including real power curtailment of PV inverters in the control scheme can be used to improve voltage quality in the network. Increasing inverter rating increases reactive power capability according to Figure 2.3.[32, 33] Curtailing PV generation in residential feeders with high PV penetration can be beneficial as typically PV generation peaks during midday when the demand is low, introducing voltage rise. Though this is often mitigated by reverse load profiles of commercial and industrial feeders.[32]

By controlling the power factor of the DG unit appropriately, the voltage rise effect can be mitigated and at the same time connection capacity of the DG unit can be increased and less generation needs to be curtailed. X/R ratio of the network influences the effectiveness of reactive power voltage control. Therefore reactive power compensation is particularly effective in weak distribution networks.[24] Possible drawbacks of local measurement based voltage control of DG units are clashes with OLTC voltage control schemes[34] problems in loss of mains protection schemes[35]. In fact, the possibility generally is not in use because DSOs are limiting the power factor, but it is a cost-effective alternative to network reinforcements[36].

Some countries require reactive power capability from DG units. In Germany, grid codes define that DG connected to MV distribution network must be able to be operated with an active power factor at any point between 0.95_{ind} to 0.95_{cap}. The grid code also sets voltage dependent reactive power characteristic $Q(U)$, where reactive power is injected or consumed only when voltage thresholds are exceeded, as introduced earlier.[37] This, however, can result in uneven reactive power dispatching among DGs as voltage deviations are larger depending how far the DG unit is from the substation, increasing the need for reactive power capability[38]. Uniform power factor, where DG real power output determines the reactive power contribution of the DG unit is suggested in [38].

2.4.3 Controllable loads

Loads that could be potentially utilized in voltage control can be found from both MV and LV networks. Peak load reduction is a known practice to reduce energy costs in households. Load control has further uses beyond peak load reduction. Using load control in voltage regulation to enhance distribution network's DG hosting capacity has been suggested in [34]. Other advantages are limiting line current overloads and supplying consumers during low cost electricity periods.[34]

To enhance the hosting capacity, load control aims to mitigate the voltage rise effect. This is done by increasing loading during times when the intermittent DG is at maximum output and the demand without load control at its minimum. Switching on energy storage loads such as hot water storages is the most convenient option from customer point of view. Load control as a voltage regulation method has higher costs than other dynamic methods like DG curtailment or DG power factor control, but compared to the passive approach i.e. network reinforcement, load control as voltage control method remains competitive for DSOs.[34] On the other hand, DSOs could control loads indirectly by setting electricity prices for specific times of the day, which then would affect customer behavior.

These two types of control: direct and indirect approaches in changes of consumption of the end-use customers is defined as Demand Response(DR). The dispatchable DR is controlled by DSOs. DSOs can use DR in voltage regulation under normal and emergency conditions. Emergency DR programs have been developed to ensure network reliability during network disturbances. Incentive payments are provided to customers who agree to reduce their loads for network reliability purposes. DSO then calls committed customers to reduce the loads during these situations.[39] In [40] the effects of load curtailment in feeder's voltage profile during transmission system disturbance with varying amount of DG units connected to the system were studied. Reliability of supply to critical loads was achieved in all cases.

In general DSOs should be more encouraged to include automation of the LV grids more into active network management. Home Energy Management Systems(HEMS) could be utilized to include DR in DSO's voltage regulation under emergency situations, or to sell ancillary services in normal conditions. DR could be also realized using interfaces for direct load control in smart meters.[3]

2.4.4 Reactive power compensation using power electronics or capacitor banks

Static VAr Compensator (SVC) and Static Synchronous Compensator (STATCOM) are most common types of power electronics controlled reactive power compensator. Both are able to continuously control reactive power output at their connection point by injecting or absorbing capacitive or inductive current. Facilitated, both of these can be classified as Flexible AC Transmission Systems(FACTS) devices. In transmission systems FACTS are considered key components in reactive power support and controlling power flows to mitigate congestions.[29] When applied to distribution networks, D-prefix is often used. D-STATCOMs have been successfully used in voltage regulation of distribution networks in [41].

DSOs may install small number of shunt capacitor banks to distribution networks. These capacitor banks act as a source of reactive power and can be connected to, or disconnected from, the network with switches according to reactive power compensation needs. During times of minimum load, when the DG generation affects the network voltage profile most, capacitors taking part in voltage regulation would be disconnected from the network[42]. Capacitor banks in distribution networks are in wider use in North America. In Finland capacitor banks are installed only at primary substations to control reactive power flows from and to transmission networks.

Optimal location planning and switching operations are needed to improve voltage quality and losses in the network. Switching operations cause transients and high-frequency harmonics which, without external filtering equipment, are unwanted disadvantages. With high penetration of intermittent PV generation, faster and more flexible control is required, and capacitor banks may not be sufficient technology to overcome the challenges.[43]

2.5 Coordinated Voltage Control

To achieve improvements in voltage quality while increasing the network's DG hosting capacity at the same time, the available active resources in the distribution network need to be better utilized. For this purpose CVC methods have been developed. CVC is defined as control scheme where actions are determined based on more extensive information of the distribution network state in [28]. The input data can be real-time measurements from the network nodes or calculated state estimates, and the control actions can be either predetermined or the control can operate in real-time. Determining a control schedule requires accurate load and production forecasts, obtaining which can be difficult. In real-time operation extensive data transfer is required between the network nodes and the actor that determines the control actions. Typically controllable resources include OLTC and DG reactive powers but also other earlier introduced controllable resources can be included in the control scheme.[28] Compared to local measurement based voltage control, even a simple application of coordinating OLTC with real power curtailment in voltage control scheme greatly increased connection capacity of the DG unit in [6].

CVC methods can be based on simple control rules or complex optimizing algorithms depending on the network topology. Computation time required to solve the control actions increases with the complexity of the network. In simple networks, where only few controllable resources exist, rule based methods are adequate. In traditional radial distribution networks controlling substation voltage or reactive power of DERs, or both, based on network maximum and minimum voltage could be a suitable case for rule based CVC. With increasing number of controllable resources in the network, defining the control rules can be burdensome and complex. When active resources are utilized extensively and cost factors are added in the equation, e.g. aiming to minimize network losses or tap changer actions, optimizing algorithms are needed.[7]

The amount of available real-time measurements in distribution networks has increased due to installment of Automatic Meter Reading(AMR) devices. These, when utilized, will improve accuracy of network state estimation. With accurate state estimates, more accurate input data can be provided for CVC algorithms.[44]

Possible implementations of control architectures for active network management are discussed in next subsections. CVC scheme with a cascade control architecture, where solving and determining of control actions is distributed across voltage levels, is introduced. Case study is then performed in this thesis on CVC in LV network. The optimization problem and the CVC algorithm implementation are described in detail in Chapter 4. Other algorithms used in the scheme are also presented in the same chapter. The algorithm utilizes all DERs that are available in the simulation network presented in Section 5.2. Controllers realizing the CVC actions in the simulation system are presented in Section 5.3.

2.5.1 Control architectures and implementation

Different types of control strategies, i.e. active network management schemes, can be used in distribution networks: Centralized, semi-coordinated or decentralized. The decentralized architecture utilizes local controls and aspires to cost savings using only limited communication or no coordination at all. Fast response and not being subjected to communication failures are advantages of decentralized methods. For example multi-agent systems are used in intelligent decentralized control systems. As many of the methods include a coordinating component, some of the decentralized methods could be described as semi-coordinated.[45]

In centralized architecture all intelligence(i.e. measurements and static data) is gathered into a central system. The logic behind control actions is concentrated there. Centralized approach requires investments in sensors, and communication and control infrastructure.[27] Most CVC methods are centralized and therefore the algorithms can be implemented as part of existing Distribution Management System(DMS). In centralized control architecture, every function and decision making is concentrated in DMS. DMS combines network state estimation and network information data from Network Information System(NIS), both of which are needed as inputs for CVC algorithms. Supervisory Control and Data Acquisition(SCADA) is commonly integrated into DMS, and provides real-time measurement data, network switching state and control possibilities to the scheme. CVC outputs, set point and reference values, can be then sent to the controllable resources directly through SCADA.[28]

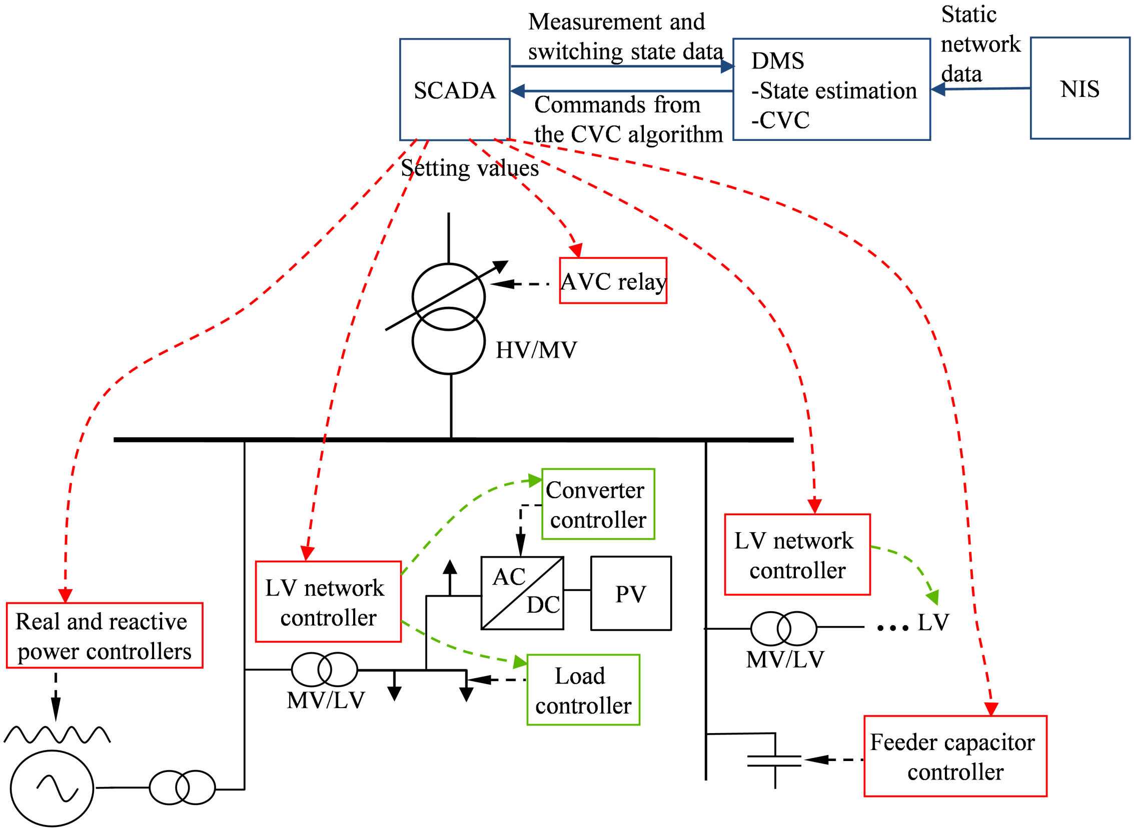

Figure 2.4 Concept architecture of coordinated voltage control [28]

SCADA/DMS system can extend to LV network management with the integration of AMR infrastructure to the centralized system. In this advanced metering infrastructure(AMI) smart meter information is widely available for real-time LV network monitoring and simple control purposes. With large number of controllable devices and available measurements in the future distribution networks, it is beneficial to store measured information and perform necessary control tasks decentralized also at lower levels of automation. This reduces data transfer to upper level CC and therefore enables improved utilization of small-scale DERs in network management. This type of decentralization enables cascade control architecture and aggregation of information in many levels. An example cascaded architecture of coordinated voltage control is presented in Figure 2.4. LV level controller installed at secondary substation aggregates information from LV side measurements and DERs, and is responsible of controlling DERs accordingly. It realizes control commands from upper level CC and updates the aggregated information of the LV network to upper level.[46]

2.5.2 Control hierarchy in future distribution networks

In future distribution networks, according to IDE4L project approach[47], the control is seen to be divided to three hierarchical levels: primary, secondary and tertiary control. Each control level operates in different network layer and with different deployment time.

Primary control is based on local measurements of each DER and therefore only local information is considered when making autonomous control decisions. The control actions could include reactive power control, transformer OLTC voltage control, or production curtailment in extreme cases, and the actions would take effect in the order of seconds or faster. As mentioned earlier primary control of DG units is generally not in use as unity power factor is often a requirement.[47]

Secondary control at primary or secondary substation level receives estimates of the network state and coordinates operation of primary controllers in the network area. Secondary control aims to minimize operational costs while ensuring voltage quality in the network. The required control actions are done in the order of minutes. Secondary control is realized on primary or secondary substation level, or on both.[47]

Tertiary control is the highest level of the control hierarchy and it coordinates actions of secondary controllers, or orders and provides flexibility services from commercial aggregators to optimize the network operation within voltage and conductor limits. The tertiary control actions are based on current and future network states from state estimation and state forecasts. Tertiary control operates in a time-frame of tens of minutes to hours. Tertiary control is located at the CC.[47]

Coordination of the aforementioned controllers is seen to greatly increase the network's DG hosting capacity when assessing the situation versus passive network planning and control, or local measurement based voltage control.[3]

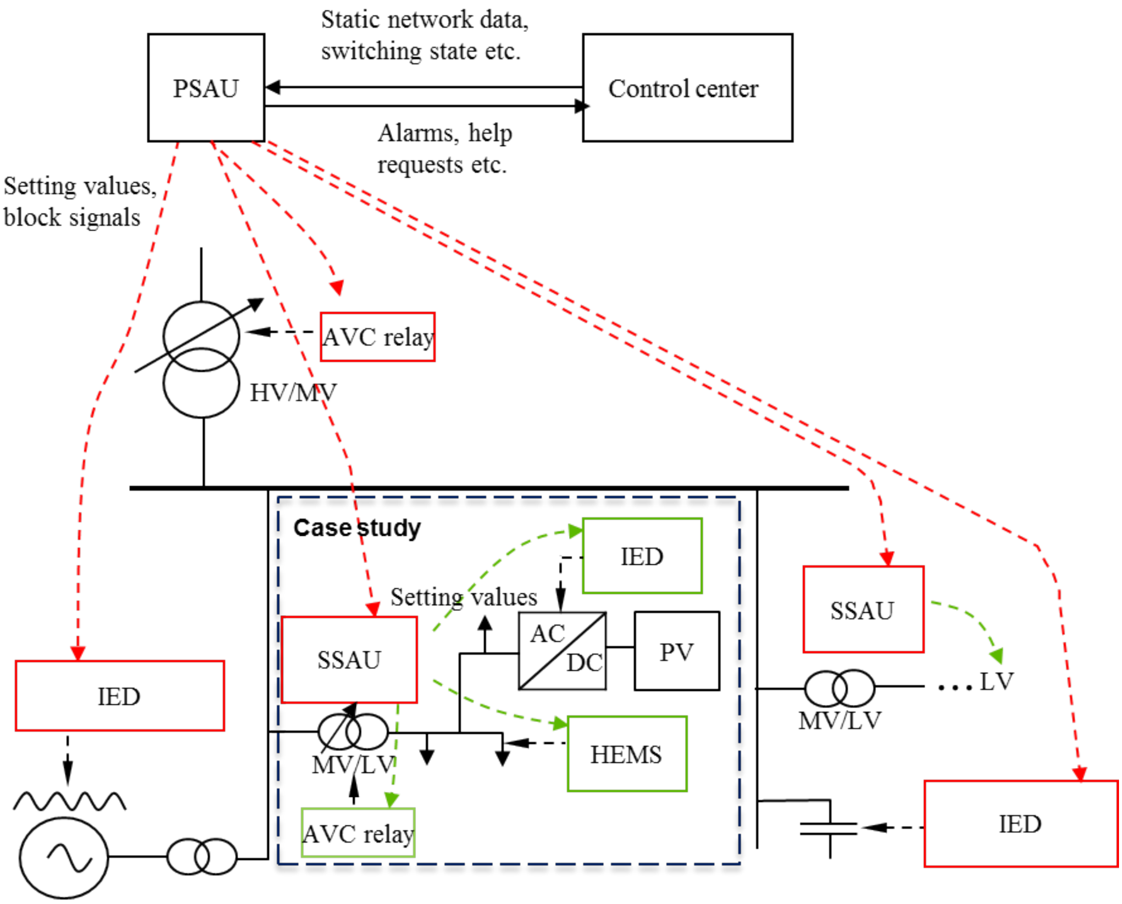

***Figure 2.5** IDE4L control architecture of coordinated voltage control*

Figure 2.5 presents the three hierarchical levels of IDE4L control architecture. The lower level controllers, Primary Substation Automation Unit(PSAU) and Secondary Substation Automation Unit(SSAU), realize the secondary control. The specification of a SAU is further opened in following chapter. Case study of the thesis is performed on LV network.

3. SUBSTATION AUTOMATION UNIT

With the increasing amount of DERs in the networks, the active network management and automation schemes are becoming complex to realize. The amount of available measurements is increasing and utilizing these requires extensive communication and data transfer across the network. Therefore a Substation Automation Unit(SAU) has been designed in IDE4L project to tackle these issues. With SAUs the automation burden can be distributed across hierarchical voltage levels. The SAU architecture concept in Figure 2.5 enables decentralizing monitoring and control functions closer to field on each voltage level. SAU collects measurements, runs state estimation and state forecasting and handles network power control, at its network location. PSAU is located at the primary substation and is responsible of MV network. SSAUs are located at the secondary substations and manage LV networks.[48]

A SAU consists of interfaces, database and functions as depicted in Figure 3.1. Data handling and storage is done by using relational database. The data stored in SAU is modeled so that it complies with latest standards IEC 61850 and IEC Common Information Model(CIM) to support interoperability. The SAU hardware can be e.g. a standard computer with Linux or Windows operating system.[48]

3.1 Interfaces and functions

Three types of interfaces are built within the SAU: interfaces to communicate with field devices and controllers, interfaces to communicate with upper level controllers(other SAUs or DMS) and database interfaces within the SAU functions. Various protocols are used in distribution automation, IEC 61850 being the newest widely accepted standard.

Field devices and controllers can lack support to IEC 61850 so therefore Modbus with a gateway is used. DLMS/COSEM is common protocol in the field of smart

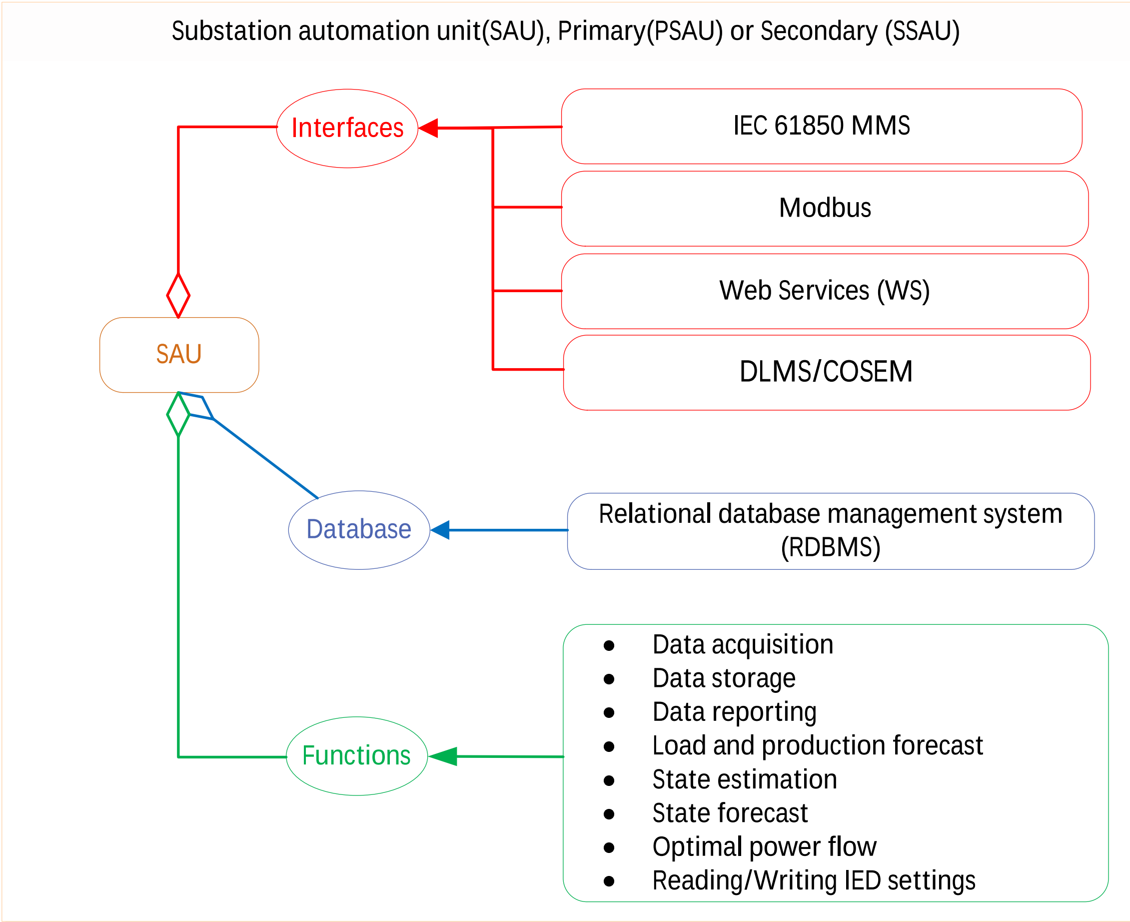

Figure 3.1 *Substation Automation Unit [48]*

metering, and is used to communicate with smart meters. Web services(TCP/IP, UDP/IP) are used to concentrate smart meter data when the meters are not directly accessible. MMS is suggested as application protocol for monitoring and control applications by the IEC 61850 standard.

The main functions of SAU are divided to monitoring and control functions. Monitoring functions are are acquiring, storing and reporting measurements, load and production forecasting, state estimation and state forecasting, and control function is the real-time power control by utilizing optimal power flow. The functions can be implemented using various programming languages. State estimation, power control and an optional coordinating algorithm for cascade OLTC operation are relevant to the CVC concept and thus further described in the next chapter.

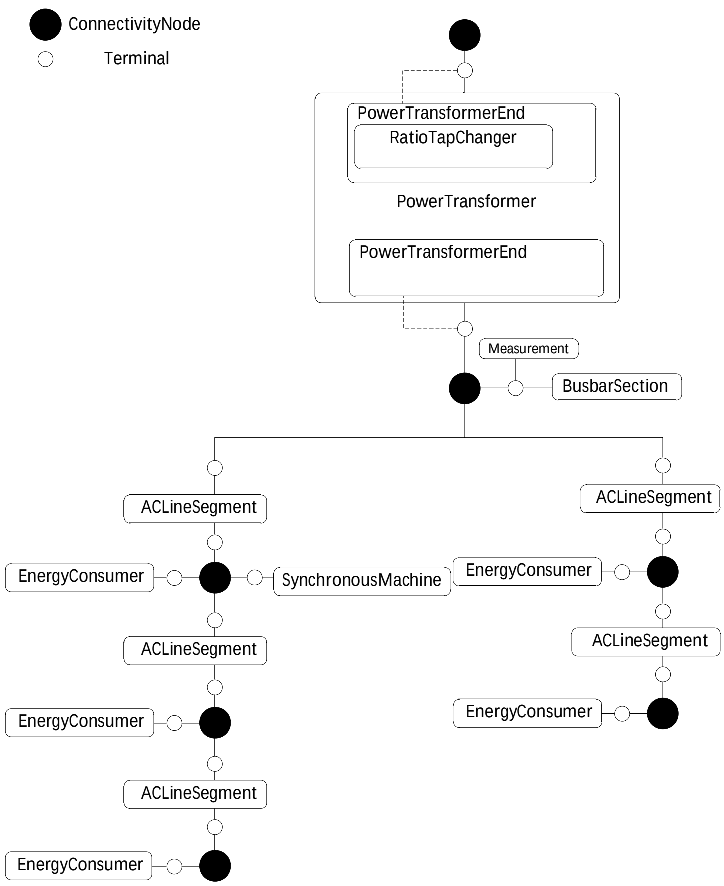

Figure 3.2 *Example of CIM network representation after CIM v15*

3.2 Data modeling

IEC 61970-301 and IEC 61968-11 are collectively known as Common Information Model(CIM) for power systems. The IEC 61970-301 *Energy management system application program interface (EMS-API) - Part 301: Common information model (CIM) base* provides a standardized approach to represent power system resources as object classes and attributes along with the connections in between. The IEC 61968-11 *Application integration at electric utilities - System interfaces for distribution management - Part 11: Common information model (CIM) extensions for distribution* extends the base CIM for the needs of distribution networks and enables integration of DSO information systems.[49] Figure 3.2 depicts CIM network representation of transformer and two feeders.

ConnectivityNodes, depicted in black, are used to define interconnection points for equipment. Each white circle, a terminal, has association with one connectivitynode and a connectivitynode may associate with multiple terminals. Terminals are also defining points for connectivity related measurements.[49] The measurements are omitted from the figure as each terminal would include multiple measurements for phase voltages, powers or currents etc. The transformer model is based on transformer model after CIM v15 presented in [50]. TransformerEnds refer to the transformer's physical terminals and contain transformer parameters as well as the tap changer. ACLineSegments represent distribution lines between network nodes. SynchronousMachine models DERs that export active and/or reactive power to the network. EnergyConsumers model consumption. The used data model for network topology in SAU database combines the classes and attributes of the CIM standard and each network topology table is based on one or more CIM classes.

IEC 61850 data model is used in monitoring and control. In SAU database the monitoring and control data is presented using IEC 61850 logical nodes, data objects and data attributes. A logical node is the smallest part of a function that exchanges data and represents a measurement or control function. The devices that perform different measurement and control functions are modeled with physical devices and logical devices within a physical device. Data objects within a logical node each have a common data class type. The data objects consist of many data attributes and thus group the data attributes sharing the same function. Finally the data attributes represent elements of the data class e.g. value or timestamp. Table 3.1 presents monitoring and control data modeled according to IEC 61850. Similar structure can be found in the SAU database tables designed for the monitoring and control purposes.

Table 3.1 *Monitoring and control IEC 61850 data model*

Monitoring and control use case	**Logical node**	**Data object**	**Data attribute**
Voltage, current, real/reactive power measurements and estimates	MMXU	A, PhV, W, VAr	phsA.cVal.mag.f[MX] phsB.cVal.mag.f[MX] phsC.cVal.mag.f[MX]
Total real/reactive power, average phase to phase voltage	MMXU	TotW, TotVAr, AvPPVPhs	mag.f[MX]
Tap changer position	ATCC	TapPos	valWTr.posVal[ST]
Energy measurement	MMTR	TotWh	actVal[ST]
Load and production forecasts	MMXU	W, VAr	phsA.cVal.mag.f[MX] phsB.cVal.mag.f[MX] phsC.cVal.mag.f[MX]
Real and reactive power set points for DGs	DRCC	OutWSet, OutVarSet	Oper.ctlVal.f[CO]
AVC relay voltage set point	ATCC	BndCtr	setMag.f[SE]

3.3 Database

Relational database management system(RDBMS) is used to store required data in each SAU for each network layer. The data is related to field measurements, control command exchanging, network topology and analyzing algorithm execution. The data is exchanged among functions and interfaces implemented in the SAU. Distributing the storage mitigates the burden of data transfer to the CC and allows more frequent data acquisition from the field. The database architecture is divided into four sections each representing different data.[48]

Network Topology model contains static network information; network components, connections, and all related characteristics and parameters. Network topology schema was designed based on CIM and each table is based on one or more CIM classes.

Dynamic network data such as real-time and historical measurements, forecast profiles and control signals are stored in Measure and Command -model. Measure and Command -model was designed based on IEC 61850 data model. It has been expanded to include the real-time, historical and forecast values, and also a socket table which stores connection parameters of physical devices.

The Measure and Command model is mapped to the Network Topology model through a simple Bridge model. The bridge model describes a relation between a measurement or a command with their location in the network topology.

The SAU algorithms are run in parallel and interactions between the algorithms are required in order to produce expected results. For this purpose, Management model was built to coordinate the concurrent algorithm execution. Flag signals are used in the model to report events of each algorithm instance. The flag or algorithm state is then read by other algorithms and used to decide if actions are needed. Logs of algorithm states and execution times are also stored in the model.

4. ALGORITHMS

This chapter introduces algorithms used in realizing a CVC scheme. The algorithms have been developed during years of Smart Grid research in Tampere University of Technology. Modularity was aspired when designing the algorithms within the IDE4L project. Thus all the algorithms were implemented as their own independent instances and all data between algorithms and IEDs in the network is transmitted through the database on SAU. The same algorithms are used at MV and LV level with minor voltage level specific modifications.

4.1 State Estimation

Network state estimation has been in use for decades in transmission networks. The estimation utilizes network model, measurements and network switching state as inputs aiming to obtain best possible estimation of network state by processing the input information. Traditionally voltage magnitudes and angles have been used as state variables and other variables (i.e. current and power flows) have been calculated using the state variables. State estimation outputs node voltages, line current flows and node power injection values. Weighted least squares(WLS) method is typical to transmission network state estimation. WLS estimation minimizes the weighted sum of squared measurement residuals. Measurement residual is the difference between the measured and the estimated value and each residual is weighted with the accuracy of the corresponding measurement. Applying transmission network state estimate techniques into distribution network state estimation is problematic due to different nature of the networks. In distribution networks the availability of real-time measurements is limited, network topology is usually radial, loads are asymmetric and decoupling of real and reactive powers cannot be used to simplify calculations due to high R/X ratio.[51, 52, 53]

The available measurements in distribution networks traditionally include substation busbar voltage, and feeder current or power flows. These combined with network data and load profiles are used to adjust feeder loads accurately. Within the feeders true loads can differ from load profiles which will cause inaccuracy in voltage and current estimates. With the growth of DG and development of Smart Grids, more measurements are available in distribution networks. AMR brings real-time power and voltage measurements also from customer connection points. Active distribution network management functions, such as CVC, require accurate real-time estimates of network voltages and power flows.[44]

To fully utilize the additional measurements and to increase the state estimation accuracy, advanced state estimation methods have been developed. Distribution system state estimation method based on WLS using branch currents as state variables instead of voltages is presented in [44] and further developed by adding bad data detection in [54]. MV state estimation has been studied extensively compared to LV state estimation. However, similar approaches can be used in LV state estimation due to similar characteristics with MV networks when compared to transmission networks. In [51] and [53] distribution state estimation was applied to LV networks. Real-time smart meter measurements and load profiles generated from historical data of past AMR measurements were used in the distribution network state estimator to gain accurate information of LV network state.

State Estimation algorithm(SE) in this thesis is the branch-current based distribution system state estimator from [53] and [54]. LV network estimation is handled from the SSAU, and the SE is run as Octave program. SE runs periodically, every minute, or on-demand from other algorithms. In real-time sequence the algorithm reads current network topology and switching state from corresponding database, reads latest real-time measurements(substation measurements, smart meter measurements and production measurements) and load and production forecasts. Load and production forecasts are used as pseudo-measurements for unmeasured load and production points. Calculated state estimates are then stored to the corresponding SAU database to be used by other algorithms. IEC 61850 data model is used and the estimates are stored similar to real-measurements but under a fake physical device in the Measure and Command -schema. State estimation outputs are mandatory inputs for Power Control algorithm presented in the next section.

4.2 Power Control

The purpose of real-time power control algorithm(PC) is to realize CVC in the IDE4L control architecture. PC mitigates congestions in distribution network, i.e. ensures voltages in the network are within acceptable limits and branch currents are within conductor thermal limits. Further, within aforementioned limits, the network state is optimized by minimizing objective function target value. The objective function will consist of minimizing network losses, production curtailment, number of load control and tap changer actions, and limiting voltage variation at each node. For this optimization problem detailed network information from state estimation results, cost parameters for the objectives and static network data are needed. The following description of the optimization problem, constraints and implementation details are referenced from [55].

4.2.1 Optimal power flow and objective function formulation

The optimal power flow(OPF) problem is a mixed-integer nonlinear programming problem (MINLP) which is defined as the most accurate but also the most complex way to represent power systems with discrete control elements[56]. The OPF problem can be presented as

$$\begin{aligned} &\min f(\mathbf{x}, \mathbf{u_d}, \mathbf{u_c}) \\ &g(\mathbf{x}, \mathbf{u_d}, \mathbf{u_c}) = 0 \\ &h(\mathbf{x}, \mathbf{u_d}, \mathbf{u_c}) \leq 0 \end{aligned} \tag{4.1}$$

where $\mathbf{x}$ is the vector of dependent variables. The vector of dependent variables

$$\mathbf{x} = [V_1, ..., V_n, \delta_1, ..., \delta_n] \tag{4.2}$$

contains voltage magnitudes V and voltage angles δ of n network nodes. The vector of discrete control variables $\mathbf{u_d}$ includes only the change in transformer tap changer position m in the study network. The vector can be formulated as

$$\mathbf{u_d} = [\Delta m_{up}, \Delta m_{down}]\,, \tag{4.3}$$

where $\Delta m_{up} \geq 0$ and $\Delta m_{down} \leq 0$. The change in tap changer position can be then calculated as

$$\Delta m = \Delta m_{up} + \Delta m_{down}\,. \tag{4.4}$$

The vector of continuous control variables $\mathbf{u_c}$ contains real powers of j DG units P_{DGj}, reactive powers of k controllable resources Q_{contk} and real power changes of m controllable loads ΔP_{DRm}

$$\begin{aligned}\mathbf{u_c} =& [P_{DG1}, ..., P_{DGj}, Q_{cont1}, ..., Q_{contk}, \Delta P_{DR1up}, ..., \\ & \Delta P_{DRmup}, \Delta P_{DR1down}, ..., \Delta P_{DRmdown}] \,.\end{aligned} \tag{4.5}$$

Similarly the real power change of a controllable load can be calculated by summing:

$$\Delta P_{DR} = \Delta P_{DRup} + \Delta P_{DRdown} \,, \tag{4.6}$$

where $\Delta P_{DRup} \geq 0$ and $\Delta P_{DRdown} \leq 0$. Real power change variable and tap changer position variable are formulated by avoiding absolute values. Absolute values in objective function calculation can lead to poor optimization result.

The optimization aims to minimize the objective function value presented in Equation 4.7.

$$\begin{aligned}f(\mathbf{x}, \mathbf{u_d}, \mathbf{u_c}) = & C_{losses} * P_{losses} + \sum (C_{cur} * P_{cur}) \\ & + \sum (C_{DR} * (\Delta P_{DRup} - \Delta P_{DRdown})) \\ & + C_{tap} * (n_{tapup} - n_{tapdown}) + \sum (C_{Vdiff} * (V_{i,r} - V_i)^2) \,,\end{aligned} \tag{4.7}$$

where C_{losses} is the cost of losses, P_{losses} is the total amount of losses, C_{cur} is the lost income due to each generation unit curtailment and P_{cur} is the amount of curtailed generation per generation unit. In addition to objective function in [7], other parameters in the equation include cost for load control C_{DR}, amount of controlled load ΔP_{DR}, cost for one tap step C_{tap}, number of tap changer operations n_{tap}, cost of voltage variation from nominal C_{Vdiff}, the reference voltage $V_{i,r}$ and estimated voltage V_i of node i. The cost parameters can differ for each active resource.

The total losses in the network can be calculated as a sum of real power injections in all network nodes

$$P_{losses} = \sum P_i \,. \tag{4.8}$$

The consumed and generated powers can be calculated by combining the uncontrollable and controllable powers from state variable $\mathbf{u_c}$ in Equation 4.5.

$$\mathbf{P_i} + j\mathbf{Q_i} = \mathrm{diag}(\mathbf{V})(\mathbf{Y_{bus}}\mathbf{V})^*\,, \tag{4.9}$$

where $\mathbf{V}$ is the node voltage vector and $\mathbf{Y_{bus}}$ the bus admittance matrix formed from network information data.

4.2.2 Constraints

Constraints in the power system calculations are divided into equality and inequality constraints. Each network node must fulfill power flow equations modeled by equality constraints. Slack node, where voltage magnitude and angle are known constants, is defined to be the substation bus i.e. the secondary side of tap changing transformer. Following equations need to be fulfilled in the slack node:

$$V_{slack} - (V_{ssmeas} + \mathit{\Delta} V_{ss}) * \frac{tap_{orig}}{tap_{new}} = 0\,, \tag{4.10}$$

$$\delta_{slack} = 0\,, \tag{4.11}$$

where V_{ssmeas} is the measured substation voltage, $\mathit{\Delta} V_{ss}$ is substation voltage change due to change in power flow through the transformer and the feeding network impedance after control actions, tap_{orig} the original tap changer position and tap_{new} the new tap changer position. The change in substation secondary side voltage, without taking change in network losses and possible unbalance into account, can be calculated from

$$\mathit{\Delta} V_{ss} = R\mathit{\Delta} P + X\mathit{\Delta} Q\,, \tag{4.12}$$

where R and X are summed resistance and reactance of the transformer and the feeding network, $\mathit{\Delta} P$ is the total change in controllable real power of generation and loads, and $\mathit{\Delta} Q$ is the total change in controllable reactive powers. These are derived from OPF state variables.

All other nodes are possible DG connection points and, because all active resources operate in reactive power control mode instead of voltage control mode, are defined as PQ nodes. In the PQ nodes real and reactive powers are known but the voltage magnitudes and angles vary. All PQ buses must fulfill following equality constraints:

$$P_i - P_{gen,i} + P_{load,i} = 0 \tag{4.13}$$

$$Q_i - Q_{gen,i} + Q_{load,i} = 0 \tag{4.14}$$

where P_i and Q_i are injected powers to the node i calculated from Equation 4.9. $P_{gen,i}$ and $Q_{gen,i}$ are the real and reactive powers generated in the ith node, and $P_{load,i}$ and $Q_{load,i}$ are the real and reactive powers consumed in the ith node.

The optimization is also limited by technical constraints in the network and the capabilities of the controllable resources. Following inequality constraints are used in the optimization:

$$V_{lower} \leq V_i \leq V_{upper} \tag{4.15}$$

$$P_{activeimin} \leq P_{activei} \leq P_{activeimax} \tag{4.16}$$

$$Q_{activeimin} \leq Q_{activei} \leq Q_{activeimax} \tag{4.17}$$

$$m_{min} \leq m \leq m_{max} \tag{4.18}$$

$$S_{ij} \leq S_{ijmax} \tag{4.19}$$

Equation 4.15 limits network node voltages to be within feeder voltage limits. Equations 4.16 and 4.17 set limits for real and reactive powers of active controllable resources. Equation 4.18 sets technical constraints for main transformer tap ratio and Equation 4.19 limits the apparent power flow S in network branches below maximum allowed value.

4.2.3 Implementation

In this thesis' simulations, solving of the optimization problem is done by using sequential quadratic programming(SQP). In SQP, solving a series of approximates of the original nonlinear programming problem, which represents behavior at optimal solution of previous iteration round, converges in to a optimal solution of the original problem.[56] The optimization algorithm will be run as an Octave program. Earlier tests have been conducted using a MATLAB program in [7]. Used PC algorithm is a further developed version of the earlier implementation. The differences between earlier MATLAB implementation and the used Octave implementation will be discussed in the results.

Required input data is fetched from the SAU database or the variables are user defined in the initialization process. The inputs include static network data, dynamic state estimation data and cost parameters, and flag signals from other algorithms. Flag signals are used to coordinate the real-time execution sequence of the used algorithms. The real-time sequence of the algorithms is further described in Section 4.4. Blocking of On-Load Tap Changers of Transformers -unit presented in the next section could be used to coordinate the operation of MV and LV power control algorithms by sending blocking signals to AVC relays.

The PC algorithm outputs set points for available controllable DER. In the simulations these will be real and reactive power set points of DG units and voltage set point of AVC relay. The new set points will be written into database and to the DG units in case they differ enough from previous set point values. After every execution loop, execution time and other optimization related parameters further described in Chapter 6 are stored in the database in order to evaluate the algorithm operation afterwards.

In the case of PC algorithm is missing adequate inputs, the network state is faulted or algorithm is not able to converge, i.e. find a solution to the congestion problem, alarm message will be output to the system operator. These three are considered as exceptional situations. Exception handling has been predefined for each case. State estimation results are mandatory inputs for PC algorithm operation and therefore the scheme tries to solve this if any problems arise. New state estimation is requested from the SE algorithm if the newest estimates have too old timestamps. If state estimation results have been unavailable for longer period of time, predefined set points for all controllable resources could be set. These would be defined offline by worst case scenario analysis i.e. minimum loading and maximum generation, or maximum loading and minimum generation, but is yet to be implemented. In the case of available controllable resources are not enough to solve the congestion, all available resources should be used to their limits to reduce violations in the network. During network faults, PC algorithm waits until fault location, isolation and service restoration has operated.

4.3 Blocking of On-Load Tap Changers of Transformers

OLTC tap actions at MV level have effect downwards at LV level. Without coordination cascade OLTCs can cause unnecessary tap actions when trying to keep voltage within admissible limits in both voltage levels. Unnecessary tap actions will then cause fluctuations to consumption point voltages and increase wear of the

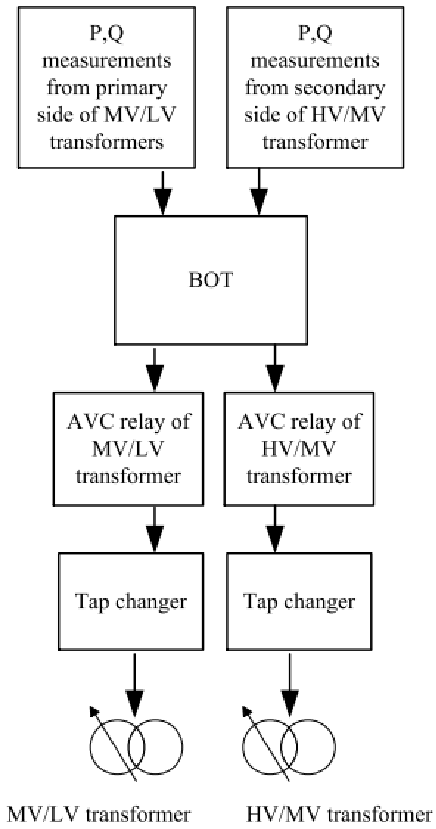

Figure 4.1 *Operation of independent BOT unit [16]*

mechanical OLTC. Increasing amount of DG resulting in bidirectional power flows requires originating of the voltage change in the network. Detected changes in LV network should cause MV/LV transformer OLTC to do the required actions and in this case HV/MV OLTC should be blocked. Likewise, during upper voltage level changes and OLTC operations the lower level OLTC should be blocked until the tap action is finished. Different time delays for each OLTC are most commonly used to manage cascade OLTC operation; upper level OLTC operating first and lower level after, if needed. This is the worst case scenario for voltage restoration time at consumption points. With communication implemented between primary and secondary substation, a block signal can be used. This enables setting of equal time delays for cascade OLTCs and therefore reduces voltage restoration time.[16]

The purpose of coordinated cascade OLTC control is to improve LV customer voltage quality by reducing voltage fluctuations and minimizing number of tap actions. Blocking of On-Load Tap Changers of Transformers(BOT) unit realizes this control method. Operation of independent BOT unit is shown in Figure 4.1. The unit is located at primary substation and it uses active and reactive power values from both secondary side of HV/MV, and primary side of all MV/LV transformers, as inputs. BOT unit determines origin of the voltage change by comparing past and present power flow information from 2 meters. After originating the changes in the network, BOT determines which OLTC to block and outputs block signal and validity time directly to AVC relays or through a database. The validity time ensures that block signal will not stay active unnecessarily in case of a communication failure. Unblocked OLTCs will then operate if the measured voltage is not within set AVC relay dead band.[16]

In the introduced IDE4L control architecture the block signals would be stored in SAU database at primary substation and would be read dynamically by PC algorithm before operating. BOT unit is therefore interpret as a coordinator for secondary voltage control, but could also operate as an independent unit. As the case study of the thesis only considers LV network, the BOT is not used.

4.4 Execution sequence of the algorithms

Figure 4.2 depicts the simplified real-time execution sequence of the algorithms. Without going too much into detail of the initialization flow and exception handling of each algorithm, the figure points out inputs and outputs of the introduced algorithms and the order of execution within given time-frames. The algorithms operate in a loop of predetermined time, e.g. one minute, or when requested by an execution or reset request set by other algorithms. The dashed line represents an example case of an execution request set by an algorithm. The coordination between the PC and other algorithms is handled by using flags in the SAU database Management schema. The SAU database is left out of the figure on purpose. All shown input and output data goes through the SAU database.

In the real-time execution sequence, the network is continuously monitored and the real-time measurements are stored in the SAU database. The polling times of the measurement devices vary between the devices. Using the newest measurements, and load and production forecasts, new state estimates are calculated by SE algorithm and the results are stored in the SAU database. Earlier estimated values are moved to historian table. BOT would operate before PC in order to determine

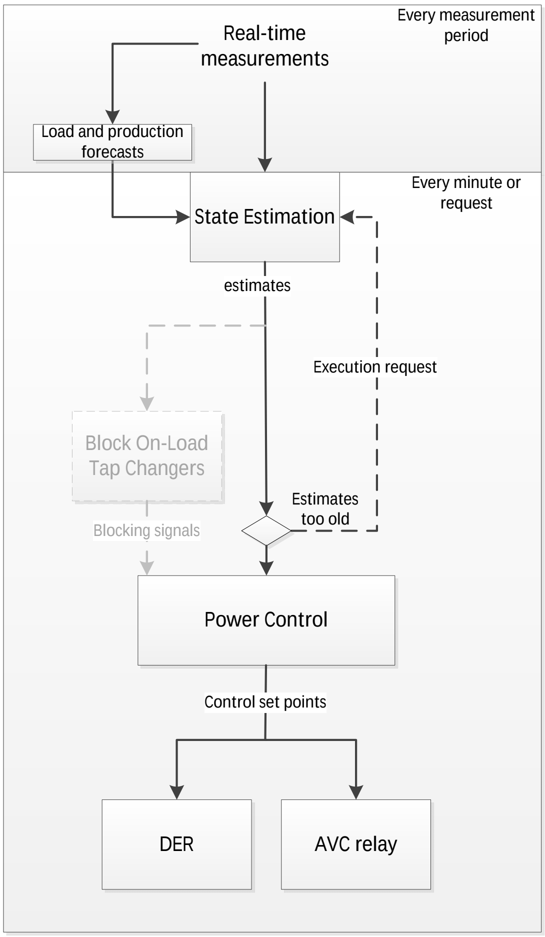

Figure 4.2 *Real-time sequence of the SAU algorithms*

which secondary controller, i.e. MV or LV power control, should perform the actions. In the case of both were to operate, BOT determines which OLTC should be blocked by sending blocking signals. PC algorithm then runs the optimization taking the blocking signals from BOT into consideration, and outputs new set points for primary controllers.

The correct and reliable operation of PC algorithm is vital to the congestion management scheme. New enough SE results are mandatory for the execution of PC algorithm. BOT is an optional addition to the scheme as it is used to prevent unnecessary control actions in a short period of time but possible failures in the algorithm do not lead to failures in the PC algorithm.

5. TESTING ENVIRONMENT

This chapter introduces the Real Time Digital Simulator (RTDS) testing environment and the external devices connected to the simulation network. The laboratory environment is illustrated in Figure 5.1. The laboratory environment is used to carry on the case study to test the algorithms. All information in Section 5.1 is gathered from [57] and [58].

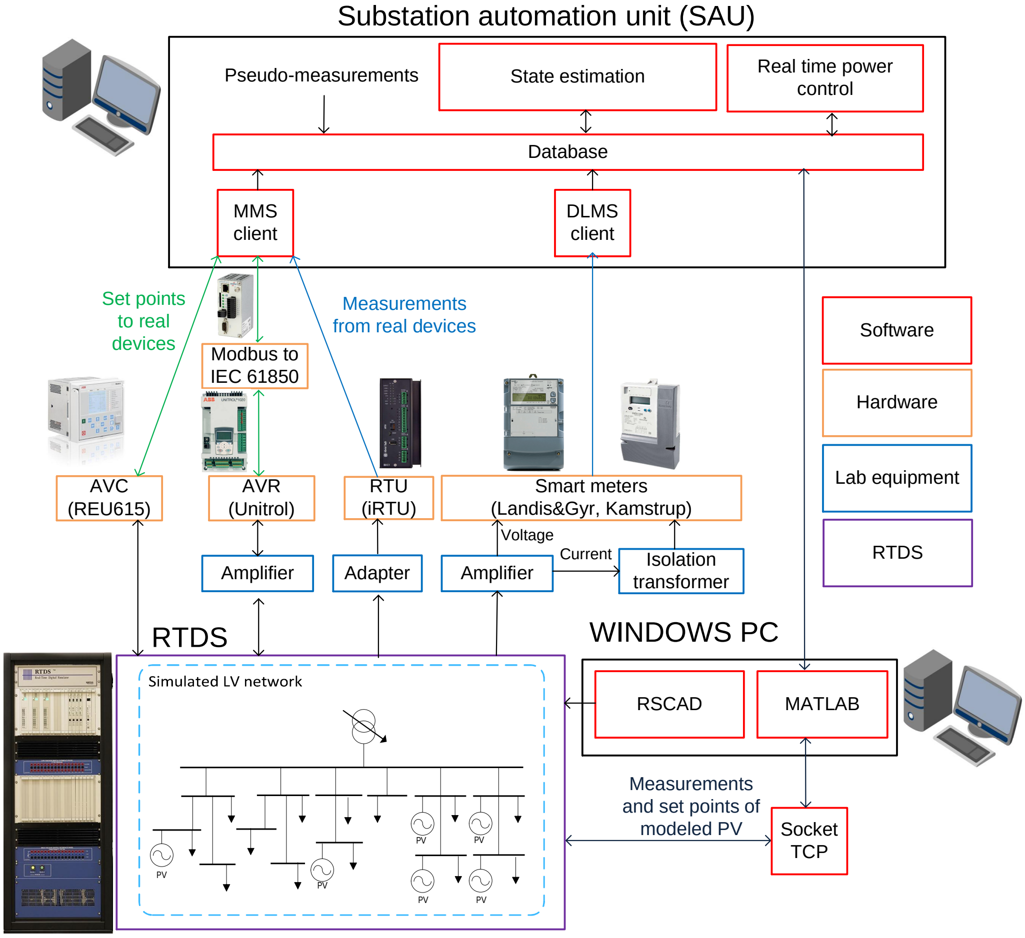

Figure 5.1 Tampere University of Technology RTDS laboratory environment

5.1 Real Time Digital Simulator

RTDS is a power system simulator designed to simulate power systems and test physical devices' interaction with power system simulation model in real-time. Modular hardware realizing the simulations is installed in racks. The racks are housed in variable-sized cubicles. Cubicle size defines the number of racks that can be installed and therefore the simulation capacity. Various types of processor and communication cards from different generations can be mounted into a rack. Together with racks, input/output cards, power supply and power entry components are housed in cubicles. Latest generation hardware is used in the simulation laboratory and therefore is introduced in this section. In conjunction with the hardware a dedicated software, RSCAD, is run on an external computer. RSCAD is used to build and run simulation network models, and analysis of the simulation results can be done in RSCAD. External devices can be connected to RTDS simulation system via input and output ports.

Figure 5.2 *Real-Time Digital Simulator cubicle[57]*

Communication between the RTDS rack and RSCAD is handled by Giga-Transceiver Workstation Interface Card(GTWIF). GTWIF also handles communication with other racks participating in simulations and coordinates data transfer between processor cards within a rack. RTDS system consisting of 3 or more racks requires a Global Bus Hub(GBH) for synchronization between GTWIF cards. System with 2 racks can be connected directly between optical ports in GTWIF cards in each rack.

Network interface card GTNETx2 provides real-time communication interface between external devices and RTDS via Ethernet. Each GTNETx2 card has two modules and each module has one Ethernet port. GTNETx2 supports various network protocols including IEC 61850 GSE, IEC-61850-9-2 Sampled Values, IEEE C37.118, DNP3, IEC 60870-5-104 and PLAYBACK of large data sets. Each GTNETx2 runs two network protocols simultaneously, and comes with configured TCP/UDP socket communication and an additional user selected protocol.

All power system computations are solved by PB5 processor cards. Each PB5 contains two processors operating at 1.7 GHz clock rate, and eight optical ports. One PB5 processor is generally assigned to one network solution. In GTWIF based systems each solution can include 72 single phase nodes, and thus maximum number of 144 single phase nodes can be included within one PB5 rack. Other PB5 processors are, however, needed to solve power and control system component models(e.g. lines, generators, transformers). The eight optical ports are used to connect the PB5 card with various analog and digital input/output cards, or for direct communication between other PB5 and older generation GPC processor cards. The GPC card has two older processors operating at 1.0 GHz clock rate. Unlike PB5, the GPC supports only one network solution per card and therefore maximum of 66 single phase nodes.

RTDS simulator performs all calculations in real-time which enables connection of commercial smart meters, remote terminal unit and voltage control relays, AVC and AVR, used for OLTC and DG control, respectively. In real-time simulations communication delays and algorithm execution times are visible and taken into account in the operation. The execution times can potentially cause issues within the real-time sequence. RTDS enables simulating sequences of events that can not be realized in real distribution networks without risking the safety of operation and equipment.

For this thesis' case study RTDS system installed at Tampere University of Technology is used. The setup consists of 2 racks and total of 7 PB5 processor cards and 2 GTNETx2 card are used. Socket TCP/UDP is used to fetch real-time measurements from DG units in the simulated network, and to write set points to the DG units.

5.2 Simulation network model

The simulated network is a model of real distribution network in the municipality of Brescia, Italy. The network is owned by Italian distribution network operator Unareti Spa. Both MV and an LV network are presented but the case study will only focus on the LV network.

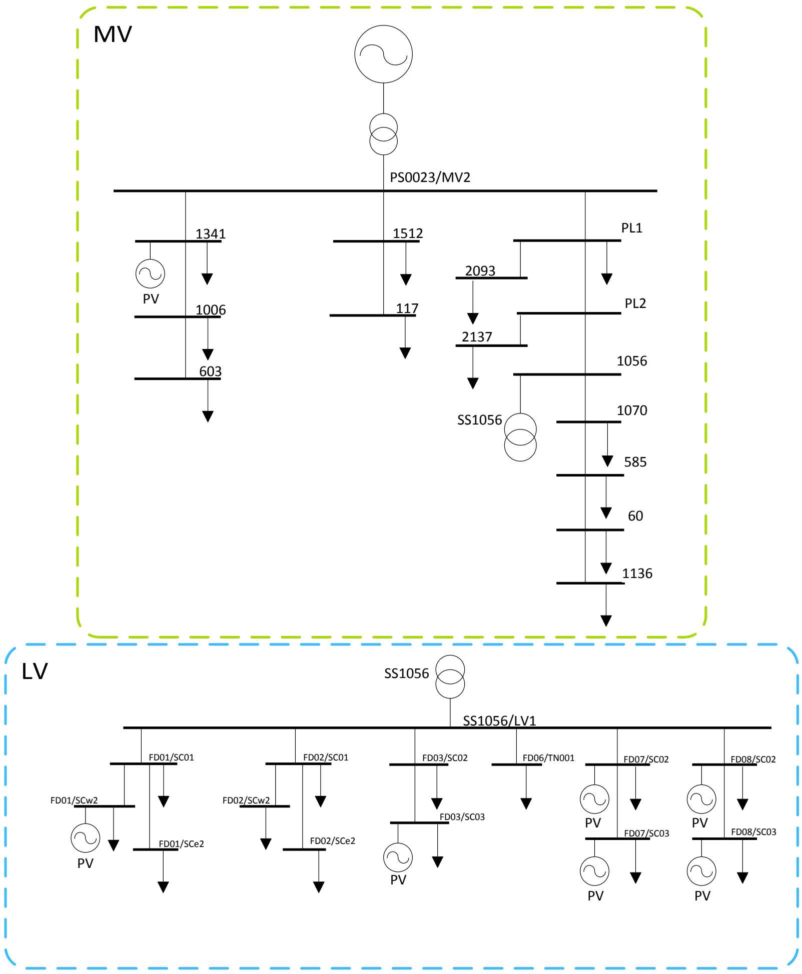

Figure 5.3 Simplified RTDS network model

The original network topology found in Figure A.1 of Appendix A was simplified for RTDS due to limitations in the simulation hardware. This was done by combining loads and line parameters using nominal loading data from the DSO. Figure 5.3 depicts the simplified network model. Criteria of 0.5% difference in original and simplified per unit voltage value was used in the node reduction process. The original and simplified LV load buses are listed in Table A.1 of Appendix A. The loads in the network are modeled as constant power loads with a power factor of 0.97, derived from DSO data. Two loading cases are chosen from times when stochastic PV generation is considered to be at its maximum output but can also vary widely due to cloudiness. The chosen loading cases are listed in Table A.2. The loading on Sundays is estimated to be 2.5 times the loading on week days. The line parameters are stored in the SAU database Network Topology tables for modeling distribution lines. Table A.3 presents the distribution line parameters of the simplified LV network. Transformer and tap changer parameters are presented in Tables A.4 and A.5 respectively.

Controllable resources in the simulation LV network are listed in Table 5.1 and the initial and nominal values for PV generation in Table 5.2. The optimum set points are calculated by the PC algorithm. Initial values of 1.0 pu for voltage reference, 100% for real power and 0 VAr for reactive power are set to the resources on algorithm startup. Also an initial optimum network state is allowed to set and stabilize before starting any simulation sequence.

Table 5.1 *Controllable resources in simulation LV network*

Controllable resource	**Network node**	**Set point**
OLTC	1 / SS1056/LV1	V_{ref}
DG3	3 / FD01/SCw2	P, Q
DG9	9 / FD03/SC03	P, Q
DG11	11 / FD07/SC02	P, Q
DG12	12 / FD07/SC03	P, Q
DG13	13 / FD08/SC02	P, Q
DG14	14 / FD08/SC03	P, Q

Table 5.2 *DG unit generation*

Network node	**Initial output (kW)**	**Nominal power (kW)**
3 / FD01/SCw2	20.4	27.72
9 / FD03/SC03	20.1	29.01
11 / FD07/SC02	19.2	28.38
12 / FD07/SC03	19.8	23.46
13 / FD08/SC02	20.7	29.64
14 / FD08/SC03	23.34	23.34

5.3 Intelligent Electronic Devices

External IEDs are connected to the RTDS system as shown in Figure 5.1. The IEDs are housed in a rack next to the RTDS cubicle. The IEDs are commercial products by different manufacturers and are further described in this section. An Omicron CMS 156 amplifier is required to amplify the voltage and current signals from the RTDS to realistic values to be used by the IEDs.

5.3.1 Automatic Voltage Regulator

The DG unit voltage control in the simulation system is handled by ABB UNITROL ®1020 AVR relay. UNITROL®1020 is an AVR relay for synchronous generators and motors with exciters. UNITROL®1020 provides five operation modes: automatic voltage control with adjustable PID controller, power factor and reactive power control with PID control algorithm, field current regulator with PI control, reactive power sharing for generators connected in parallel and in island operation, and automatic synchronizing and voltage matching prior synchronization.[30]

Figure 5.4 *ABB UNITROL®1020 [30]*

UNITROL®1020 is connected to the RTDS system using analog signals. The measured voltages and currents received from RTDS are amplified to expected levels. UNITROL®1020 uses Modbus communication protocol and therefore it is connected to the 61850 Ethernet through an IEC 61850 Gateway. The gateway changes the communication protocol, and maps a provided dataset from UNITROL®1020, containing real power, reactive power and voltage measurements from the generator it's controlling, to IEC 61850. IEC 61850 MMS reporting is used to transfer data between the IEC 61850 gateway and SAU. IEC 61850 MMS client on the SAU reads MMS report from the MMS server on the gateway every 15 seconds, and writes the values to the database. The new calculated generator set points are written to the AVR relay through the same gateway.

5.3.2 Automatic Voltage Controller

Dedicated transformer configuration of voltage protection and control relay ABB REU615 is used as an AVC relay. The AVC relay regulates the substation voltage by controlling the OLTC at primary and secondary substation. The REU615 is connected to RTDS system with IEC 61850 Sampled Values(SV) messaging of GT-NETx2 communication card. The relay provides current tap position and substation phase voltages to the SAU database. IEC 61850 MMS client on the SAU reads MMS report from the IEC 61850 MMS server every 15 seconds and writes the substation phase voltages and the current tap position to the database. New voltage reference set points from PC algorithm are written to the AVC relay during the real-time sequence. The relay compares the difference of its substation voltage measurement and the voltage set point to its dead band value and operates accordingly after tap changer delay. A standard value of 1.5% is used as the AVC relay dead band.

Figure 5.5 *ABB Voltage protection and control REU615 [59]*

5.3.3 Remote Terminal Unit

A remote terminal unit(RTU) is connected to the simulation network at the secondary substation. iRTU manufactured by iGrid T&D is used. The RTU provides total secondary substation real and reactive power measurements and phase currents from the transformer secondary side. The measurement signals from RTDS are converted to right level using an adapter.

Figure 5.6 *iGrid iRTU Remote Terminal Unit -series [60]*

IEC 61850 MMS client on SAU reads the report from the IEC 61850 interface on the iRTU, and writes the reported values to the SAU database.

5.3.4 Smart meters

Commercial smart meters from Landis+Gyr and Kampstrup are installed to the RTDS system to measure chosen critical network nodes. The meters are depicted in Figure 5.7. Both meters provide voltage and power measurements from their network connection points. The measuring systems of the meters are different. The Kampstrup is measuring real voltages and currents directly, and the Landis+Gyr expects external current and voltage measurement transformers. The output signals from RTDS are connected to the meters via an amplifier and, in addition, current transformers are used with Kampstrup. A DLMS/COSEM client running on SAU polls the meters for measurements and writes the fetched measurements to the database. The meters are polled every 30 seconds. More information regarding the meters can be found in [61] and [62].

Figure 5.7 *Kampstrup OMNIPOWER(left) and Landis+Gyr E650(right)*

5.4 Connection setup and implementation

The connection setup in the laboratory was illustrated in Figure 5.1. The IEDs are connected with the SAU through MMS or DLMS/COSEM interfaces with a possible gateway in between. The outputs of RTDS are amplified, if necessary, and allow the metering devices to measure the RTDS model. In addition, a dedicated Windows PC runs the simulation software RSCAD. The simulation network is built and run in RSCAD and the software is then used for control and analysis of the simulations. Further, an instance of MATLAB is run on the same Windows PC to allow use of TCP/UDP socket of GTNETx2 card. The socket is used to read generator measurements from, and to write set points to DG units where real AVRs are not used for monitoring and control.

Figure 2.5 depicted the hierarchy of controllers. Only SSAU, LV algorithms and the IEDs in LV network are included in the case study of the thesis. The algorithms related to CVC presented in this thesis are implemented in Octave. Other SAU algorithms are implemented in various programming languages, e.g. load and production forecasters are implemented in Python. Expanding to MV level in the testing environment is possible. PSAU would be in charge of processing the data at primary substation level and would run MV SE and PC algorithms. Necessary data, such as secondary substation total loading, would be exchanged between PSAU and SSAU using SAU-SAU interface, i.e. IEC 61850 server on SSAU, and client on PSAU. Both PSAU and SSAU could run on the same Linux computer in the laboratory and multiple instances of Octave could run the voltage level specific algorithms presented in this thesis. In general one SAU computer would maintain one database in secondary substation and one in primary substation. The SAU database is implemented using PostgreSQL version 9.3.

6. CASE STUDY: COORDINATED VOLTAGE CONTROL IN LV NETWORK

The operation of the CVC scheme presented in this thesis is studied in RTDS simulation laboratory. In addition, reference cases without control and with local control are simulated to be able to compare the performance of the introduced CVC scheme. Production and load profiles generated from real network measurement data were available, and are used to some extent. Simulation sequences are divided to resemble real network conditions and artificial conditions. By repeating the field measurements, i.e. the changes in real power of DG and loads according to collected AMR data, the operation of the scheme can be verified under real network conditions. In order to further test the algorithms artificial conditions have been created to disturb the network condition to exceed voltage limits on purpose.

This chapter first introduces the used control schemes, network conditions and test sequences. Finally, key performance indicators (KPIs) used to assess the performance and operation of the algorithms in terms of economical, operational and technical safety point of view are introduced.

6.1 Control schemes

Four different control schemes were used during the tests:

1. Base case without control
2. Local control, AVR+AVC (Local)
3. Local control, AVR with dead band+AVC (Local+DB)
4. CVC.

Reference cases are simulated first without voltage control and using local voltage control of the primary controllers, AVC and AVR, after. In base case off-load tap changer sets transformer ratio to a value so that voltages are high enough considering only voltage drop along the feeders in the network. Local control has AVC relay controlling substation voltage and AVR at DG nodes controlling local voltage of the nodes. The AVC and AVR both have voltage reference value of 1.0 pu. In AVR control the PID controller parameters were set to $K_p = 50$, $K_d = 0.015$, $T_i = 0.01$ and $T_d = 0.1$ for all PID controllers. The parameters are not ideal, which emulates the non-instantaneous control in real operation. When a dead band is used with AVR control, the reactive power output is changed by the PID controller only when the local voltage is outside of allowed reference±DB value to bring the voltage back within limits. The DB is set to 5%. The AVC relay delay is set to 8 seconds. In local control the AVR and AVC are not coordinated and thus in some situations the local measurement based voltage regulation and AVC operating the OLTC may cause clashes and unnecessary control actions.

The results from these three control schemes will then be comparable to the results achieved using CVC scheme. Also variations of CVC cost parameters are used in some sequences to see if desired results were obtained.

6.2 Test conditions

Test conditions are categorized under real and artificial conditions. In real conditions the used production and load changes are made according to data received from the DSO. From the measurement data collected by the DSO, the PV generation at the area is expected to be at its maximum output between 10:00 and 13:00. According to an example of stochastic PV generation in Figure 6.1, during this time the output can drop from peak of the day to 30% of peak value due to cloudiness and possible other factors. Near Mediterranean the PV output is somewhat similar throughout the year but loading may change. In fact, at least two different loading conditions can be identified: load is at its lowest in this time interval at 10:00 and peaks at 12:00. On working days the total load is lower than on Saturdays and Sundays.

Artificial conditions have been included to introduce violations in voltage limits to observe efficiency of the schemes in these conditions. The simulation network is expected to be particularly strong and therefore real network conditions may not cause voltage fluctuations over voltage limits or exceeding branch current limits. Therefore the nominal powers of DG units have been increased with a factor of 3 to see these effects and to evaluate the algorithm performance versus other schemes in

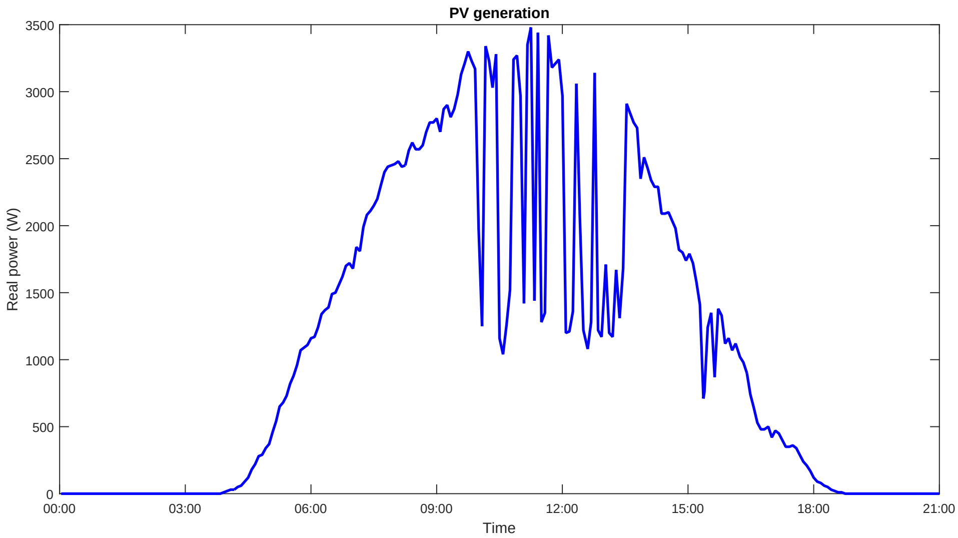

Figure 6.1 *Stochastic PV generation*

these conditions.

Throughout the tests allowed voltage limits are set to ±5% of the nominal. The voltage limits could be lowered to, for example, 1.02 pu and 0.98 pu to see control actions in these conditions if necessary.

6.3 Test sequences

Different test sequences have been chosen to test the operation and to evaluate performance of the CVC scheme. Also new features and differences in the CVC algorithm after earlier simulations in [63] are observed during the simulations. Communication delays are visible in real-time simulations, and therefore don't require dedicated sequences to verify the effect on the algorithm operation.

At the beginning of each test sequence an initial network state is set and the network is allowed to set stable before starting the timed sequence. Thus, a change to the tap position or set points for reactive power may have been set before starting the sequence. The times to execute changes were chosen so that first change is made before first execution of PC, and the PC algorithm is let to run twice after each sequential change. Therefore the sequence times do not necessarily follow any pattern.

6.3.1 Maximum and minimum generation and loading scenarios

First test sequence resembles the worst case generation and loading scenarios under the introduced network conditions. Therefore the sequence has been compressed to go through these conditions within 10 minutes of simulation time. The sequence of events is listed in Table 6.1. The 100% DG output values can be found in the second column of Table 5.2. The 30% output is then proportion of these values. The minimum loading values are found in the second column(Working day 10:00) of Table A.2, and the maximum loading values from the third column(Sunday 12:00).

Table 6.1 *Test sequence 1 - Maximum and minimum generation and loading*

Time	DG output	Loading
0s	100 %	MIN
50s	30 %	MIN
230s	30 %	MAX
410s	100 %	MAX
600s	end	end

6.3.2 DG output changing in groups

As the outputs of DG units don't necessarily change at the same time for example when clouds are moving and reducing output of some DG units while some are still producing maximum output. Therefore a sequence was created to illustrate this event. The sequence is listed in Table 6.2. The DG units are grouped into two groups: DG group 1 includes DG units in network nodes 3 and 9, and group 2 includes units in nodes 11, 12, 13 and 14. The output of the units is reduced to 30% a group at a time, and then back to 100%.

Table 6.2 Test sequence 2 - DG Groups

Time	DG group1	DG group2
0s	100 %	100 %
50s	30 %	100 %
230s	30 %	30 %
410s	100 %	30 %
600s	end	end

6.3.3 Supply network voltage variations

Supply network voltage has great effect on the voltage level of the LV network. The supply network voltage can vary due to loading of HV/MV transformer or disturbances in HV network. Typical situation of 40% loading of the HV/MV transformer means certain voltage level at the MV network feeding the LV network. With similar approach the voltage levels can be found for 10% and 90% worst case MV network loading scenarios. Third sequence loops through the worst case voltages derived from the scenarios as listed in Table 6.3.

Table 6.3 Test sequence 3 - Supply network voltage variations

Time	Supply network voltage (kV)
0s	14.63
50s	13.98
170s	14.63
290s	14.98
420s	end

6.3.4 Intra-minute voltage variations

As the SE and PC algorithms are run once in a minute, outputs of the algorithms will be snapshots with a minute interval in the database. In reality voltage variations within this minute of time can and will happen. Therefore fourth sequence has been created to analyze intra-minute voltage variations due to all-time varying generation conditions. The sequence is illustrated in Figure 6.2. The red markers point out moments when SE and PC algorithms are executed.

The sequence goes through possible scenarios where DG output varies within a minute and ends up in a value at the time of SE and PC algorithm execution. At

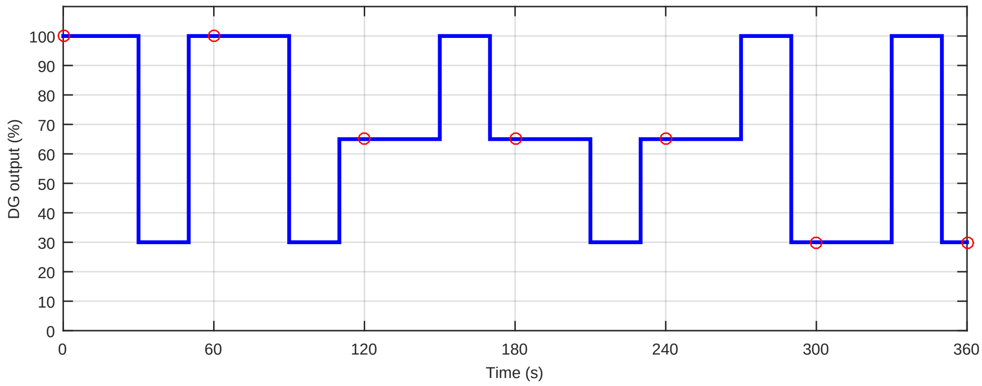

Figure 6.2 *Sequence 4 - Intra-minute voltage variations*

30 seconds the output of all DGs is set to the lowest earlier determined value, and increased back to the original value at 50 seconds. All possible variations of DG output changes within the minute interval are gone through after. It is expected that these variations are not detected by SE and PC algorithms, but can be analyzed from RTDS data directly.

Results of this sequence can be compared to values obtained directly from RTDS to see the effects of the one minute execution loop on control performance. The performance can be then compared to local schemes which detect and react to these variations.

6.3.5 Effect of cost parameters

The objective function value in Equation 4.7 greatly depends on cost parameters set by the user. As the PC aims to minimize the objective function value, the cost parameters have direct correlation on the PC outputs. By changing the cost for tap changer operations C_{tap} or cost for node voltage difference from nominal C_{Vdiff} the control actions of PC algorithm can be influenced. Out of cost parameters in the objective function, these two have greatest uncertainty when defining the parameters. The effect of changing these parameters is studied in this sequence from graphs and KPI values. Three different cases with different cost parameters shown in Table 6.4 are considered.

Table 6.4 Cost parameter cases, $S_b = 20$

Case	C_{tap}	C_{losses}	C_{cur}	C_{Vdiff}
1	0	$5{*}S_b$	$10{*}S_b$	0
2	1	$5{*}S_b$	$10{*}S_b$	$5{*}S_b$
3	1	$5{*}S_b$	$10{*}S_b$	$500{*}S_b$

6.3.6 Production curtailment

Short sequence is run to test the production curtailment functionality in CVC. This could be either done by further increasing generation in the network, reducing cost parameter for production curtailment or decreasing the rated current of a line near generation. The last approach was chosen in order to simultaneously demonstrate also over-current limiting functionality in PC algorithm. Line from node FD08/SC02 to FD08/SC03 near DG14 was chosen, and the rated current was reduced to 20 A. Table 6.5 lists the changes made in the sequence.

Table 6.5 Production curtailment functionality test

Time	DG14 output(%)	Other DGs(%)
0s	0	100
30s	100	100
240s	end	end

6.4 Key Performance Indicators

Key performance indicators(KPIs) are used to assess the results in terms of algorithm performance and network reliability. For LV network power control, the KPIs are defined in [64]. The chosen KPIs consist of economical, operational and technical parameters. Economical parameters evaluate the benefits and performance of control schemes:

1. Curtailed production [kWs]
2. Network losses [kWs]
3. Average target function value

Operational performance is evaluated with the following parameters:

4. Average OPF algorithm execution time [s]
5. Alerts [pcs]
6. OLTC steps taken [pcs]
7. P set point changes [pcs]
8. Q set point changes [pcs]
9. V set point changes [pcs].

Technical safety parameters are related to voltage and current limits in the network:

10. Over-voltage volume [pu*s]
11. Under-voltage volume [pu*s]
12. Duration the voltage is out of bounds [s]
13. Over-current volume [A*s]
14. Duration the current is out of bounds [s].

These parameters are calculated for each test sequence and compared among control schemes when applicable. Total production curtailment is available only in CVC scheme and thus is calculated by the PC algorithm and stored in the database. Network losses are calculated by subtracting real power loads from the sum of real power flowing through the transformer and generation in the network nodes. The SE algorithm calculates and stores the network losses for each estimate in the database. For comparison in base case and local control schemes the network losses are obtained directly from RTDS measurements. During CVC schemes the losses value calculated by SE can be compared to the losses calculated by RTDS. Target function value and OPF execution times are related to PC algorithm execution and stored in the database for each algorithm execution. Average of these values during the interval of examination is then calculated. Number of alerts is recorded by counting certain flag values(e.g. convergence problems) in the database during the simulation time. OLTC steps are counted from both algorithm calculated values and history of tap position measurement. In this thesis the set point changes are assumed to always take place and therefore are counted directly from the PC algorithm outputs.

Over- and under-voltage volume areas are calculated using trapezoidal integration with time and voltage(pu) -axes. Over-voltage violation area for each node is obtained from areas where maximum node voltage exceeds maximum voltage limit and under-voltage violation area from areas where minimum voltage limit exceeds minimum node voltage. The limits are 1.05 pu and 0.95 pu respectively. The searched total volumes are sums of all over- or under-voltage areas. Over-current volume is calculated similarly but looks at network branches, branch currents and rated current of the branches instead of network nodes, node voltages and static voltage limits. Both currents and voltages are obtained from SE in CVC scheme, and directly from the RTDS in base case and local control schemes. The total durations of out of bounds voltages or currents are found by summing the time intervals when voltages or currents are observed to be out of bounds. Database values are estimates, snapshots from every minute when the state estimator is run. These are then compared to real-time measured values from RTDS to obtain a reference. Table 6.6 shows an example table which presents KPIs for each control scheme during a sequence. Dash means the KPI is not applicable to the scheme and two values in same field in the KPI table mean estimated value on the left and value measured directly from RTDS on the right.

Table 6.6 *Example simulation sequence evaluation table with KPIs*

KPI (estimated/RTDS)	**Base case**	**Local control**	**Local control+DB**	**CVC**
Curtailed production [kWs]	-	-	-	
Network losses [kWs]				
Average target function value	-	-	-	
Average OPF algorithm execution time [s]	-	-	-	
Alerts [pcs]	-	-	-	
OLTC actions [pcs]	-			
P set point changes [pcs]	-	-	-	
Q set point changes [pcs]	-	-		
V set point changes [pcs]	-	-	-	
Over-voltage volume [pu*s]				
Under-voltage volume [pu*s]				
Duration the voltage is out of bounds [s]				
Over-current volume [A*s]				
Duration the current is out of bounds [s]				

7. RESULTS

This chapter presents the results for each control scheme and simulation sequence using the earlier introduced KPIs and graphs plotted from simulation history data from SAU database and RTDS. In the following sections, most interesting findings and graphs are presented. The timestamps in the graphs are from the simulation history data and thus vary in every sequence and scheme.

7.1 Real conditions

7.1.1 Maximum and minimum generation and loading scenarios

Table 7.1 summarizes the KPIs for sequence 1 obtained using real network conditions. Figures 7.1 and 7.2 present the most interesting graphs for the sequence.

Table 7.1 *Real conditions - Sequence 1 KPIs*

KPI (estimated/RTDS)	Base case	Local control	Local control+DB	CVC
Curtailed production [kWs]	-	-	-	0
Network losses [kWs]	497.2	1258.3	497.2	447.2
Average target function value	-	-	-	3.94
Average OPF algorithm execution time [s]	-	-	-	9.96
Alerts [pcs]	-	-	-	0
OLTC actions [pcs]	-	0	0	0
P set point changes [pcs]	-	-	-	0
Q set point changes [pcs]	-	-	0	7
V set point changes [pcs]	-	-	-	0
Over-voltage volume [pu*s]	0	0	0	0
Under-voltage volume [pu*s]	0	0	0	0
Duration the voltage is out of bounds [s]	0	0	0	0
Over-current volume [A*s]	0	0	0	0
Duration the current is out of bounds [s]	0	0	0	0

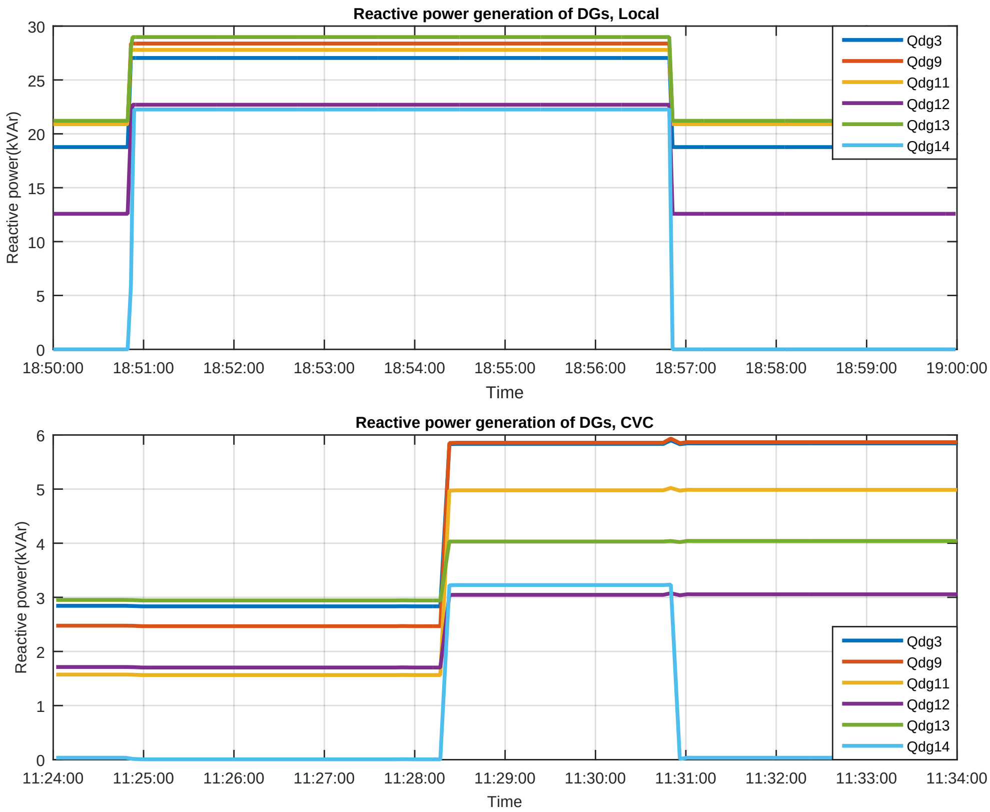

Figure 7.1 *Sequence 1 - Reactive powers in Local and CVC schemes*

The table and figures summarize that reactive power was the only used control resource during the sequence. The graphs in Figure 7.1 illustrate the use of reactive power to support local voltages at the DG connection points. The CVC used less reactive power supply to increase the voltages and instead set higher voltages using substation voltage reference value and the tap changer.

All in all the voltages did not differ much from nominal in base case and local control schemes, and only few control actions were made. No control actions were made in local+DB case because no voltages were violated. One step difference in initial tap position of off-load and on-load tap changer set before starting the sequence increased voltages in the network by tap size in Base and Local+DB schemes and thus similar voltage profile and network losses were obtained in these two schemes. The voltage graphs in Figure 7.2 present the difference of CVC with other schemes. CVC obtained clearly the lowest network losses. This was due to substation voltage reference which was set higher than nominal 1.0 pu, and thus the voltages were optimized close to the upper limit throughout the sequence with the use of tap changer.

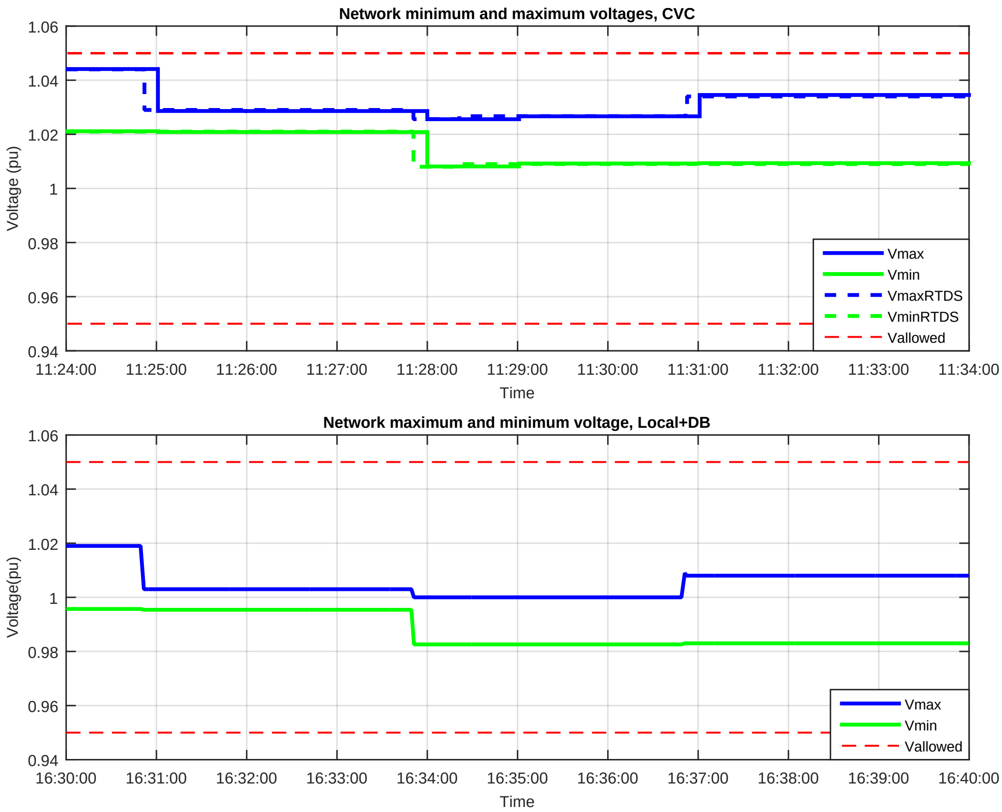

***Figure* 7.2** *Sequence 1 - Minimum and maximum voltage in CVC and Local+DB scheme*

7.1.2 DG output changing in groups

Table 7.2 summarizes the KPIs for sequence 2 using real network conditions. Results of this sequence mimic the earlier sequence. No voltage violations were observed. Again the highest network losses were found in local control scheme and the lowest in CVC. Figure 7.3 presents the network node voltages in local scheme. The voltages were aimed to be kept around nominal locally. Therefore a lot of reactive power capability, when available, was used at the cost of network losses similarly as in Figure 7.1. Under real conditions the DG groups did not have great impact on the control schemes and thus more demanding conditions are more interesting.

Table 7.2 *Real conditions - Sequence 2 KPIs*

KPI (estimated/RTDS)	Base case	Local control	Local control+DB	CVC
Curtailed production [kWs]	-	-	-	0
Network losses [kWs]	273.7	939.8	273.2	248.4
Average target function value	-	-	-	2.34
Average OPF algorithm execution time [s]	-	-	-	9.05
Alerts [pcs]	-	-	-	0
OLTC actions [pcs]	-	0	0	0
P set point changes [pcs]	-	-	-	0
Q set point changes [pcs]	-	-	0	0
V set point changes [pcs]	-	-	-	0
Over-voltage volume [pu*s]	0	0	0	0
Under-voltage volume [pu*s]	0	0	0	0
Duration the voltage is out of bounds [s]	0	0	0	0
Over-current volume [A*s]	0	0	0	0
Duration the current is out of bounds [s]	0	0	0	0

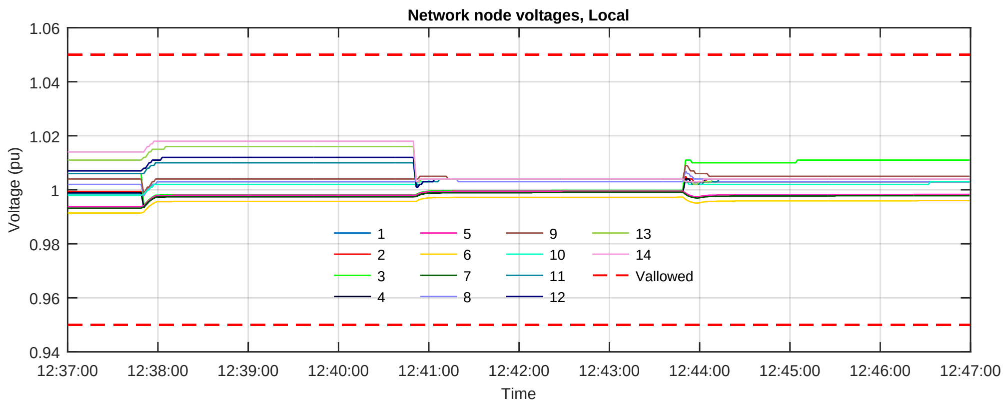

Figure 7.3 *Sequence 2 - Network node voltages in Local scheme*

7.1.3 Supply network voltage variations

Table 7.3 summarizes the KPIs for sequence 3 using real network conditions. Figure 7.4 illustrates voltages and tap position during local control scheme and Figure 7.5 the same tap position for Local+DB scheme. Figure 7.6 presents network minimum and maximum voltages, reactive power generation and tap position in CVC scheme.

The outcome of the sequence was that introducing disturbances to the supply network voltage level causes voltage violations already with existing DG penetration levels. The difference in local and local+DB schemes was that local scheme used reactive power with the tap changer to overcome the first voltage drop. Thus, the network voltages afterwards were closer to nominal and did not cause voltage

Table 7.3 Real conditions - Sequence 3 KPIs

KPI (estimated/RTDS)	Base case	Local control	Local control+DB	CVC
Curtailed production [kWs]	-	-	-	0
Network losses [kWs]	399.1	794.9	394.1	364.7
Average target function value	-	-	-	4.7
Average OPF algorithm execution time [s]	-	-	-	7.73
Alerts [pcs]	-	-	-	0
OLTC actions [pcs]	-	3	5	3
P set point changes [pcs]	-	-	-	0
Q set point changes [pcs]	-	-	0	0
V set point changes [pcs]	-	-	-	0
Over-voltage volume [pu*s]	0	0	0.520	10.8 / 1.64
Under-voltage volume [pu*s]	0	0	0	0
Duration the voltage is out of bounds [s]	0	0	74.0	1309 / 192.73
Over-current volume [A*s]	0	0	0	0
Duration the current is out of bounds [s]	0	0	0	0

violations after the following voltage variations. The use of reactive power was visible from the highest network losses. Local+DB scheme used two tap changer steps which led to over-voltages when voltage increase in the sequence was made. Base case avoided all voltage violations as no control actions were made to mitigate changes in the network, and the changes were not severe enough from the initial voltage level.

Here the same applied to CVC scheme that voltages were initially set high with the tap changer as seen from third graph in Figure 7.6, and after the first voltage drop, only one step could be used to increase the voltages in the network. With the tap-changer being at maximum position, the second voltage change in the network eventually led to a small over-voltage volume. Initially optimized reactive power set points were preserved throughout the sequence as the PC algorithm did not go into optimization loop when it detected AVC relay or tap changer were operating due to outside voltage variations. The higher estimated over-voltage volumes and duration voltages are out of bounds were due to one minute execution interval and trapezoidal integration.

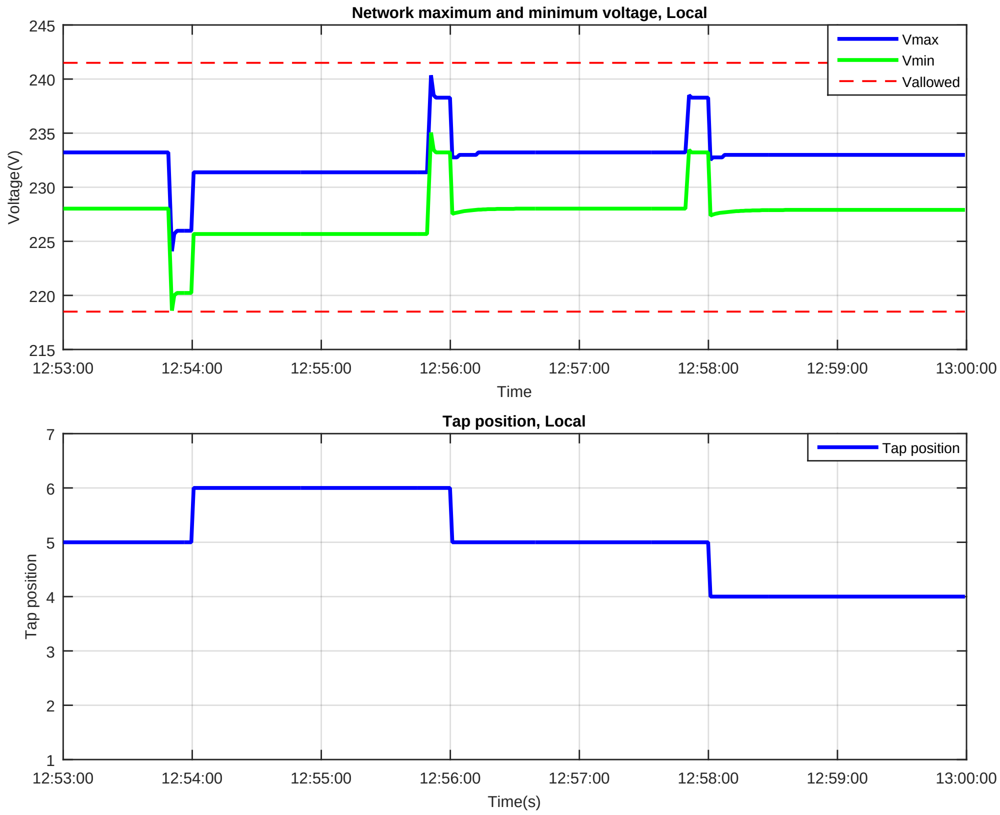

__Figure 7.4__ Sequence 3 - Local Graphs

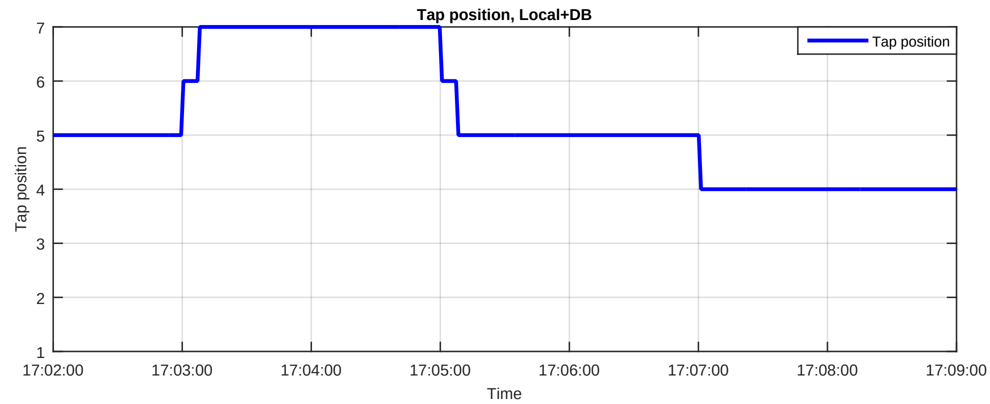

__Figure 7.5__ Sequence 3 - Local+DB Graphs

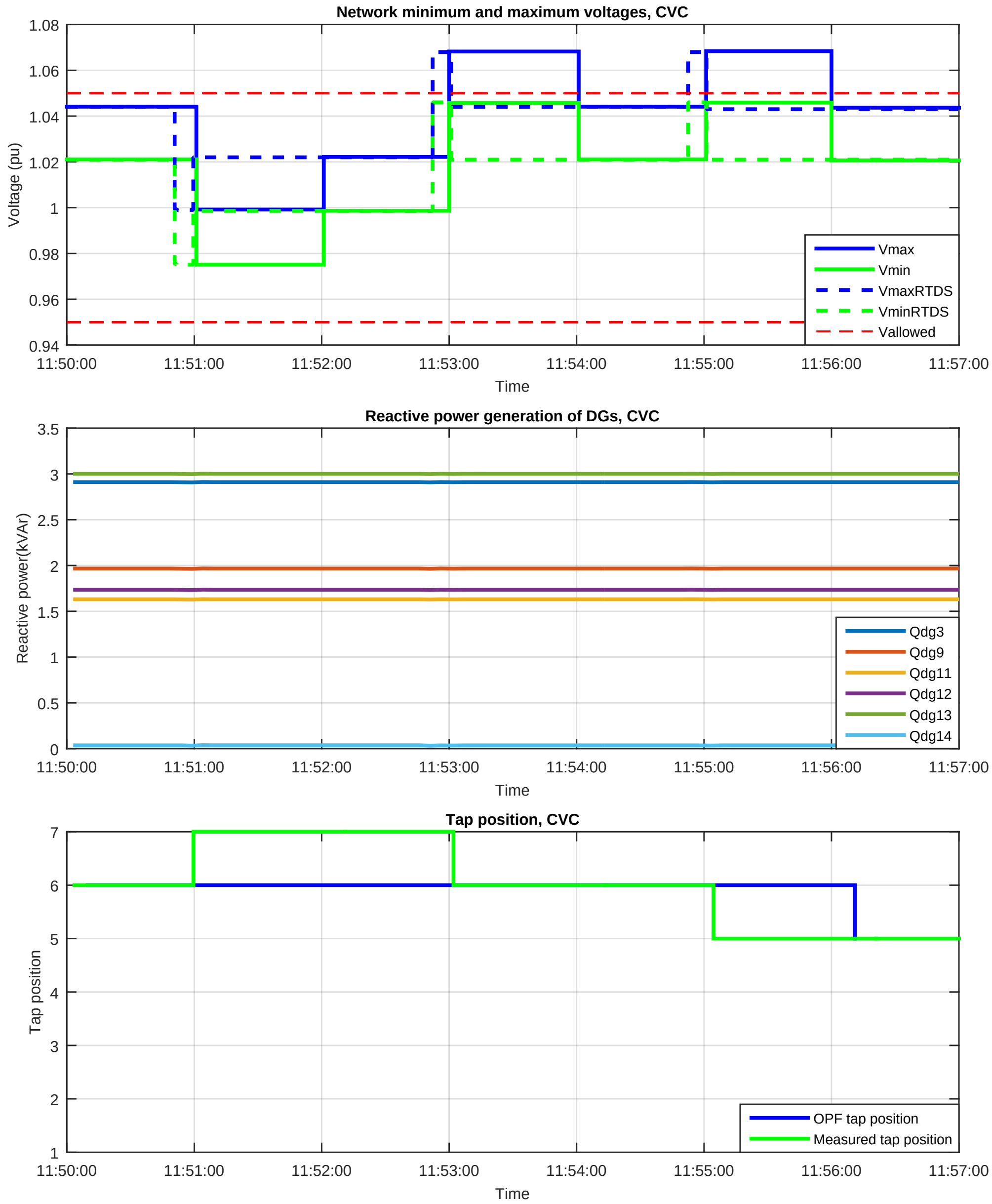

Figure 7.6 *Sequence 3 - CVC Graphs*

7.1.4 Intra-minute voltage variations

Table 7.4 summarizes the KPIs for sequence 4 using real network conditions. This was the last sequence simulated using real conditions as the artificial conditions generally provided more interesting results from the algorithm point of view. Figure 7.7 illustrates node voltage changes during the sequence.

Table 7.4 *Real conditions - Sequence 4 KPIs*

KPI (estimated/RTDS)	Base case	Local control	Local control+DB	CVC
Curtailed production [kWs]	-	-	-	0
Network losses [kWs]	173.7	495.6	175.7	156.5
Average target function value	-	-	-	2.49
Average OPF algorithm execution time [s]	-	-	-	8.1
Alerts [pcs]	-	-	-	0
OLTC actions [pcs]	-	0	0	0
P set point changes [pcs]	-	-	-	0
Q set point changes [pcs]	-	-	0	0
V set point changes [pcs]	-	-	-	0
Over-voltage volume [pu*s]	0	0	0	0
Under-voltage volume [pu*s]	0	0	0	0
Duration the voltage is out of bounds [s]	0	0	0	0
Over-current volume [A*s]	0	0	0	0
Duration the current is out of bounds [s]	0	0	0	0

The made changes are clearly reflected from the node voltage graphs in the Figure. In local scheme the reactive power outputs were changed considering the local voltages after each DG output change in the network. Thus all voltages were set very close to nominal. Local+DB scheme set tap position such that voltages were a bit higher and the substation voltage was closer to reference 1.00. The network node voltages in CVC were again optimized closer to the upper limit and thus lowest losses were obtained.

The node voltages in CVC followed the pattern in the sequence similarly which can be seen from the dashed direct RTDS measurement lines. However, the estimated maximum and minimum voltages in CVC scheme remained the same almost throughout the sequence because most of the time the made change was reverted before the start of the minute and thus the latest measured voltages for state estimation as inputs remained the same. Reactive power set points were again preserved as the target function value limiter stepped in when the value didn't change enough compared to previous set points.

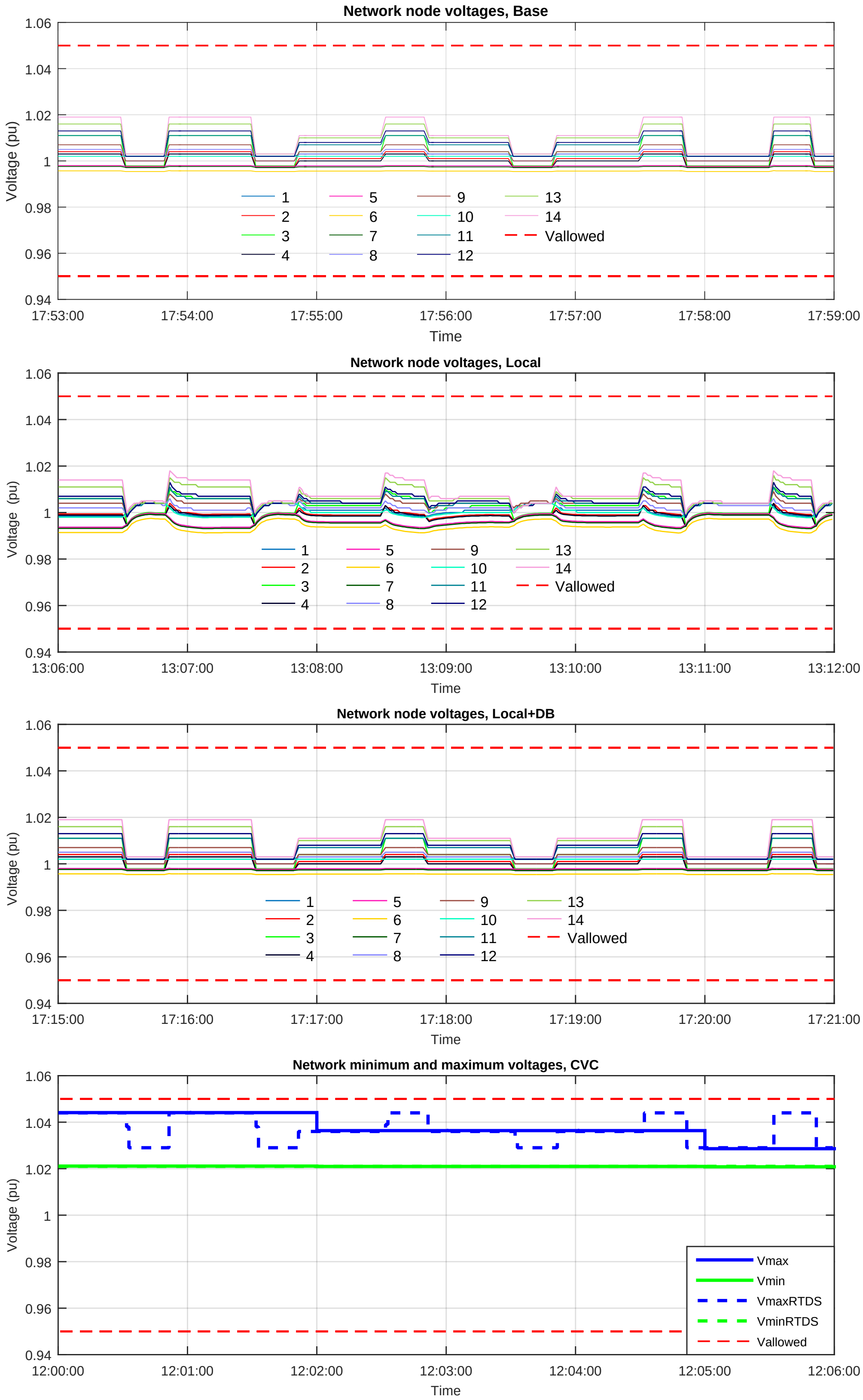

Figure 7.7 *Sequence 4 - Node voltages in Base, Local and Local+DB schemes, and network voltage extremes in CVC*

7.2 Artificial conditions

As the results in Section 7.1 confirm, no voltage rise problems with chosen network voltage limits were observed when the changed variable was DG output or loading. Some over-voltages were observed under severe supply network voltage variations. Therefore the artificial conditions in terms of increasing penetration of PV generation are needed and presented in this section in order to test the performance of the CVC scheme and optimization in general. The initial outputs and nominal powers of DG units in Table 5.2 were multiplied by 3.

7.2.1 Maximum and minimum generation and loading scenarios

Table 7.5 summarizes the KPIs for sequence 1 using artificial network conditions.

Table 7.5 *Artificial conditions - Sequence 1 KPIs*

KPI (estimated/RTDS)	Base case	Local control	Local control+DB	CVC
Curtailed production [kWh]	-	-	-	0
Network losses [kWs]	2721.7	7423.2	2723.7	2729
Average target function value	-	-	-	29.62
Average OPF algorithm execution time [s]	-	-	-	16.90
Alerts [pcs]	-	-	-	0
OLTC actions [pcs]	-	1	0	4
P set point changes [pcs]	-	-	-	0
Q set point changes [pcs]	-	-	0	18
V set point changes [pcs]	-	-	-	2
Over-voltage volume [pu*s]	1.02	0.365	1.022	4.12 / 3.33
Under-voltage volume [pu*s]	0	0	0	0 / 0
Duration the voltage is out of bounds [s]	287.8	116.2	288.1	295 / 240.3
Over-current volume [A*s]	0	5492.2	0	0 / 0
Duration the current is out of bounds [s]	0	414.3	0	0 / 0

Figure 7.8 illustrates over-voltage volumes in Base case which is identical to the Local+DB case. In both cases substation voltage remained within limits but end of the feeder voltages violated limits. Even though the over-voltage volumes are smaller than with CVC, these schemes cannot return the voltages back within limits without changes in the network state. This is also reflected from the lower losses obtained by Base and Local+DB cases. Local control with DB did not set any new reactive power set points because the only over-voltage violation happened at node with no reactive power capability. The situation is non-feasible for the scheme and in this

case it cannot recover from the voltage violations without external change in the network.

In CVC optimizing network voltages closer to the allowed limits caused larger over-voltage volumes after changes in the network, as seen in Figure 7.9. The cost parameter for tap changer actions was set to zero and therefore two new V_{ref} set points were given and tap changer was used on every possible occasion. However, the over-voltages were brought back within limits after one PC execution time but trapezoidal integration and the one minute interval of state estimation results in longer duration calculated. Parameters not visible to other schemes than CVC, current limits of the network lines were found to be violated first time with over-voltages. Local control did not consider the current limits and therefore the current limits were violated almost throughout the sequence. CVC managed to completely optimize the currents to be within limits.

Clash with OLTC and local voltage measurement based reactive power output of DG units was observed in Local scheme. Figure 7.10 depicts the situation. At 14:12:50 DG output was increased back to 100% and the DGs started to consume reactive power in order to lower voltages. This caused substation voltage to drop low enough for AVC to increase voltage using tap changer. In the end the voltage violation became non-feasible for the local scheme similarly to the Local+DB case with the DG unit without reactive power capability. Thus the minor over-voltage prevailed until the end of the sequence.

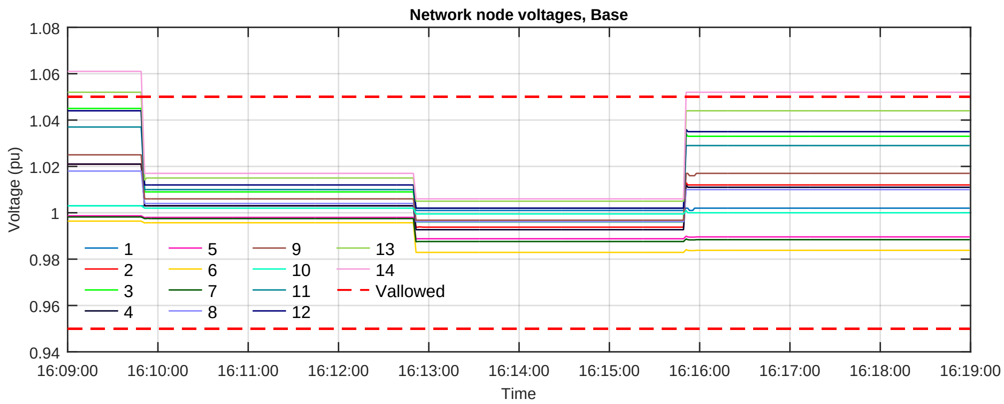

Figure 7.8 *Artificial Sequence 1 - Base case voltages*

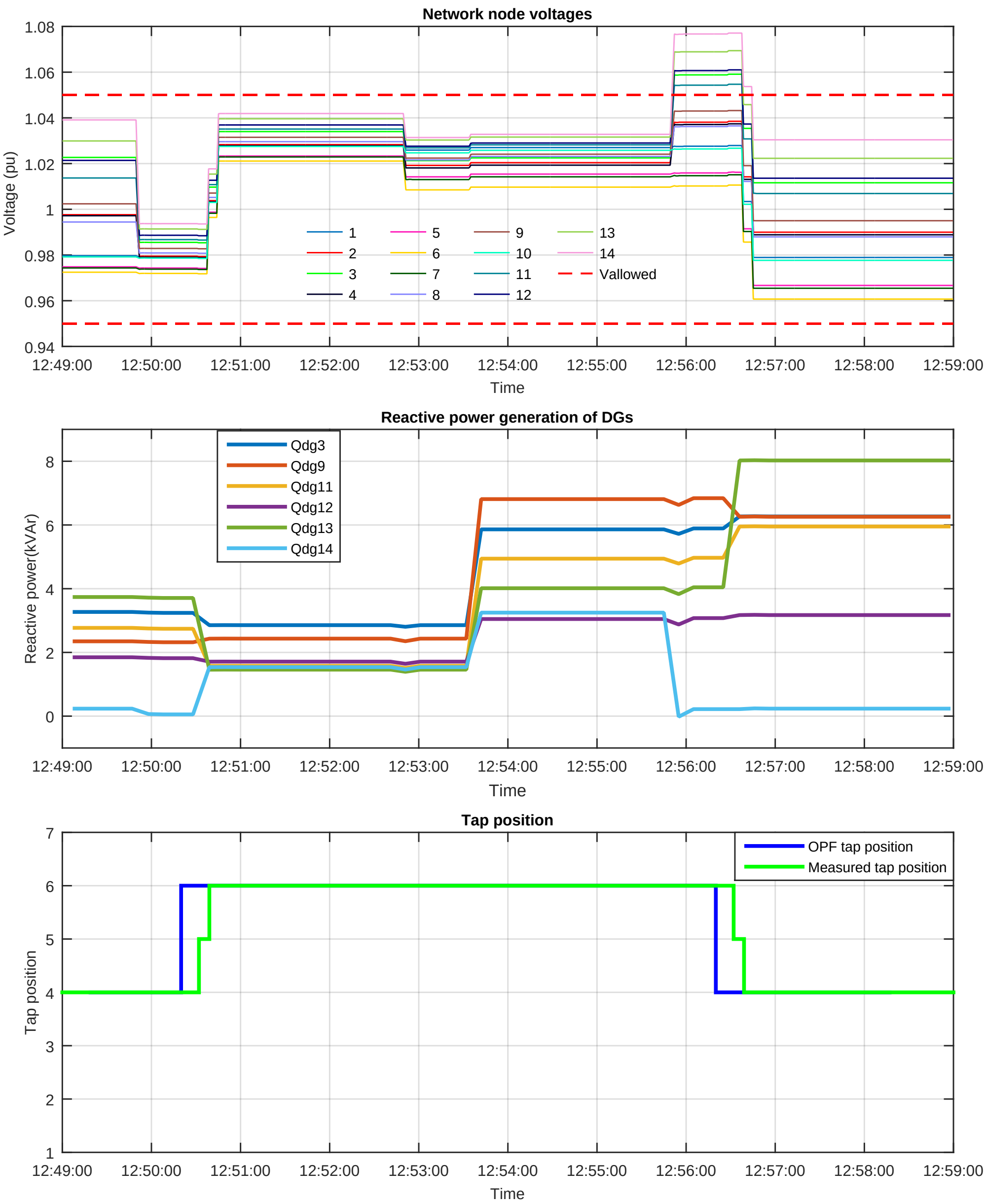

Figure 7.9 Artificial Sequence 1 - CVC graphs

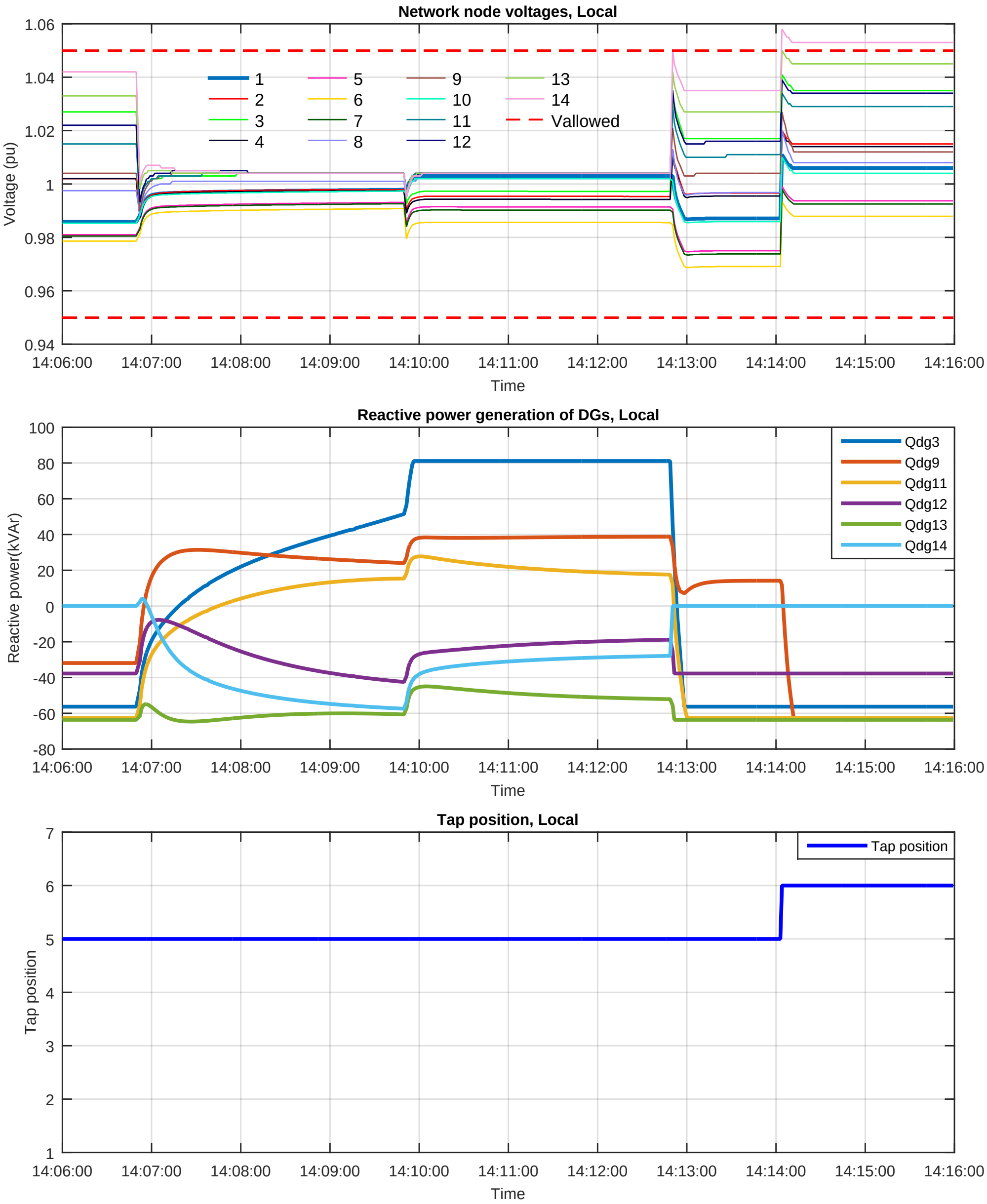

Figure 7.10 *Artificial Sequence 1 - Local scheme graphs*

7.2.2 DG output changing in groups

Table 7.6 summarizes the KPIs for sequence 2 using artificial network conditions.

Table 7.6 *Artificial conditions - Sequence 2 KPIs*

KPI (estimated/RTDS)	Base case	Local control	Local control+DB	CVC
Curtailed production [kWh]	-	-	-	0
Network losses [kWs]	3264.5	11798	3269.1	3349.3
Average target function value	-	-	-	30.63
Average OPF algorithm execution time [s]	-	-	-	16.8
Alerts [pcs]	-	-	-	0
OLTC actions [pcs]	-	0	0	3
P set point changes [pcs]	-	-	-	0
Q set point changes [pcs]	-	-	0	18
V set point changes [pcs]	-	-	-	2
Over-voltage volume [pu*s]	2.99	3.548	2.99	1.18 / 0.96
Under-voltage volume [pu*s]	0	0	0	0 / 0
Duration the voltage is out of bounds [s]	458.4	459.1	459.2	61.0 / 49.3
Over-current volume [A*s]	0	14792.8	0	0 / 0
Duration the current is out of bounds [s]	0	600	0	0 / 0

Again local control did not consider current limits and both violation volumes and out of bounds durations of voltages and currents reflect that. Figure 7.11 illustrates node voltages in CVC scheme. Voltage of generation node 3 violated limits after DG group1 output changed from 30% to 100% at 13:11:50. This was due to all voltages having been optimized close to the voltage limits as seen in the figure. Local and Local+DB to start the sequence with over-voltages as the schemes cannot handle situation where substation voltage is near nominal but voltage violations are happening in nodes without local reactive power capability. This is illustrated in Figure 7.12. This is a situation where CVC is superior as in this case new set point for substation voltage reference is set and all voltages can be restored within limits. However, in order to avoid similar over-voltages due to voltages being optimized too close to limits e.g. cost for voltage difference from nominal C_{Vdiff} should be set to adequate value.

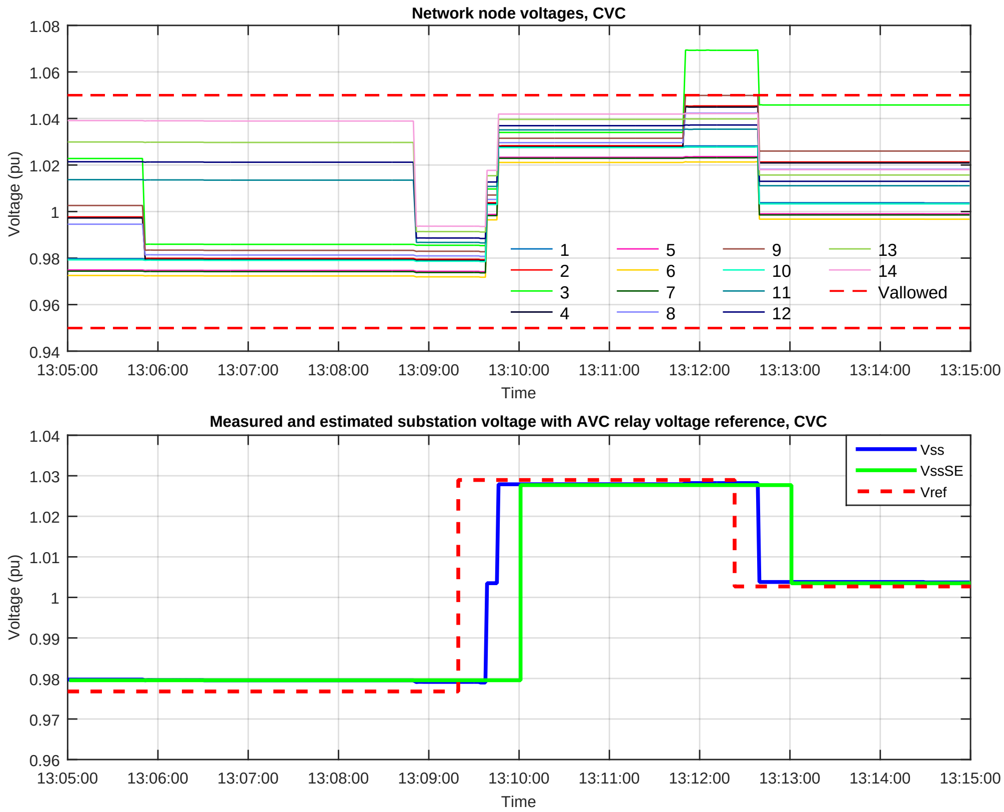

Figure 7.11 *Artificial Sequence 2 - Node voltages in CVC*

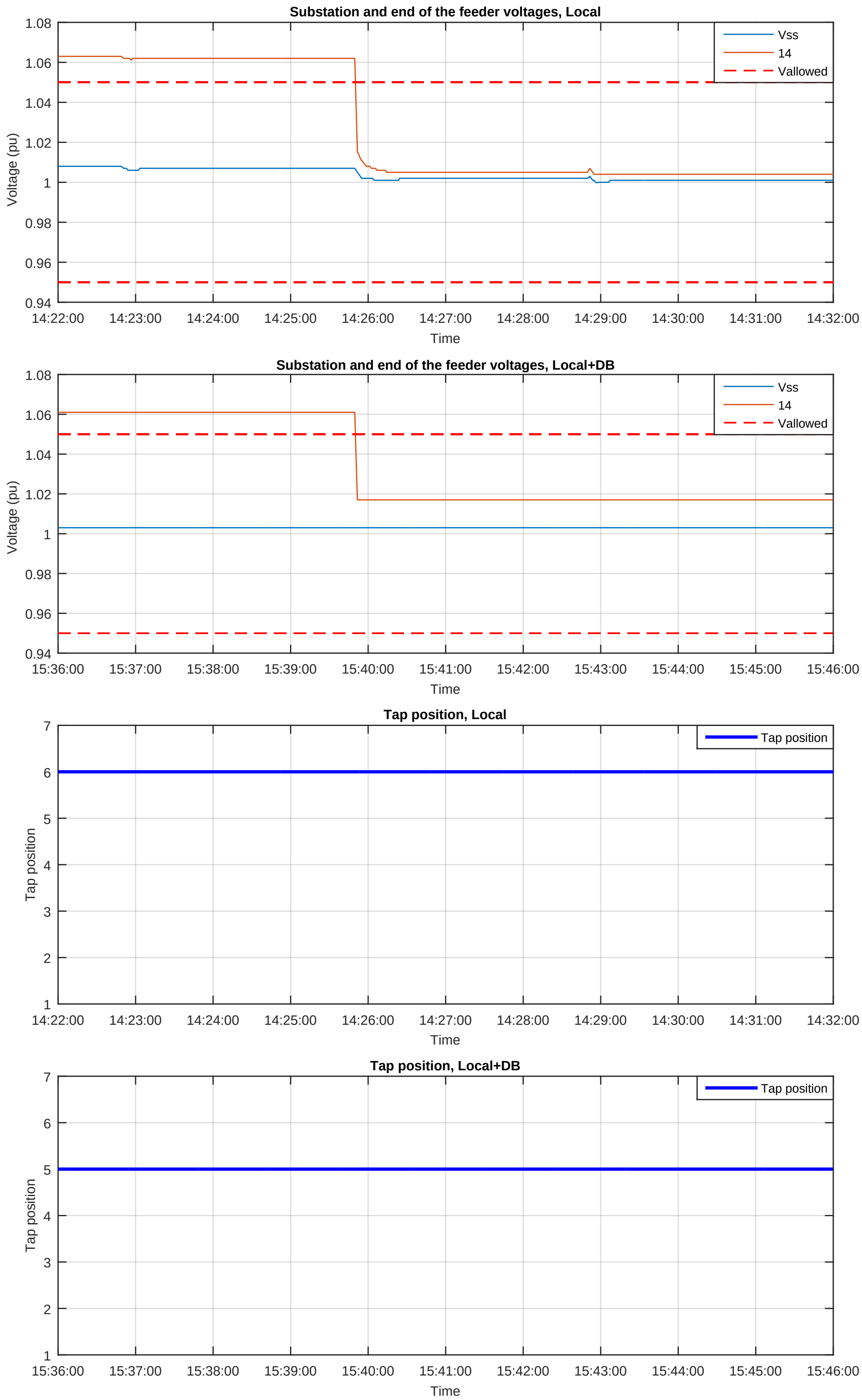

Figure 7.12 *Artificial Sequence 2 - Substation voltage, end of the feeder voltage and tap positions in Local and Local+DB schemes*

7.2.3 Supply network voltage variations

Table 7.7 summarizes the KPIs for sequence 3 using artificial network conditions. Figure 7.13 presents graphs for Local+DB and Figure 7.14 for CVC.

Table 7.7 *Artificial conditions - Sequence 3 KPIs*

KPI (estimated/RTDS)	Base case	Local control	Local control+DB	CVC
Curtailed production [kWs]	-	-	-	0
Network losses [kWs]	5493.5	8589.8	5552.2	5627
Average target function value	-	-	-	68.66
Average OPF algorithm execution time [s]	-	-	-	15.52
Alerts [pcs]	-	-	-	0
OLTC actions [pcs]	-	3	5	5
P set point changes [pcs]	-	-	-	0
Q set point changes [pcs]	-	-	23	0
V set point changes [pcs]	-	-	-	0
Over-voltage volume [pu*s]	15.8	7.14	8.66	8.09 / 2.54
Under-voltage volume [pu*s]	0	0	0	0 / 0.9
Duration the voltage is out of bounds [s]	988	663.2	953.8	480 / 200.5
Over-current volume [A*s]	0	5504.7	212.6	0
Duration the current is out of bounds [s]	0	419.6	21.8	0

Now with the increased DG penetration levels more severe voltage violations were observed in base case and reactive power consumption was activated in local+DB scheme. This is a situation where in local control both the AVR and AVC operated simultaneously and very fast, which can be a drawback when the AVC alone could possibly solve the network voltage violations.

Again zero current limit violations were achieved only with CVC when compared to local control. Voltages were close to the limits throughout the sequence and therefore CVC achieved second lowest network losses during this sequence while having the best technical safety parameters if measured directly from the RTDS. Otherwise CVC operated in a similar manner as with the real conditions. Rougher the conditions, the better CVC seems to perform when compared to the other schemes.

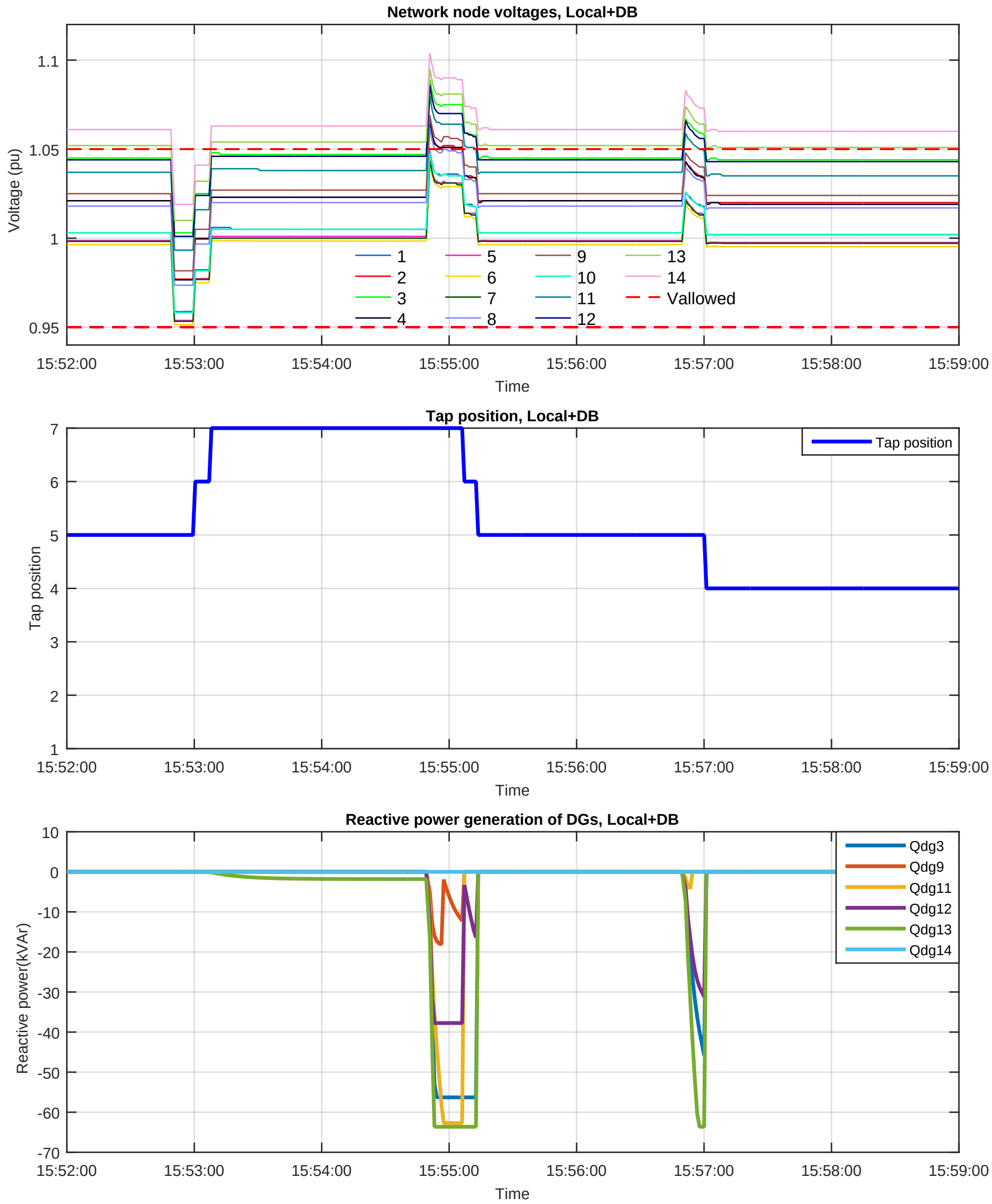

Figure 7.13 *Artificial Sequence 3 - Local+DB graphs*

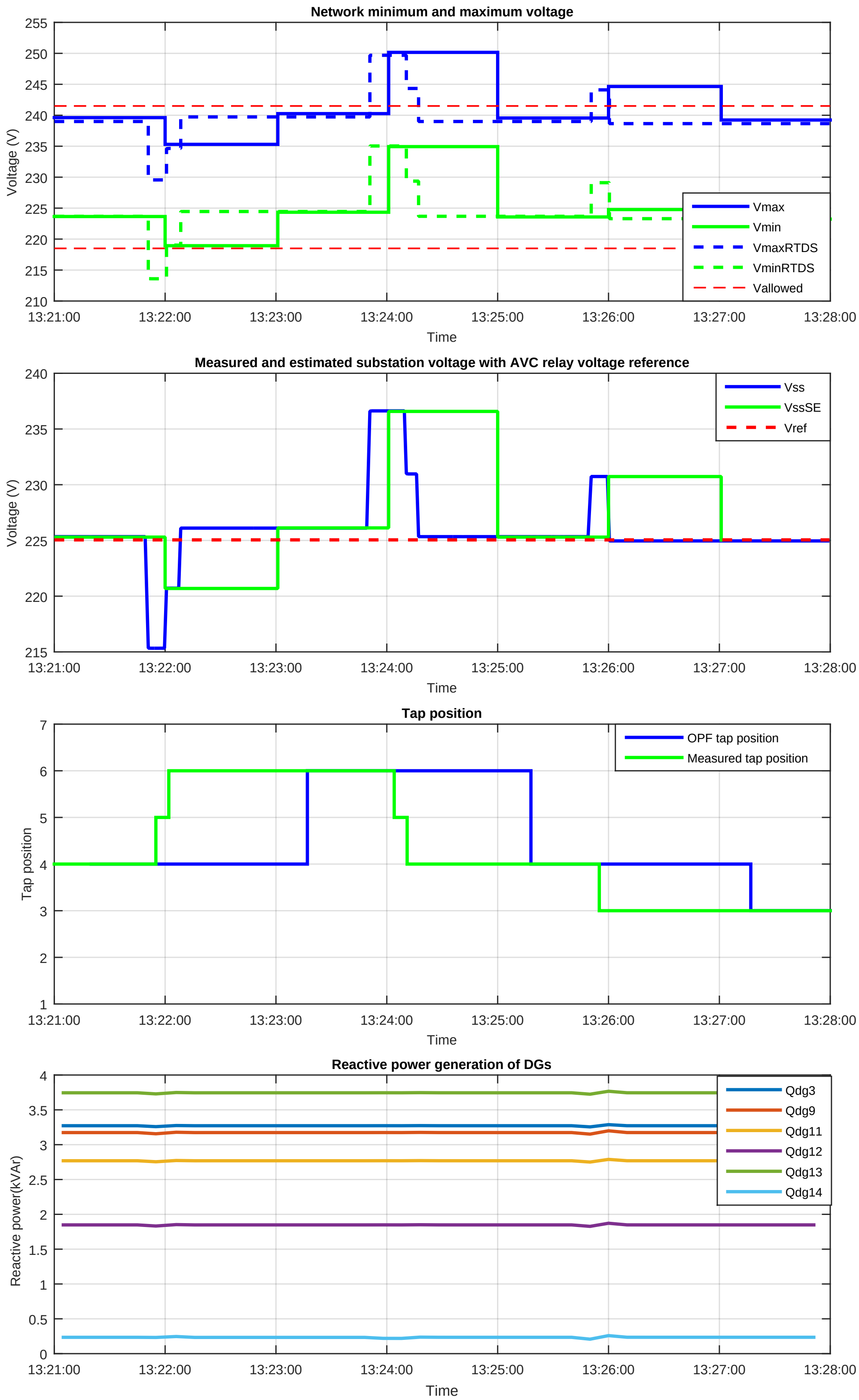

Figure 7.14 *Artificial Sequence 3 - CVC graphs*

7.2.4 Intra-minute voltage variations

Table 7.8 summarizes the KPIs for sequence 4 using artificial network conditions.

Table 7.8 *Artificial conditions - Sequence 4 KPIs*

KPI (estimated/RTDS)	Base case	Local control	Local control+DB	CVC
Curtailed production [kWs]	-	-	-	0
Network losses [kWs]	2365.8	7110.26	2364.9	2375.4
Average target function value	-	-	-	36.1
Average OPF algorithm execution time [s]	-	-	-	17.2
Alerts [pcs]	-	-	-	0
OLTC actions [pcs]	-	0	0	2
P set point changes [pcs]	-	-	-	0
Q set point changes [pcs]	-	-	0	17
V set point changes [pcs]	-	-	-	0
Over-voltage volume [pu*s]	1.709	2.2	1.71	0 / 2.21
Under-voltage volume [pu*s]	0	0	0	0 / 0
Duration the voltage is out of bounds [s]	259.7	260.3	260.2	0 / 168.7
Over-current volume [A*s]	0	6581.3	0	0
Duration the current is out of bounds [s]	0	359.0	0	0

Again in local scheme reactive power was changed according to local voltages after each DG output change in the network. The changes are visible in first graph of Figure 7.15. The second graph presents network voltages and substation voltage with bold line. The substation voltage remained within deadband limit from nominal and therefore the tap changer was not used.

Figure 7.16 presents network node voltages in Local+DB scheme. Reactive power was not used as PV unit at node 14 did not have reactive power capability when the voltages were violated, and unit in node 13 seemed to have some measurement accuracy error as the voltage of the node seemed to be outside of the limit 1.05 pu but the reactive power capability was not activated. Other voltages remained within the limits in the scheme.

Figure 7.17 presents graphs for the CVC scheme. Looking at the estimated results from the database, everything in the network seemed fine throughout the sequence. This is due to the CVC scheme not detecting the intra-minute variations made in the sequence, and therefore no correcting actions were made when over-voltages happened during the sequence. This should be taken into consideration when implementing the CVC in real network.

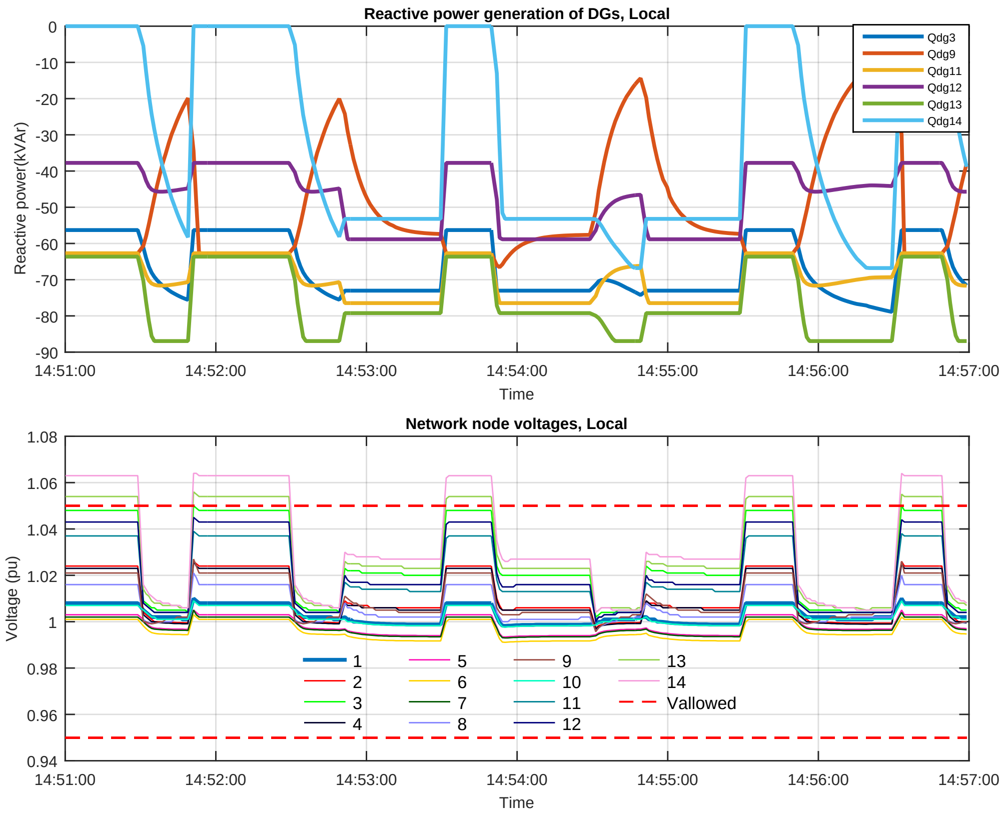

Figure 7.15 *Artificial Sequence 4 - Local graphs*

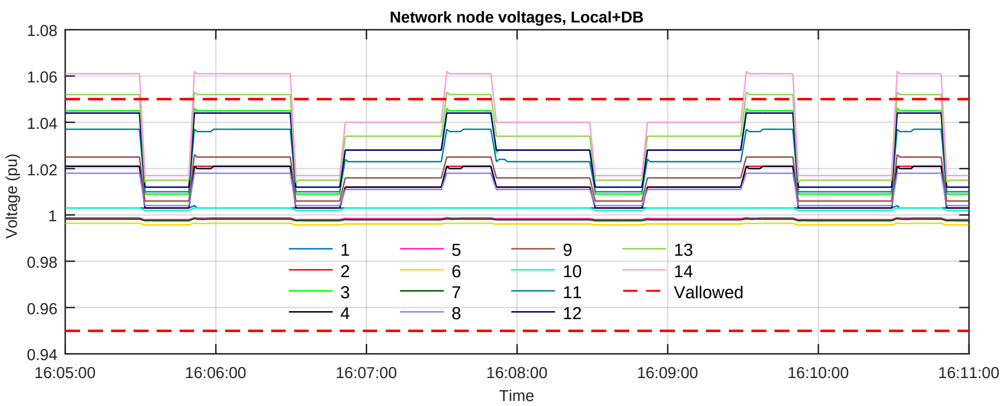

Figure 7.16 *Artificial Sequence 4 - Local+DB*

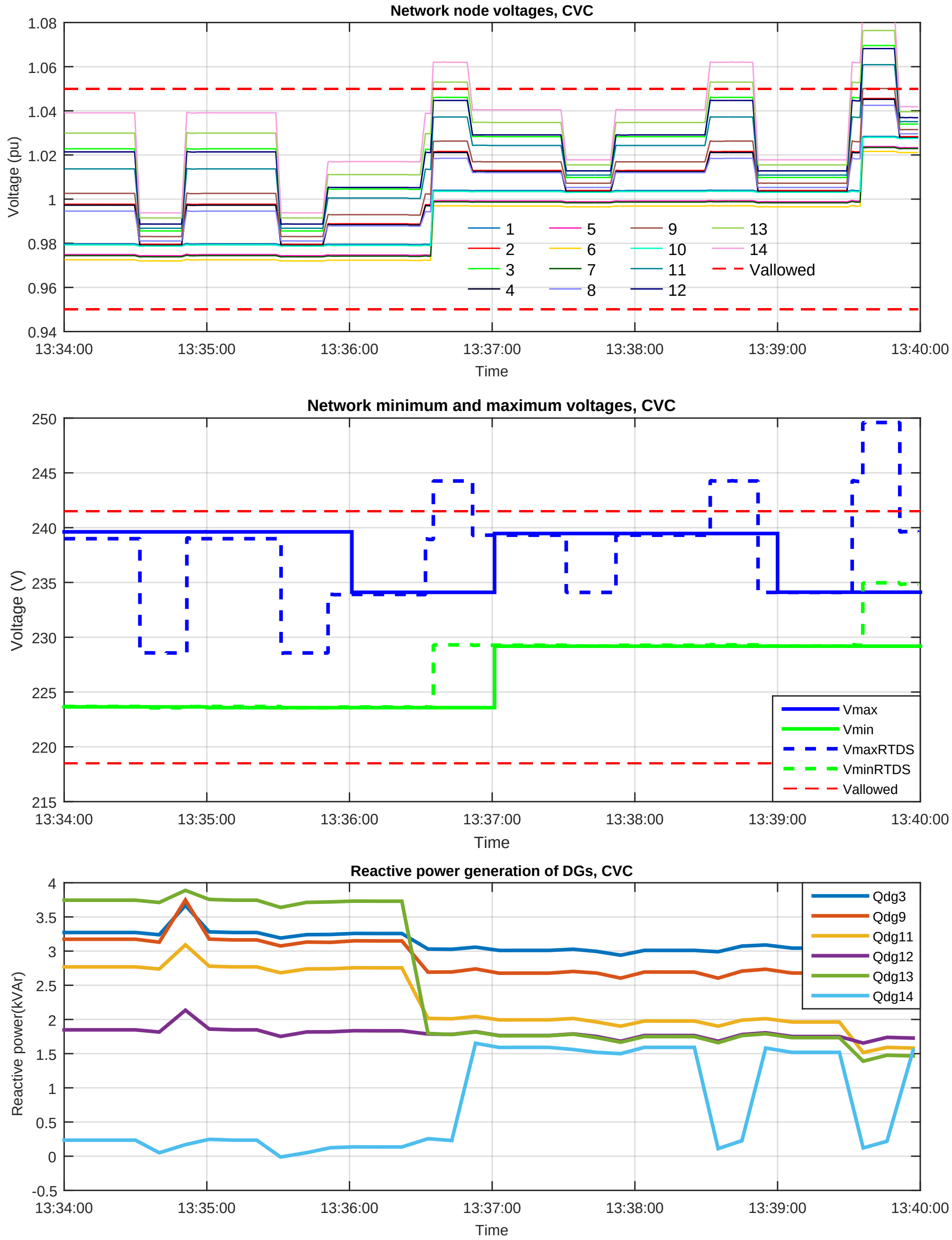

Figure 7.17 *Artificial Sequence 4 - CVC graphs*

7.2.5 Effect of cost parameters

Table 7.9 lists calculated KPIs for simulation Sequences 1 and 4 (Maximum and minimum generation and loading scenarios, and intra-minute voltage variations) with the cost parameter cases listed in Table 6.4. Artificial conditions were chosen instead of real conditions in order to better show the effect of cost parameters in CVC scheme. Only relevant KPIs are presented.

Table 7.9 *Cost parameters cases in sequences 1 and 4*

KPI (estimated/RTDS)	1 Case1	1 Case2	1 Case3	4 Case1	4 Case2	4 Case3
Network losses [kWs]	2729	2775	3031	2375	2440	2757
Average target function value	29.62	28.51	108.54	36.12	38.22	161.05
Average PC execution time [s]	16.90	14.89	26.48	17.22	15.05	22.99
OLTC actions [pcs]	4	2	2	2	1	0
V set point changes [pcs]	2	2	2	2	1	0
Q set point changes [pcs]	18	20	47	17	22	34
Over-voltage volume [pu*s]	4.12 / 3.33	0.30 / 0.16	0.80 / 0.38	0 / 2.21	0 / 0.13	0 / 0
Under-voltage volume [pu*s]	0 / 0	0 / 0	0 / 0	0 / 0	0 / 0	0 / 0
Voltage out of bounds [s]	295 / 240.3	60 / 49.3	118 / 64.79	0 / 168.7	0 / 18.3	0 / 0

First changes to cost parameters in the Sequence 1 reduced the amount of tap changer actions and slightly increased the amount of reactive power set point changes as expected. This was due to the introduction of cost for tap changer operations. With these changes over-voltage volume and voltage out of bounds time were both reduced whereas network losses increased slightly. Further in Case 3, after the substantial increase in cost parameter for network node voltage difference from nominal, the dominant control variable was reactive power as voltages were aimed to kept further away from the voltage limits with available reactive power capability at all times. The substantial increase also caused some numerical instability in the optimization, which is seen from the amount of Q set point changes. Average target function value increased significantly due to adding the cost parameter for voltage difference from nominal. The optimization algorithm execution time also nearly doubled, which ended up increasing over-voltage volume and voltage out of bounds time when compared to Case 2 as restoring the voltage back within limits took longer.

Similar results can be verified from cost parameter cases in Sequence 4. Over-voltage volumes and voltage out of bounds times were reduced with sequential cases and down to zeros in Case 3. Vice versa average target function value, network losses and reactive power set point changes sequentially increased. The graphs for Sequence4 run using Case3 parameters are presented in Figure 7.18. These can be compared to the graphs in Figure 7.17 which represent the Case1 parameters. Considering available reactie power capability, here the nodes with voltage below nominal produce reactive power to increase the voltages and nodes with voltages over nominal consume(-) reactive power to decrease the voltages.

Regardless of the severity of the changes in happening in the network, the best practice seems to be finding optimal network state slightly further away from the network voltage limits. By doing so, the effects of intra-minute voltage changes can be mitigated. This can be achieved by setting stricter than actually desired voltage limits within the algorithm, or by using the cost parameter for node voltage difference from nominal which requires experimenting different parameters.

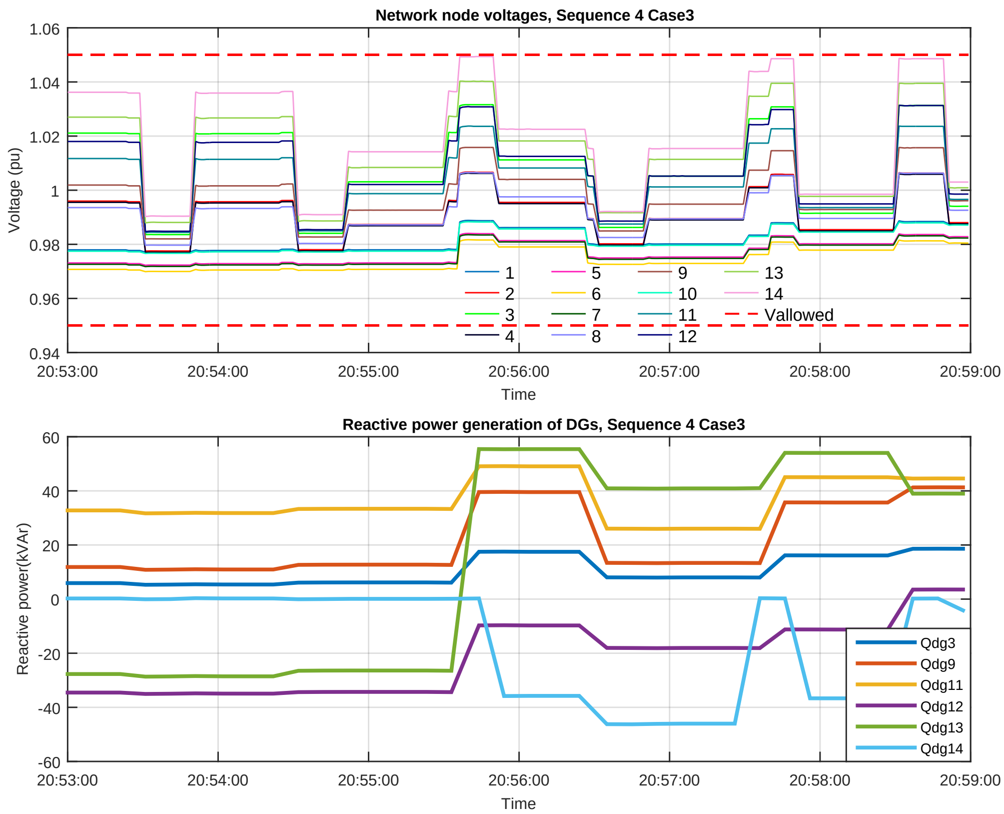

Figure 7.18 *Cost parameter Sequence 4 Case3 graphs*

7.2.6 Production curtailment

Figure 7.19 presents graphs for the production curtailment sequence. Network node voltages, DG unit outputs and the line current of line connecting network nodes FD08/SC02 and FD08/SC03 are presented in the graphs.

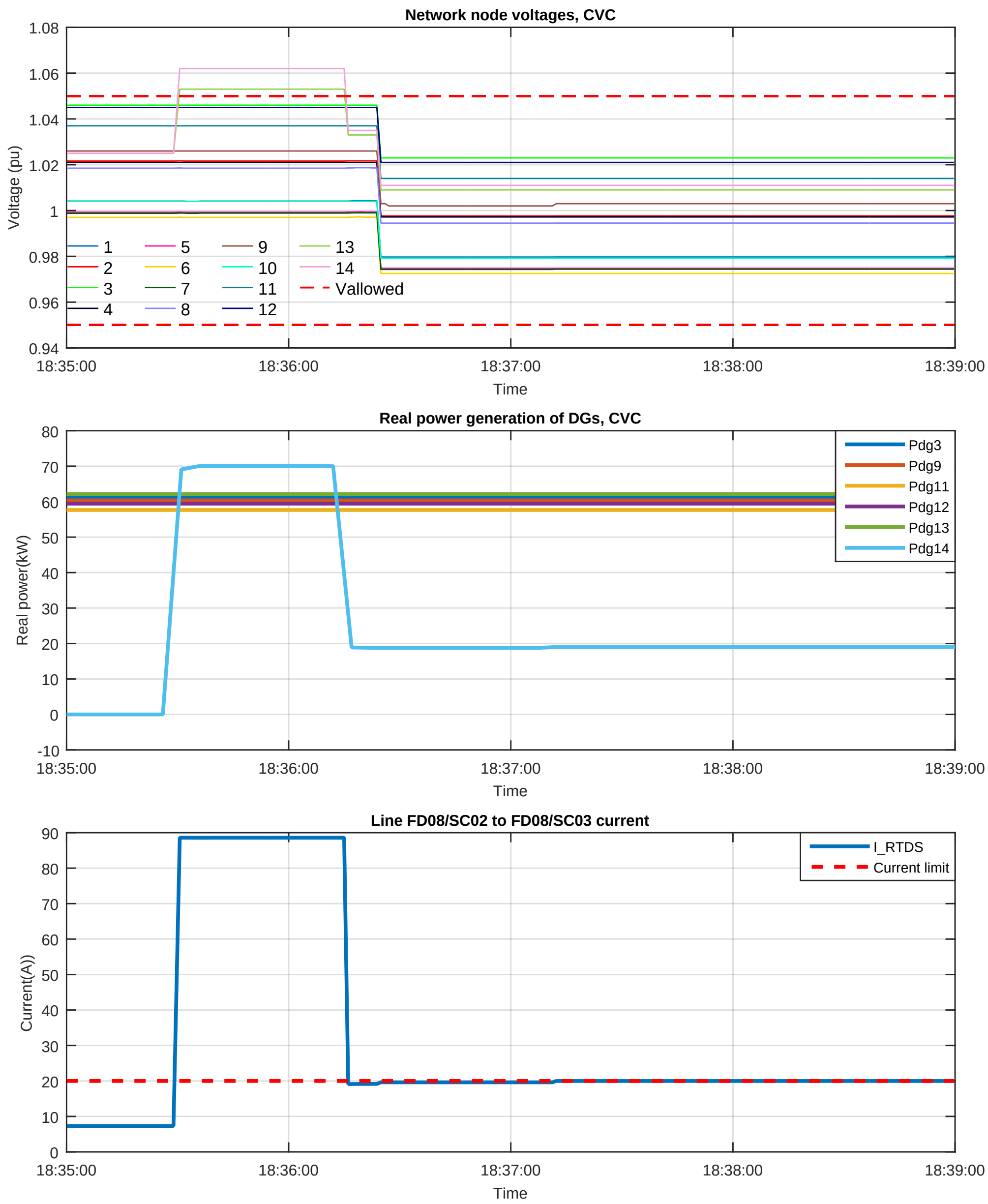

Figure 7.19 *Production curtailment Sequence - graphs*

After the DG output change at 30 seconds, the next optimization resulted in curtailment of the DG unit 14 to the highest possible value without violating the set current limit. After the optimization, the line current remained right below the artificially set limit of 20 A. As the cost parameters were not modified from other artificial conditions, and the production curtailment had highest cost, also new value for the substation voltage reference was used to reach the objective.

8. DISCUSSION OF THE RESULTS

This chapter summarizes and further discusses results obtained in Chapter 7. Limitations in realizing the scheme and achieving such results are acknowledged. Also suggestions for future development are made.

The results validate the correct operation of the CVC scheme. No unnecessary or erroneous control actions were observed during the simulation sequences and thus it is ready to be used in real network demonstrations. Compared to the local schemes with no communication links, and which react to the changes in the network very fast, the CVC managed to always correct voltage violations without further external changes made in the network. A few situations occurred during the sequences where local schemes could not return all voltages within limits due to lack of communication and reactive power capability of certain resource, or made unnecessary control actions among AVR and AVC. Local control without dead band always led to highest losses in the network. In real conditions CVC managed to obtain lowest network losses in each simulation sequence. Over-voltage volumes in CVC scheme were perceived during supply network voltage variations, but in real network operation such variations would not probably happen inside one minute and the CVC scheme would have time to react before. Intra-minute voltage variations were not detected by the CVC scheme which obviously was expected. The effect of these variations to technical safety parameters is better seen when operating closer to the voltage limits. Artificial conditions stressed the control schemes even further and the CVC scheme proved to do the better the tougher the conditions. Comparably low network losses and over-voltage volumes were achieved during all artificial sequences, and both under-voltage and line current limit violations were completely avoided during the simulation sequences which was one goal of the optimization. This is of course due to the nature of how the optimization was tuned to optimize the voltages closer to upper voltage limit to lower the network currents and therefore the network losses.

Consequently the user chosen parameters proved to be effective in fine-tuning the optimization to provide expected results in the network. With different network in question, some of the parameters (C_{Vdiff}) may be complex to determine and may cause numerical instability if set too high. After all the choice in the cost parameters is left for user to decide. However, the cost for losses can be derived from electricity market data, and cost for production curtailment from network feed-in tariffs. Cost for tap changer operation could be determined from the investment cost and the estimated accumulated amount of mechanical operations, and maintenance costs. In reality it may not be so easy to define. Also the cost for voltage variation in network nodes greatly depends on the number of nodes in the network topology. In this thesis' simulations, the number of nodes was considerably reduced from the number of nodes in original network due to computational limitations of the RTDS simulator. The parameters used in this thesis are suggestive how the parameters should be chosen in other networks.

Production curtailment, earlier depicted as last resort resource, was not needed in all but one sequence. CVC always managed to fix the network state in the subsequent optimization round using other available, more cost-effective, resources. If other resources would have been inadequate, then production curtailment would have been used regardless of the cost parameter set. Therefore the last sequence concentrated on this by setting branch current limit low enough. Production curtailment was then observed to correctly bring the node voltage and current of the branch back within limits. Thus, no alerts of OPF not converging or not being able to restore the network to acceptable state were recorded during the simulation sequences. The developed target function value limiter reduced the amount of new set points during stable network operation and thus prevented hunting behavior.

Average algorithm execution times were between 7.73 and 9.96 seconds under real conditions, and increased up to 17.2 seconds under artificial conditions. After adding the cost parameter for voltage difference in Case3 of cost parameter cases the execution times increased further up to 26.48 seconds. The execution times will increase with increased amount of network nodes in the network topology, and with increased amount of nodes with controllable resources. Though, it was noticed that the tap changer seemed to greatly increase the execution time. All in all, the SQP solver of Octave proved not to be as effective as in earlier MATLAB implementation in [7], which increased the algorithm execution time. MATLAB implementation is always an available alternative.

Currently the CVC inputs, the state estimates, were assumed to be accurate as real-time measurements were obtained from each generating unit directly and the feeder currents from the substation were available. Excluding the inaccuracy in these real-time measurements, the only inaccurate inputs in the scheme were pseudo-measurements. As all loads were not measured, pseudo-measurements were used for non-measured loads and were set in correct proportion but did not really correspond the actual loading values. The pseudo-measurements remained the same through the varying loading conditions. Measurement IEDs seemed to lose connection with the SAU at times, and even though the connection recovered shortly after, it may have had effect on the SE results. No time synchronization was implemented among SAU computer, Windows computer and the physical devices. All times were synchronized manually, which does not affect the optimization but may have had minor effect on the plotting of the results as the result data includes timestamps from the database. Better PID-controller parameters could have been used for faster/slower and more accurate response in local control schemes. The parameters were chosen with trial and error method, and were the same for each DG unit. This could have impact on the KPIs of local control schemes in the performance comparison, but the outcome would still remain the same.

8.1 Future studies and development

Unbalanced network conditions are reality as LV networks often have one-phase connected PV inverters and loads. The CVC algorithm was further developed from earlier implementation which modeled the network within the algorithm as single-phase equivalent. Now three-phase network model from the SAU database is used as input and considered within the algorithm. Therefore, the scheme is capable of using single phase resources in the optimization. In the RTDS laboratory this requires changing the three-phase load and generator models to one-phase models, and slight modification of the network model in SAU database network topology tables. Doing so, also real network loading variations during one day from the DSO could be simulated using schedulers to feed the load models. In future, integrating TUT HEMS laboratory to the simulation system is planned. With HEMS load control could be added to the control scheme. Adding another source of measured and controlled resources further stresses the algorithm performance e.g. execution time.

To test the control hierarchy mentioned in Section 2.5.2, the SAU computer is planned to be used also as a PSAU and to maintain two databases and run two sets of algorithms. Alternatively other computer could be used for the purpose. The communication among the SAUs is easy to implement in this case, but in real network a SAU-SAU MMS client/server communication would be used. In the lab, further preparations require running a network model with both MV and LV networks in RSCAD and populating a PSAU database with the MV network data.

9. CONCLUSIONS

This thesis concentrated on studying voltage control in distribution networks with increasing amount of distributed energy resources. The resources in distribution networks were introduced in terms of local control capabilities, and further how utilizing and coordinating the control capabilities of the resources could be used to optimize future distribution network operation. Implementation of coordinated voltage control was discussed and a concept architecture of one implementation was introduced. The architecture decentralizes automation and decision making of distribution networks into hierarchical levels where lower levels deliver only necessary information to upper level controllers. This solves information exchange problems when implementing coordinated voltage control in networks with increasing amount of small scale DERs. The automation units, SAUs, act as secondary controllers and are located at primary and secondary substations. SAUs are responsible of monitoring and controlling of the network part in question.

The main objective of the thesis was then to realize, and to verify operation and performance of Coordinated Voltage Control scheme in Real-Time Digital Simulator laboratory, which naturally required the new proposed automation architecture to be built. This included integrating a SAU and real network monitoring and control devices distributed in the simulation network, and creating communication links between SAU, RTDS and the devices. Algorithms required by the CVC scheme, State Estimation and Power Control, introduced in the thesis, were installed on the SAU.

Case study was then performed on LV network CVC scheme, and was carried out under two possible network conditions. Real conditions mimicked conditions in the real network which in this case was modeled in RSCAD according to network data received from a real DSO. Artificial conditions were generated to further see the operation of algorithms in varying scenarios which four different simulation sequences went through. The sequences featured minimum and maximum generation and loading scenarios, production emphasis switching, higher voltage level voltage variations and intra-minute voltage variations, all of which are probable events during real network operation. Under both conditions the CVC scheme found optimum network state with no exceptions. This meant returning over-voltages within limits and completely avoid exceeding conductor thermal limits. As a secondary optimization objective network losses were minimized to the lowest value of the baseline. In order to reduce the network losses, the voltages were optimized closer to the allowed maximum limit. This led to over-voltages in some sequences as the changes made in the network were substantial and instantaneous. The over-voltages were then completely avoided in further simulations by setting cost parameters for the algorithm to optimize voltages further away from the limits. Other control schemes were found to be either inadequate in more demanding conditions, or local control would do contradictory control actions among the resources. Further, local control without the deadband led to high network losses in all cases. Production curtailment was specifically tested in an artificial scenario and was correctly used to bring branch current below set limit by the CVC scheme. In all other sequences production curtailment was still available as reserve resource in the CVC scheme but was not used due to the scheme preferring more cost-effective resources. Thus the objectives of algorithm verification and assessment with other control schemes were accomplished.

Studying unbalanced network model and conditions was left for future work. The simulation laboratory has planned extensions where HEMS laboratory, i.e. controllable loads, are integrated into the system. Studying the control architecture further by adding MV network and another SAU at primary substation to the simulation system is possible. The simulation sequences could have been slightly improved so that varying algorithm execution times, due to available reactive power capability or severity of the change in the network, would have not that big of a influence in the KPIs. Though seeing this in the results acknowledges some of the limitations the CVC scheme has, as in reality the changes are unpredictable. Future validation of the concept is held through a real network demonstrations.

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APPENDIX A. SIMULATION NETWORK

Figure A.1 *Original LV network*

Table A.1 *Simplified LV network load nodes*

New node	Combined loads
2 / FD01/SC01	
3 / FD01/SCw2	
4 / FD01/SCe2	
5 / FD02/SC01	
6 / FD02/SCw2	
7 / FD02/SCe2	
8 / FD03/SC02	FD03/SC01
9 / FD03/SC03	
10 / FD06/TN001	
11 / FD07/SC02	FD07/SC01
12 / FD07/SC03	
13 / FD08/SC02	FD08/SC01
14 / FD08/SC03	

Table A.2 *LV network loading (kW), cos φ = 0.97*

Node	Working Day	Sunday
no./name	**10:00**	**12:00**
2 / FD01/SC01	6.31	15.775
3 / FD01/SCw2	5.74	14.35
4 / FD01/SCe2	5.45	13.625
5 / FD02/SC01	3.44	8.6
6 / FD02/SCw2	5.74	14.35
7 / FD02/SCe2	5.16	12.9
8 / FD03/SC02	7.46	18.65
9 / FD03/SC03	4.88	12.2
10 / FD06/TN001	3.16	7.90
11 / FD07/SC02	7.75	19.375
12 / FD07/SC03	4.88	12.2
13 / FD08/SC02	6.31	15.775
14 / FD08/SC03	5.16	12.9

Table A.3 *LV network line parameters*

From bus	To bus	R(Ω)	X(Ω)	B(S)	R_0(Ω)	X_0(Ω)	B_0(S)	Rated current(A)
SS1056/LV1	FD01/SC01	0.06715	0.001564	0	0.2686	0.006256	0	91
SS1056/LV1	FD02/SC01	0.050232	0.008102	0	0.333216	0.033467	0	166
SS1056/LV1	FD03/SC02	0.04925	0.01379	0	0.334703	0.059827	0	249
SS1056/LV1	FD06/TN001	0.023667	0.003817	0	0.156996	0.001577	0	166
SS1056/LV1	FD07/SC02	0.0525	0.005817	0	0.35679	0.063777	0	249
SS1056/LV1	FD08/SC02	0.06825	0.006258	0	0.463827	0.08291	0	249
FD01/SC01	FD01/SCw2	0.072933	0.001176	0	0.483804	0.048592	0	166
FD01/SC01	FD01/SCe2	0.012063	0.001081	0	0.482524	0.004325	0	116
FD02/SC01	FD02/SCw2	0.068932	0.006179	0	0.275728	0.024715	0	116
FD02/SC01	FD02/SCe2	0.010703	0.009593	0	0.428104	0.003837	0	116
FD03/SC02	FD03/SC03	0.02275	0.00637	0	0.156996	0.027637	0	249
FD07/SC02	FD07/SC03	0.02275	0.00637	0	0.154609	0.027637	0	249
FD08/SC02	FD08/SC03	0.0235	0.00658	0	0.159706	0.028548	0	249

Table A.4 *Secondary substation transformer parameters*

Transformer	SS
Primary voltage (kV)	15
Secondary voltage (kV)	0.4
Rated Power (kVA)	630
Winding connection	Dy11
Z_k (%)	0.04
P_0 (kW)	1.03
P_k (kW)	5.4
I_m (pu)	0.007

Table A.5 *Secondary substation tap changer parameters*

Tap changer	SS
Steps (+/- nominal)	3/-3
Step size (%)	2.50