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Coordination des moyens de réglage de la tension à l'interface réseaux de transport et de distribution, évolution du réglage temps réel de la tension dans les réseaux de distribution

Joint TSO-TSO voltage and reactive power control at HV/MV systems interface and development of real-time Volt Var Control of distribution networks

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Acronyms

ADA Advanced Distribution Automation.

AVR Automatic Voltage Regulation.

CB Capacitor Bank.

CVR Conservation Voltage Reduction.

DCC Demand and Connection Code.

DG Distributed Generation.

DMS Distribution Management System.

DNCC Distribution Network Control Center.

DSE Distributed State Estimator.

DSO Distribution System Operator.

EHV Extra High Voltage.

Enedis ex ERDF (Electricité Réseau de Distribution France), a French DSO.

GSP Grid Supply Point.

HV High Voltage.

LV Low Voltage.

MPC Model Predictive Control.

MV Medium Voltage.

NLTC No Load Tap Changer.

OLTC On Load Tap Changer.

TSO Transmission System Operator.

VVC Volt Var Control.

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General Introduction

Thesis Context and abstract

This PhD work has been conducted within the Laboratory of Electrical Engineering and Power Electronics (L2EP) of Lille and in partnership with the major French DSO, Enedis. The objectives defined by Enedis were to quantify how the evolution of the distribution system may impact the voltage control and reactive power management, and more specifically at the interface of High Voltage (HV) and Medium Voltage (MV) systems. Then, several solutions could be proposed and compared to enhance the coordination of voltage control at the HV/MV interface.

Distribution networks are nowadays undergoing major changes that put into question the relevance of traditional voltage control and reactive power management schemes of the electrical power system. These changes are namely the massive insertion of Distributed Generation (DG), the replacement of overhead lines by underground cables and the evolution of the load. As a result, distribution networks are prone to an increase of voltage profiles and a change in reactive power flows leading in some situations to reactive power flowing upwards at the distribution/transmission system interface. These flows may impact voltage control and reactive power management strategies on both MV (Medium Voltage) and High Voltage (HV) networks. The coupling between HV and MV systems is thus strengthened: the coupling is more erratic, variable and hardly predictable. Along with this technical evolution, any new distribution system will have to comply with the new regulatory framework defined by the European Grid Codes. More specifically, in the Demand and Connection code, any new distribution system should be able to restrain the reactive power flowing upwards HV grid at low consumption.

To cope with the new operational concerns and the regulatory framework, there is a need to define new strategies at the interface between transmission and distribution systems. In this work, a strategy based on an evolution of the real-time Volt Var Control (VVC) in distribution system and an increased coordination between Transmission and Distribution System Operators (TSO, DSO) has been developed. With regard to all the aforementioned evolutions, the real-time VVC scheme should be enhanced in order to reach a twofold objective: to improve control of reactive power exchanges between HV and MV grids while maintaining a suitable MV voltage profiles. To this end, three VVC schemes have been developed and compared: a rule-based method, an optimization based method and a Model Predictive Control (MPC) method. These schemes take advantage of the MV network control actions by adjusting in a coordinated manner

the reference of On Load Tap Changer (OLTC), the reactive power of DGs and the number of activated step of Capacitor Banks. The main contribution of the works lies in the definition of the predictive scheme. In short, this scheme is merging MPC with the OLTC inner control algorithm and embeds all of the OLTC nonlinearities. Hence, fundamental modifications of the existing control devices and operating processes are avoided while the minimization of tap change occurrence (and thus the control cost) is accurately limited.

Then, the relevance of a TSO-DSO coordinated reactive power management scheme to maintain HV voltage and control HV reactive power flows has been further discussed for a medium-scale system, that is a system which encompasses several distribution grids connected to a HV grid. Thus, it is possible to study and take into account both DSO and TSO needs, requirements and constraints. An Optimal Power Flow based strategy has been developed to reach such a coordination that yields the optimal reactive power limitation at the HV/MV interfaces to be enforced. The association of the proposed coordinated management with the real-time VVCs of distribution networks has been more particularly studied.

Thesis organization

The thesis is divided in three parts, split into two or three chapters.

PART A is entitled “Voltage Control in Distribution Networks and Reactive Power Exchange at the Transmission and Distribution System Interface”.

CHAPTER I is dedicated to a general background on electrical power systems and more specifically on the presentation of the traditional voltage control and reactive power management in the distribution system. The French situation is more particularly explained. The transmission network control schemes are briefly introduced.

CHAPTER II deals with the undergoing changes of distribution systems. The interest of developing new voltage control strategies for MV network and at the HV/MV systems interface is assessed. Then, the opportunities as well as the technological limitations for voltage control and reactive power management are further discussed.

CHAPTER III gives the motivations as well as the position of our work. In short, the strategy developed is based on an enhancement of the real-time Volt Var Control of distribution networks and on an increased coordination between both Transmission and Distribution System Operators. The scientific approach as well as the tools and networks considered are also detailed in this last chapter of Part A.

PART B is dedicated to the design of an original real-time Volt Var Control for distribution network. Such a control must be compliant with present industrial requirements and able to enforce a suitable MV voltage profile with an appropriate reactive power exchange at the HV/MV system interface.

CHAPTER IV consists of a survey on the real-time VVC of distribution networks. In this Chapter, the relevance of using centralized strategies based on Model Predictive Control is more specifically assessed. Two standards methods, *viz.* a rule-based and a one-step ahead optimization based methods, are introduced in this chapter for comparative purposes.

CHAPTER V underlines the methodology used for the design of an original predictive Volt Var Control. In order to assess the performances of such a control, a robustness study has been designed and performed.

CHAPTER VI gives the results of a comparison based on dynamic simulations of the proposed predictive controller with the two standard methods introduced in Chapter IV. The results corroborates the relevance of selecting a MPC method for the design of a real-time VVC.

PART C handles the design of joint TSO-DSO reactive power management based on a reactive power support from MV grids.

CHAPTER VII discusses the interest of such a support from the TSO point of view. The need to perform dynamic simulations, on a a medium scale system combining several MV grids connected to the same HV system is stated.

CHAPTER VIII aims to propose a joint TSO-DSO reactive power management based on an Optimal Power Flow method. This management addresses the voltage and reactive power requirements of the TSO while considering the limitations of MV grids. The association of such coordination with the real-time predictive VVC of distribution networks is studied through dynamic simulations on a medium scale system.

Thesis contribution

The main contributions of this work lie in the design of a real-time VVC for MV grids and a joint DSO-TSO reactive power management.

Regarding the real-time VVC for MV grids, the key-features of the proposed approach are:

- To propose a coordination of many actuators for voltage regulation and reactive power exchange at TSO/DSO interface;
- To show the relevance of considering MPC-based methods for the design of the control law and proposal of methods to assess the performances of such a control;
- To guarantee the minimization of tap changes during all life of the OLTC since the criterion is explicitly considered in the cost function;
- To keep and consider the classical OLTC inner control to avoid fundamental modifications of the existing control devices and operating process.

On the other hand, for the joint reactive power management, there are some points that should be more specifically considered. Due to the cross interactions between MV and HV grids, a coordination among these grids should be considered to develop an appropriate and efficient reactive and voltage control at the interface between HV and MV systems. In our work, the TSO was assumed to be responsible for this coordination that is yet jointly designed with the DSO. A control located within the Transmission Network Control Center was proposed.

Since the control was designed for a specific system and under specific circumstances, the results are not to be generalized. However, these results enable to draw conclusions and give

recommendations for the design of a suitable TSO/DSO coordination. As a reminder, such a coordination should tackle the voltage and reactive power concerns at TSO/DSO systems interface while using a support from MV grids:

- Connections and network planning studies should be jointly performed by TSO and DSO to ensure that the objectives of the control are relevant and achievable;
- Real-time management of reactive power within a HV grid should result from a optimum of reactive power resources of TSO and DSO. Optimal Power Flow based solutions are of interest to handle the design of such a solution;
- Dynamic simulations should be performed on a medium scale system in order to take into account the true behavior of MV and HV grids and their own control;
- Relevant information to be exchanged by TSO and DSO should be identified. More especially the real-time reactive power reserve at the interface should be exchanged between the TSO and the DSO.

A general conclusion summarizes the main recommendations and opens the work towards new research studies.

Thesis publications

Conference publications

- J.Morin, F.Colas, X. Guillaud, and S. Grenard, “Determination and origins of a reactive power flows in HV/MV substations”, in *23rd International Conference and Exhibition on Electricity Distribution (CIRED 2015)*, Lyon, 2015.
- J.Morin, F.Colas, X. Guillaud, S. Grenard and J.Y. Dieulot, “Rules based voltage control for distributions networks combined with TSO-DSO reactive power exchange management”, in *IEEE Eindhoven Powertech*, Eindhoven, 2015.
- J.Morin, F.Colas, X. Guillaud, S. Grenard and J.Y. Dieulot, “Coordinated predictive control in active distribution networks with HV/MV reactive power constraint”, in *IEEE PES Innovative Smart Grid Technologies (ISGT) Europe*, 2016, Accepted for an oral presentation.

Journal publications

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- J.Morin, F.Colas, X. Guillaud, S. Grenard and J.Y. Dieulot, “Embedding OLTC nonlinearities in predictive Volt Var Control for active distribution networks”, *Electrical Power System Research*, Submitted in May 2016, accepted for publication.
- J.Morin, F.Colas, X. Guillaud, S. Grenard and J.Y. Dieulot, “Coordinated predictive control of active distribution networks to help transmission system in emergency situation”, *Sustainable Energy Grids and Networks*, Submitted in July 2016, under review.

Part A

Voltage Control in Distribution Networks and Reactive Power Exchange at the Transmission and Distribution System Interface

Chapter I

Existing control and structure of electricity power system networks

Introduction

Voltage control is of paramount importance to ensure a secure and reliable operation of the electrical power system. This control aims to maintain the voltage level within an acceptable voltage range in compliance with normative requirements. Indeed excessive voltages can be harmful for the networks components and equipment while low voltages may lead to equipment malfunctions. This can be achieved by properly managing the reactive power especially in transmission system. Transmission System Operator (TSO) and Distribution System Operator (DSO) are more specifically responsible for voltage control for their own network.

The scope of this chapter is to recall the traditional voltage control and reactive power management strategy in the electrical system, more especially in the distribution system and at the interface between transmission and distribution grids. After a brief description of the power system and the role of system operators (See section I.1), the traditional control strategies are presented in section I.2.

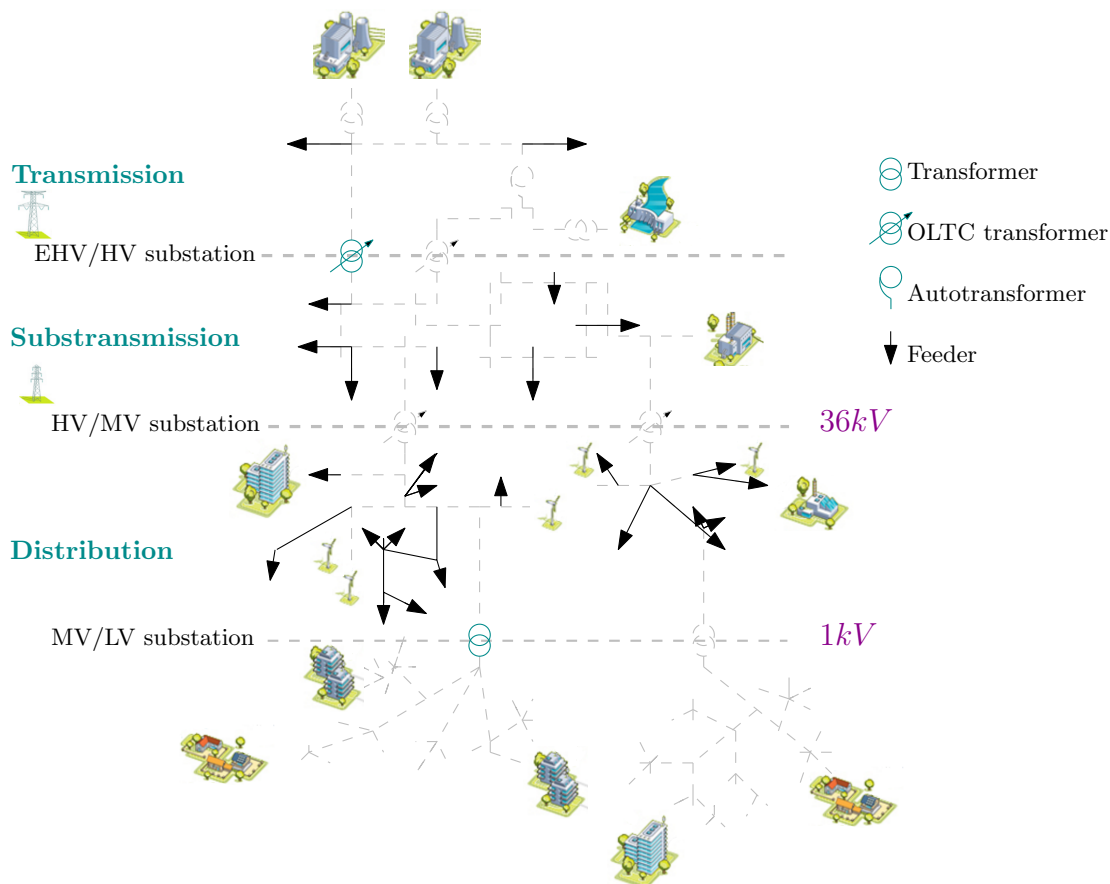


Figure I.1: General structure of power systems [1]

I.1 Public Electricity Distribution Networks

I.1.1 General structure of electricity power systems

Electrical power systems are traditionally divided into three main layers that are operated at different voltage levels [1] as illustrated in Figure I.1:

- Transmission at Extra High Voltage (EHV) level;
- Subtransmission system at High Voltage (HV) level;
- Distribution system at Medium Voltage (MV) and Low Voltage (LV) levels;

According to the European standardisation bodies, the HV level is above 36 kV while MV is in [1 – 36] kV and LV below 1 kV. Figure I.3 gives the voltage level of European MV networks.

The EHV grid is the backbone of the electrical system and hosts most of the large power plant units such as nuclear power, hydroelectric or fossil plants. The EHV grid is a long-distance bulk network connected to the HV grid through EHV/HV stations where the voltage is stepped up by transformers.

The role of the subtransmission system is to convey the electricity from the transmission to the distribution systems and to major industrial loads. Usually, transmission and subtransmission networks are associated, and the transmission system term encompasses both transmission and subtransmission grids.

The HV power is converted in the HV/MV substations corresponding to physical boundaries between the subtransmission and distribution systems. At the final stage of the electricity networks, the distribution grids are designed to deliver electricity to the end users. Generally, the distribution systems are subdivided into two levels: MV and LV grids. Medium size industrial loads and distributed generators are connected to the MV level, while downstream MV/LV substations, commercial and residential consumers are connected to the LV feeders as well as small distributed generators.

The French MV distribution grid is made of 2 240 HV/MV substations, 1.3 million kilometers of lines and underground cables, and 751 000 MV/LV substations ¹. In addition to these physical elements, there are 30 Distribution Network Control Centers in France responsible for the secure operation of a given regional area and hosting the distribution management tools (such as Distribution Management System (DMS), Advanced Distribution Automation (ADA), Distributed State Estimator (DSE)...). 232 636 production sites are connected to the distribution system.

As in most of European countries, French distribution grids are organized as rings but operated as radial networks. The radial structure is indeed optimal for maintenance purposes, fault detection and eases protection strategies.

¹<http://www.erdf.fr/fonctionnement-du-reseau>.

I.1.2 Public electricity distribution networks in France

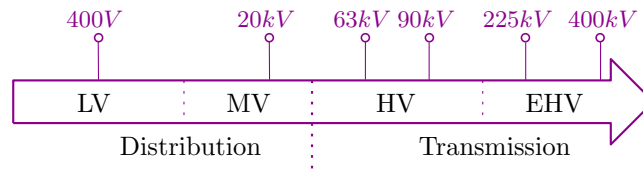


Figure I.2: Voltage levels in France

In France, most of the distribution networks are owned by the local authority. The MV network supplies the voltage at 20kV, while the LV networks supplies the voltage at 400V as given by Figure I.2.

A classical MV distribution network consists of:

- HV/MV substations that generally include several transformers with On Load Tap Changer, and in some of them, a Capacitor Bank (CB) is connected to the MV busbar of the HV/MV substations;
- MV customers, such as small industrial loads, the MV/LV substations or DGs, if the maximal active power is below 12 MW²;
- MV feeders (namely the overhead lines and underground cables), that can be further classified in three categories:
 - Dedicated feeder: a feeder hosting only a DG,
 - Mixed feeder: a feeder with both DGs and loads,
 - Other feeder: with only loads.

The LV grids are made of:

- MV/LV substations equipped with transformers;
- LV customers (namely loads and DGs with a maximal nominal power below 250 kVA);
- LV feeders.

²up to 17 MW as an exception.

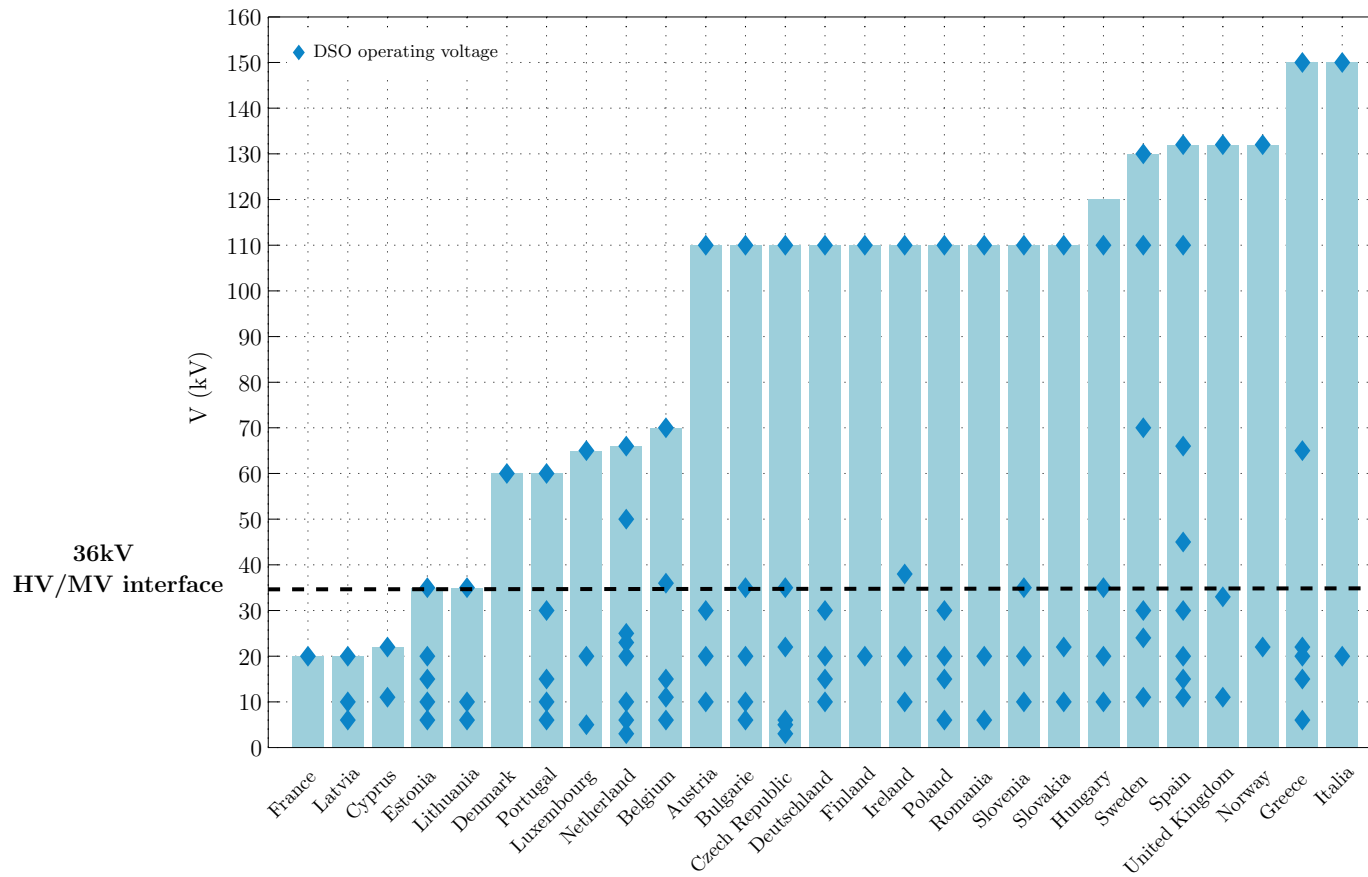


Figure I.3: Comparison of the DSO operating voltages and TSO-DSO interfaces in Europe according to EURELECTRIC (Union of the Electricity Industry), http://www.eurelectric.org/media/113155/dso_report-web_final-2013-030-0764-01-e.pdf

I.1.3 Distribution and Transmission system operators

Transmission System Operators (TSOs) and Distribution System Operators (DSOs) are responsible for a secure and reliable operation of the power system. More specifically TSOs are entrusted for "operating and insuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity" as defined by the directive 2009/72 of the European Commission. Accordingly, DSOs are responsible for the distribution of electricity.

In France, the electricity distribution is a regulated activity supervised by the French Energy Regulator (CRE). Enedis is entrusted to manage around 95 % of the French public electricity network through a public service delegation. Enedis should thus fulfill a twofold mission: ensure service continuity and quality of supply, and provide a non-discriminatory access to the network.

It should be borne in mind that the voltage levels area managed by the European Distribution System Operator (DSO) is not the same as shown in Figure I.3. Hence, the role of the DSO is quite different from a country to another. Nonetheless, a DSO is more specifically responsible for maintaining the MV and LV voltages within acceptable ranges of values for a secure and reliable grid operation.

In France, this specified range comply with standards (EN 50-160), legal (according to the 2007-1826 decree) and contractual (contract for access to the distribution system) requirements. To meet these requirements, the LV voltages should be maintained in normal operating conditions around $\pm 10\%$ of the nominal value at the connection point. As for the MV voltages, they should stay within $\pm 5\%$ of a contractual voltage value, that is around $\pm 5\%$ of the nominal value at the connection point. This requirements should be enforced 95% of the time, by steps of 10 minutes for a week.

Besides, in network planning studies, Enedis makes sure that the voltage rise does not overshoot 2% in mixed feeder and 7% in dedicated feeder, while the voltage drop is limited to 5%.

I.2 Current practices of Voltage Control and Reactive Power Management in Distribution and Transmission Grids

This section aims to present traditional voltage control and reactive power management schemes. The French case is more specifically enlightened.

I.2.1 Control strategy at the distribution level

In short, the main concern of the voltage and reactive power control strategy is to comply with normative, legislative and contractual requirements. To this end, Enedis has set up industrial policies that are mainly based on network planning studies and the use of On Load Tap Changers (OLTC), No-Load-Tap-Changers and CBs. These studies specify the network reinforcement needs and set the local control of dynamic actuators as illustrated in Figure I.4:

- The voltage reference of the OLTC inner control;
- The power factor ($\tan(\phi)_{DG}$) or $Q = f(U)$ law of DG;
- The Var-Metric-Process (VMP) e.g. the on/off switching rule of CBs.

Then, the Automatic Voltage Regulation (AVR) (namely the OLTC inner control) automatically controls the MV voltage profile while the VMP of CB adjusts the reactive power at HV/MV systems interface for winter time to enforce legal (2007-1826 Decree) and contractual (contract to access to the transmission system, CART) requirements.

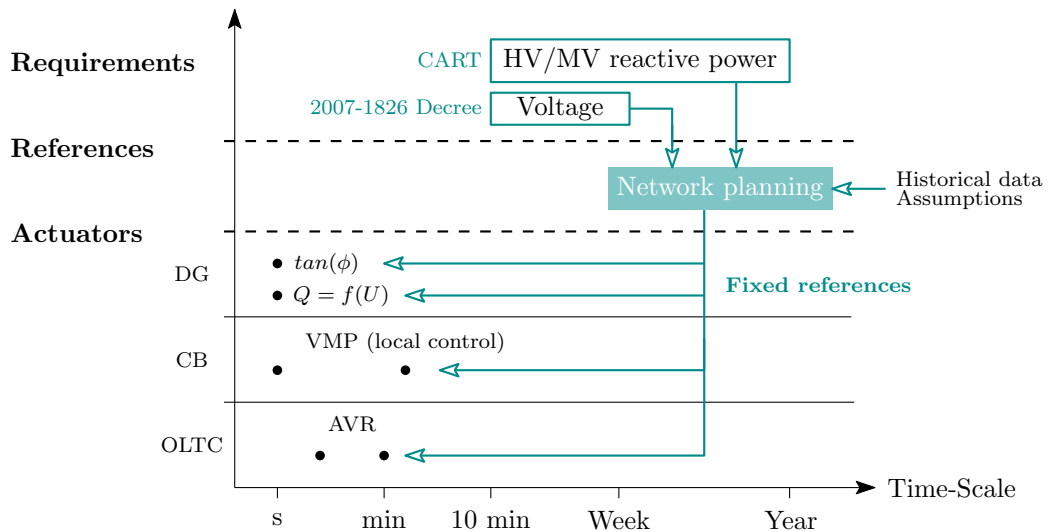


Figure I.4: Present voltage and reactive power control strategy in French Distribution System

I.2.1.a Voltage and reactive power control in France

To maintain an acceptable voltage profile, Enedis mainly uses On Load Tap Changer (OLTC) in HV/MV substations and No Load Tap Changer (NLTC) in MV/LV substations described in

Table I.1. For both the OLTC and NLTC, the principle is to step down the voltage by changing the ratio of the transformer thanks to a variable number of winding turns. The evolution of the voltage profile along a distribution feeder without significant DGs production is depicted in Figure I.5.

OLTC and NLTC to adjust the voltage

Some turns in the windings of the MV/LV transformer can be either added or removed manually from the main winding. Generally, MV/LV NLTC have three positions to adjust the voltage by step of 2.5 %. Since, this adjustment must be realized off-load, the position of the NLTC is infrequently updated (for instance during maintenance works).

Nowadays, Enedis is performing advanced R&D works on smart MV/LV substation and more specifically on a smart MV/LV transformer [2].

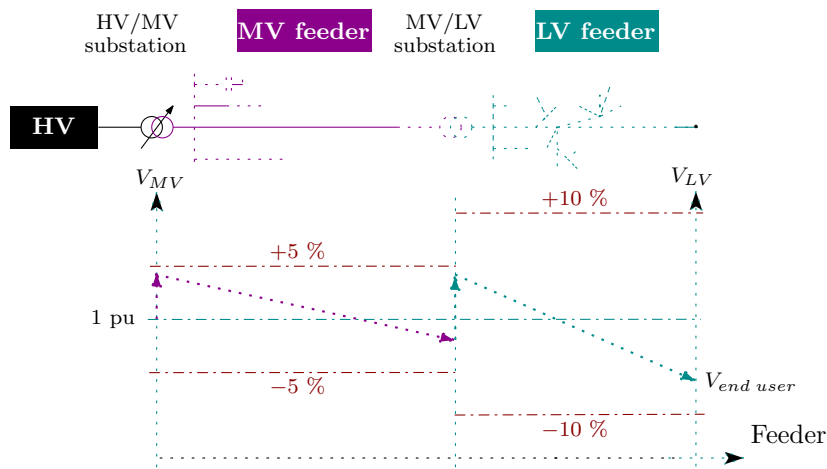


Figure I.5: Evolution of the voltages along a distribution feeder without significant production

Table I.1: Existing levers for voltage control in French distribution networks

Levers	Location	Details	Control
OLTC	HV/MV substations	17, 21 or 23 steps $\pm 14\%$ or $\pm 12\%$	Automatic control
NLTC	MV/LV substations	3 steps [+0%, +2.5%, +5%]	Manual Off-load

OLTCs are of paramount importance for voltage control in radial distribution networks. Their principle is to maintain the voltage at the secondary side of a transformer by automatically adjusting the ratio $r = \frac{V_{HV}}{V_{MV}}$ by discrete step corresponding to a change of tap n_{OLTC} according to an inner control (generally called Automatic Voltage Regulator) algorithm as illustrated in Figure I.6 [3, 4]. Their aim is to partially decouple the MV voltages from the HV voltages.

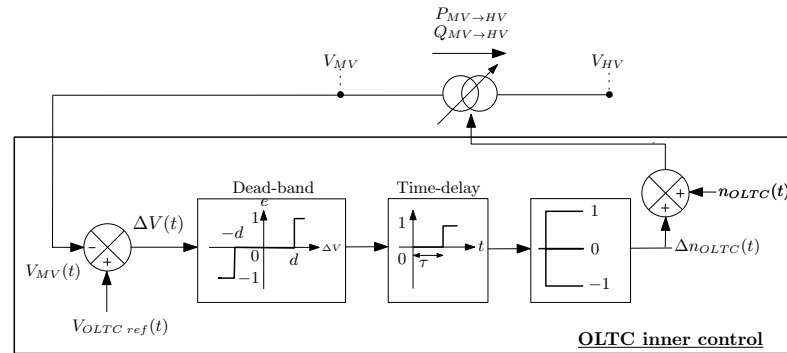


Figure I.6: Inner control (AVR, Automatic Voltage Regulator) of the OLTC

The AVR continuously monitors the voltage at the secondary side of the transformer V_{MV} . If the difference between the voltage reference $V_{OLTCref}$ and this voltage V_{MV} exceeds the half dead-band d for a time longer than the time-delay τ , a change of tap is triggered. Each change of tap generates a change in voltage V_{tap} at the secondary side. The dead-band $2d$ is classically chosen equal to this voltage change: $2d = V_{tap}$. In practice, this value is around 1 – 1.5 % and there are 17 tap positions.

This industrial control system has been designed to optimize the life span of the OLTC. For instance, the dead-band and the time-delays have been chosen to avoid excessive switching that can cause an early wear. In France, time-delays are of 60 s for the first tap change and 10 s for subsequent tap changes and are consistent with the EHV/HV OLTC time-delays.

Reactive power compensation using CBs

In distribution systems, there is no close relationship between the voltage and the reactive power contrary to the transmission grids. However, reactive power is necessary for a proper operation of the system to maintain the transmission voltages close to their nominal values, reduce the line currents (and hence the losses) or for stability purposes [3, 5]. This compensation should be done locally to avoid large power flows and to relieve the transmission system during peak load conditions.

The easiest and common mean of reactive power compensation is the use of Capacitor Banks. In France, CBs have been mainly connected to the MV busbar of the HV/MV transformers to compensate for the loads connected to the MV and LV feeders.

Table I.2 gives the main reactive power levers in use in the French distribution networks. By comparison, the reactive power compensation in transmission system is far more developed. There are for instance dynamic devices such as the FACTs or synchronous compensators that could be potential levers for distribution systems as well. Next, shunt reactance are connected to certain EHV/HV stations and can be automatically switched off/on from the Transmission Network Control Center.

Table I.2: Existing levers for reactive power compensation in French distribution networks

Levers	Location	Details	Control
CB	HV/MV substations	3 steps 1.2 to 1.8 MVAR	· VMP · manual

Enedis industrial policies

Enedis policy is a traditional voltage control strategy based on solutions such as grid reinforcement or "fit and forget" design approaches. Any new equipment to be connected to the grid is sized to prevent over or under voltage in the most critical situations (namely high consumption with no production and low consumption with high production cases) during network planning studies.

Since the distribution systems were designed to deliver the power to the end users, only unidirectional flows (from upstream to downstream) were considered. The voltage control methods were set up to mitigate the voltage drop along the distribution feeders by means of transformers. The maximal voltage drop should not overshoot 5% in normal operating conditions, and 8% in emergency situations.

i) Normal operating conditions: The insertion of DGs has made more complicated the voltage control policies. Traditionally, a compounding technique was used [6] in France for the OLTC. This technique consists in adjusting the voltage reference depending on the current flowing through the transformer that was reflecting the level of consumption in the MV feeders:

$$V_{OLTCref} = V_{nom} + kI. \quad (I.1)$$

Where V_{nom} is the nominal MV voltage, typically 20 kV. However, due to the insertion of the DGs in the distribution networks, this current does not reflect anymore the true level of consumption (and thus the voltage drop along the feeder) and this technique had to be dropped off. New policies have been set up to ensure that DGs can be connected to the distribution networks without inducing over-voltages:

- $V_{OLTCref} + 4\%$ for a feeder without a significant amount of production,
- $V_{OLTCref} + 2\%$ for a feeder with a high amount of production to prevent over-voltages.

For some substations embedding numerical control law technologies, it is possible to dynamically adjust the voltage reference through a remote control system within the range $[V_{nom} + 2\%, V_{nom} + 4\%]$.

Nowadays, the DGs do not take part in the reactive power compensation scheme, but their reactive power can be used as an alternative to grid reinforcement to limit their connection costs. To this end, for the DGs connected in a mixed MV feeder, the power factor $\tan(\phi)_{DG} = \frac{Q_{DG}}{P_{DG}}$ is specified in the following range according to the decree of 23 April 2008³

$$\tan(\phi)_{DG} \in [-0.35, +0.4] \quad (I.2)$$

³<https://www.legifrance.gouv.fr/affichTexte.do?cidTexte=JORFTEXT000018698004>

This value is defined in network planning in order to ensure that even in the most stressed conditions (namely high loading associated with no generation and low loading with high generation), the MV voltages remain within the contractual range of values. The network planning processes are further described in [7]. For the DGs connected to LV feeders or dedicated MV feeders, the $\tan(\phi)_{DG}$ is set up to zero. Table I.3 summarizes the reactive power compensation of DGs connected to the French distribution grid.

It could be noted that, given the relationship between voltage and reactive power, the DGs connected to mixed MV feeders can be seen somehow as a voltage control lever. In fact, it is an alternative to grid reinforcement to minimize the DGs connection cost and not a voltage control lever.

Yet, Enedis has designed a law $Q = f(U)$ that modulates the reactive power of DGs depending on the voltage at their point of connection. This law will be more specifically detailed in Part B. $Q = f(U)$ laws have the very same purpose than a constant power factor ($\tan(\phi)_{DG}$) operation of DG. However, the main advantage of such laws is to avoid requesting reactive power when unnecessary. The reactive power is called for only if there is an overshoot of the voltage at the DG connection point. Yet, this implies that the reactive power cannot be used for another purposes than the local control of the voltage at this DG point of connection.

Table I.3: Reactive power compensation of DGs connected in the French distribution grid

Location	Details	Control
MV dedicated feeder	$P \leq 12$ MW	$\tan(\phi) = 0$
MV mixed feeder		$\cdot \tan(\phi) \in [-0.35, +0.4]P_{max}$ $\cdot Q = f(U)$
LV feeder	$P \leq 250$ kVA 3- Φ $P \leq 6$ kVA 1- Φ	$\tan(\phi) = 0$

Regarding reactive power compensation, historically, the off/on switching of the CB steps was done following a seasonal schedule set up according to the consumption pattern. With the evolution of the loads and the insertion of DGs, one is able to understand the limitation of such a procedure. Nowadays, substations are equipped with a VMP (Var Metric Process) controller responsible for the automatic switching of the CB steps. The control law is detailed in [6].

ii) Emergency situations: During emergency situations, the OLTC voltage reference can be lowered or the tap changer can even be blocked by a special request of the TSO from the Transmission Network Control Center sent to the Distribution Network Control Center. Moreover, if the OLTC has been deactivated after a TSO request, the CB switching are also disabled to prevent a further degradation of the situation.

To sum up, the industrial policies set up by Enedis aim to maintain the MV and LV voltages in the required range of values to ensure a high quality of supply for the final customers (that can be either a load or a production site). This strategy should be able to deal with an increased penetration of DGs in the distribution grids. Indeed, such an increase should be expecting according to the European objectives on DGs connection. These objectives purposes are to raise

the share of renewable energy sources in the energy consumption up to 20% from 2020 and 27% by 2030.

In other countries, energy saving and efficiency are targeted. In this case, Conservation Voltage Reduction (CVR) strategies are developed. Such strategies are briefly introduced and discussed hereafter.

I.2.1.b Conservation Voltage Reduction schemes

Conservation Voltage Reduction (CVR) is a technology that was developed in the 1950s and is commonly used in United States, Canada, Australia or Ireland. The main concern of this technique lies in increasing energy efficiency by lowering as much as possible the voltage downstream the HV/MV substations [8]. Indeed depending on the load types (mainly the load to voltage relationship), lowering the voltage will turn in lowering the power consumption. This very simple principle is also used to reduce the consumption during peak conditions. Concretely, CVR can be achieved through several methods [8, 9]. The most employed solution is based on a coordination between OLTC and the off/on switching of CB connected throughout a MV feeder. The voltage reference is lowered as much as possible while the CBs are used to flatten the voltage profile along the feeder as shown in Figure I.7.

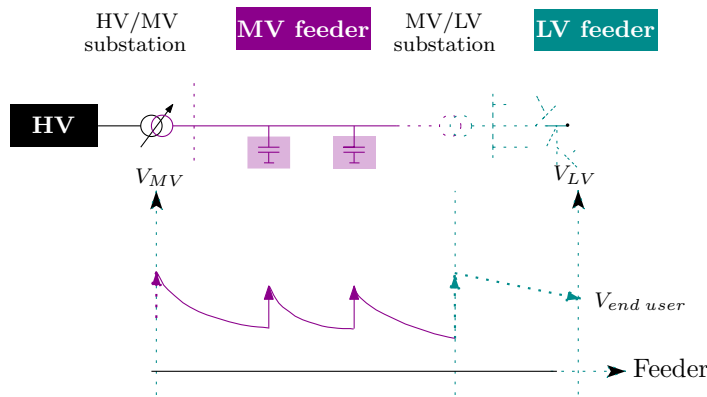


Figure I.7: Evolution of the voltage profile with a CVR scheme

However, there are still some limitations to expand the implementation of CVR, especially in France:

- Poor quality of supply (due to low voltage operating conditions);
- Technical difficulty: coordination of several actuators connected throughout the MV/LV feeders;
- Influence of the massive insertion of DGs on the CVR scheme. For instance wind turbines can induce fast and large voltage variations.
- Difficulty to estimate the true gain yielded by such a method, that mainly depends on the type of load but can also have an impact on losses. A major uncertainty lies in the load to voltage relationship. CVR method has little relevance for constant power loads or for loads with a "rebound" effect. In France, when diminishing the OTLC voltage reference

by 5% after an emergency request from the TSO, a significant growth in consumption is generally observed after a temporarily reduction;

- CVR is designed for networks with a specific topology, more specifically for distribution systems that exhibit long MV feeders with CBs connected throughout the grid and short LV feeders. In France, the LV feeders can be widespread particularly in rural areas, and the voltage drop may be quite large. Next, the CBs are only connected at the secondary side of the HV/MV substations.

I.2.2 Control strategy at the transmission/distribution system interface in France

The link between TSO and DSO is defined by the 6 October 2006 Decree⁴. This decree stipulates that the TSO and DSO should act in an coordinated manner to ensure the secure operation of the system. To this end, both voltage and reactive power management control are mandatory objectives.

In fact, the TSO-DSO link is mainly contractual as defined by the CART (Contract for Access to the Transmission System). In this document, the value of the power factor at the point of connection (i.e. the interface between transmission and distribution system) is specified. This value should not exceed a threshold limit defined for a given area that is supposed to be electrically homogeneous. There are two types of zones, either "green" or "red" associated with different range of values [10].

The performance monitoring consists in checking that the $\tan_{HV \rightarrow MV}$ monthly mean values at the point of coupling by step of 10 minutes remain within the specified range only during the winter period (from 1st November to 31 March), between 6 – 22h.

Moreover, the TSO can send special requests to the DSO during emergency situations as aforementioned. These requests can for instance correspond to:

- A decrease by 5 % of the OLTC voltage reference to temporarily reduce the load demand,
- A deactivation of the OLTC of HV/MV substation in order to prevent voltage collapse,
- A load shedding of MV feeders.

I.2.3 Control strategy at the transmission level in France

I.2.3.a 3-level voltage control in EHV

In EHV voltages, the lines reactive impedance is around ten times the lines resistance. As a result, there is a strong link between reactive power and EHV or HV voltages. An inappropriate reactive power flow in the network would result in unsuitable voltages. Also, to maintain the voltage profile in the network, the TSO should ensure that enough reactive power is available. To this end, the TSO can use several devices which can be either static (such as shunt, CB, FACTS) or dynamic (synchronous generators, generators). The main devices used in France are given in Table I.4.

In France, as in other countries, EHV voltage control has been organized in three levels [11] by RTE (Réseau de Transport d'électricité, the French TSO). The classification is made depending on the time response and the geographical areas.

⁴<https://www.legifrance.gouv.fr/affichTexte.do?cidTexte=LEGITEXT000006054713>

The Primary Voltage Control (PVC) automatically adjusts within a few seconds the reactive power output of the generators or synchronous generators by controlling the excitation system (V_{exc}). This control aims to enforce a specified voltage profile. The Secondary Voltage Control (SVC) supervises this voltage profile: the reactive power resources (Q_{ref}) are coordinated to maintain the voltage at specified pilot nodes. A pilot node is supposed to embody the voltage level of a regional area. Each area is assumed to be electrically homogeneous and independent from other areas. The SVC is thus decentralized.

RTE has designed a Coordinated SVC (CVSC) [12] to enhance the SVC by taking the interactions between the regional areas into account.

The Tertiary Voltage Control (TVC) is a manual control and consists of the dispatching center actions that coordinate the SVC and CSVC voltage profile (V_{pilot}).

The overall structure of such a hierarchical control is given in Figure I.8.

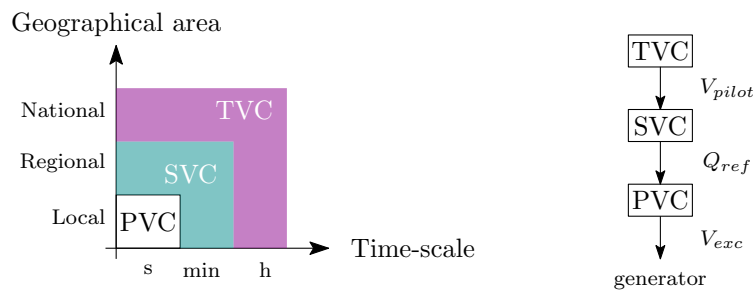


Figure I.8: Structure of the three level voltage control in the French transmission system

Table I.4: Reactive power devices used in France

Devices	Types	Details
Generators	Dynamic	Automatic control (PVC)
Synchronous Generators	Dynamic	Automatic control (PVC), only one in France
Shunt reactance, CB	Static	Modify the network characteristics
FACTs	Static	Modify the network characteristics, few in France

I.2.3.b Voltage Control in HV systems

In French HV system, the voltage control is quite coarse compared to the EHV voltage control. It is performed through EHV/HV OLTC. The voltage reference can be remotely adjusted to $V_{nom} + 1\%$, $V_{nom} + 2,5\%$ or $V_{nom} + 5\%$.

The reactive power regulation imposed at the HV/MV interface are incentives to maintain the power factors of distribution networks as closed as possible to the unity.

Conclusion

Traditional methods for voltage control and reactive power management at the HV/MV systems interface have been introduced. In distribution systems, even with a presence of Distributed Generation, such a control is mainly achieved through network planning studies that are based on "fit and forget" solutions. These control methods aim to define among others a specified reference to feed the local control of dynamic actuators (*viz.* On Load Tap Changer, Distributed Generation and Capacitor Bank) as illustrated in Figure I.4. These actuators exhibit distinct dynamics. DGs local control act within a few second, while the OLTC embeds time-delays (traditionally of 60s and 10s).

However, some distribution grids are facing major changes that are both technical and regulatory. Chapter II is dedicated to the presentation of these changes. As a consequence, the relevance of the traditional control methods is to be questioned while the interest of using active control scheme is raised.

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Chapter II

Recent technical and regulatory transformation of distribution networks: a need for a new solution

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Introduction

In the last decades, the distribution networks have been undergoing major changes that put into questions the relevance of traditional voltage control and reactive power management schemes. These changes are namely the massive insertion of Distributed Generation (DG), the replacement of overhead lines by underground cables, the evolution of the loads... The place where the network changes are occurring and the main consequences are depicted in Figure II.1. As a result, distribution networks are facing an increase of their voltage profiles and could also face difficulties to limit the reactive power flowing upwards at the distribution/transmission system interface in case low loading. These flows may, in turn, impact voltage and reactive power management in High Voltage networks. The coupling between HV and MV systems is thus more erratic, variable and hardly predictable.

Along with these technical evolutions, any new distribution system must also comply with the recent regulatory framework defined by the European Grid Codes. More particularly, in the Demand and Connection Code (DCC), any new distribution system should be able to restrain the reactive power flowing between TSO-DSO networks at times of low consumption.

To cope with the new operational concerns and the regulatory framework, there is a need to define new strategies at the interface between transmission and distribution systems.

In section II.1, the undergoing changes of distribution systems and subsequent consequences are investigated. Then, in section II.2, opportunities and possible technological limitations for voltage control and reactive power exchange management in distribution networks are further discussed.

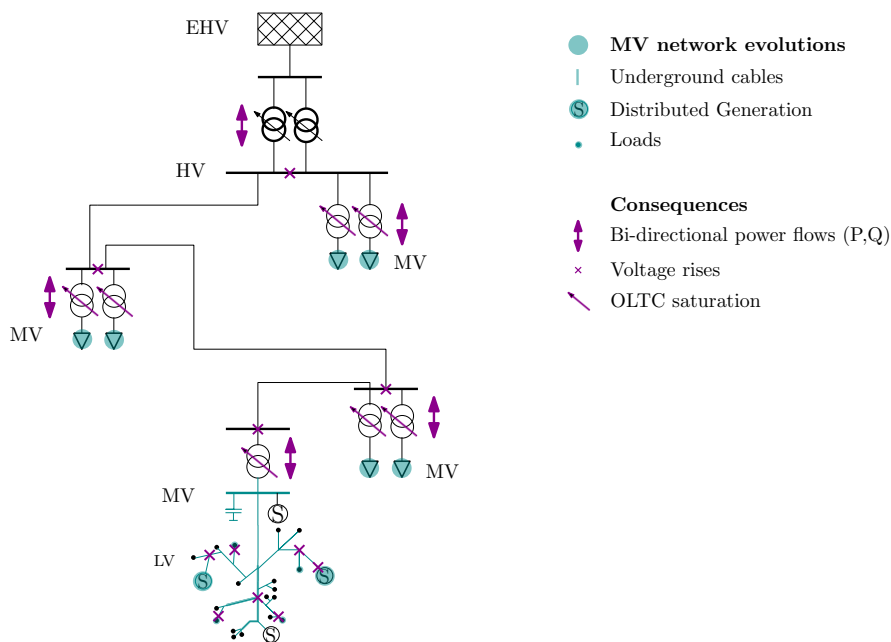


Figure II.1: Location of MV network evolutions and their consequences

II.1 Issues raised by the recent developments in the distribution grid and the new regulatory standards

In this section, we will more specifically introduce the distribution system developments and the subsequent issues (illustrated in Figure II.1) regarding voltages and reactive power flows. In short, the consequences are voltage rises at the MV and HV level, the saturation of HV/MV OLTC, and the difficulty to manage reactive power flows. As a result, the interactions between HV and MV grids are more erratic and exhibit a high variability.

II.1.1 Consequences of distribution networks transformation

II.1.1.a The massive insertion of DGs

Since mid 2000s, a massive insertion of DGs in the distribution networks occurred. As a reminder, a DG is, according to the definition presented by T. Ackermann: " an electric power source connected directly to the distribution network or on the customer site of the meter" [1]. This development was strongly supported by European and French policies and incentive rates for "green" energy. However, this massive integration has repercussions on the electricity networks.

First, the assumption of unidirectional power flows is no longer valid. Without being exhaustive, the following consequences can be recalled [2–6]:

- Local impacts:
 - Impact on protection plans, no detection of islanding operations that can jeopardize technicians;
 - Impact on voltage quality and in particular for DC technology whom power electronic devices generate harmonics. These harmonics may distort the signal called TCFM (remote control musical frequency) used in France to automatically change rates from normal to peak load tariffs,
- More global impacts:
 - Impact on the overall stability of the network with an intermittent and stochastic power injection that changes the dynamic of the network,
 - Impact on congestion management
 - Impact on losses...

More specifically, focusing on voltages and reactive power:

- Impact on voltage profile: the presence of DGs can cause rises even at low level of penetration. Indeed, with the active power injection, the voltage increases at the point of DG connection and in the DG vicinity.
- Impact on the active/reactive flows that become more and more unpredictable, and that can be reversed at HV/MV substations. In the usual case of weather-dependent DGs, there are intraday fluctuations (day/night for PV) and even faster fluctuations (hourly).

This change in production patterns has repercussions on the DSO and TSO operations (voltage, balancing...). For instance, this reduced observability on the load downstream HV/MV transformer has among others forced to give up on the compounding technique (presented in I.2.1.a) used to tune the HV/MV OLTC voltage reference.

Another issue concerns the size of the DGs. Indeed, due to their small size, it is usually not cost efficient to observe and hence to control them for the DSO. In France, the connection of any DGs with a power injection capacity above 36 kVA implies a complete network planning to determine the possible consequences on the network (namely the voltage profile) and whether a grid reinforcement has to be performed. Such a reinforcement may require a significant investment. On this other hand, if the reinforcement is not achieved, a saturation of the network hosting capacity may occur [7]. Next, beyond a certain penetration level of small DG units around a given local area, a saturation of this area hosting capacity can happen. As a result, reinforcement may be required.

In order to keep increasing the level of DGs penetration in the distribution networks at low cost without jeopardizing the DSO and TSO operations, innovative solutions need to be found. These solutions should address the concern of voltage rises as well as the active and reactive power flows variability and uncertainty.

II.1.1.b The replacement of overhead lines by underground cables

For several years, overhead lines have been replaced by underground cables. Such a replacement was motivated by reliability concerns but also for maintenance purposes. There also exists a strong public opposition to overhead lines. Indeed, it was frequent in rural areas that a tree falling on a overhead line causes a power cut and damages the quality of supply. As a result, in France, around 39% of the MV networks and 35 % of the LV grids conductors are underground cables.

Table II.1: Typical MV lines and cables parameters

Conductor	Details	X (Ω/km)	R (Ω/km)	C (nF/km)	S_{nat} (MVA)
Overhead Lines	75 ² Almelec	0.35	0.44	5	0.845
	148 ² Almelec	0.35	0.22	5	0.845
Underground Cables	95 ² Alu	0.13	0.32	177	8.33
	150 ² Alu	0.13	0.206	250	10

However, this change deeply modifies the reactive power flows in the network. Indeed, depending on its loading level, a given conductor (either a line or a cable) would not exhibit the same reactive behavior. Let S_{nat} be the natural power of a line, that is to say the power consumed by a line when loaded under its characteristic impedance $Z_c \simeq \sqrt{\frac{L}{C}}$ [8]:

$$S_{nat} = 3V_{nom}I = \frac{U_{nom}^2}{Z_c}. \quad (II.1)$$

This impedance corresponds to a specific loading condition, when the reactive power of the line is equal to zero. When the active power transmitted over the line is below S_{nat} , the same line exhibits a capacitive behavior, while loaded above S_{nat} its behavior is inductive. Table II.1 gives S_{nat} of the most widely used MV conductors. It should be noted that the natural power of MV underground cables is around ten times higher than the overhead lines natural power. As a result, at low loading condition, underground cables may be responsible for high reactive power flows. This reactive power can even flow upwards the HV grid causing overvoltages in the MV and HV networks, and it may lead to the saturation of OLTC as it will be demonstrated in Chapter III.

II.1.1.c An increased number of actors and a changing load

With the energy market liberalization, the number of actors in the distribution system has been skyrocketing. This liberalization has been a significant driver for the connection of small size DG units. However, these actors may have contradictory motivations and often compete with each other.

Similarly, the expected growth in Electrical Vehicles and other advanced loads such as demand response schemes may imply that new actors would take part in the distribution system. By 2020, Enedis estimates that the number of EV could reach 2 Millions. These new players contribute to add variability in the MV grid behavior and thus complexity in the distribution operations. This complexity raises the concern of the new roles of DSOs.

In the same time, the load behavior is also changing. It has been observed that the reactive part of the load tend to diminish this past years and that this decline is a longstanding trend across Europe [9]. Also, the issue of reactive power flowing upwards transmission systems is exacerbated increasing the probability of OLTC saturation and difficulty to manage reactive power flows in HV grids [10].

II.1.2 Definition of a new regulatory framework: Demand and Connection Grid Codes

Along with the physical evolution of the distribution grid, DSO must comply with the new regulatory framework demanded by the European Grid Codes. These codes are drafted by ENTSO-E (European Network of Transmission System Operators for Electricity) and are to be validated by ACER (Agency for the Cooperation of Energy Regulators). They consist of a set of rules aiming to facilitate the harmonization, integration and efficiency of the European electricity market. This market is viewed as a driving force to reach the EU "20-20-20" objectives ¹.

There are three main types of codes that encompass the three main area of the electricity sector:

- Connection Codes that cover the challenges of the integration of more decarbonized energy sources. It sets requirements for generators, HV/MV substations, demand-side, HVDC connections...

¹<http://ec.europa.eu/energy/en/topics/energy-strategy/2020-energy-strategy>

- Operational Codes that tackle the issue of ensuring a reliable, stable operation of the grid across the member states by promoting a higher coordination. It consists of several rules aiming to assess adequacy, planning outages, system security, emergency situations...
- Market Codes that cope with the development of a fair electricity market to encourage competition, energy source diversification and optimization of existing infrastructures (day ahead and intraday capacity calculation, system balancing...).

More particularly, one of the Connection Codes, named "Demand and Connection" (DCC²) defines reactive power rules for customers (and hence distribution networks) at their interface with the transmission system. This code was positively voted by the member states in October 2015, and is effective since Spring 2016. The DCC stipulates that every new distribution systems to be connected to the transmission network shall:

- Be able to maintain their steady-state operation at their connection point in a reactive power range specified by the relevant TSO, as illustrated in Figure II.2. This range shall not be wider than 0.9 power factor of their maximum export capability.
- The TSO can require that the distribution networks have the capability to not export reactive power (at nominal Voltage) at an active power flow less than 25% of the maximum import capability. This forbidden area is embodied by the violet area in Figure II.2.

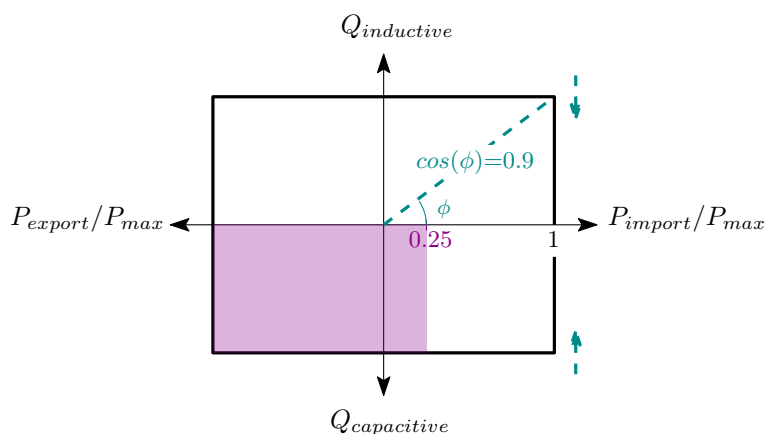


Figure II.2: Schematic diagram of the DCC requirements regarding reactive power flows at the distribution/transmission system interface

Apart from these constructive capability requirements, there is also a more dynamic one: distribution networks shall be able to actively control the exchange of reactive power at the interface with the transmission system.

Traditionally, TSOs use large power plants to provide ancillary services such as the reactive power management. However, with the current evolution of the distribution networks (mainly the rise of the insertion of DGs), distribution networks are injecting active power on the transmission network while it is becoming more difficult to ensure a normal voltage level at the point

²<http://networkcodes.entsoe.eu/connection-codes/demand-connection-code/>

of connection. There are tighter interactions between transmission and distribution systems. Next, distribution networks can be responsible for high reactive power flowing upwards at transmission system especially at low loading condition. These inappropriate reactive flows turns into reducing and disturbing the traditional reactive power support. For these reasons, TSOs need to rely on other means to ensure a secure operation of the system. In the DCC, distribution networks are considered as reactive power levers. It is thought that this reactive power can be provided by the DGs.

By comparison, the present French rules for the contractual values of the $\tan(\phi)$ at the HV/MV grid interface were limited to winter months (assumed to be peak load conditions). In case of non-compliance, financial penalties are defined in the contract. Therefore, through the DCC, there is a significant evolution from tariff-based rules towards constructive capacity without considering the loading conditions. However, the DCC requirements can be modified "in situation where either technical or financial system benefits are demonstrated by the relevant TSO and DSO through joint analysis". No further specifications regarding performances monitoring, steps and time-line for fulfilling the requirements are given in the DCC.

Admittedly, there is an obvious interest for system security and operation to have clear and harmonized rules for any customer to be connected to the transmission system. However, it is likely that an economic optimum can be reached as anticipated by the Grid Codes. Also there is presumably an economic interest to differentiate the DCC requirements since MV grid can exhibit disparate behaviors depending on the geographical areas (rural or urban networks) and the DGs penetration level for instance. It can be noted that the DCC considers the TSO-DSO interface, yet as mentioned in Chapter I (See Figure I.3) DSO operating voltages are quite disparate across Europe. Moreover, the needs of the TSO could differ from an area to another, while some distribution networks may have a higher influence on the transmission system than others depending on their location and transmission system topology. Next, reactive power cannot flow beyond a certain distance since reactive power is causing voltage droops. The influence of reactive power flowing upwards HV grids (or EHV grids) is consequently mainly local.

To sum up, distribution electricity networks are nowadays undergoing significant changes that put into question the relevance of traditional voltage control and reactive power management schemes and the operation of the electrical system. Indeed, with the massive insertion of DGs, the replacement of overhead lines along with a more complex distribution system, distribution network are prone to overvoltages, difficulty to mitigate reactive power exchange at HV/MV grids interface with an increase variability of flows. Next, with the new regulatory framework, the role of DSOs is to be redefined.

II.2 New drivers and technological limitations for voltage control and reactive power exchange management in distribution networks

To take-up the challenges of voltage control and reactive power exchange management, DSOs can take advantage of existing and future flexibility / opportunities to enhance the controllability of the distribution grid. The main levers that can be considered are:

- **Remote control of transformer with OLTC:** remote control of the voltage reference;
- **Reactive power from DGs:** following a remote control or a local control/rule;
- **CBs or shunt reactance;**
- **Power Electronic Solutions:** FACTs for instance;

In the literature, demand side response schemes, ancillary services from DGs (active power curtailment), or the development of storage solutions are also called upon to provide such a flexibility. It can be noted that Enedis is not allowed to have storage sites according to the French regulatory framework. The authors of [11–13] have also demonstrated the interest of using tap stagger technique in comparison with the use of shunt reactors. This technique consists of operations of OLTC parallel transformers with different tap position to provide a mean of absorbing reactive power. Note that this technique is not relevant for the French case. Indeed, the HV/MV transformers cannot be operated in parallel in France due to the protection schemes.

The existing levers in France are namely the OLTC, the reactive power from DGs and the CBs. The other lever should thus be considered carefully. Power Electronics solutions and storage solutions may be quite expensive. Next, regarding the active power curtailment of DG, it is difficult to remunerate such a service (how to assess the amount of energy lost for weather dependent DGs?) and the regulatory framework should be modified. Selective load shedding should be considered as a last resort solution since in nowadays operation it is possible to cut only an entire MV feeder.

As a result, in this work the possible levers have been limited to DGs reactive power, the CBs, and the OLTC.

II.2.1 New opportunities raised by the DGs: a reactive power modulation

As stated before, the insertion of DGs can be an issue for the DSO. If more DGs have to be connected to the distribution networks, new solutions based on their reactive contribution should be implemented.

Indeed, if DGs may alter the MV and LV feeder voltage profiles, they can mitigate the voltage rise by adjusting their reactive power injection. Let us consider the simplified system of Figure II.2.1. The voltage droop ΔV along the feeder can be approximated by:

$$\Delta V = \frac{R(P_L - P_{DG}) + X(Q_L - Q_{DG})}{V_2} \quad (\text{II.2})$$

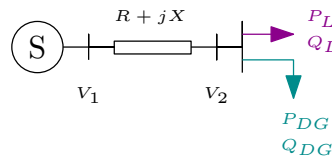


Figure II.3: One-line diagram of a simplified system to illustrate the reactive power support from DGs

Thus, by adequately compensating the reactive power of the DGs, it is possible to maintain the MV voltage within a specified range of values.

However, it may be difficult for the DSO to assess the reactive power "reserve" available from the DGs and this reserve shall not be fully used at any time. First, this reactive capacity depends on the general condition of the network and the operating point. Then DGs may not have the capacity to either absorb/inject reactive power. That raises the concern of reactive power availability: except for generators equipped with suitable and costly power electronics interface, the reactive power availability and capacity is limited depending on the active power injection and the technology. Especially at low active production, absorption/injection of reactive power is often not technically feasible. For instance, Figure II.4 presents the constructive reactive power capacity that must be complied by DG according to a) French regulatory framework, b) technical requirements of DSO, and c) the ideal case (speaking of reactive power reserve). It can be noted that the case b) is the more realistic.

Then, the respect of distribution networks operational constraints must be ensured at any time; even if the generators have the capacity to modulate their reactive power, it may not be possible to use this reactive reserve as it could impact the voltage profiles, the loading of the lines, the OLTC technical limits...

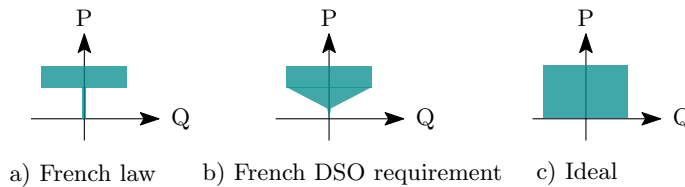


Figure II.4: Schematic (P,Q) diagram of DG connected to the MV network

II.2.2 Smart and active grid developments: real-time voltage control opportunities in MV networks

Recent breakthroughs in sensors and communication technologies are paving the way for smart grid solutions that favor real-time control. According to the European Commission, a smart grid is a "network that can automatically monitor energy flows and adjust to changes in energy supply and demand accordingly"³. Smart grid concept is generally associated with smart metering systems. Also, an increase in the number of intelligent devices connected to the grid such as sensors to monitor the states of the system can be expected. This observability

³<https://ec.europa.eu/energy/en/topics/markets-and-consumers/smart-grids-and-meters>

is essential for the development of new control laws, taking advantage of the network flexibility. Nowadays, it is possible to measure the voltage magnitude at specified point of the MV networks. With such information, it is possible to implement coordinated real-time voltage control strategies as experiences in the French R&D demonstrators VENTEEA. To realize such a control, the Distribution Network Control Center (DNCC) tools must be updated and fully re-designed.

According to the definition proposed by the CIGRE (International Council on Large Electric Systems) active distribution networks "have systems in place to control a combination of distributed energy resources [...], loads and storage. Distribution system operators have the possibility of managing the electricity flows using a flexible network topology. Distributed energy resources take some degree of responsibility for system support, which will depend on a suitable regulatory environment and connection agreement".

The main hurdles for the development of smart grids technology lies in:

- The high investment costs to equip the network with sensors technologies and for the implementation of new tools to be able to deal with a high amount of data, and to remotely activate in real-time the flexibility [5]. The integration of smart meters raises also the concern of data protection, and security as well as the interoperability issues between technologies.
- The need of new methods to conduct the network planning studies with the substantial changes in operational principles. The traditional approaches to investigate if the normal and secure operating conditions are guaranteed at all time based on the study of the worst conditions (high loading/low loading) could turn to be quite expensive. Finding the optimal planning strategy reducing the DG integration costs is a true challenge [14].
- The new roles of DSOs that smart grid development involves. For DSOs, the development of smart grid is a new paradigm that will compel them to use resources they may not own such as the DGs and to rely on agregators to coordinate the flexibility. Also a proper regulatory and policy framework is needed.

Enedis has already developed Advanced Distribution Automation (ADA) (namely for fault location and automatic restoration) housed in the distribution management system [15] and is now conducting studies and experiments to improve the real-time voltage control and reactive power managements [16] in MV network. The main developments are presented in the second part of the report that is dedicated to real-time VVC for MV networks.

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Chapter III

Motivation and position of the works

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Introduction

The undergoing changes in the MV grids are raising new operational constraints in both transmission and distribution systems, and have therefore changed the interactions between MV and HV grids. Also, there is a need to define new schemes for voltage control and reactive power management at the interface between distribution and transmission system. This need implies:

- An evolution of the MV voltage control.
- An increased coordination between TSO and DSO.

Evolution of the MV voltage control

To cope with the new operational concerns raised by the deep changes of distribution grids and the regulatory framework (namely the Grid Codes), DSOs need to define new solutions. These new solutions should also foster the insertion of DGs in the grid to reach the EU objectives. Hence, new voltage control and reactive power management schemes must tackle the concern of:

- Maintaining the MV and LV voltages within a specified range of values.
- Constraining the reactive power flowing upwards at the HV/MV system interface.

To this end, one can consider two main approaches than can be combined together: that is real-time control and/or grid reinforcement. Grid reinforcement is often viewed as a conservative and expensive solution that nonetheless is 100% reliable in normal operating conditions. On the other hand, recent breakthroughs in communication technologies are paving the way for smart grid solutions and foster real-time control. Therefore, there could be several advantages in improving existing real-time control in order to get a more flexible and adaptive solution that would enable a better coordination of voltage and reactive power control. Next, real-time control enables to tackle emergency situations that could theoretically occur but remain unlikely (few hours per year for instance). However one needs to make sure that the reliability of such solution does not worsen the quality of supply compared to common solutions based on grid reinforcement and reactive power levers investments. Hence, real-time control and grid reinforcement should be combined together to optimize investments and quality of supply.

In this work, we will focus on real-time Volt Var Control schemes to deal with the aforementioned issues. If the topic of real-time VVC has been widely studied in literature [1–3], these schemes commonly disregard the concern of reactive power flowing upwards at the HV/MV interface, except briefly [2], in the framework of the European project FENIX (Flexible Electricity Network to Integrates the eXpected energy evolution ¹). Usually, the proposed schemes are taking advantage of the network flexibility adjusting the reactive (even active) power outputs of DGs, the voltage reference of OLTC and the switching statuses of CBs while minimizing the control and operational costs for the DSO to correct the MV voltages only. A review on real-time VVC is given in Part B.

Next, only existing flexibilities are considered herein to ensure the proposed strategy can be implemented in short-term distribution network as illustrated in Figure III.1. This Figure can be

¹www.fenix.project.org

compared with Figure I.4 of Chapter I. The major difference is that the references are adjusted in real-time while they were specified during network planning in the traditional control.

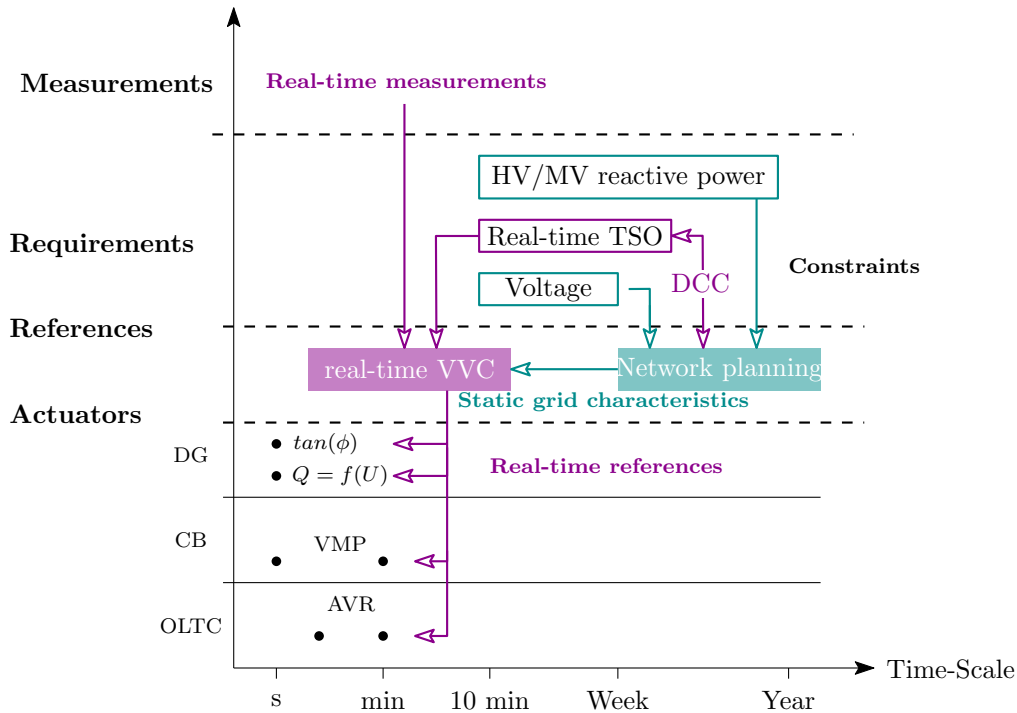


Figure III.1: Proposed evolution of traditional voltage and reactive control strategy in distribution network

Also, the novelty of this work lies in the **real-time VVC with reactive power flows limitation**. In part B, several VVC schemes will be detailed and compared to reach such an objective. Special cares have been given to the industrial implementation of the solutions accounting for the technical limitation of nowadays distribution grids. Next, in most of real-time VVC, the transmission grid voltage are supposed to be stiff. This assumption is questionable in degraded operating conditions [4] and when there exists a tighter interdependence of HV and MV grids [5]. In this work, simulations have been performed in a medium-scale system combining HV and MV grids. Only the EHV voltage is assumed to be stiff.

An increased coordination between TSO and DSO

Since there are tighter interactions between the MV and HV grids, an increased coordination between DSO and TSO should be targeted. To do so, there is a need to conduct **medium scale simulations**, namely, a system encompassing several MV grids connected to a HV grid as depicted in Figure II.1. Thus, it is possible to take both TSO and DSO requirements, constraints and needs into account. In the literature, and in the new regulatory framework (DCC) it is often assumed that distribution networks will be requested to adjust the reactive power (through the DGs) at the HV/MV interface to support the transmission system. Thus, new schemes and

methods are proposed to investigate how and to what extent the distribution networks can contribute to maintain the HV voltages. A literature review is given in Part C. However, the possible constraints in the distribution network are often disregarded and the simulations are reduced to the HV grids and consist in static studies (load flow simulations). These constraints are namely the MV voltages, the MV lines thermal constraints, the amount of reactive power that can be requested from DG...

Thus, when reactive power support is needed, it seems irrelevant to rely on distribution grid VVC alone, or consider only a supervisory control of the TSO. First, there is a need to enhance the real-time VVC of distribution network by adding a reactive power exchange limitation objective. Then, the real-time simulations should be carried out on a medium-scale system combining both transmission and distribution networks with their own requirements and control schemes in order to reach a greater coordination between TSO and DSO.

Scientific approach and novelty

In this work, an original strategy based on an evolution of the real-time Volt Var Control in distribution system and an increased coordination between Transmission and Distribution System Operators has been developed.

The motivations of this work can be summed up by the following three main key-points:

- **Problem 1:** Assessment of new constraints and need in the medium-scale system regarding voltage control and reactive power management.
- **Problem 2:** Definition of real-time VVC for distribution network with HV/MV reactive power flows limitation.
- **Problem 3:** Definition of a joint TSO-DSO coordinated reactive power management in a medium-scale system.

Chapter III is more specifically dedicated to Problem 1. In this chapter, the most critical situations are assessed through load flow simulations on a real 20 kV network. The needs of both TSO and DSO are also further investigated.

Problem 2 is the topic of Part B. After a bibliographic survey on real-time voltage control strategies in active distribution networks (Chapter IV), several VVC schemes are proposed and further compared (Chapters V and IV).

The last part of this report, part C, is devoted to the topic of Problem 3. In this part, several concerns are further addressed:

- Derivation of reactive power limitation at transmission/distribution systems interface to be prescribed;
- Investigation on the interest of the coordination of several MV networks to provide a reactive power support;
- Definition of a DSO-TSO joint optimal reactive power management scheme in a HV grid associated with distribution network real-time VVC.

To address these issues a number of simulations has to be performed. The scope of this chapter is to present the tools, the simulations architecture as well as the systems that have been

studied (see section III.1).

Then, the results of the first prospective studies are given in section III.2. These studies consist in assessing the static behavior of distribution networks with respect to the aforementioned changes. To this end, several static studies (namely load flow calculations) have been performed on a real MV network. The consequences of the MV grid evolution are quantitatively illustrated as they were only introduced in Chapter II. The use of passive solutions to tackle the concern of HV/MV reactive power exchange limitation imposed by the Demand and Connection Code (DCC) are further discussed.

The results corroborate the relevance of using real-time control strategy and head in the direction of a greater coordination between TSO and DSO.

III.1 Simulation architecture, tools and data

III.1.1 Simulations overview

Table III.1 goes over the simulations needs according to the three main aforementioned issues. The type (dynamic/static) as well as the scales of the study are clarified. Note that a "medium scale system" stands for a group of several distribution grids interconnected through a part of a HV grid as depicted in Figure III.2.

Table III.1: Simulations needs

Topic	Type	Scale
1	Static (load flow)	· distribution grid · medium scale system
2	Dynamic	· distribution grid
3	Static and dynamic	· medium scale system

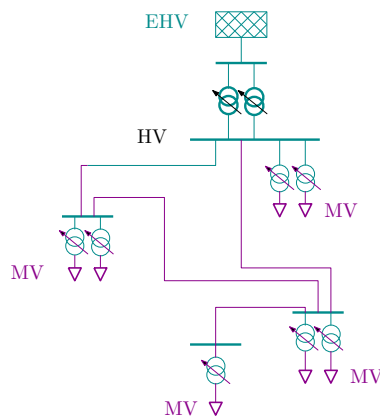


Figure III.2: Schematic of the medium-scale system

III.1.2 Tools

There are several criteria for the selection of the simulation tools:

- Ability to conduct dynamic and static simulations,
- Ability to be interfaced with other software (such as Matlab) for the implementation of the control laws,
- Data format for data exchanges.

Two tools have been selected to carry out the simulations: **PowerFactory DigSilent** and **RAMSES** (Relaxable Accuracy Multithreaded Simulator of Electric power System).

PowerFactory DigSilent is currently used in Enedis static studies. The second one [6], has been developed at the university of Liège within the European project PEGASE framework ². It is designed for dynamic simulation of large-scale systems, such as a system combining both transmission and distribution networks. The use of parallel programming techniques enable to speed up the simulation procedure. One of the attractive features of this portable and scalable algorithm lies in its ability to be easily interfaced with other tools (such as Matlab), and the possibility to modify the code.

For these grounds, RAMSES has been chosen for the dynamic simulations while Powerfactory DigSilent was used for the static studies. In addition, Enedis doesn't use PowerFactory DigSilent for dynamic studies. However, the graphical interface of PowerFactory DigSilent can be helpful for the design and the visualization of load flow results. Also this latter tool was used for static simulations.

In order to export the data from PowerFactory DigSilent (PFD) to RAMSES, a procedure was developed:

1. Export the data in ".txt" file through a PFD script
2. Convert and modify the data to be readable by RAMSES through a Matlab script

The process has been validated by load flow comparisons on several case studies. The simulation procedures and the data exchanges between the three softwares are detailed in the sequel (parts B and C).

III.1.3 Presentation of the systems to be studied

III.1.3.a Real and simplified MV grids

The simulations that involve one (or several) distribution grid(s) have mainly two objectives:

1. To illustrate the consequences of the undergoing changes of distribution systems,
2. To assess the relevance of the proposed real-time VVC strategy for distribution grid.

The main difficulty regarding the selection of a distribution grid lies in the fact that there does not exist a generic MV network but rather a lot of specific networks. Also, the generalization of the results is barely possible as well as obtaining explicit results. Typical networks with pertinent

²<http://www.fp7-pegase.com/>

cases must be simulated in order to show the consequences of distribution networks changes and to assess the relevance of VVC schemes.

Regarding the real-time VVC performances assessment, there is an interest to have quite simple networks to make comparative studies possible, or to ease the results analysis in the case of the medium scale system that involves several distribution grids.

Next, distribution grids are usually designed to face the most critical situations without requiring any special action. Also to test the real-time VVC, either these grids should be impacted by large (and thus with little occurrence probability) disturbances to activate the real-time VVC, or to be deeply modified (by a massive insertion of DGs for instance). Also, two different models have been considered herein: a real and a simplified MV network.

The real network was specifically used to assess the consequences of the undergoing changes of the distribution system while the simplified network was used for the other points, namely the dynamic simulations. Indeed, with a simplified network it is possible to dissect the operations of the grid and to find relevant control strategies. The proposed real-time VVC was nonetheless tested with the real network that is presented hereafter.

A real french MV network

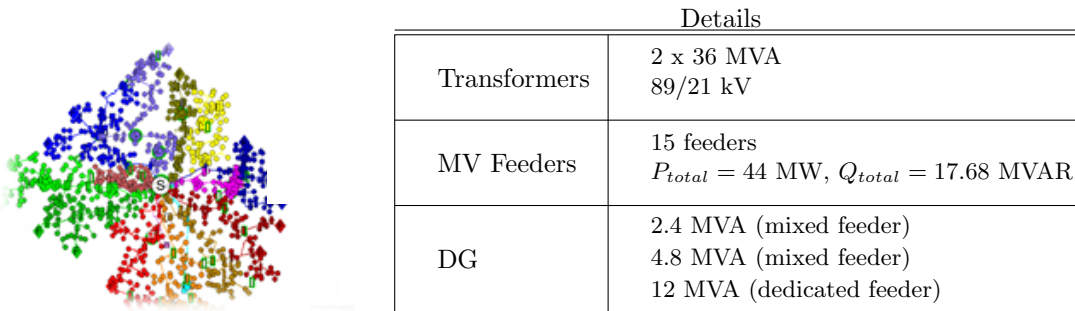


Figure III.3: Presentation of the real french 20 kV grid used in simulations

The real 20 kV network is described in Figure III.3. It consists of a semi-urban grid with a 90/20 kV HV/MV substation. Next, this grid has been more precisely selected since there are the three type of feeders (defined in Chapter I): dedicated, mixed and with only consumption. There are two HV/MV transformers with OLTC in the substation. Their nominal ratio is 89/21 kV since HV/MV transformer have usually been designed to face low voltage conditions. In total, 19.2 MW of DGs are connected to this network. This amount is almost equal to the half of the maximal active consumption of the MV grids. Next, around 17.2% of the MV conductors consist of underground cables.

This model is reduced to the MV part of the distribution grid, there is no information on the LV feeders. Also, the loads embody either an aggregation of several LV feeders downstream a MV/LV transformer, or a medium MV consumer.

Then, this grid exhibit features (*viz.* underground cables, DGs) that are typical of the MV grids changes.

Next, the 10-minutes measurement of the 2013 year of the active and reactive powers flowing through the HV/MV transformers as well as the active power injection of DGs were provided by Enedis. The maximum active power of each load associated with the power factor of the load were also provided. Since there is no indication on the distribution of the loads, in all of the simulations, the load distribution has been assumed to be uniform and homogeneous.

A simplified MV network

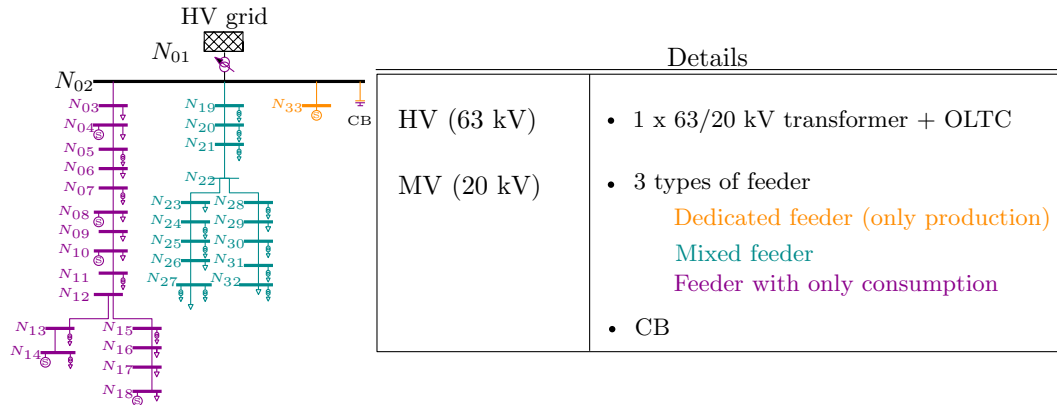


Figure III.4: Presentation of the simplified 20 kV grid used in simulations

The simplified network is also made up of the three types of feeders as depicted in Figure III.4. This fictional grid is inspired of the simplified network presented in [7], topological data (namely the position of loads and actuators) have been kept for the most part. However, some changes were made to better match the French case. For load models, a constant impedance model has been assumed for reactive power whereas a constant current was considered for active power. Industrial loads were modeled as small motors whose parameters are available in [8]. The OLTC associated to the HV/MV transformer has 17 tap positions ($[-8, +8]$) with 1.5% voltage per tap. Next, a CB of three 1.8 MVAR steps was added at the secondary side of the HV/MV substation.

The level of DG penetration varies depending on the simulations and would be specified for each case, as for the loading level. The loads are allocated according to their maximum power, that is assumed to be reached at the 7 p.m. case of [7].

This topology was also used to embody each MV network connected to the HV system.

III.1.3.b Description of the HV system

The HV network is a 63 kV meshed network as shown in Figure III.5. This system embodies a rural network. Specifically, the distribution grids connected to this grid exhibit long feeders, and except from substation 3, which is very close to the Extra High Voltage (EHV)/HV station, their short-circuit is rather low. The choice of such a structure is justified in Part C.

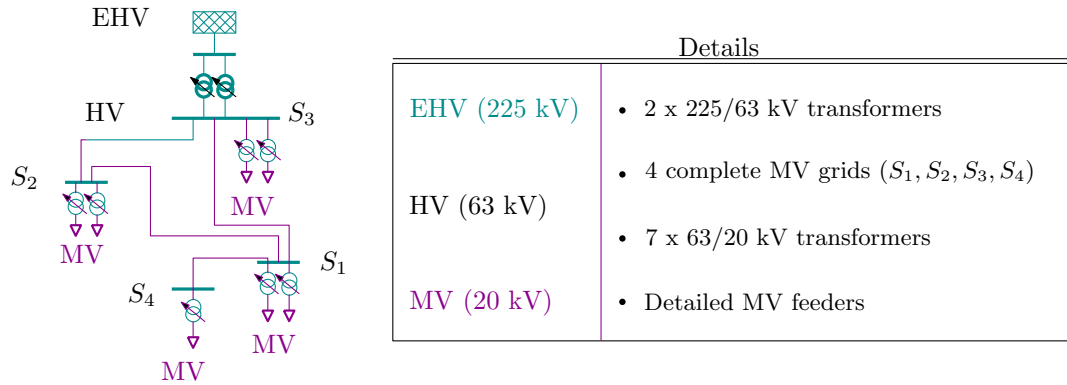


Figure III.5: Detail of the medium scale system used in simulations: several MV grids connected to a HV grid

III.2 Steady-state consequences of changes in distribution networks : a case study

The question of the impact of the distribution system evolution on the MV network and voltage control has already been widely addressed in the literature [1, 9–11]. Also, in this work, the primary focus is on the investigations of the consequences at the HV/MV interface and more specifically on the evolution of reactive power exchange. To this end, two types of static simulations have been conducted:

- **Type 1:** Simulations on the real french 20 kV network (presented in section III.1), that aims to illustrate the evolution of the reactive power flows at the HV/MV interface
- **Type 2:** Simulations and theoretical demonstration to assess the subsequent consequences:
 - Difficulty to assess the (P,Q) diagram of a given substation,
 - Saturation of the HV/MV OLTC.

The relevance of real-time and joint DSO-TSO strategy are also discussed.

In the sequel the HV/MV interface is the Grid Supply Point (GSP) of the MV network to the HV grids.

III.2.1 Evolution of reactive power flows at the HV/MV interface

III.2.1.a Origin of reactive power flows

The reactive power flows seen by the TSO at the GSP come from:

- Reactive power consumed by the load connected to the distribution networks,
- Reactive power losses in the distribution network feeders (overhead lines and underground cables),
- Reactive power losses in HV/MV and MV/LV transformers,

- Reactive power from reactive power compensators connected to the distribution network,
- Reactive power absorbed or produced by DGs depending on the contractual value of $\tan(\phi)_{DG}$.

The decomposition of reactive power according to the several aforementioned sources at the interface between TSO and DSO is therefore not straightforward to evaluate. Indeed, reactive power losses in transformers and feeders are highly dependent on load and production conditions. As a consequence, a precise evaluation of reactive power capacity of a given substation should be performed by simulations, considering several operating points. The presented results are obtained with simulations mainly based on load-flow calculation and performed with the software Powerfactory Digsilent.

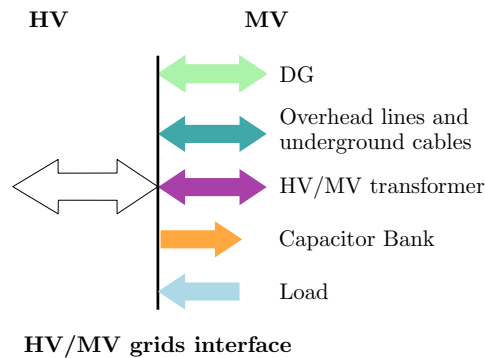


Figure III.6: Origins of reactive power at the HV/MV grids interface

III.2.1.b Evolution of the reactive power flow at GSP

Several cases have been conducted in order to assess the influence of each evolution. Table III.2 describes those cases. The present network corresponds to case C.

Table III.2: Case studies to investigate the evolution of reactive power flows at GSP

Case	A	B	C	D	E	F
MV underground cables	0%	0%	17%	17%	17%	17%
Total generation (MW)	0	17.2	17.2	17.2	17.2	17.2
$\tan(\phi)$ mixed feeders	0	0	0	0	0.4	-0.35
$\tan(\phi)$ load	0.4	0.4	0.4	0.2	0.4	0.4

Case B aims to illustrate the influence of distributed generation, case C the consequences of the replacement of MV overhead lines by MV underground cables, case D the evolution of the reactive part of the load. Cases E and F investigate the influence of power factor in “mixed” feeders’ DG. Two different power factors have been considered herein (-0.35 and +0.4), which corresponds to the current maximum French contractual limitations.

Figure III.7, Tables III.3 and III.4 propose a detailed analysis of reactive power origins for each case and for two particular situations: at maximum loading and no production, and at low

loading condition (20%) with 100% production. More situations have been considered in the publication [12]. These situations correspond to reference situations currently used for network studies.

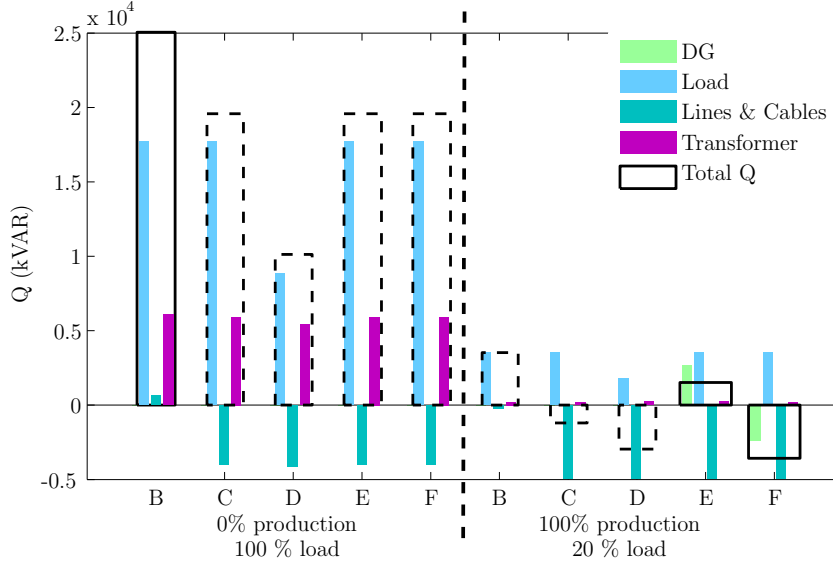


Figure III.7: Origins of reactive power flows at GSP

Table III.3: Detailed origin of reactive power flows (in MVAR) at 100% loading - 0% production

Case	B	C, E, F	D
$Q_{MV \rightarrow HV}$	24.45	19.58	10.13
Q_{DG}	0	0	0
Q_{Load}	17.68	17.68	8.84
$Q_{lines/cables}$	0.68	-4.02	-4.15
$Q_{HV/MV\ trfo}$	5.70	5.52	5.08
$Q_{MV/LV\ trfo}$	0.39	0.40	0.35

Table III.4: Detailed origin of reactive power flows (in MVAR) at 20% loading - 100% production

Case	B	C	D	E	F
$Q_{MV \rightarrow HV}$	3.53	-1.20	-2.96	1.52	-3.58
Q_{DG}	0	0	0	2.67	-2.38
Q_{Load}	3.54	3.54	1.77	3.54	3.54
$Q_{lines/cables}$	-0.22	-4.94	-4.94	-4.94	-4.93
$Q_{HV/MV\ trfo}$	0.1999	0.186	0.206	0.235	0.183
$Q_{MV/LV\ trfo}$	0.013	0.014	0.012	0.013	0.013

III.2.1.c An increased probability of reactive power flowing upwards HV grid

From the results, several conclusions can be drawn:

- The evolution of the maximum reactive power flows in the substation is mainly linked to the replacement of overhead lines (see Figure III.7). For instance, by comparing case B and C one can observe a significant reduction of the reactive power at the HV/MV interface. The contribution of the conductors compared with the other sources/consumers of reactive power are shown in Figure III.7: around 100 km of underground cables can produce up to 5 MVAR at low loading conditions. Depending on loading conditions, this contribution decreases the reactive power flows in substations and can even lead to reactive power flow from distribution network up to transmission network.
- The reactive power losses in transformers are proportional to XI^2 and are significant at high loading conditions, especially for HV/MV transformers. For instance, in Figure III.7, at high loading the HV/MV reactive power losses are about 5 MVAR, while these losses are around 0 MVAR at low loading conditions. In our simulations, the short circuit voltage U_{cc} of HV/MV transformers is about 17% and about 3% for MV/LV transformers. The insertion of DGs and underground cables can contribute to increasing or decreasing these reactive power losses.
- The reactive part of the load may slowly diminish with new equipment (based on power electronics).
- If DG connected to “mixed” feeders (i.e. with both load and generation) have a non-zero power factor ($\tan(\phi)$) or a $Q = f(U)$ characteristics to maintain MV voltage, the real-time reactive power flows in HV/MV substations would be more erratic and therefore, more unpredictable. Indeed, the reactive power depends on the active production of DGs. Comparing case E and F, a significant difference of total reactive power at GSP can be observed either in Figure III.7 or in Tables III.3, III.4.

III.2.2 Consequences of high reactive power flowing from MV grids

III.2.2.a Prospective study based on the (P,Q) diagram of a given HV/MV substation

Determination of a HV/MV substation (P,Q) diagram

Since the power flows tend to be more erratic and unpredictable, how to derive the (P,Q) diagram of a given substation and to assess the reactive power reserve this substation can either provide or consume? The assessment of reactive power needs and reserve is not straightforward; to have an accurate estimate a number of load flows calculation should be performed. Indeed, through load flows calculation, it is possible to account for the variability, stochastic behavior of DGs, and their contingent control (such as $Q = f(U)$, or $\tan(\phi)_{DG}$). A first rough assessment consists in positioning the substation (P,Q) points measurements after subtracting the contribution of DGs and CB in order to evaluate the net demand without the influence of any reactive power lever and the active power of DGs. Then, the influence of each lever can be considered one by one:

- Active and reactive power of DGs,
- Reactive power from CBs.

Such a study, which consists in reactive power reserve assessment, is beyond the scope of our works. Here, the concern is to make a prospective comparison among several solutions to control the reactive power exchange between HV and MV grids. However, Figure III.8 roughly schematizes the influence of DG and CB on the (P,Q) diagram of a given substation. The sub-figure b) aims to illustrate the influence of a $Q = f(U)$ local rule for DG on the diagram.

Theoretically, the high voltage conditions in MV networks occur at low active power consumption, and would lead to an absorption of reactive power from DGs equipped with such a $Q = f(U)$ law. As a result, the bottom left-hand corner of the diagram would be more particularly impacted. On the contrary, in the case of low voltage condition, the top right-hand corner of the diagram would be modified. This case normally corresponds to peak conditions, and thus with a reactive power injection from DGs.

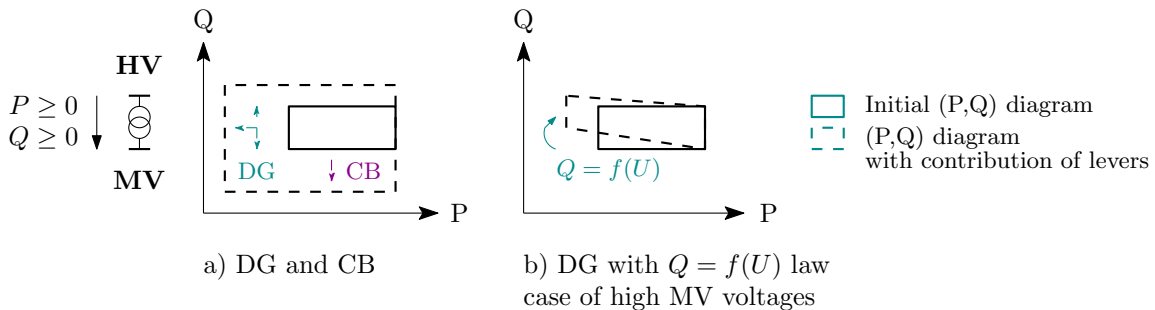


Figure III.8: Coarse evaluation of the DG and CB influence on the (P,Q) diagram of a given substation

The aforementioned approximation is tantamount to neglect the active and reactive losses in the lines/transformers when using a given reactive lever in the network. Next the discrete nature of CB compared to the reactive power injection of DGs is not taken into account. Once again, if the DGs are following $Q = f(U)$ rules, the impact of the diagram would be far more difficult to estimate. It would take to perform several load flows calculations to investigate this issue or to take into account the variability of the DGs active power injection.

Passive solutions to comply the DCC requirement

The following case study has been further investigated: from the 10 minutes measurements of active and reactive flowing through the real 20 kV substation as depicted in Figure III.9, find passive solutions to comply with one of the DCC requirements.

In Figure III.9, this requirement is embodied by the dark rectangle. According to this requirement no reactive power must flow upwards the HV grid at an active consumption below 25 %. With the simple and fast process described above, and assuming that the DGs have an ideal (P,Q) diagram, one can easily compare the following two passive solutions:

- Demand a specified $\tan(\phi)_{DG}$ for any DGs connected in the mixed feeders,

- Demand a constant reactive power absorption/provision of reactive power from the DG in the dedicated feeder for a given period of time (day/night, summer/winter, ...).

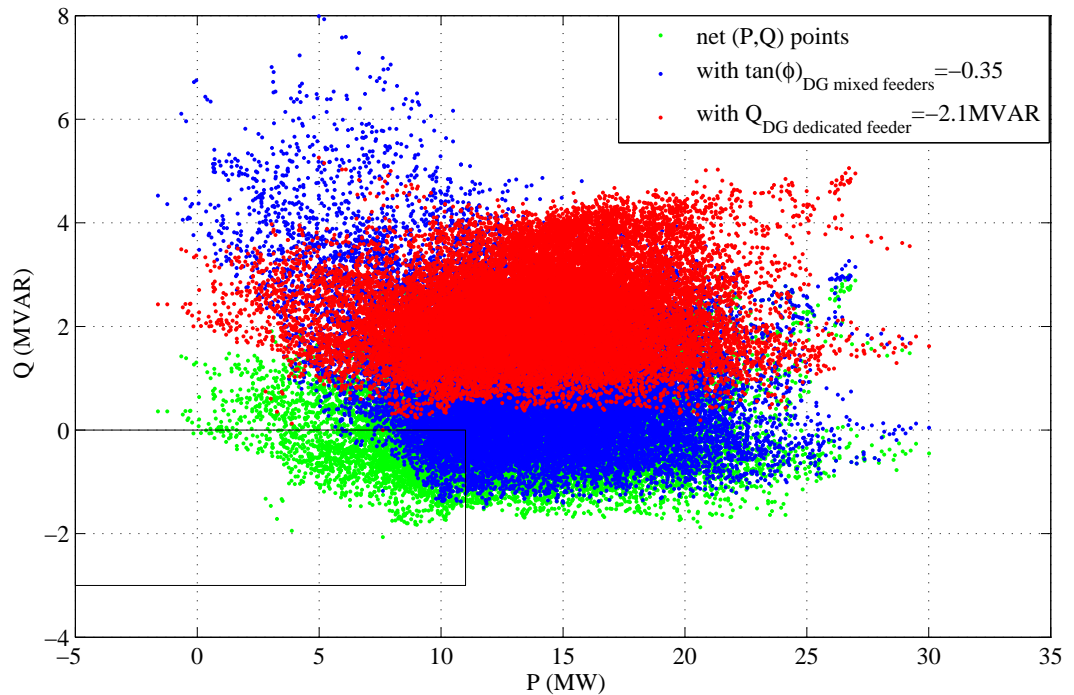


Figure III.9: 10-minutes (P,Q) points of the anonymous substation for summer time

These two solutions are illustrated in Figure III.9 for the specific case of the substation presented in the previous section III.1, during summer time 2013. From this figure, it can be observed that the first solution (in blue) is irrelevant. Indeed, the periods of active power injection do not necessarily match with periods where there is a significant amount of reactive power flowing upstream the HV/MV substation. On the other hand, having a constant reference for the reactive power for the DG in the dedicated feeder (in red) enables admittedly to correct the reactive power exchange, but would result in an overuse of this reactive power reserve. And this would result in additional cost to size the levers needed.

To sum up, this quite simple example promotes the use of a real-time strategy to address the concern of the reactive power flows through HV/MV substations limitation. Indeed, the reactive power needs is neither correlated with the period of DGs power injection nor the voltage at their point of connection. Next, real-time control enables to avoid unnecessary use of the reactive power levers (that may increase losses) compared to a passive solution, typically a constant reference for a period of time.

III.2.2.b Saturation of the On Load Tap Changer

Such evolution of reactive power are leading to higher voltage conditions on both HV and MV networks and can be responsible for OLTC to reach their technical limits. In France, the number of alarms regarding saturation of OLTC at high voltage conditions has increased over the past few years. Indeed, OLTC have traditionally been designed to deal with high loading and corresponding low voltage situations. The tap position n_{OLTC} can be estimated according to the following formula (in per unit):

$$n_{OLTC} = n_{OLTC_{nom}} + \frac{r - 1}{\delta V_{tap}}. \quad (III.1)$$

$n_{OLTC_{nom}}$ represents the tap position at nominal condition, δV_{tap} the voltage variation induced by a tap change and r the ratio of the transformer in the transformer base ($V_{MV_{nom}}, V_{HV_{nom}}, S_{nom}$):

$$r = \frac{V_{HV}}{V_{HV_{nom}}} / \frac{V_{MV}}{V_{MV_{nom}}}. \quad (III.2)$$

Thus, each tap of the transformer can be associated with a ratio. r_{max} is the ratio associated with the last OLTC position. Since the ratio X/R of HV/MV transformer is rather high, around 35 for the transformer considered herein, the resistance can be neglected and the reactance approximated in per unit by the short-circuit voltage U_{cc} . Also, the internal voltage droop is related to the reactive power flows according to:

$$\delta u_{trf} = R \frac{P}{S_{nom}} + X \frac{Q}{S_{nom}} \approx U_{cc} \frac{Q}{S_{nom}}. \quad (III.3)$$

Then depending on the MV and HV voltages and the transformer parameters, the maximum reactive power that can flow from distribution upwards transmission grid can be derived by the following formula:

$$Q_{max_{MV \rightarrow HV}} = \frac{S_{nom}}{U_{cc}} \left(V_{MV_{ref}} - \frac{V_{HV} V_{MV_{nom}}}{r_{max} V_{HV_{nom}}} \right). \quad (III.4)$$

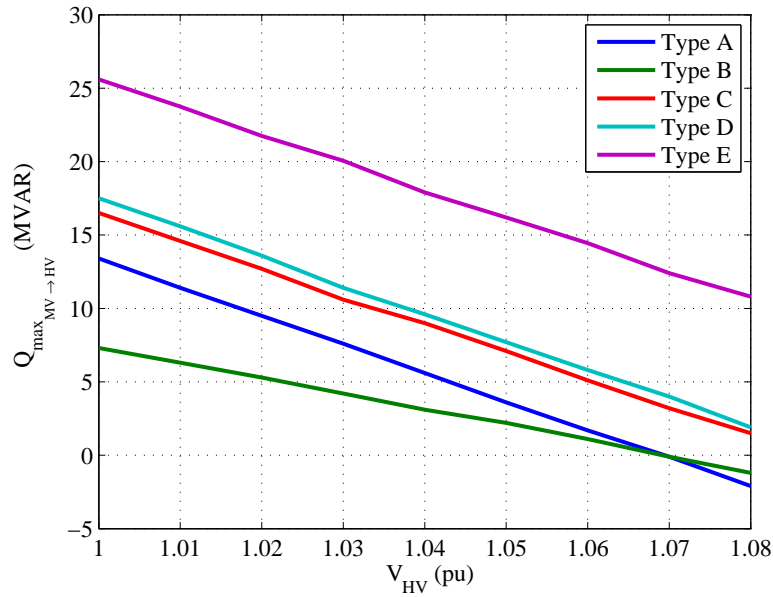


Figure III.10: Maximum reactive power from MV to HV networks before OLTC saturation

Type	A	B	C	D	E
U_{cc} (%)	17	17	17	17	17
S_{nom} (MVA)	36	20	36	36	36
$V_{HV_{nom}}/V_{MV_{nom}}$ (kV)	89/21	89/21	89/21	89/21	90/20
δV_{tap} (pu)	0.015	0.015	0.015	0.015	0.015
Tap positions	17	17	17	17	17
Amplitude (%)	12	12	14	12	12
$V_{MV_{ref}}$ (pu)	1.02	1.02	1.02	1.04	1.02

Table III.5: Detailed parameters of HV/MV transformers

The maximum ratio can be obtained with (III.3) and (III.4). Figure III.10 illustrates the maximal amount of reactive power flowing from MV to HV network before saturation of OLTC depending on the HV voltage and several parameters of the transformer. These parameters are given in Table III.5.

The worst situation occurs when HV voltage is at 1.08 (maximal contractual value) whereas the MV OLTC reference is low –typically 1.02 pu for the French distribution network. These calculations have been validated in simulations and give an assessment of the potential risk of OLTC to saturate. This risk is higher when HV voltage rises. Other parameters have some minor influence such as the nominal power of the transformer or the range of OLTC.

Note that case E does not exist in existing French distribution networks. Indeed, HV/MV transformer have been designed to face low voltage conditions, at peak conditions. Nowadays this

choice is questionable since a given distribution grid can face both low and high voltage conditions due to the variability of DGs that are weather-dependent. Also shifting the nominal ratio of HV/MV OLTC transformer is not a generic solution. First, it may not be sufficient to relieve every constraints (high and low loading conditions), and this would lead to make the management of the transformers stock harder.

To sum up, with regard to the distribution networks evolution, saturation of HV/MV OLTC is more likely to occur. As a result, there is no more uncoupling between HV and MV voltages.

III.3 Conclusion: relevance of real-time solution based on a greater TSO-DSO coordination

The undergoing changes of distribution grids (*viz.* the insertion of Distributed Generation and the replacement of overhead lines by underground cables) have contributed to change the reactive power pattern at the HV/MV interface. These reactive power flows tend to be more erratic and difficult to estimate. However, an overall reduction, even a reversed power flow is to be expected with a high variability and uncertainty depending on the loading and production level.

As a result, it is difficult to assess the (P,Q) diagram of a given substation or to assess the reactive power reserve at MV side. This can be a concern with regard to Demand and Connection Code requirements on reactive power exchange with the HV system. The prospective studies on a real MV grid have confirmed the risk of On Load Tap Changer to saturate, especially if the HV voltage profiles are high. Yet, reactive power flowing upwards at transmission grids can lead to over-voltage in HV grids or disrupt HV traditional voltage control schemes. This point is further discussed in part C. As a result, the interdependence of MV and HV grids is strengthened.

Reactive power from DGs can be used to mitigate the reactive power flowing upwards the HV grids. However, DGs may not always have the technical capacity to do so or even the possibility depending on the MV operational constraints. To address the issue of the reactive power limitation, requiring a specified $\tan(\phi)_{DG}$ or a specified amount of reactive power may not be relevant. Indeed low or reversed power flows do not necessarily coincide with DG active injection period.

For these reasons, it is of interest to consider real-time control. Then, the real-time scheme should also encompass the technical limitation and constraints of both MV grids and HV grids. So, a greater coordination between TSO and DSO should be targeted to tune such a scheme.

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Conclusion on Part A: Relevance of real-time control strategies and a greater TSO-DSO coordination

In Chapter I, the general structure and control strategies of the electrical power system have been recalled. The traditional voltage and reactive power control strategies have been more specifically given for passive distribution systems and at the interface between Medium Voltage (MV) and High Voltage (HV) grids.

In Chapter II, section II.1, the undergoing changes of distribution networks have been detailed. These changes are namely the massive insertion of Distributed Generation (DG), the replacement of overhead lines by underground cables or the evolution of the load. Along with this physical evolution, Distribution System Operator (DSO) should comply with the new regulatory framework (the Grid Codes). More particularly, in the Demand and Connection Code (DCC), any new distribution network should be able to restrain the reactive power flowing upwards HV grids at low consumption.

To cope with the new operational concerns and the regulatory framework, there is a need to define new strategies at the interface between transmission and distribution systems. In Chapter II, section II.2, the new opportunities and barriers of new control strategies due to the breakthrough in communication and information are discussed.

In this work, an original strategy based on an evolution of the real-time Volt Var Control (VVC) in distribution system and on an increased coordination between DSO and Transmission System Operator (TSO) has been developed as explained in Part III.

To this end, a simulation architecture has been defined and several tools selected (See Chapter III). The results of a first prospective study to illustrate the consequences of the evolution of the distribution networks are given in III.2. It is shown that reactive power can flow upward HV grids and that these flows exhibit a high variability and uncertainty. As a result, it is difficult to assess the (P,Q) diagram of a given substation and thus the need in reactive power reserve to comply with the new regulatory framework. Next, the probability of a saturation of HV/MV On Load Tap Changer (OLTC) has increased. These flows can also disturb the HV voltage profiles and the reactive power management strategy at EHV level. The results corroborate the relevance of real-time control strategies and head in the direction of a greater coordination between TSO and DSO.

Part B

Real-time Volt Var Control in Active Distribution Networks with HV-MV Reactive Power Exchange limitation

Chapter IV

Review on real-time VVC for distribution networks

Introduction

As stated in Part A, due to the undergoing changes of distribution systems, new MV voltage control strategies should be studied. In this work, the proposed solution is based on an evolution of the real-time Volt Var Control (VVC) of distribution networks. Next, the new strategies should also be able to limit the HV/MV reactive power exchange to comply with the Demand and Connection Code (DCC) requirements.

In this Chapter IV, a bibliographic survey on real-time VVC that can be found in literature or among DSO demonstrator projects is proposed. The relevance of a coordinated control structure is established. The methods to design the control laws are also further discussed, such as rule-based and optimization-based methods; as well as the technical limitations of present distribution networks. The relevance of a particular optimal multi-step control method, namely Model Predictive Control (MPC), for the design of real-time VVC is stated.

As a result, a MPC VVC scheme has been designed in this work (See Chapter V). To assess the performances of the MPC method, two classical (optimization and rule-based) schemes considering present/short-term future technical possibilities are introduced in the last section IV.1.2 of this Chapter for illustrative and comparative purposes.

IV.1 Survey on VVC centralized control structures to manage HV/MV reactive power exchanges

The topic of real-time voltage control for active distribution networks in the presence of DGs is widely addressed. There exists a substantial literature proposing a variety of methods as listed in Table IV.1. These methods can be roughly divided into two main categories: global and local control. The selection of the control structure and method is further described hereafter.

Table IV.1: Voltage control and reactive power management for MV networks in literature

Method	Details
Global control	<ul style="list-style-type: none"> · Expert-system / rule-based control [1–5] · Multi-agent system [6, 7] · Multi-level, hierarchical control [8–10] · Optimal Control [2, 11–15] · Model Predictive Control [8, 16–19]
Local control	<ul style="list-style-type: none"> · rule-based [20–26] · Optimization-based [27, 28]

Generally, these schemes aim to enforce specified constraints on the MV voltages. To chose a relevant solution among the set of possible ones, several secondary objectives to be achieved can be selected as summarized in Table IV.2. Some of them can be antagonistic, such as the losses minimization and the energy efficiency. In our cases, apart from maintaining the MV voltages, the real-time VVC should also control the reactive power flowing from MV grid towards HV grid.

In our view, some objectives (such as loss minimization, or the increase in DG hosting capacity) can be achieved in a large extent at the design (grid reinforcement and development) stage of the network. The real-time VVC should deal with emergency cases where the priority is given to the respect of the constraints at any costs.

Table IV.2: Objectives of VVC in literature

Objective	Remark
MV voltage management with DGs	Main objectives
Energy Efficiency	Such as CVR scheme
Losses minimization	Lines Joule losses and transformers iron losses
Control effort minimization	Maintenance and durability (OLTC)
HV/MV reactive power exchange limitation	To support HV voltage

To achieve the specified objectives, several actuators are usually considered in the literature, see Table IV.3. In this work, only the already existing levers and with a proper regulatory framework have been used, *viz.* the reactive power of DGs, the OLTC and CBs.

Table IV.3: Reactive and Voltage levers for VVC in literature

Actuators
Transformers with OLTC
DG reactive power
DG active power limitation
Storage solution
Power electronic
Selective Load Shedding

In short, these methods can be divided in two main categories: uncoordinated (local) and coordinated (global) schemes as illustrated in Figure IV.1. Uncoordinated schemes are rather used in industrial framework and enable local regulation. On the other hand, provided that both measurement and communication systems exist, coordinated structures enable to have a control on the scale of the distribution system. These systems mainly exist as demonstrator projects and are one of the main hurdles for coordinated schemes due to the possible high investment cost required. Then, generally either rule-based or optimization-based methods are considered to handle the design of the control command law.

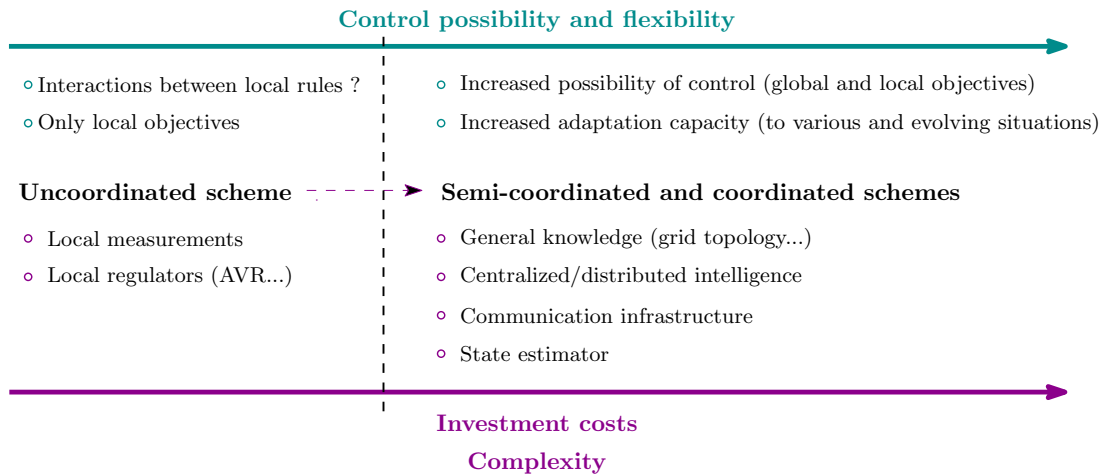


Figure IV.1: From uncoordinated (local) to coordinated control structures

IV.1.1 Relevance of coordinated structure compared to local control strategies

IV.1.1.a Uncoordinated strategies

Uncoordinated control strategies are based on local measurements only and aim to achieve local objectives. The needs associated in equipment or infrastructure for communication and measurements are thus rather limited. These rules consist in a first step towards active distribution networks and lead to an increase in the distribution networks hosting capacity [20–24]. The major advantage of such a structure, besides the low complexity, is a quite high reliability.

For example local voltage control rules for DGs are often considered to minimize the DG penetration adverse impacts and alleviate the possible voltage rises:

- **Operation in Power Factor Mode**, i.e. with a specified ratio of reactive power over active power ($\tan(\phi)_{DG} = Q_{DG}/P_{DG}$). This mode is commonly used by DSO, and the $\tan(\phi)_{DG}$ value is derived through planning connection studies to limit the cost of the DGs connection.
- **Operation in Voltage Control Mode or with a $Q = f(U)$ characteristic** [21–23]. In this solution, the reactive power output of DGs is adjusted to control the voltage using the Automatic Voltage Control relay of DGs. The $Q = f(U)$ voltage control rule used by Enedis is more specifically introduced in Section IV.2.
- **Active power Curtailment**. This solution is often considered when every other solutions are exhausted. For instance, in [25], a generation curtailment scheme based on voltage-sensitivity is proposed.
- **Operation with a $Q = f(P)$ characteristic**. For instance, in [26], reactive power absorption is proposed depending on the active power injection and the equivalent R, X parameters of the grid in order to reach the voltage profile as if there were no DGs. Provided enough reactive power is available, the voltage at the DG connection point is independent of the generation. However such a scheme results in high reactive currents and thus impacts the OLTC operation or increases the losses.

Several modes can be combined together. Dual mode combining Power Factor and Voltage Control Mode are for instance studied in [24]. In [20], the same dual mode is also combined with active power curtailment as a last resort.

However, with such a local method it is barely possible to reach a common objective, such as to control the reactive power at the HV/MV systems interface. Moreover, the reactive power of DGs cannot be used to mitigate a voltage rise/drop occurring at another area than the DG connection point.

Next, it may happen that the local controls interfere with each other. Along with a high level of DGs penetration, a proper coordination among the actuators (OLTC, DGs, CBs) is essential to reach a global optimum situation [22, 29] or to avoid excessive OLTC operations. Moreover, the coordination between OLTC and DGs increases more strenuously the control possibilities of the MV network. Also, if a distribution network is equipped with a coordinated real-time VVC, then the hosting capacity of a given network (regarding voltage constraints only provided that the thermal constraints have been taken into account) can be enhanced according to the planning and connection studies.

IV.1.1.b Coordinated strategies

On the other hand, coordinated strategies rely on global measurements and are able to reach global objectives and exhibit better performances than local schemes. Both schemes are further compared in [30] that demonstrates the relevance of coordinated control structures. Most of recent works focus on coordinated control strategies (See Table IV.1).

These advantages come at a price: the investment needed for the communication and measurement infrastructure. Next, these schemes are viewed as less reliable than purely local schemes since any failures in the communication or measurement devices may jeopardize the entire control strategy.

The most fragile schemes are the purely decentralized ones such as the multi-agent system method that are based on a cooperation between actuators. Decentralized methods imply a high level of communication between actuators. On the other hand, the needs (and thus the dependence), in communication and measurements infrastructure can be limited if there is only communication link between the actuators and a centralized intelligence for instance.

Also, when selecting the control architecture (from centralized to decentralized architecture), several factors need to be considered [31]: security and safety, speed, complexity (flexibility), reliability and the associated costs. Since these factors can compete with each other, a trade-off must be reached.

The location of the intelligence (substation, Distribution Network Control Center, local...) and the location of measurement devices are also key-questions.

To sum up, two main approaches are usually considered: uncoordinated (local) or coordinated (global) schemes as sketched in Figure IV.1. The former, and easiest one, proposes a local vision of the grid and consists of local controls independent of each other. The latter relies on a more global/centralized vision leading to very different control structures and needs in communication equipment.

Managing the reactive power exchange at the HV/MV systems interface compels to consider coordinated schemes for real-time VVC strategies. Indeed, these strategies will rely more on the

DGs reactive power: this reactive power is to be used jointly with the OLTC to manage the MV voltages, and in a coordinated manner to achieve the objective of regulating the reactive power flowing upwards the HV grid. In other words, the control strategies should coordinate slow acting levers having a global influence on MV voltages (such as the OLTC) with DGs having faster dynamics and a local influence on voltages but a global influence on reactive power.

In the literature, the issue of the reactive power exchange limitation at the HV/MV systems interface is generally not addressed. The proposed VVC strategies aim to control the MV voltages only. Nonetheless, the authors of [17] propose to integrate a constraint either on voltage or reactive power at the primary side of the HV/MV substation within a predictive approach (see Subsection IV.1.2).

Hence, in this work, several coordinated control strategies have been considered and are introduced hereafter. To limit the need in communication and equipment infrastructure, no communication will be necessary between the local actuators. Next, to improve the reliability of the solution, the present local control (OLTC for instance) should not be dropped out but rather integrated in advanced control schemes. At last, these choices are consistent with Enedis ones regarding the control architecture and measurements devices deployment to ensure that the proposed solutions can be implemented and suitable for future distribution grids.

IV.1.2 Standard methods for coordinated voltage control

Several methodologies can handle the design of command laws for large scale systems such as the distribution grids. Generally these methods have been designed to integrate as far as possible the knowledge and skills of the network engineers. Also, two methods are usually considered:

- Rule-based methods that consist of a set of technical and process rules;
- Optimization-based methods that aim to minimize a relevant criterion (from both technical and economical points of view).

IV.1.2.a Rule-based methods

Historically, rule-based methods, also named expert systems, have been proposed in the early 1980s. Their development was linked with the evolution of techniques based on artificial intelligence or fuzzy methods [1, 32]. Such a method is quite easy to implement and, providing a relatively simple system, it does not require a high computational effort.

Yet, for large scale systems, or with a high number of actuators, there is a true difficulty for the experts to determine the most relevant rules. Likewise, if several objectives are targeted, the determination of the control rules can become a tedious task [33].

Next, a set of rules is not generic, especially for large scale systems that exhibit various topologies and actuators such as the distribution systems. Moreover, in case of a network reconfiguration (change in topology or connection of a new devices), a full update of the rules is to be considered. And, if new devices are to be connected to the system, a lack of expert assessment may happen.

Also, such a method is not flexible or would require advanced tools (optimization or self-learning tools for instance).

Furthermore, using rule-based method, it cannot be guaranteed that every specified constraints are met, or that the optimal solution has been reached. All of these concerns can be tackled by designing optimization-based methods as introduced hereafter.

Nowadays, rule-based control methods are rather proposed in industrial contexts [2–5]. Example of demonstrator projects are introduced in subsection IV.1.3

IV.1.2.b Optimization-based methods

Optimal control is a control strategy based on an optimization process. This optimization aims to bring a system from an initial state to a specified final one, while a given criterion is achieved. Several constraints can be as well considered in the resolution of the optimization problem. The system is usually described by two equations that link the output variables (y), with the control variables (u) and the states of the system (x):

$$\begin{aligned} \dot{x} &= f(x, u, t), \\ y &= h(x, u, t). \end{aligned} \tag{IV.1}$$

The criterion is given by an objective function to be minimized and can be written as follows:

$$J = g(x_0, t_0, x_f, t_f) + \int_{t_0}^{t_f} r(x, u, t) dt \tag{IV.2}$$

The first part of this equation ($g(x_0, t_0, x_f, t_f)$) is related to terminal conditions (i.e. to be enforced at initial t_0 and final t_f stages). The second part ($\int_{t_0}^{t_f} r(x, u, t) dt$) is related to the objective to be reached. It can consist, for example, in minimizing an economic cost function or in limiting the control effort. Next, the problem can be subjected to either equality or inequality constraints on x, y or u :

$$\begin{aligned} g_{eq}(x, u, t) &= 0; \\ g_{ineq}(x, u, t) &\leq 0. \end{aligned} \tag{IV.3}$$

Problem formulation

The optimization problems can be classified as linear and nonlinear problems. When the objective function (equation (IV.2)) and the constraints (equations (IV.1) and (IV.3)) are linear, the problem is said linear. In this case, there is a unique solution and there are several techniques that can handle a fast resolution even for large-scale systems.

Here, the system (namely the distribution network) is a Mixed Integer Non Linear Problem (MINLP). Indeed, there exist both continuous (reactive power from DGs) and discrete actuators (CBs and tap change of OLTC) that compel to use specific techniques. For instance, some methods such as branch and bound techniques can be used. Generally the discrete nature of actuators is disregarded in the literature about VVC for distribution networks, and a continuous approximation is used [34]. A simple way to take the discrete nature control input into account consists in performing an optimization assuming all variables are continuous. Then, at a second

stage, the discrete variables are successively assigned to the two nearest discrete values. The alternative leading to the smallest objective function is selected [2].

In addition, enforcing the constraints (correlated with normative, legislative and contractual requirements) on MV voltages and reactive power exchange at TSO-DSO interface is an important challenge for DSOs. The cost function is generally selected to determine the best solution among the control possibilities to reduce the DSO expenses.

When setting the optimization problem, several concerns must be addressed:

- Definition of the objective function, especially in case of a multi-objective problem;
- Degree and quality of information needed (selection of the model and measurements requirements);
- Computational time;
- Problem infeasibility: in our case when the constraints cannot be enforced;

Usually, the system modeling is either based on the load flow equations or on a simplified linearized model such as a sensitivity matrices based model. This model is used to find an optimal solution that ensures the MV voltages at every or specific nodes only of the distribution network remains in a specified range of values. Secondary objectives can be considered as well. For instance, if losses minimization has been selected as an objective, having an accurate model of the power flows (or currents) in the system depending on the control variables and real-time measurements is essential.

For the resolution of the problem several methods can be found in the literature on real-time VVC:

- Linear Programming;
- Non Linear Programming [12, 13];
- Soft computing methods:
 - Genetic Algorithm [14];
 - Particle Swarm Optimization [15].

Soft optimization techniques are efficient to avoid local minimum, but quite time-consuming (computational burden) and thus not well adapted for real-time purposes.

The constraints infeasibility issues can be dealt with using slack variables that relax the constraints. This method is further discussed in Chapter V.

In the literature, the optimization-based control can be further divided in two main categories namely single-step optimization and predictive control (multi-step optimization).

Single-step Optimization

In single-step optimization, decisions are taken at once, and the references are sent successively. Also, this strategy is particularly dependent on the accuracy of the system modeling. Model inaccuracies have repercussions on the overall system response that in turn could damage the robustness, speed and stability of the control.

For instance, in [33], the active and reactive power of DGs are coordinated with the OLTC tap changes. The objective function consists in minimizing the losses and the active power curtailment. The model is based on the load flow equations that are solved knowing the voltage and the active and reactive power injection of DGs. The resolution of the problem can be quite time-consuming. The resolution can be simplified using the linearized model of the network.

For example, in [11] an intra-day scheduler that adjusts the OLTC voltage reference and the DGs active and reactive power outputs according to a day-ahead scheduling is proposed. To this end, an optimization problem is solved every 15 minutes. The resolution yields a succession of references to be applied and uses a linearized model based on sensitivity matrices.

In [35], the principle of Coordinated Secondary Voltage Control of the transmission system (See Subsection I.2.2 for more explanation on SVC) is applied to the distribution system using the reactive power of DGs only. In this optimization the future states of the network are anticipated. A control action is derived once the system has been updated by measurements. Such a procedure, which consists of a closed-loop approach, mitigates the errors and inaccuracies of the system modeling. This scheme was further enhanced in [13] that also considers the OLTC operation. Instead of having a centralized intelligence, a multi-agent system structure was proposed. In this method, it is assumed that every agent (OLTC and DGs) embeds a local intelligence able to process and exchange data and to take decisions accordingly. Also the industrial implementation is limited.

On the other hand, using a multi-step optimization process can increase the robustness of the method or enable to anticipate for constraints infeasibilities. And, unlike one-step ahead methods, it is possible to ensure that the constraints are enforced during the corrective process. Since there are actuators with time-delay (namely the OLTC), fast switching between two positions may happen in one-step optimization, while time-delay can be easily integrated in the multi-step approach as well as the actuators behavior on a given temporal horizon.

Model Predictive Control or multi-step optimization process

Model predictive control strategy for real-time VVC of distribution networks was proposed in [8, 17, 18]. Historically, MPC was developed in the 1970s for refinery and petrochemical processes [36–38]. MPC strategy is an optimal multi-steps control that can deal with various constraints, time delay and can anticipate known disturbances. The multi-steps approach allows the system to track smoothly the desired state, as the introduction of slack variables helps handle constraints infeasibility whenever needed.

The principle of MPC is a "receding horizon" method and can be described as follows:

1. **Prediction** of the system behavior (x^p) within a temporal horizon called **prediction horizon** (N_p). This prediction is realized based on a model of the system and last real-time measurements.
2. Definition of a **reference trajectory** within a control horizon (N_c) to bring the system in the targeted state. For example the convergence can be specified.
3. Derivation of an **optimal sequence of control actions** (u^{opt}) that minimizes a specified objective function.

4. **Application of the first element** only of the optimal sequence of control actions. The system is fully updated by measurements and the whole process is then repeated.

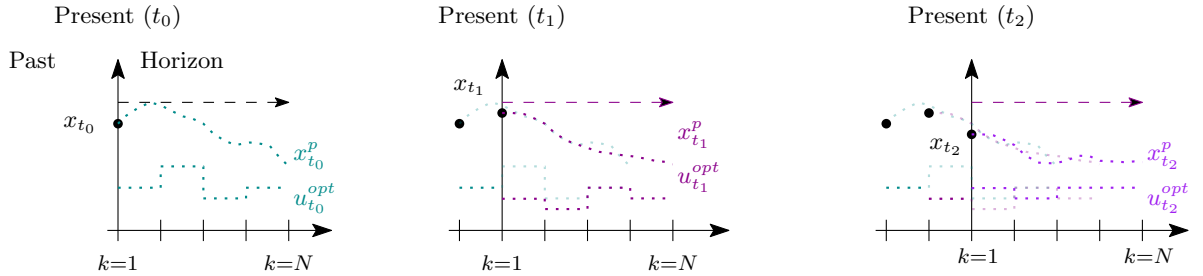


Figure IV.2: MPC receding horizon principle

Figure IV.2 illustrates the receding horizon principle with a prediction and a control horizon having the same length. [37, 38] provide circumstantial survey and history of MPC methods and give the essential references on the topic.

In short, the advantages of a MPC method are:

- All advantages of optimization-based methods:
 - Optimality (according to the selected objective function);
 - Multi-input, multi-output;
 - Multi-objectives;
 - Generic method that can be applied to a generic network model;
- Ability to deal with complex and various constraints evolving with time;
- Ability to anticipate the behavior of actuators, or any predictable disturbances;
- Ability to handle time-delays
- Natural robustness due to the closed-loop nature of the receding horizon that alleviate the consequences of errors and inaccuracies in the model.

IV.1.2.c Pros and cons of standard methods

Rule-based and optimization-based methods are the most widespread methods to handle the design of the real-time VVC algorithm since they can easily integrate the networks engineers knowledge and expertise. Because optimization-based methods minimize a specified objective function, they exhibit better performances than rule-based method. These optimal schemes are also more flexible and adaptive, and above all, the respect of constraints can be guaranteed (if there are no infeasibility cases).

Though, simpler and more realistic algorithms such as rule-based controllers can achieve rather good performances and are easier to implement. Next, optimization-based method generally require a model of the network in order to work properly. Even so, some rule-based methods use as well a model of the network to enhance control strategies (See [33, 39]). Having such a model is not straightforward as there are a lot of actuators in distribution systems and a high

level of uncertainties. For instance, load models is one of the major sources of uncertainties. MPC method exhibits good performances regarding robustness to errors and uncertainties due to its closed-loop nature.

Table IV.4 compares both of the optimization and rule-based approaches. One can also refer to [2] for a detailed comparison.

Table IV.4: Rule-based versus Optimization-based control methods

Methods	Advantages	Drawbacks
Optimization	·Guaranteed optimality / constraints respect(minimization of a specific objective function)	·Model of the system ·Definition of the optimization problem (objective function, constraints, infeasibility issues...)
Rule-based	·Easy to implement, intuitive (low mathematical complexity)	·Based on expert assessment ·Concern regarding the scale of the system (computational burden) ·Not very flexible : full update is required in case of a changing topology (self-learning tools...)

Henceforth, in this work, several methods have been considered:

- Two classical methods:
 - A rule-based method defined in Subsection IV.2.1;
 - An optimization-based method defined in Subsection IV.2.2;
- A Model Predictive Control method defined in Chapter V.

The choice of a MPC strategy has been briefly justified hereinbefore and the proposed strategy is further compared in Chapter VI (qualitatively and quantitatively) with the classical methods introduced in the next section.

IV.1.3 Present technical possibilities of distribution networks regarding real-time coordinated VVC

The infrastructure required for most of the present control strategies in literature is far from nowadays technical possibilities. Few methods are addressing the issue of the control algorithm implementation as stated in [40]. Next, the performances of the proposed coordinated control is often performed with networks exhibiting a very high penetration level of DGs. Hence, there is a gap between demonstrators VVC projects and the VVC in the literature.

However, Grid Codes requirements consider present distribution grids. Also there is a need to design intermediate solutions towards active distribution networks. These solutions should be flexible enough in order to be easily adapted to various and evolving grids.

IV.1.3.a Demonstrator projects of coordinated voltage control strategies

There are few examples of coordinated real-time VVC implementations in distribution networks. Even if it is difficult to get information about the control structures and methods of field experimentation, it is of interest to present some of the demonstrator projects in Europe:

- **Flexible Plug and Play (FPP)**¹ [41, 42];
- **Aura-NMS** (An autonomous Regional Active Network Management System) [43];
- **ZUQDE** (Zentrale spannungs U und blindleistungsregelung Q mit DEzentralen)².
- **FAR within the VENTEEA project**³, FAR stands for "Fonctions Avancées de Réseau" that means Advanced Grid Functions;

Both VENTEEA and ZUQDE demonstrators are part of the IGREENGrid project (IntegrationG Renewables in the EuropEaN Electricity Grid)⁴.

FPP

The FPP project aims to provide a smart active management of distribution system to increase the hosting capacity while minimizing the grid reinforcement expenditures. The main principle is a fast connection and disconnection of various devices. This project is tested in a area located between Peterborough and Cambridge with a high level of DGs penetration and consist of a 33 kV distribution grids.

This project was partly funded by UK Power Networks and the LCNF (Low Carbon Network Funds). Fields experiments ended in December 2014.

Among others, this project has defined a new voltage control strategy in distribution networks. This new strategy is based on two points:

- An enhancement of the OLTC control technique using a method called "Super tap n+" (See [42]). This method is similar to the compounding technique presented in Part A. The load is better estimated by notably monitoring the DGs power injection.
- A law called "sgs" that modulated first reactive and then if needed active (curtailment) power of DGs depending on the voltage level at their point of connection. This second law complete the action of the OLTC to maintain the MV voltages and is part of the active management systems housed in a Distribution Network Control Center.

¹[http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Flexible-Plug-and-Play-\(FPP\)/](http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Flexible-Plug-and-Play-(FPP)/)

²<http://www.igreengrid-fp7.eu/scope-of-work/demonstrators/austria/zuqde.aspx>

³<http://www.venteea.fr/en/>

⁴<http://www.igreengrid-fp7.eu>

In the second law, the active and reactive power of DG to be cut off are derived through the uses of sensitivity matrices: SF_P and SF_Q . SF_P (SF_Q) indicates the change in voltage at the DGs terminal that is induced by a change of active power (reactive power). Then, the calculation is done as follows:

$$\Delta Q = \frac{\Delta V}{SF_Q}, \quad (IV.4)$$

if ΔQ overcomes the systems limits, then the value is limited to the DG limit and the active power to be curtailed is assessed according to:

$$\Delta P = \frac{\Delta V - \Delta Q SF_Q}{SF_P}. \quad (IV.5)$$

The FPP voltage control principle was only tested through simulations.

Aura-NMS

Aura-NMS project started in January 2007 and ended in 2010. Among the partners of this project, there are two DSOs: EDF Energy and SP Energy Networks and a major manufacturer (ABB). The scope of this work was to propose an active power flow management and a steady voltage control.

Focusing on voltage control, the solution is based on the coordination of the OLTC and the reactive power of DGs by adjusting in real-time the OLTC tap position and the power factor of DGs.

To this end, two methods have been proposed: a case-based reasoning method and a constraint programming approach (namely an Optimal Power Flow). A case-based reasoning method was selected to avoid the possible non-convergence issues of OPF. The performances of such a method is highly correlated with the set of pre-enumerated configurations that are used to derive the solution depending on the real-time measurements.

In Aura-NMS, the control and communication structure is decentralized to handle the complexity. More specifically, the voltage control is located in the substation: the latter should be able to send references to the OLTC and the DGs.

ZUQDE

The goals of this demonstrator is to propose and demonstrate the relevance of a centralized voltage control with DGs. This project was conducted by the Austrian DSO "Salzburg Netz GmbH", in partnership with Siemens.

The demonstrator is located in the Lungau (in Salzburg province) area. It corresponds to a mountain rural network operated at 30 kV and with several DGs (small hydroelectric power plants, PV and wind turbines).

The centralized voltage control assumes the existence of a Distributed State Estimator (DSE) that yields the voltage amplitude and phase of the entire MV network according to the latest available measurements. Then, an optimization is performed either on the whole system or on a feeder only. The optimization gives the OLTC voltage set-point and the DGs reactive

power references. The objective of the optimization is first to maintain the voltages and then to minimize losses.

Only few details are given on the optimization method but some reports related to this project can be found online ⁵.

FAR (VENTEEA)

This project is conducted by Enedis and EDF R&D. It consists of field experiments performed on a rural 20 kV network that hosts several wind farms.

The voltage control method is based on the existence of a DSE. This DSE retrieves real-time voltage measurements and then calculates the amplitude of the MV voltage profile only of the entire network.

Then, several rules are considered to maintain the voltages. A global rule adjusts the voltage reference of the OTLC every 10 minutes, while it is assumed that the reactive power of DGs connected to mixed feeders follow a local rule ($Q = f(U)$).

Both laws are detailed in Section IV.2 since they were used as a base for the development of one of the proposed the centralized VVC schemes.

Apart from the local $Q = f(U)$ characteristic, the rules are centralized in a Distribution Network Control Center (DNCC) with the DSE function.

IV.1.3.b Conclusion: Assumptions regarding distribution networks

To sum up, in order to enhance the real-time VVCs of distribution network, there is a need to have local measurements to be combined with a DSE. Such a DSE should yield at least the voltage amplitude of the MV network.

By comparison, the present measurements are quite limited, often not synchronous and not necessarily retrieved to the DNCC.

In France, the following data are currently known in the DNCC:

- **HV/MV substations** the following states are monitored and retrieved in real-time (every 10 minutes):
 - MV busbar voltage amplitude only;
 - The current flowing through the HV/MV transformer, and for some substation the active and reactive power;
- **DGs:** Active and reactive power as well as the voltage amplitude are measured:
 - These information are retrieved only by request (generally using telephone service);
- **Real-time grid topology.**

There are other indicators that are able to send real-time information to the DNCC, such as the fault detection indicators. In the DNCC, there is no knowledge of the grid upstream the HV/MV

⁵http://www.smartgridssalzburg.at/content/website_smartgrids/de_at/downloads.html

substations. Next, the parameters of the MV grids (namely the resistance and reactance of lines and cables) are assumed to be known, but with a variable reliability.

Consequently, there is a gap between the technical limitations of distribution system and the alleged capacity of distribution systems in literature, more specifically regarding the MPC strategy. For instance, in [16] and [8], a control action is sent every 30 seconds. No details are given regarding the measurements, and one can assume that the MV voltages are known with a high accuracy. In [17–19], a control action is sent every 10 s while measurements are retrieved every 10 s and consist of an average of 11 local measurements taken every 0,2 s. The measurement accuracy is assumed to be of 1 %, and white gaussian noise is superimposed on the measurements. To ensure the proposed control strategies can be implemented and are consistent with future distribution grids, realistic assumptions regarding the control structure, measurements and communication infrastructures have been considered in our work.

Indeed, it is assumed that a DNCC exists as in present French distribution networks. This supervision center is able to retrieve measurements and send references to actuators every minute. A set of measurement is taken every 10 seconds and consists of the powers flowing through the HV/MV substation, the active and reactive power injections of DGs and representative node voltages (typically 3 nodes by feeders) of the MV grids.

Then, these measurements are averaged over 6 measurements (6 times 10 s), and the average values are being sent every minute to the DNCC. Moreover, it is assumed that the DNCC tools encompass a state estimator as detailed in [3]. Thus, the accuracy of voltages and reactive power is assumed to be of 0.5% and 1% respectively.

Regarding the reactive power capacity of DGs, it is assumed that reactive power can be required in the range $[-0.35, +0.4]P_{max}$ at maximal active power injection.

IV.2 Introducing two usual real-time VVC schemes compliant with industrial requirements

In this Section, two real-time VVC schemes are introduced; a rule-based method (named R-VVC) and an optimization-based method (O-VVC). These methods are rather classical compared to the existing control structures that can be found in literature. A third control strategy based on Model Predictive Control (MPC) has been further developed and is introduced in Chapter V. The two more classical VVCs have been used for comparison purposes (See Chapter VI) to assess the relevance of the predictive strategy. Also, the illustrations of both methods are given in Chapter VI.

IV.2.1 A semi-coordinated rule-based voltage control: R-VVC

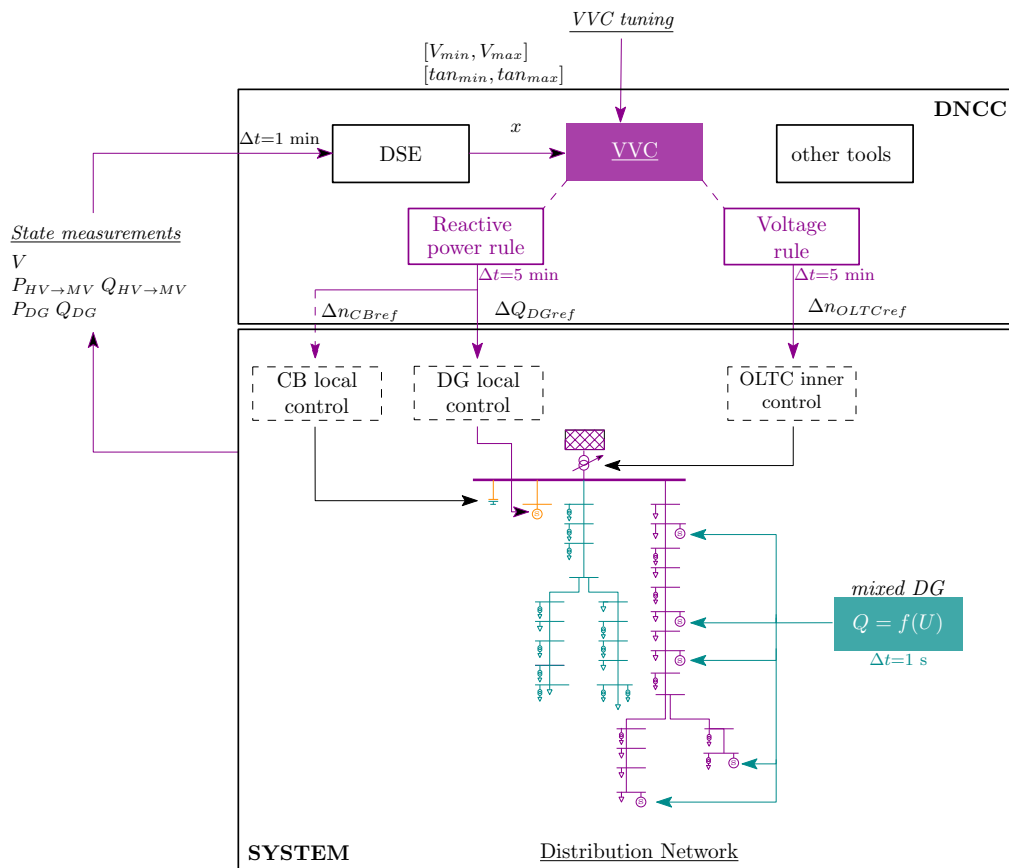


Figure IV.3: The rule-based control structure

The real-time control solution presented herein is based on a 2 (global) +1 (local) set of rules inspired from the demonstrator project FAR (See Subsection IV.1.3) led by Enedis. The first rule is dedicated to voltage control of the MV network by setting the OLTC voltage reference.

The second rule handles the reactive power management at the TSO-DSO interface by adjusting the reactive power references of CBs and dedicated DG. Next, a local rule is considered for the reactive power of mixed DGs. This law is a $Q = f(U)$ characteristics.

The control structure is depicted in Figure IV.3. The two global rules are located in the DNCC, and send references to the corresponding actuators every 5 minutes. The local rule has a faster dynamic: the reactive power is adjusted every second. Since there are global and local rules, this strategy can be viewed as a semi-coordinated control.

IV.2.1.a Voltage rule: OLTC voltage set-point

The OLTC voltage set-points's rule is similar to the one proposed in [3]. Depending on the measurements and state estimations of the MV voltages, the reference of the OLTC is adjusted in order to prevent the MV voltages to be outside a specified range of values, the contractual range $[0.95, 1.05]$ pu herein. In order to avoid unnecessary tap changes (and thus a premature wear of the OLTC), the reference is not modified if the voltage lies within the contractual limits at every node.

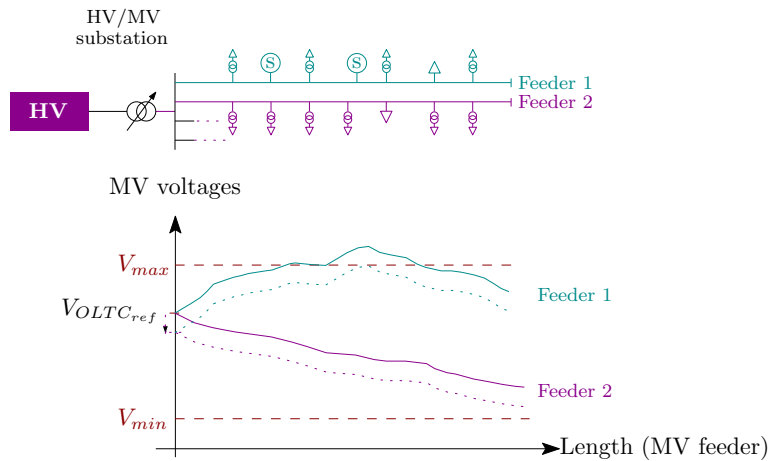


Figure IV.4: The OLTC voltage reference rule

IV.2.1.b $Q = f(U)$: a local voltage control rule for DGs in mixed feeder

The reactive power of DGs can be adjusted following a $Q = f(U)$ characteristic as illustrated in Figure IV.5 that is similar to the rule presented in [21].

Depending on the real-time DG voltage measurements, the reactive power is adjusted. A dead-band is included around the nominal voltage in order to avoid an excessive usage of the reactive power. Next, the voltage measurements are filtered (30s, for a measurement taken and a reference sent every second) to prevent requiring reactive power in case of disturbances with fast dynamics.

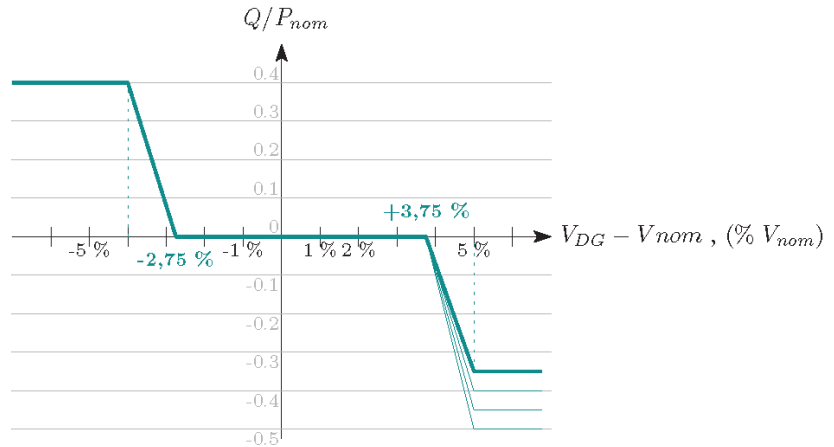


Figure IV.5: Principle of the $Q = f(U)$ rules

Parameters tuning has been done in accordance with the accuracy of the OLTC (around 1%) assuming that the OLTC voltage set-point can be adjusted within the range $[1.02 - 1.04]$ pu.

In some cases, the use of a constant power factor solution is the most relevant option. This is the case for instance when the voltage constraints violation does not occur in the vicinity of the DGs, or when the $Q = f(U)$ law results in providing insufficient reactive support and less than the $\tan(\phi)$ solution. The choice among a $Q = f(U)$ and $\tan(\phi)$ solutions is made during connection studies. Another remark lies in the fact that the parameters of this rule are not correlated with the sensitivity of voltage to the reactive power at the DG point of connection. Also, the rule is not optimized for voltage control purposes.

Nonetheless, compared to a solution based on a constant power factor, e.g. $\tan(\phi) = \text{constant}$, this law limits the use of reactive power and thus limits the losses induced by reactive power flows.

It should be borne in mind that this law exhibits the same results as the $\tan(\phi) = \text{constant}$ policy regarding the increase in the DGs hosting capacity of MV feeders.

IV.2.1.c Reactive power rule: references of reactive power for dedicated DGs and CBs

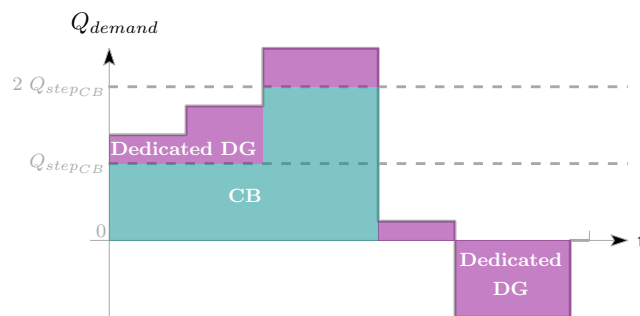


Figure IV.6: The reactive power rule

The aim of this rule is to limit the reactive power exchange at TSO-DSO interface. To this end, the reactive power references of both DGs connected to dedicated feeders and CBs are modified. Given the discrete nature of CBs, they are used uppermost while the reactive power of DG is used as an adjustment variables. This is an assumption and other choices could be made based on a trade-off between technical and economic factors. This rule is illustrated in Figure IV.6.

IV.2.2 A coordinated optimization-based voltage control: O-VVC

The mathematical formulation of the optimization problem is quite similar to the MPC problem formulation. Indeed, the optimization problem can be considered as a specific case of a MPC approach with a prediction horizon $N_p = 1$. That is why the control structure of the optimization strategy is only briefly introduced hereafter while the MPC control strategy is more specifically explained in Chapter V.

IV.2.2.a Control structure

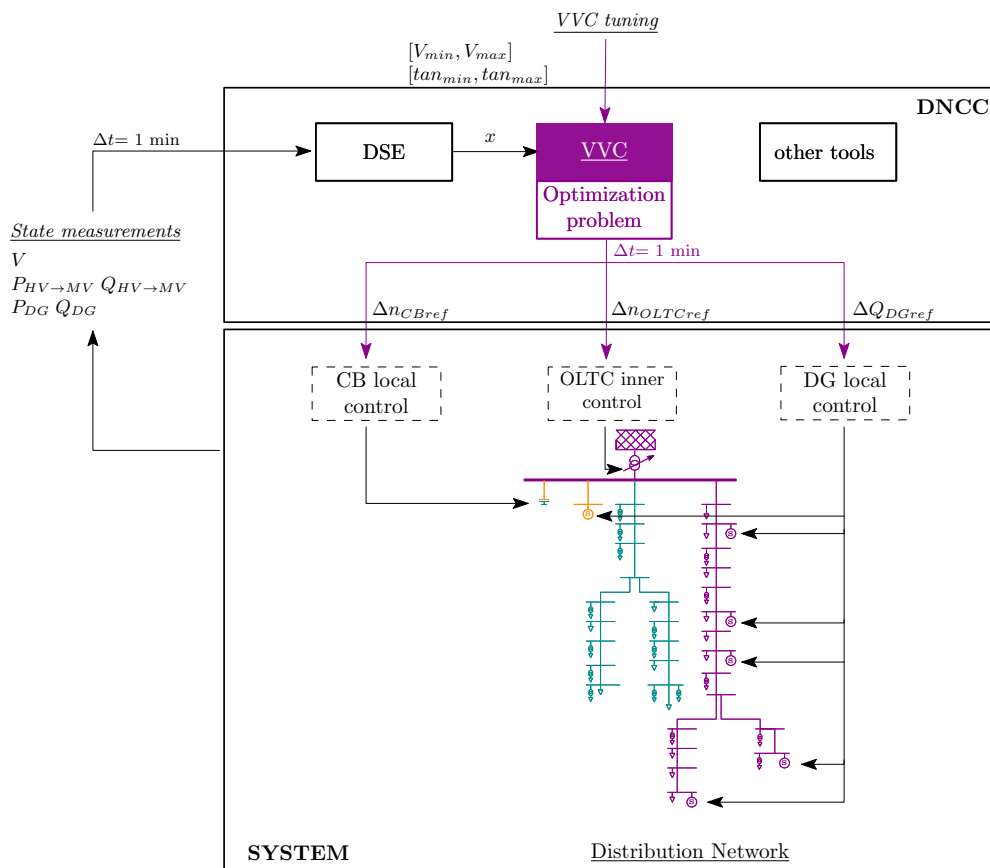


Figure IV.7: Control structure of the proposed optimization-based VVC strategy

The control structure of the second strategy is illustrated in Figure IV.7. The control consists in coordinating all of the actuators based on the resolution of a specified optimization problem that is described hereafter.

As stated before, the controller should meet two objectives:

1. Maintain the n nodes voltages ($V \in \mathbb{R}^n$) in the distribution network inside a predefined range of values $[V_{min}, V_{max}]$.
2. Regulate the reactive power exchange at the interface of MV/HV networks by maintaining the ratio of reactive consumption over active consumption of the distribution network ($\tan_{MV \rightarrow HV} = \frac{Q_{MV \rightarrow HV}}{P_{MV \rightarrow HV}}$) around a target value inside $[\tan_{min}, \tan_{max}]$. Thus, the DSO can comply with the technical or regulatory requirements regarding reactive power exchange with the transmission system.

To reach these aforementioned objectives, the controller takes advantage of some of the MV networks flexibilities, adjusting:

- The reactive power of DG (Q_{DGref}),
- The number of activated steps of CB (n_{CBref}).
- The OLTC voltage reference ($V_{OLTCref}$),

The controller should coordinate levers that exhibit different dynamics and influences. The OLTC have a global influence on MV voltages but slow dynamic (1 minute) while DGs have a faster dynamic (within few seconds) and a more restrained influence on voltage (but a global one on HV-MV reactive power flows). Also, given the dynamics of OLTC, the actuators references are adjusted every minute only.

If needed, the active power of DG could easily be integrated as a control variable. The change in control effort at a given time k are defined by:

$$\Delta u(k) = [\Delta n_{OLTC ref}, \Delta Q_{DG ref}, \Delta n_{CB ref}](k). \quad (IV.6)$$

IV.2.2.b Optimization control strategy: minimization of DSO's costs

The objective of the control is to minimize the DSO costs that are linked with the control effort and the active losses P_{loss} . This objective can be written as:

$$\min(J)_{\Delta u} = \Delta u R \Delta u^T + \alpha P_{loss}^2, \quad (IV.7)$$

where R is the cost matrix associated with control efforts, α is linked with the active losses in the distribution network. If losses estimates are not available or not accurate enough, this parameter can be set to zero.

In the sequel, $\alpha = 0$. Indeed, it is assumed herein that this VVC scheme set up in accordance with the network design (grid reinforcement and development) will be activated only for emergency cases, where the priority is given to the respect of the constraints at minimal control effort

cost. Next, loss minimization can be considered in a large extent during the design stage of the network or indirectly by the VVC scheme enforcing the voltages to remain around a limited range of values [18]. Moreover, due to the uncertainty of loads it is difficult to assess the true gain yield [44]. Indeed, a model of the losses expectation is required to incorporate the loss minimization, and thus a model of the active and reactive power flowing in the MV grids with respect to the control variable u . However, these flows highly depend on the load model, and more specifically on the load to voltage sensitivity. Nowadays, load models remain one of the main source of uncertainty in dynamic simulations.

IV.3 Conclusion

To sum up, the main goal of the real time VVC of distribution network is to help control MV voltage profile. Generally, the methods proposed in literature are either local or global (coordinated). The relevance of coordinated strategy has been well established in particular for multi-objective control.

Then, to handle the design of the coordinated command laws, two methods are generally considered: rule-based and optimization-based methods. The principle of a rule-based method consists in automating the electrical engineer or dispatcher skills. Also, this method is not generic, and the convergence cannot be guaranteed. On the other hand, the principle of an optimization-based method is to find a solution that ensures the constraints achievement while minimizing a given cost function, usually based on both technical and economic criteria. Such a method is generic and the optimality can be guaranteed.

However, the convergence and the dynamics of the system is not controlled with a one step-ahead (single-step) optimization. Also, the solution can lead to a transient violation of the constraints, or abrupt control actions. Next, since distribution systems embed quantized (discrete) actuators, such as the CBs, or the OLTC, a one step-ahead method can lead to undesirable oscillations.

For these reasons, it is appealing to consider a Model Predictive Control (MPC) method, that is a multi-step optimization method. Then, it is possible to integrate the dynamic of the system and the behavior of actuators (even with time-delays) and thus to tune the convergence of the system. Moreover, the MPC method exhibits a natural robustness to external disturbances due to the closed-loop nature of such a control.

Also in this work, a predictive control strategies has been selected for the design of the real-time VVC controller. The following Chapter V is dedicated to the presentation of the proposed predictive strategy.

Both rule-based and optimization-based approaches introduced in Subsection IV.2.1 and IV.2.2 are further compared from a quantitative and qualitative point of view with the MPC based strategy. In this chapter, simulation results are given to better illustrate the specific features of each method.

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Chapter V

Definition of a real-time predictive VVC with a reactive power exchange limitation

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V.1 Predictive control strategy of voltage and reactive power exchange between HV and MV grids

As asserted in Chapter IV, MPC control exhibits attractive performances [1–4] compared to other real-time VVC control strategies notably for economic strategies minimizing operational costs [5]. Since this method is a closed-loop control, it exhibits a high robustness to external disturbances as it will be shown through simulations in the sequel. In this work an original MPC VVC strategy has been proposed and designed.

The MPC strategy follows the same objectives and is quite similar to the optimization-based one of Section IV.2.2. The major difference lies in the fact that the multi-step optimization process results in sharing the control effort within a temporal horizon, the control actions are smoother and updated with the latest available measurements. Next, it is possible to accurately embed the actuators behaviors inside the predictive horizon. Also, in this Section the MPC strategy is presented and the main differences with the optimization-based strategy highlighted.

Compared to the existing MPC methods in literature, the key-features of the approaches are:

- To coordinate many actuators for both voltage regulation (similar to what can be found in literature) and for the management of the reactive power exchange between MV and HV networks;
- To guarantee minimization of tap changes during the whole life of the OLTC since this criterion is explicitly considered in the cost function;
- To enable keeping and considering the classical OLTC inner control to avoid fundamental modifications of the existing control devices and operating processes. In the end, the proposed approach is a step forward smart distribution grid.

Indeed, an industrial control system is integrated in the OLTC, which has been designed to optimize its life span and this inner loop control cannot be removed but rather integrated within the advanced control approaches. The OLTC is more specifically a slow-acting device that integrates time-delays and a dead-band in its low level control [6]. This inner control has been introduced in Chapter I.

Usually few papers consider the nonlinear nature of the OLTC (and more generally of actuators) in the design of their real-time controller [7]. Designing hybrid continuous-discrete or nonlinear MPC methods is not trivial and raises complexity and numerical issues [8, 9].

For instance, in [4], the OLTC is not considered as a control lever in the MPC corrective process but called for only in case of failure of the control. In [2], the OLTC is considered inside the MPC algorithm as a continuous non-delayed variable, while future predicted tap changes are included as a known disturbance inside the prediction algorithm.

Henceforth, the minimization of tap operations is never fairly addressed. Still tap changes should be avoided insofar as possible since OLTC are fragile devices with expensive maintenance cost. The cost of a tap change can be derived knowing the maximal number of OLTC operations before maintenance. Next disregarding the complex behavior of the OLTC can lead under specific conditions to control failures in a MPC scheme: the controller is not able to bring the system in a state that respects every specified constraint.

Section V.2 is dedicated to the presentation of the method that embeds the nonlinearities of the

OLTC. To this end a two-step control strategy has been designed. The first step consists in solving the MPC problem that yields among others the optimal change of tap within the prediction horizon. At a second stage, the voltage reference of the OLTC to respect these optimal sequences of tap changes is derived as illustrated in Figure V.1.

V.1.1 MPC control strategy: the MPC-VVC

The MPC control strategy is illustrated in Figure V.1., the local control of the OLTC, CBs and DGs are shown since there are taken into account inside the MPC control scheme.

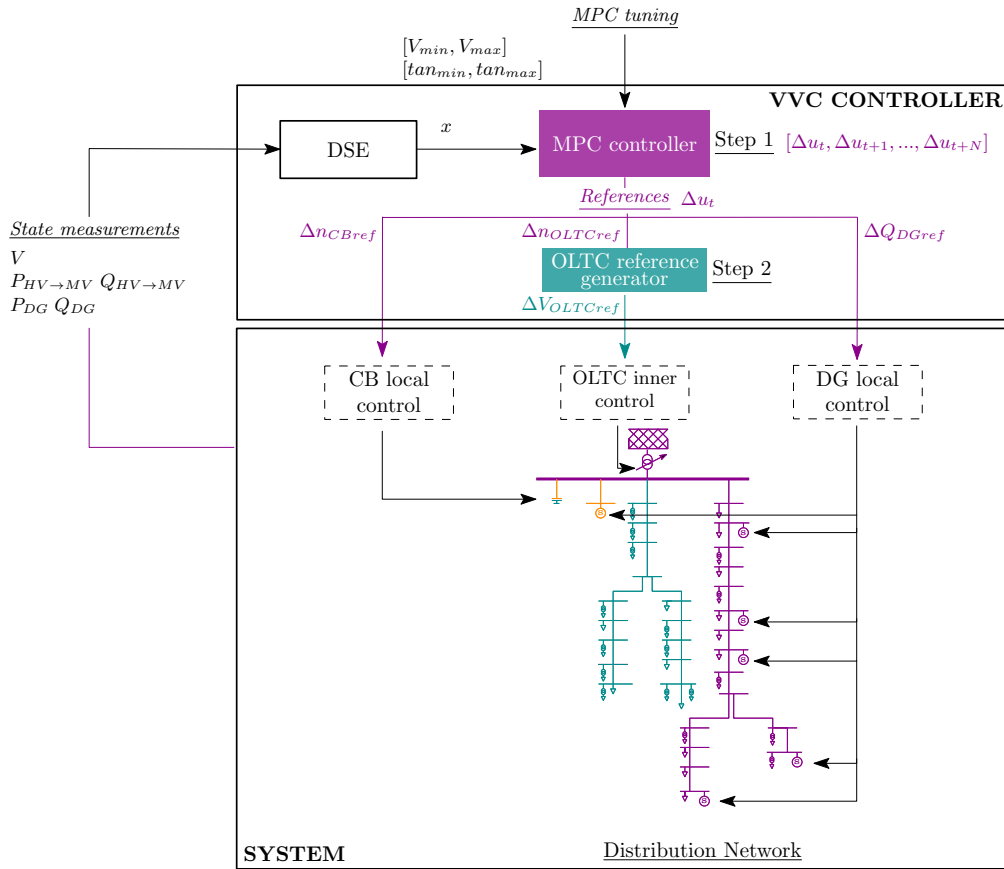


Figure V.1: Schematic of the proposed MPC control structure

The aims of the VVC controller are exactly the same as these introduced for the optimization-based controller in Chapter IV (See IV.2.2). In short, the controller should maintain both the MV voltage and reactive power flows from MV to HV system within a range of specified values. To this end, the VVC controller yields a sequence of changes in reactive power reference of DGs, number of activated steps of CBs and taps of the OLTC. If needed other actuators, such as the active power of DGs, can be easily integrated in this flexible approach. In the sequel, the

optimal sequence of control actions is noted as follows:

$$\Delta u_{k \in \{1, N\}} = [\Delta Q_{DGref}, \Delta n_{CBref}, \Delta n_{OLTCref}]_{k \in \{1, N\}}. \quad (\text{V.1})$$

The cost function consists also in minimizing the control effort but within the prediction horizon:

$$\min(J)_{\Delta u} = \sum_{k=1}^N [\Delta u(k) R_{\Delta u} \Delta u(k)^T + \alpha P_{loss}(k)^2] + u(N) R_u u^T(N), \quad (\text{V.2})$$

where $R_{\Delta u}$ is the costs matrix associated with the change of control efforts while R_u is associated with the total control effort at the end of the prediction horizon. Also, R_u penalized the unnecessary use of reactive power for instance, and insofar as possible would aim to reduce the total amount of reactive power requested. Then, α is linked with the active losses in the distribution network. In the sequel, $\alpha = 0$ on the same grounds as stated in the definition of the optimization-based VVC (See IV.2.2).

V.1.1.a Objectives and constraints

The twofold objective of the problem has been integrated as hard constraints (that is to say, a constraint that should be enforced without any consideration for the associated costs) at the end of the prediction horizon:

$$V_{min} \leq V(N) \leq V_{max}, \quad (\text{V.3})$$

$$\tan(\phi)_{min} \leq \tan(\phi)_{HV \rightarrow MV}(N) \leq \tan(\phi)_{max}. \quad (\text{V.4})$$

Then, the physical limits of actuators should be taken into account within the prediction horizon i.e. $\forall k \in \{1, N\}$:

$$u_{min} \leq u(k) \leq u_{max}, \quad (\text{V.5})$$

$$\Delta u_{min} \leq \Delta u(k) \leq \Delta u_{max}. \quad (\text{V.6})$$

Equation (V.5) embodies the limits on the voltage references of OLTC, switching statuses of CBs, and reactive power of DGs. These latter can vary depending on the active production of the considered DG, the voltage at its terminal or the technologies. Equation (V.6) limits the change of rate between two control actions.

Contrary to single-step optimization, a reference trajectory can be defined as well as complex constraints on the evolution of inputs, outputs and control variables since MPC controls have the ability to deal with various constraints, time delay, and can anticipate any predictable disturbances. Also, the convergence of the MV voltages V and $\tan_{MV \rightarrow HV}$ can also be specified $\forall k \in \{1, N\}$:

$$V_{min}(k) \leq V(k) \leq V_{max}(k), \quad (\text{V.7})$$

$$\tan_{min}(k) \leq \tan_{MV \rightarrow HV}(k) \leq \tan_{max}(k). \quad (\text{V.8})$$

When $k = N$, these constraints are named "terminal constraints". Note that these constraints can evolve inside the prediction horizon for a progressive tightening [3] of the constraints within the prediction horizon.

V.1.1.b Process constraints: exponential convergence and objectives prioritization

In order to specify the trajectory of the controlled variables, a funnel can be defined inside the horizon. The controlled variables must evolve inside this funnel to reach the final objectives. An exponential funnel has been defined herein:

$$x_{max}(k) = x_{max} - \alpha_x^{f(k)}(x_{max} - \max(x(t), x_{max})), \quad (V.9)$$

$$x_{min}(k) = x_{min} - \alpha_x^{f(k)}(x_{min} - \min(x(t), x_{min})), \quad (V.10)$$

With:

$$0 \leq \alpha_x \leq 1, \quad (V.11)$$

$$\alpha_x^{f(0)} = 1 \text{ and } \alpha_x^{f(N)} \rightarrow 0 \quad (V.12)$$

With these conditions it is possible to choose β to define the function f :

$$f(k) = k^\beta \quad (V.13)$$

x corresponds either to the MV voltages V or to the tangent $\tan(\phi)_{HV \rightarrow MW}$.

The introduction of these constraints enables to tune the speed of convergence depending on the parameter α as illustrated in Figure V.2. Thus, fast changes with a high amplitude of control actions can be avoided.

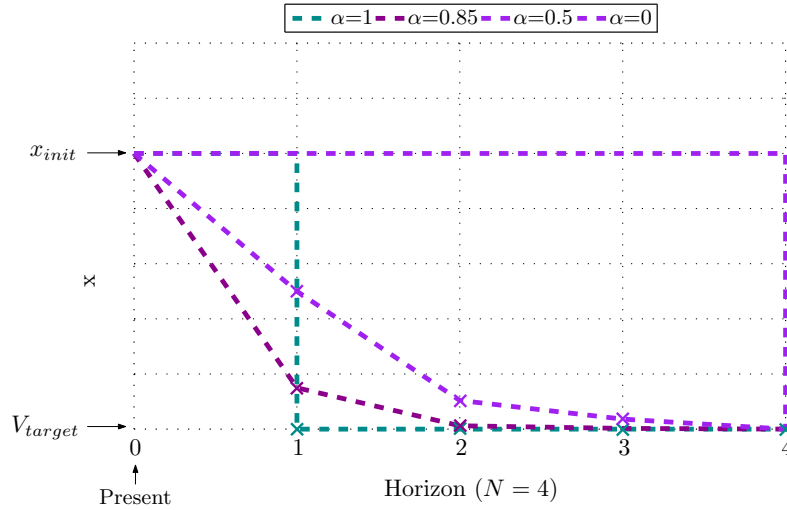


Figure V.2: Illustration of the exponential convergence for several values of α and $\beta = 0.0001$

Next, both objectives can be uncoupled by separately tuning parameters α_V and $\alpha_{\tan(\phi)}$ related to the MV voltages and the power factor $\tan_{HV \rightarrow MV}$ respectively.

V.1.2 Networks and actuators modeling

MPC relies on a model to predict and anticipate the future behavior of the output of the system ($V, P_{MV \rightarrow HV}, Q_{MV \rightarrow HV}$) with respect to the inputs (references Δu and state measurements) under a temporal horizon. Again, a classical model based on sensitivity matrices has been used herein. Sensitivity matrices are commonly used [3, 10–12]. These matrices can be easily derived from load flow calculations and from the inverse of the Jacobian matrix of the system. These matrices correspond to the partial derivative of the states (here V and $\tan_{HV \rightarrow MV}$) with respect to the inputs (Δu).

This modeling can suffer from inaccuracies. The estimates of the sensitivity matrix highly depend on the general knowledge of the network (network parameters or load models for instance). It should be reminded that these parameters are not well known in practice [3]. In order to take into account this limited available knowledge, constant sensitivity matrices can be used as a fair approximation and in this work, they were evaluated considering a constant load model [1]. Active and reactive powers consumed by the load are assumed to remain constant between two control actions, as well as the active power injections of DG while different load models were used during the simulations. This is a classical but important assumption.

In order to properly consider the actuators behavior inside the prediction horizon, one must pay attention to the different time-scales. Compared to the sampling time t_s , which is equal to one minute, the DG and CB are supposed to act instantaneously without lag. Both the communication delay t_a and computational time are also reckoned to be far smaller than t_s . In France, OLTCs act with time delay, the first one is of one minute, while the subsequent time delay is 10 s. Given the ability of MPC to deal with time delays, these lags can be easily embedded inside the prediction model.

When a voltage reference change is sent to the OLTC, the induced tap change will take place after some time $t_a + t_s$. This is further illustrated in Figure V.3. The first sub-figure shows a change of OLTC discrete reference at t_0 . The second sub-figure shows the continuous OLTC and sampled voltage response with a delay of two periods due to communication and actuation lags as explained above.

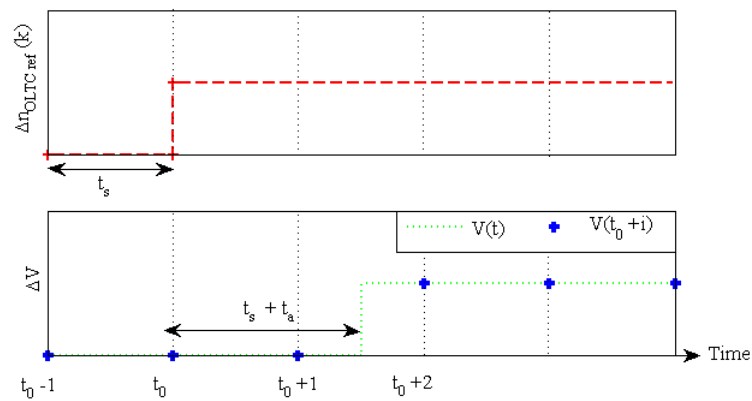


Figure V.3: Integration of the OLTC actions within the prediction horizon at $t = t_0$

The prediction equations are detailed in the following equations (V.14)-(V.16):

$$V(k+1) = V(k) + \frac{\delta V}{\delta Q_{DG\ ref}} \Delta Q_{DG\ ref}(k) + \frac{\delta V}{\delta n_{CB\ ref}} \Delta n_{CB\ ref}(k) + \frac{\delta V}{\delta n_{OLTC\ ref}} \Delta n_{OLTC\ ref}(k-1), \quad (V.14)$$

$$Q_{MV \rightarrow HV}(k+1) = Q_{MV \rightarrow HV}(k) + \frac{\delta Q_{MV \rightarrow HV}}{\delta Q_{DG\ ref}} \Delta Q_{DG\ ref}(k) + \frac{\delta Q_{MV \rightarrow HV}}{\delta n_{CB\ ref}} \Delta n_{CB\ ref}(k) + \frac{\delta Q_{MV \rightarrow HV}}{\delta n_{OLTC\ ref}} \Delta n_{OLTC\ ref}(k-1), \quad (V.15)$$

$$P_{MV \rightarrow HV}(k+1) = P_{MV \rightarrow HV}(k) + \frac{\delta P_{MV \rightarrow HV}}{\delta Q_{DG\ ref}} \Delta Q_{DG\ ref}(k) + \frac{\delta P_{MV \rightarrow HV}}{\delta n_{CB\ ref}} \Delta n_{CB\ ref}(k) + \frac{\delta P_{MV \rightarrow HV}}{\delta n_{OLTC\ ref}} \Delta n_{OLTC\ ref}(k-1). \quad (V.16)$$

No disturbances are integrated inside the prediction equation, but any predictable disturbance could be accounted for and easily added in the model. For instance, the active power injection of DGs is assumed to remain constant in the prediction horizon, but is updated at each sampling time. If an accurate prediction of the active power production of DGs was available, it can be easily integrated in the MPC framework. The sensitivity matrices have been evaluated through consecutive load flow calculation.

Besides, the active power $P_{MV \rightarrow HV}$ is assumed to be independent on the change in reference Δu_{ref} , that is to say, the dependence of active power losses in the distribution network on the control actions is negligible.

Next, the reactive power $Q_{MV \rightarrow HV}$ is supposed to be independent of $\Delta n_{OLTC\ ref}$.

V.1.3 Resolution and constraints infeasibility issues

V.1.3.a MPC typologies and resolution techniques

The MPC can be classified as linear or non linear as any optimization problem and then further divided into subclasses [13, 14]. The problem is said:

- **Linear** if the constraints are linear and the cost function linear or quadratic. More precisely, the problem is:
 - **LP** (Linear Programming) if there are only continuous valued inputs;
 - **MILP** (Mixed Integer Linear Programming), if there are both continuous and quantized valued inputs, that is to say inputs that belong to a finite set of integer values;
- **Non linear**, if the constraints are non linear. Then the problem can be classified as:
 - **NLP** (Non Linear Programming), if there are only continuous valued inputs;

- **MINLP** (Mixed Integer Non Linear Programming) if there are both continuous and quantized valued inputs.

Few methods in literature are dealing with the design of hybrid continuous discrete methods. Such a design is not trivial and can raise complexity and numerical issues [8, 9].

Then, the problem can be also further divided in convex or non-convex optimization. If constraints and state-space solution are both convex, the problem is convex. If the problem is non-convex the optimality is not always guaranteed, but the convergence towards a heuristic solution can be ensured.

There are several methods to handle the resolution of a quantized nonlinear MPC [15, 16]:

- Use a continuous optimization and an a posteriori quantization of input, such as a projection method;
- Formulate an outer approximation:
 - MIP / LP relaxation;
 - NLP relaxation (generally based on branch and bound methods)
- Design specific methods: a mid-processing method is proposed in [15] for instance, that directly integrates the quantization aspects within the optimization routine. First a continuous NLP is solved, then the output are rounded to the nearest integer values. The sequence of integer values is concatenated with the past values (on a specified horizon) and filtered to avoid an oscillating behavior. Then, after the filtering, the sequence is again quantized.

The use of a continuous optimization with an a posteriori quantization can lead to undesirable oscillations (and thus a massive usage of the quantized actuators), and the optimality cannot be guaranteed. On the other hand, outer approximation based method are generally difficult to design, time-consuming and the solvers are generally not free for use.

The optimization problem considered herein consists of a quantized non linear MPC and can be classified as a MINLP. Indeed, there are two types of inputs: continuous valued inputs (reactive power of DGs) and quantized valued inputs (CBs and tap position of the OLTC). Next, the problem is non linear due to the inner-control of the OLTC (that embeds time-delay and a dead-band).

V.1.3.b Handling the discrete nature of CB and OLTC

In order to handle the discrete nature of some actuators (namely the OLTC and CB), a multi-step resolution can be figured out:

- 1.** Resolution of a continuous problem, i.e. assuming that every variable is continuous;
- 2.** Determination of the discrete possible positions of OLTC and CB depending on the continuous solution found in **1.**
- 3.** Successive tests of the every possible combination of discrete positions that are introduced as hard constraints in the problem;

4. Selection of the cheapest solution that respects every aforementioned constraints.

The main concern of this method, lies in the potential computational burden. Specifically, in the case of a multi-step optimization, the number of possible combinations of discrete variables to be tested can be quite high, in particular if the optimal switching time of the discrete variables should be determined.

Since the switching statuses of CBs should not be triggered too often (for maintenance and durability purposes), it is possible to limit the switching by adding a constraints. For instance it is possible to specify that only one switching at the first step of the prediction horizon can be requested. Then, the classical method introduced earlier can be used.

Regarding the OLTC tap change, Section V.2 is dedicated to the investigation on how to properly integrate the OLTC nonlinearities within the MPC approach and whether it is relevant to use a continuous approximation that was used at first in our work. This is a widespread assumption in predictive VVC strategy [1–4].

V.1.3.c A hierarchical relaxation of constraints

It may happen that the problem is not feasible if the objectives are too strict or if the system has experienced a severe perturbation. However the controller should still be able to bring the system as close as possible to a situation respecting every aforementioned constraints.

The MPC controller can cope with infeasibility issues through a relaxation of the constraints using slack variables $\varepsilon(k)$ [3, 4]:

$$x_{min}(k) + \varepsilon_{min}(k) \leq x(k) \leq x_{max}(k) + \varepsilon_{max}(k) \quad (\text{V.17})$$

x can correspond to the voltage V or the $\tan_{HV \rightarrow MV}$. In order to avoid the competition between the double objectives of the control and between these and the relaxation of the constraints, a hierarchical structure has also been defined. If the general problem is not feasible:

- 1.** First a relaxation of the exponential convergence of the tangent is considered (constraint (V.8)_{1 ≤ k ≤ N-1}, with $1 \leq k \leq N - 1$), Then if the problem is still not feasible the following constraints can be relaxed one after the other:
- 2.** Relaxation of constraints at the end of the prediction horizon on tangent (constraint (V.8)_N with $k = N$);
- 3.** Relaxation of exponential convergence on voltages ((constraint (V.7)_{1 ≤ k ≤ N-1}, with $1 \leq k \leq N - 1$));
- 4.** Relaxation of terminal constraints at the end of the prediction horizon on voltages (constraints (constraint (V.7)_N with $k = N$);).

Table V.1: Cost function associated to the relaxed optimization problem

Problem	Cost function	Relaxed constraints
0.	$J_0 = \sum_{k=1}^N [\Delta u(k) R_{\Delta u} \Delta u(k)^T] + u(N) R_u u^T(N)$	None
1.	$J_1 = J_0 + \sum_{k=1}^{N-1} [\varepsilon_{tan}(k) S \varepsilon_{tan}(k)^T]$	(V.8) $_{1 \leq k \leq N-1}$
2.	$J_2 = J_1 + \varepsilon_{tan}(N) 2S \varepsilon_{tan}^T(N)$	(V.8) $_{1 \leq k \leq N}$
3.	$J_3 = J_2 + \sum_{k=1}^{N-1} [\varepsilon_V(k) S \varepsilon_V(k)^T]$	(V.4) $_{1 \leq k \leq N}$, (V.7) $_{1 \leq k \leq N-1}$
4.	$J_4 = J_3 + \varepsilon_V(N) 2S \varepsilon_V^T(N)$	(V.8) $_{1 \leq k \leq N}$, (V.7) $_{1 \leq k \leq N}$

The use of slack variables $\varepsilon(k) = [\varepsilon_V, \varepsilon_{tan}](k)$ is heavily penalized through a quadratic penalty on the objective function with the cost matrix S as detailed in Table V.1. The elements of this cost matrix should be indeed set far higher than the coefficients of the cost $R_{\Delta u}$ which represents actuators change costs. Note that the slack variables $\varepsilon(N)$ on terminal constraints are assumed to be twice costlier than those inside the prediction horizon.

Indeed, correction of the MV voltages has been considered as the primary goal of the control, while others are secondary objectives and considered only if this primary goal is reached. Since every objective constraint has been relaxed at this end of the proposed relaxation scheme, theoretically, there are no case of infeasibility.

V.1.4 MPC tuning

In the sequel, an horizon of $N = 5$ was selected, and the controller is acting every minute $t_s = 60$ s. Also, the controller is able to anticipate the behavior of the system on a 5 minute period. Regarding the costs of function (V.2), all coefficients of the matrix $R_{\Delta u}$ are identical since every variables are normalized, while the coefficients of S regarding the relaxation of constraints are 100 time higher. Then, only the coefficients related to the reactive power of DGs of matrix R_u are non-zero and equal to the corresponding coefficients of $R_{\Delta u}$. It is recalled that these costs are configurable and can evolve within the prediction horizon.

Regarding the exponential convergence, the parameter β has been set to have $f(1) = \alpha$ and $f(N) = 1.10^{-4}$ (accuracy on the constraints to be respected at N) – f defined in equation (V.13).

For the convergence speed $\alpha_V = 0.75$ and $\alpha_t = 0.5$ have been chosen. That choice implies that the constraints on voltage inside the horizon are tighter than the constraint on HV/MV reactive power exchange.

V.2 Embedding the OLTC nonlinearities into the predictive VVC

The MPC control presented herein computes the optimal control effort Δu to minimize the objective function (V.2) and subject to the following constraints (V.7)-(V.8). Among others, the resolution yields the optimal tap change $\Delta n_{OLTCref}$. However the OLTC is controlled through the voltage reference in its existing inner control (introduced in Subsubsection I.2.1.a). As explained in the introduction, the idea is to embed the traditional OLTC inner control inside a MPC approach to avoid frequent tap changes and ensure a faster response in case of perturbations or failure of the centralized control. To do so, a two-step approach has been designed:

- Step 1: Calculation of optimal tap changes $\Delta n_{OLTCref}$ in the MPC problem. The existence of the time-delay is handled by the proposed MPC approach.
- Step 2: Generation of the voltage reference of the OLTC to induce the optimal tap changes. At this second stage, the existence of the OLTC dead-band has to be accounted for.

In the following, the irrelevance of using a continuous tap change instead of a discrete tap change is shown through simulations. This approximation leads to a model mismatch and the controller can be, under specific conditions, unable to maintain the voltage within the specified range.

V.2.1 OLTC voltage reference generation from optimal tap changes

The problem consists in choosing a suitable voltage reference $V_{OLTCref}(k)$ which will generate the correct tap changes $\Delta n_{OLTCref}$ computed by the MPC controller. Due to the existence of the dead-band no explicit inversion model can be found. Also, there exist a infinite number of strategies, and the concern is to find a suitable method. Considering the following voltage reference:

$$V_{OLTCref}(k) = \widehat{V}_{MV}(k+1) + \Delta n_{OLTCref}(k)V_{tap}, \quad (V.18)$$

this reference ensures that, the prediction of voltage $\widehat{V}_{MV}(k+1)$ remains in the range:

$$[V_{OLTCref}(k) - d, V_{OLTCref}(k) + d].$$

The prediction $\widehat{V}_{MV}(k+1)$ is the voltage at the secondary side of the OLTC if all control actions but the change $\Delta n_{OLTCref}$ are achieved.

For instance, if $\Delta n_{OLTCref} = 0$, following equation (V.18), one can check that

$$V_{OLTCref}(k) = \widehat{V}_{MV}(k+1),$$

also no tap change is triggered. However, if $\Delta n_{OLTCref} = 1$, then

$$V_{OLTCref}(k) = \widehat{V}_{MV}(k+1) - V_{tap}.$$

According to the OLTC inner logic, a tap change will be generated.

Since the prediction is never truly realized due to external disturbances and inaccuracies in the model, this choice allows to avoid unwanted tap changes while the errors in the prediction are smaller than the half dead-band d . This will be further illustrated in V.2.2.

This equation is used by the "OLTC reference generators" shown in Figure V.1; first, the MPC resolution gives the optimal $\Delta n_{OLTCref}$ while the OLTC reference generator gives the voltage reference that feeds the OLTC inner control.

V.2.2 Irrelevance of the continuous OLTC approximation

At this stage, quantization issues are not addressed, even though the correct tap change reference is generated through equation (V.18). The OLTC tap change is an integer, and more specifically:

$$\Delta n_{OLTCref}(k) \in \{-1, 0, +1\}.$$

A rough approximation consists in considering the OLTC as a continuous variable:

$$-1 \leq \Delta n_{OLTCref}(k) \leq 1.$$

The MPC controller is then more tractable since only continuous variables will be considered, and the use of LP solvers is possible.

For example, such a MPC controller can generate $\Delta n_{OLTCref} = 0.25$. In this case, the true value will be $\Delta n_{OLTC} = 0$. A tap change will be triggered only if:

$$|\Delta n_{OLTCref}| \geq 0.5.$$

The next subsection shows that the controlled system is not robust with respect to tap change rounding.

V.2.2.a Simplified network for illustrative purposes

For concision and intelligibility purposes, the first simulations presented herein have been conducted on a quite simplified network. The three-bus system of Figure V.4 has one infinite bus (HV network), a HV/MV transformer with an OLTC, two lines of 5 km, a load and a DG. The load embodies a feeder for which the load is higher than the production; the voltage at this node can be interpreted as the minimal MV voltage. On the contrary, the second feeder is a DG, and this node is prone to over-voltage.

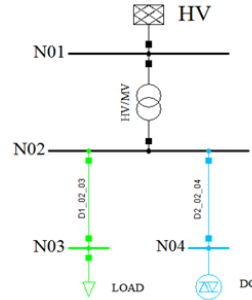


Figure V.4: Three-bus simplified network

The DG is assumed to be able to produce/consume reactive power in a restrained range of values $[-0.7; +0.7]$ *MVAR*. Transformer parameters correspond to the HV/MV transformer of the network presented hereafter. The load is consuming 17 MW with a 0.93 power factor, and the DG produces 14.5 MW with a zero power factor.

In this case, the objective of the controller is to maintain the voltage inside the range:

$$[V_{min}, V_{max}] = [0.95; 1.05] pu$$

by adjusting the reactive injection of the DG and the OLTC voltage reference. At the initial state, the voltage $V_{N04} = 1.0566 pu$ is outside the targeted range.

The controller is activated at $t = 120 s$ and is called every minute $t_s = 60 s$.

V.2.2.b Control failures due to model mismatch

Figure V.5 gives the simulation results, measurements are updated every 10 s. The first graph (a.) gives the voltage at typical nodes of the network, graph (b.) shows the tangent at the primary side of the transformer, the third (c.) gives the reactive power output of DG and the fourth graph (d.) shows the voltage reference of the OLTC in green and the measured voltage at the secondary side V_{MV} in blue. The dead-band is represented by the dark dotted lines. The last graph (e.) gives the tap position of the OLTC.

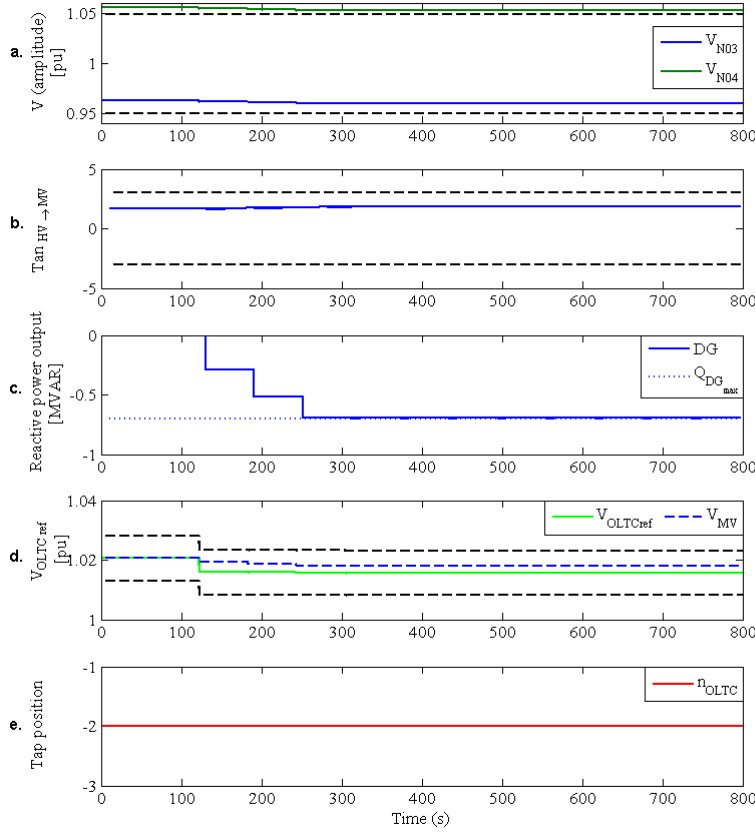


Figure V.5: Results and control, continuous approximation

From this figure, several conclusions can be stated. First, using the continuous model leads to a failure of the controller. It is not able to bring the system in a satisfactory situation where $V \in [V_{min}, V_{max}]$. Indeed the controller is not able to accurately anticipate the behavior of the OLTC.

Thus, the final solution corresponds to a situation where lowering the voltage by:

$$\Delta V(k) = V_{OLTC\ ref}(k) - V_{MV}(k)$$

would solve the constraints. However, this voltage change is too low (compared to the dead-band) to trigger a tap change, and the controller is not able to modify the voltage reference sent to the OLTC. In the considered situation, the only possible way to correct the voltages is: 1/ to decrease the voltage with a tap change, and 2/ to adjust the voltage with a positive reactive power injection.

V.2.3 Correct tap change mechanism using a discrete resolution

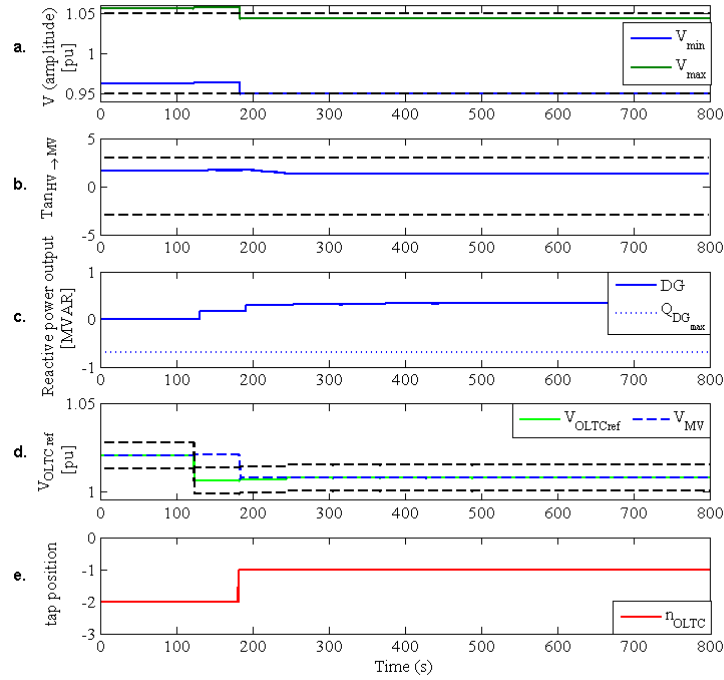


Figure V.6: Results and control, discrete model

In order to avoid such issues, the discrete nature of tap needs to be accounted for. In the MPC problem, a new constraint has been added: the change of tap $\Delta n_{OLTCref}$ is enforced to take a set of integer values:

$$\Delta n_{OLTCref} \in \{-1, 0, 1\}.$$

$V_{OLTCref}(k)$ is generated subsequently according to (V.18). Thus, three features of the OLTC are taken into account: the existence of time delay and dead-band as well as its discrete nature inside the MPC problem.

The resolution of the MPC turns into a problem with both integer and real values which calls for the use of a MINLP solver. There exist several solvers able to handle quantized MINLP MPC [16]. Most of them are commercial softwares (CPLEX, Gurobi, and Mosek...). A free and widespread software embedded in YALMIP [17] and Matlab (without requiring the global optimization toolbox) is "bnb". Also, this solver that is based on an implementation of a standard branch and bound algorithm for mixed integer programming, has been chosen.

Note that without the proposed two-step approach, embedding all of the OLTC nonlinearities directly inside the MPC formulation would have led to a highly nonlinear problem not easily solvable; the proposed mixed approach relaxes the computational burden.

Results are given in Figure V.6. To conclude, with the proposed procedure, the predictive controller succeeds to find an appropriate set of references to correct the MV voltages and maintain the $\tan_{HV \rightarrow MV}$ within the specified range of values.

V.2.4 Conclusion

It was shown through simulations on a simplified network that using a continuous approximation for the OLTC can lead to inappropriate references and thus to constraints violations. Simulations on a more complex network were also carried out (See [18]). A two-step process was proposed in this work to embed the OLTC nonlinearities in predictive real-time VVC controller. The effectiveness and relevance of such a procedure is further assessed in Section V.3.

The major advantages of the proposed methods are:

- A true coordination of many actuators for both voltage regulation and reactive power exchange limitation at TSO-DSO interface;
- To guarantee the minimization of tap changes during all the life of the OLTC since the criterion is explicitly considered in the cost function;
- Keeping and considering the classical OLTC inner control to avoid fundamental modifications of the existing control devices.

V.3 Simulation results on the three-feeder 20 kV network under external and parametric uncertainties

In Chapter IV, it was claimed that the MPC method was naturally robust due to its closed-loop nature and exhibits good performances in comparison with other methods. This section aims to assess the relevance of the proposed predictive VVC controller under uncertainties and disturbances, that corresponds somehow to a study on the robustness of the method. Indeed, the robustness can be defined by the capability of a control system to maintain some prescribed properties such as stability and performances even in the presence of disturbances [14].

It is difficult to explicitly demonstrate the robustness of the proposed method since the system embeds highly nonlinear actuators (such as the inner control of the OLTC) and quantized valued control input.

Also, an illustration of the performances has been realized in worst-case conditions, under external disturbances and with a realistic level of parametric uncertainties.

The simulations show the paramount importance of having an accurate modeling of the actuators behavior to ensure the constraints are enforced even in extreme conditions. Note that this result has been already illustrated in Section V.2 for the OLTC modeling within the predictive controller.

V.3.1 Method to assess the performance of the MPC-VVC: robustness studies

V.3.1.a Different type of uncertainties and disturbances

The system, that is the MPC-VVC associated to a specific distribution grid can be affected by various disturbances and uncertainties. The robustness of the method, i.e. the ability of the method to reach a suitable situation should be ensured. More specifically, the robustness can be divided in two main categories:

- **Parametric uncertainties** that corresponds to the model inaccuracies:
 - Inaccuracies in the sensitivity matrices;
 - Inaccuracies in the actuators models (continuous/discrete tap change, availability of a given lever...);
- **External disturbances:**
 - Measurement noise;
 - Consumption and production patterns;
 - More generally any disturbance that can affect the distribution grid (disturbance on HV grids, outage of a line...).

Figure V.7 illustrates how these factors can affect the VVC controller. Regarding the robustness to external disturbances, one of the objective of the real-time methods is to be able to adapt and evolve in real-time with the prevailing conditions of the MV grids to enforce a suitable MV voltage profile. Next, it is barely conceivable nowadays to have very accurate production and consumption forecast to be integrated within the MPC VVC as known disturbances. The only point that can be enhanced regards the noise on real-time measurement.

Regarding the robustness to parametric uncertainties, it is difficult to obtain a good accuracy of the sensitivity matrices due to the lack of reliable information and difficulty to obtain an accurate model for the load for instance. Next these models may not be constant in time. However, it is possible to obtain a more accurate representation of the actuators.

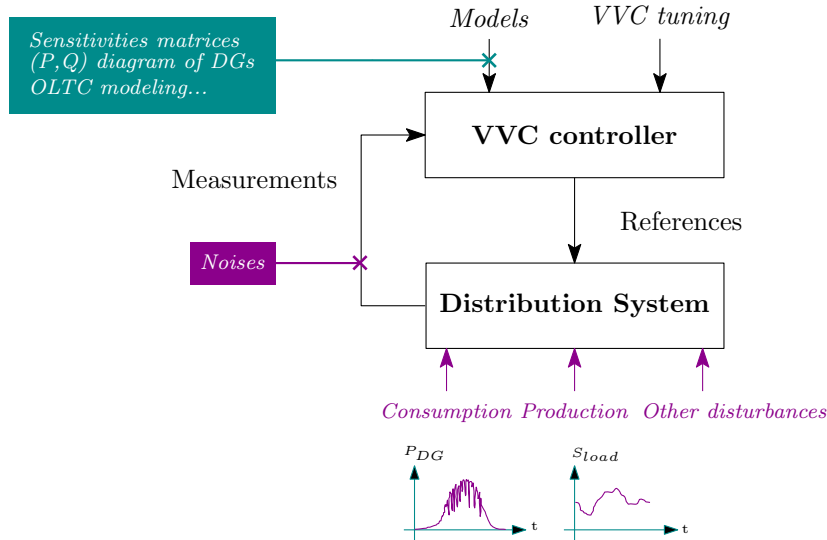


Figure V.7: Parametric uncertainties (blue) and external disturbances (magenta) that can affect the VVC controller

V.3.1.b Robustness studies through simulations

In our case; a formal demonstration of the robustness is barely possible, because of the high dimension and complexity of the problem. A number of experiments should be performed to ensure a high reliability of results. As such, a design of experiments can be useful. Indeed, the robustness properties of a MPC method can be demonstrated for continuous nonlinear MPC based on Lyapunov method [14, 19, 20]. There exist also some techniques to improve the robustness. For instance, the prediction horizon can be set longer as the control horizon or simply by properly adding terminal constraints [21].

The problem considered herein is a quantized MINLP problem. Some works based on an explicit MPC have been conducted to ensure the convergence of the system. These methods are based on an number of off-line evaluations to have a high range estimates of errors [22]. Such a method implies a number of off-line evaluation, that is not well-suited for distribution networks that can exhibit various and evolving topology, conditions... Besides, the method was tested for a system that embeds two valves with a finite number of positions to be considered.

The robustness of the MPC method was already partially appraised in the literature through simulations. Indeed, to assess the performance of the predictive controller, in [1–4, 23], the distribution system is subjected to various and evolving disturbances such as a change in consumption and/or production profiles, a severe perturbation on the HV voltages... Moreover, in [1–3], there are Gaussian white noises superimposed to the measurements, and the robustness

to the sensitivity matrices is more particularly investigated in [2]. This article concludes that the MPC approach is naturally robust to the inaccuracies in the sensitivity matrices, and an error on these matrices will lead either to a speeding up or slowing down of the convergence.

Moreover, it should be borne in mind that some inaccuracies and errors are unavoidable. For instance, there are inevitably noises and errors in the real-time measurements. And, due to the lack of accurate information on lines and loads, there will be inaccuracies in the sensitivity matrices, and it barely possible to update them at each control step for computational time purposes.

As a result, in this work, the robustness to errors in the actuators modeling has been more particularly investigated while realistic assumptions have been made. For instance to account for the present level of knowledge and accuracy, a Gaussian white noise has been superimposed on measurements, and the distribution system has been subjected to various disturbances. Next, the sensitivity matrices were derived once and for all, assuming a constant load model while in the simulation dynamic load models has been used.

It can be noticed that the use of a continuous approximation for the OLTC is somehow an error on actuator modeling. The studies conducted in Section V.2 has concluded to the relevance of using an accurate OLTC model in the control to avoid failures and constraints violation. Herein, the consequences of an error on the real-time DG reactive power will be more specifically studied.

V.3.1.c Robustness of the MPC-VVC to errors on sensitivity matrices

A first prospective study has been conducted on a simplified network to assess the sensitivity of the method to errors on sensitivity matrices. The reactive power flowing through the HV/MV substation was unbounded (the only objective was to maintain the MV voltages within a specified range of values), and the system was affected by several disturbances (disconnection of the dedicated DG, and severe perturbation on the HV part of the grid as described hereafter). Noises were also superimposed on measurements.

To this end, a number of simulations have been performed:

- 100 simulations with a random Gaussian white noise of 5% superimposed on sensitivity matrices;
- 100 simulations with a random Gaussian white noise of 10% superimposed on sensitivity matrices;
- 100 simulations with a random Gaussian white noise of 20% superimposed on sensitivity matrices;

Then the results has been compared with a simulation with more accurate sensitivity matrices that were evaluated at the initial condition of the network. In any case, the VVC controller succeeded to enforce the constraints on MV voltages at the end of the simulation. However, the main difference regards the speed of convergence, that was either speeded up or slowed down due to use of inaccurate sensitivity matrices.

To illustrate such a result, the values of the maximal constraint violation was integrated during all of the simulation time, the results are given in Table V.2. From this table, the mean value of the constraint violations is similar regardless the level of noise superimposed to the sensitivity matrices: the system is quite robust. However, the standard deviation increases with the noise

as it was expected. This result indicates that the speed of convergence is affected by errors in sensitivity matrices and corroborates the conclusion found in [2].

Table V.2: Comparison of the maximal constraints violation on MV voltages depending on the level of Gaussian white noise superimposed to sensitivity matrices

Constraints violation [pu.s]	No noise	5% noise	10% noise	20% noise
Mean	5.9914	5.9802	5.9790	5.9788
Standard deviation	-	0.01642	0.0171613	0.029058

V.3.2 Simulation overview to illustrate the performance of the predictive VVC strategy

Since the main objectives of the control is to enforce constraints on MV voltages and HV/MV reactive power exchanges (constraints (V.3) and (V.4)), the method is to be said robust if at the end of the corrective process, these constraints are really achieved. Then, a comparison regarding the costs of the corrective process can also be made.

As stated before, there are disturbances that cannot be anticipated by the VVC and there are also errors that are unavoidable. Table V.3 summarizes the realistic assumptions that have been considered in this work. More specifically the level of accuracy on the measurements or calculation method of the sensitivity matrices is given.

The simulations have been carried out on the simplified network introduced in Chapter I, Section III.1.

Table V.3: Errors and inaccuracies to account for present limitations

External disturbances	Measurements noises	$\pm 1\%$ on voltages
		$\pm 0,5\%$ on power
	Load profile	Yes
	Consumption profile	Yes
	Severe disturbance	on HV network
Parametric uncertainties	Sensitivity matrices	(P,Q) constant for load model
		Never updated
		Evaluated at full load and production

V.3.2.a Simulation objectives

The objectives of the MCP controller are :

- Maintain the MV voltages within $[0.95, 1.05]$ pu;
- Maintain the $\tan_{HV \rightarrow MW}$ within $[-0.2, +0.2]$.

V.3.2.b Modeling the reactive power reserve of DGs

In many articles, the reactive power of DGs is assumed to be available without consideration for their active power injection. However, the amount of reactive power that can be required according to the contractual requirements depends on the DG active power output.

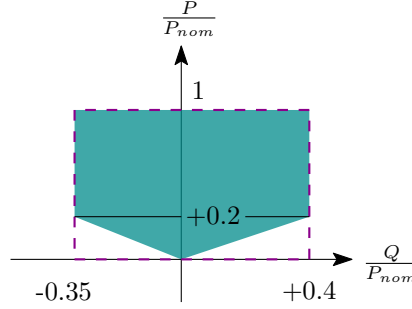


Figure V.8: Assumptions regarding the (P,Q) diagram of DGs

In Figure V.8, an ideal (P,Q) diagram of a DG is illustrated and can be compared with the (P,Q) diagram in the French DSO requirements.

In order to assess the consequences of a bad estimate of the reactive power availability, the reactive power of DGs in the network systems has been limited to the French DSO requirement diagram. Then, inside the MPC control, this (P,Q) diagram has been (i.e. reactive power availability) assumed to be:

- **MPC 1:** Ideal (P,Q) diagram (the constraints (V.5) on the reactive power are hence linear);
- **MPC 2:** True (P,Q) diagram, with a lack of reactive power availability at low active power injection (and thus the constraints (V.5) are nonlinear).

V.3.2.c Case studies: high and low loading conditions

Two specific cases have been considered: at high and low loading conditions to assess the performances in various operating conditions as summarized in Table V.4 that gives the simulation overview. These cases consist of limiting conditions (and expected worst-case) for the network that are generally used in network planning studies.

Table V.4: Simulation overview

Case	Initial loading conditions	Disturbances
Case A	Low loading conditions	· Load profile (20 % to 50%)
		· Production profile
		· $V_{HV} = +0.08$ pu at $t = 1600$ s
Case B	High loading conditions	· Load profile (100 % to 40%)
		· Production profile
		· $V_{HV} = +0.08$ pu at $t = 1600$

A production profile was created for each of the 6 DGs based on a Gaussian distribution as illustrated in Figure V.9 with Gaussian white noise to account for the stochastic behavior of the DG production. In this production profile, there are also two sudden variations of the active power injection of DG2 and DG3. A loading profile was also created for Case A and Case B and can be observed in Figure V.10.

As aforementioned, a Gaussian white noise has been superimposed on the 10 s measurements (1 % on voltage and 0.5 % on power) as illustrated in Figure V.11. Note that these measurements are averaged on a period of 1 minute (6 measurements) before being retrieved to the DNCC and used by the MPC controller.

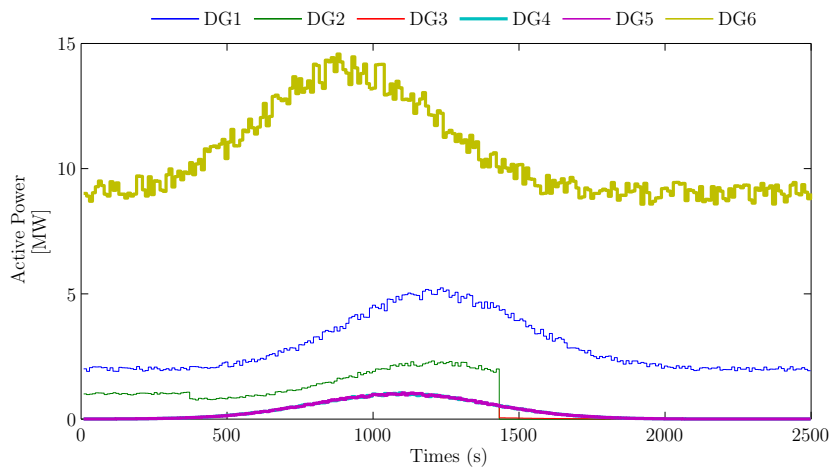


Figure V.9: Production profile for robustness assessment

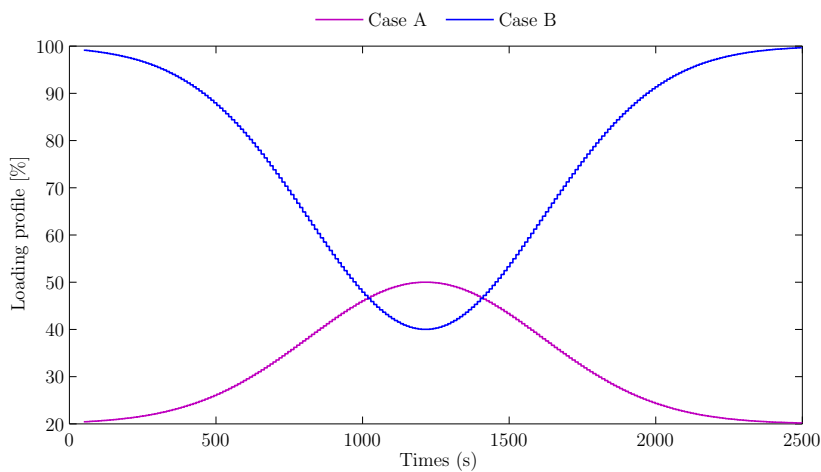


Figure V.10: Loading profile for robustness assessment

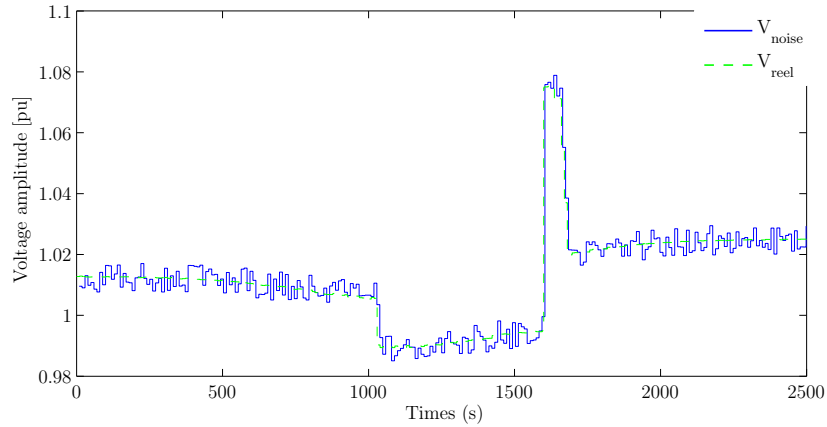


Figure V.11: Visualization of a noisy voltage measurement

V.3.3 Application of the proposed robustness study method to the three-feeders 20kV grid

V.3.3.a Case A

The results of the first simulation, case A, are given in Figure V.12 for the MPC1 and Figure V.13 for the MPC2. In these figures, the first graph a. illustrates the evolution of the minimum ($\min(V)$) and maximum ($\max(V)$) MV voltages, and the voltages at the HV (V_{HV}) and the MV (V_{MV}) side of the HV/MV transformer without the noise to ease the results analysis. In graph b., the evolution of the $\tan_{HV \rightarrow MV}$ can be observed. In the third graph (c.) the reactive power output of DGs is given compared to their active power injection given in graph (d.). Then, in the last graph (e.), the evolution of the tap position can be studied.

Comparing Figure V.12 and Figure V.13, the VVC controllers exhibit similar performances and succeed to meet its twofold objectives in the presence of evolving load and production, and with noisy measurements. The only difference lies in the reactive power requested from the DGs. More reactive power is absorbed in the case of MPC2: with the accurate (P,Q) diagram of DGs, the predictive controller is able to anticipate the lack of reactive power of DG2 and DG3. Also, when comparing the reactive power references sent to the DGs and the reactive power output of each DGs (illustrated in Figure V.14 for MPC1 and V.15 for MPC2), the references sent to the DG2 and DG3 are not satisfied at $t = 1600$ s in the case of the MPC1. When the reactive power reserve is accurately modeled, the differences between the references and the real reactive power output of DGs result from the various disturbances (loading and production profiles, noises...) that cannot be anticipated by the VVC controller.

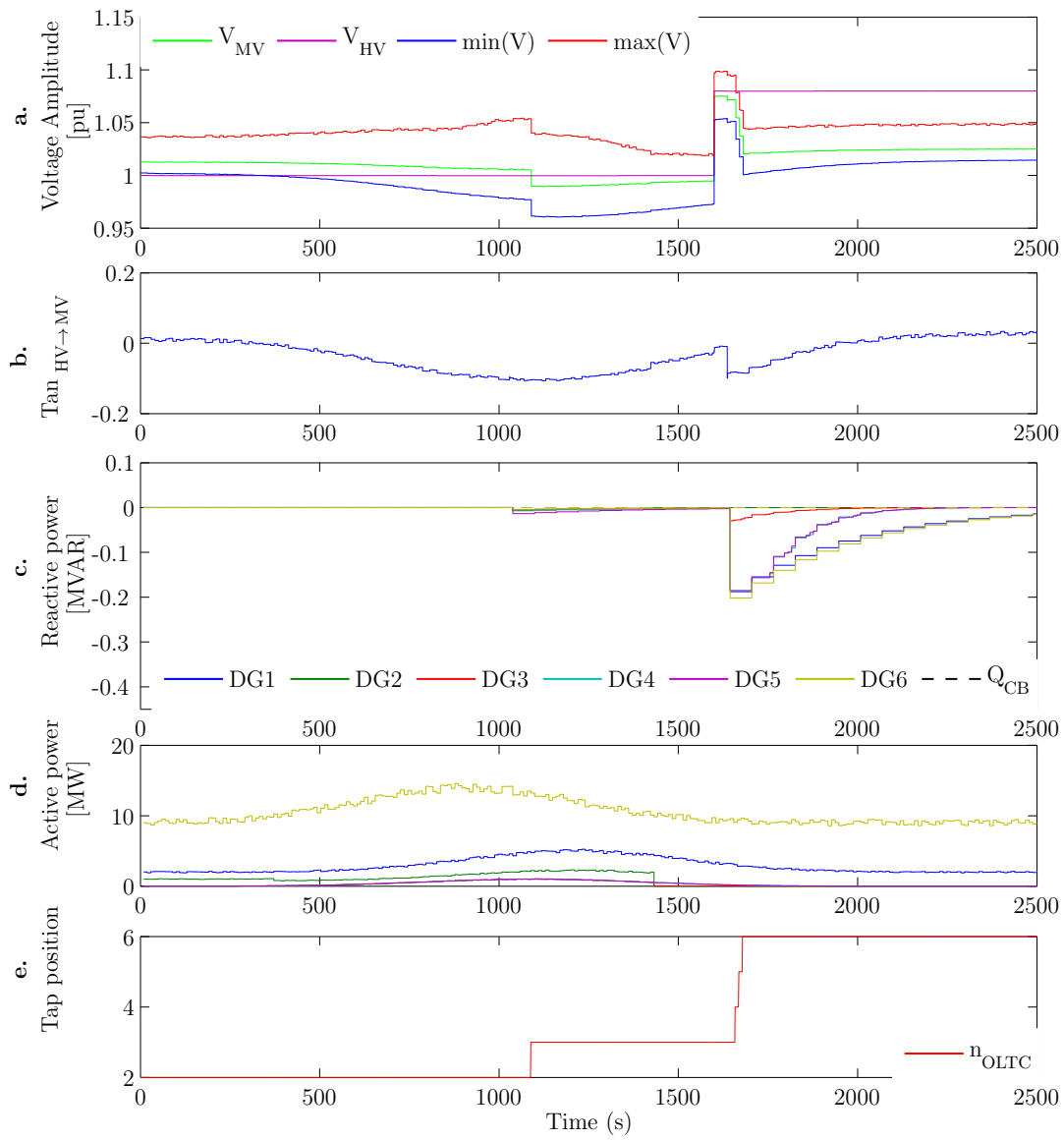


Figure V.12: Results and control action, case A, MPC1

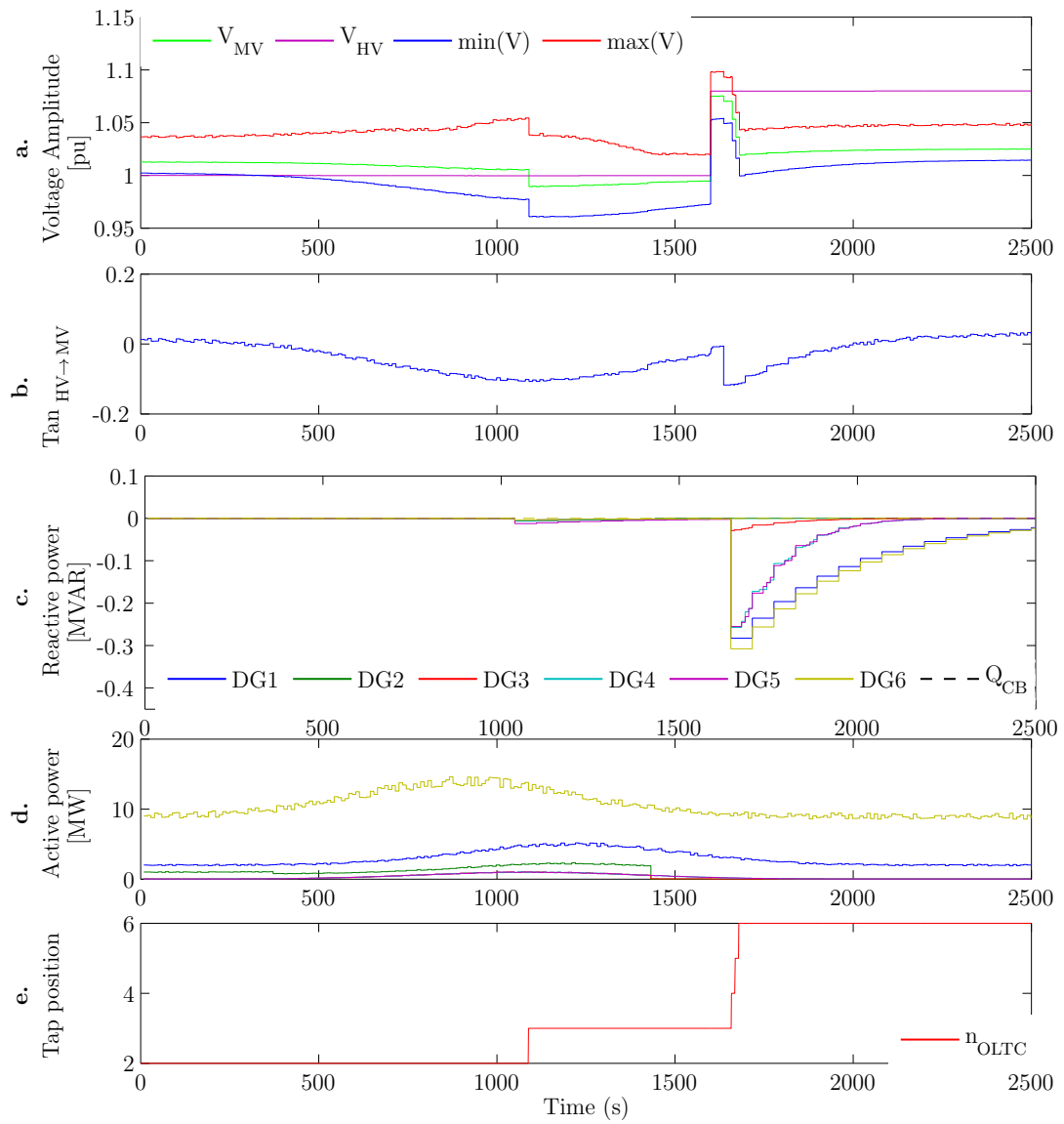


Figure V.13: Results and control action, case A, MPC2

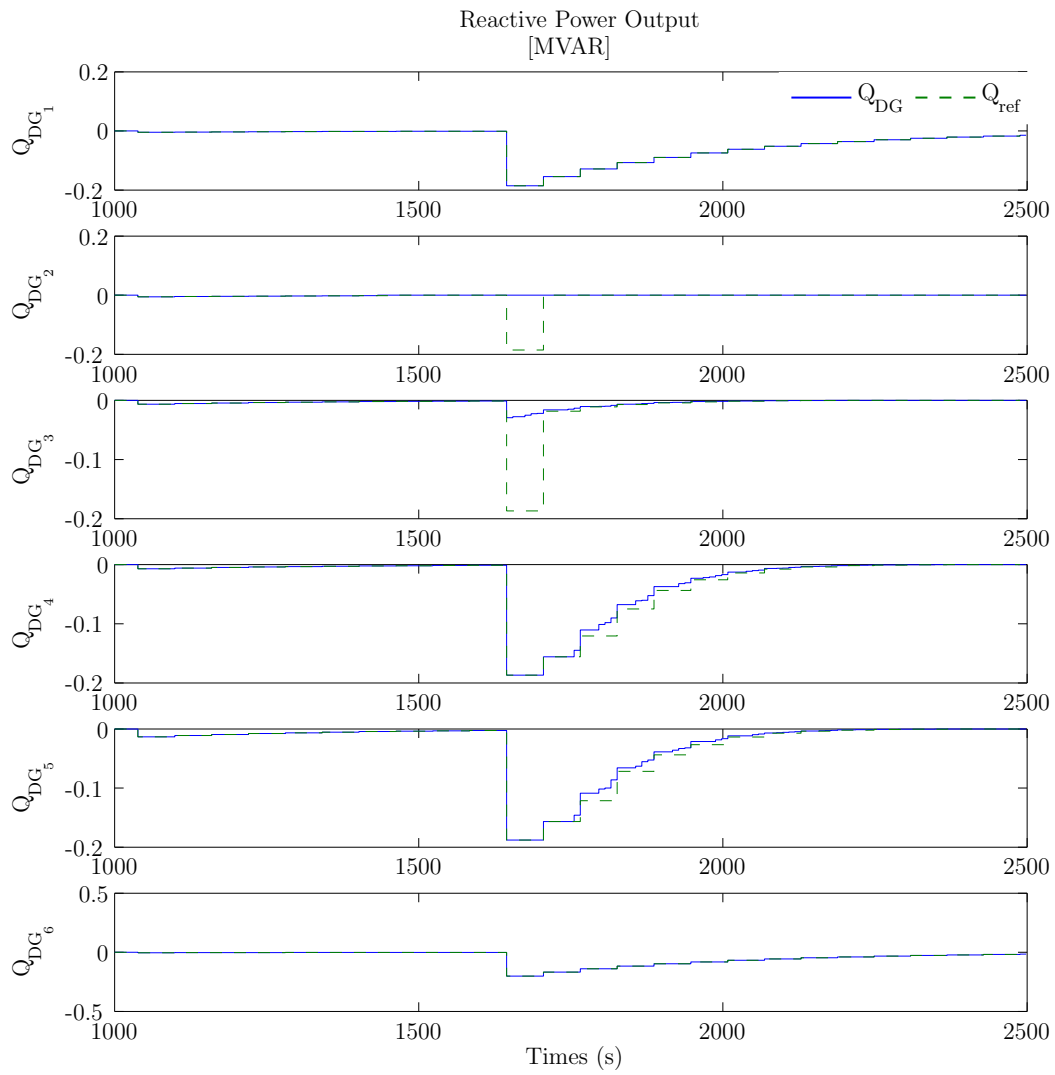


Figure V.14: Comparison of DGs reactive power output and DG reactive power reference, case A, MPC1

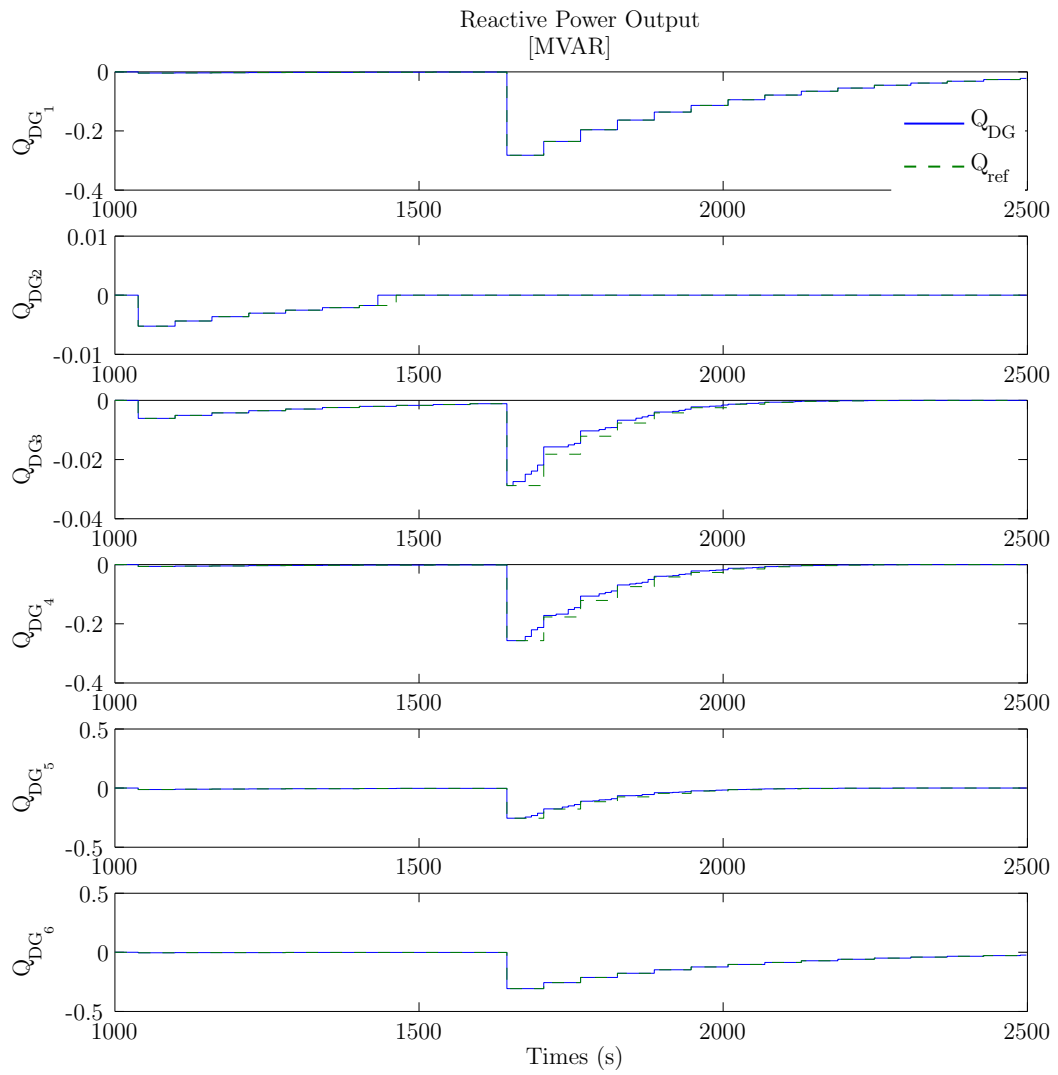


Figure V.15: Comparison of DGs reactive power output and DG reactive power reference, case A, MPC2

V.3.3.b Case B

However, in Case B, the inaccurate modeling of the reactive power capacity of DGs leads to a violation of the constraints on the $\tan_{HV \rightarrow MV}$ after the large disturbance affecting the HV side of the network. This can be observed in Figure V.16. Comparing with the results obtained with MPC2, illustrated in Figure V.17, the predictive controller is able to meet its twofold objective at the end of the simulation. The exponential convergence can be observed for the $\tan_{HV \rightarrow MV}$.

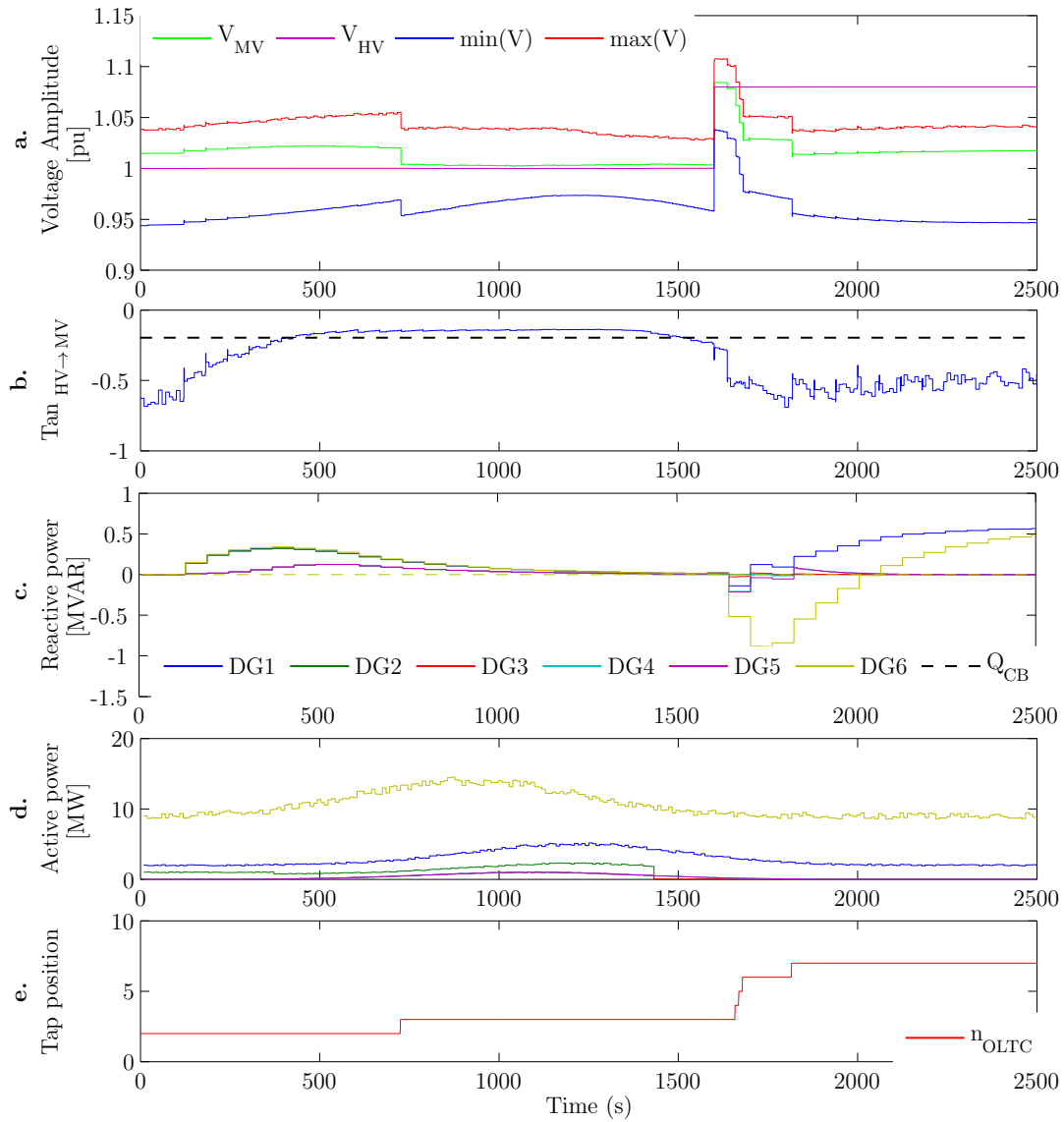


Figure V.16: Results and control action, case B, MPC1

In Figure V.18, comparing the reactive power references and the reactive power output of DGs, it can be concluded that the MPC1 controller failed to correct the $\tan_{HV \rightarrow MV}$ because it is not able to anticipate that the reactive power references would not be respected for DG2, DG3 and DG4.

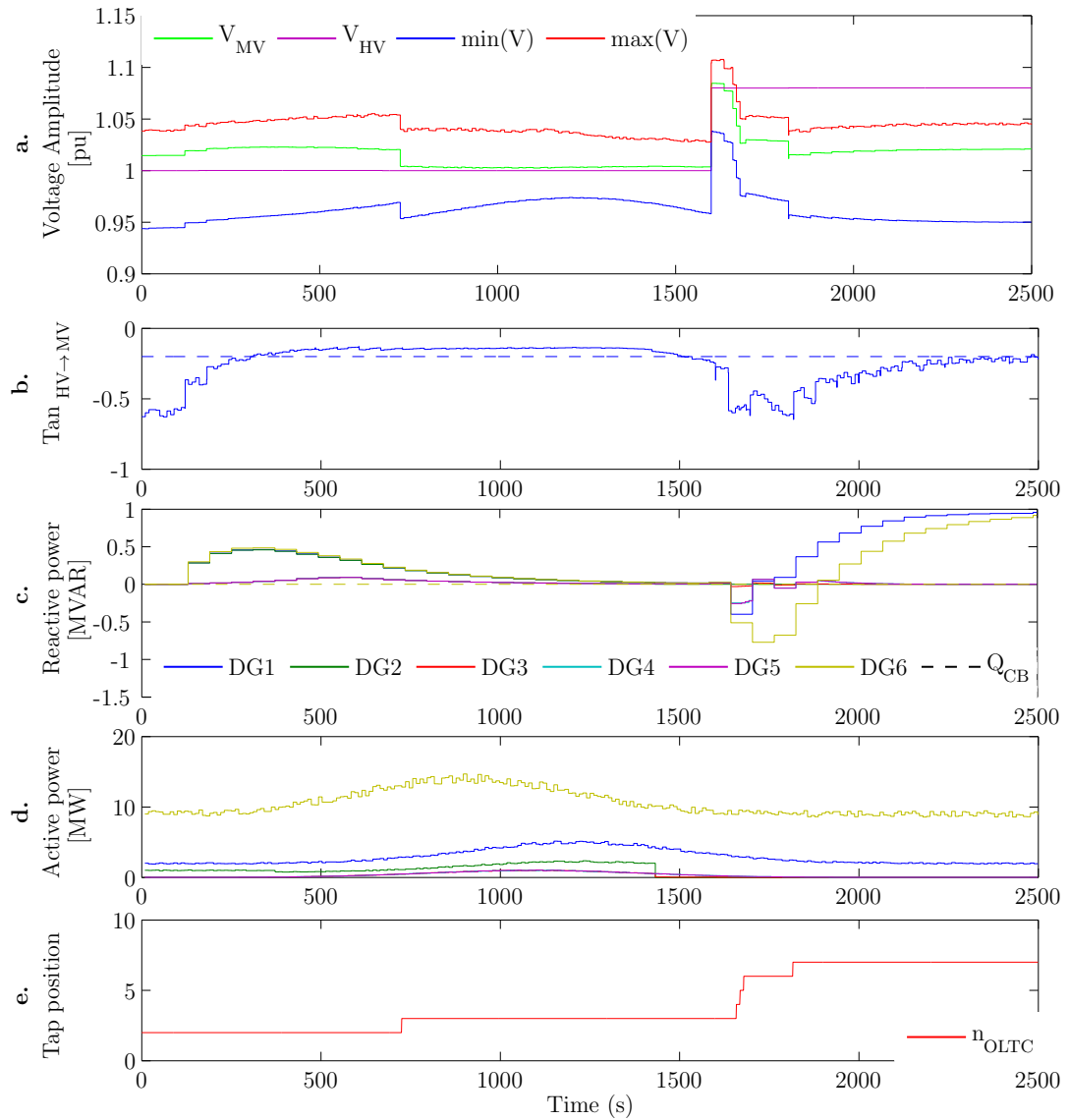


Figure V.17: Results and control action, case B, MPC2

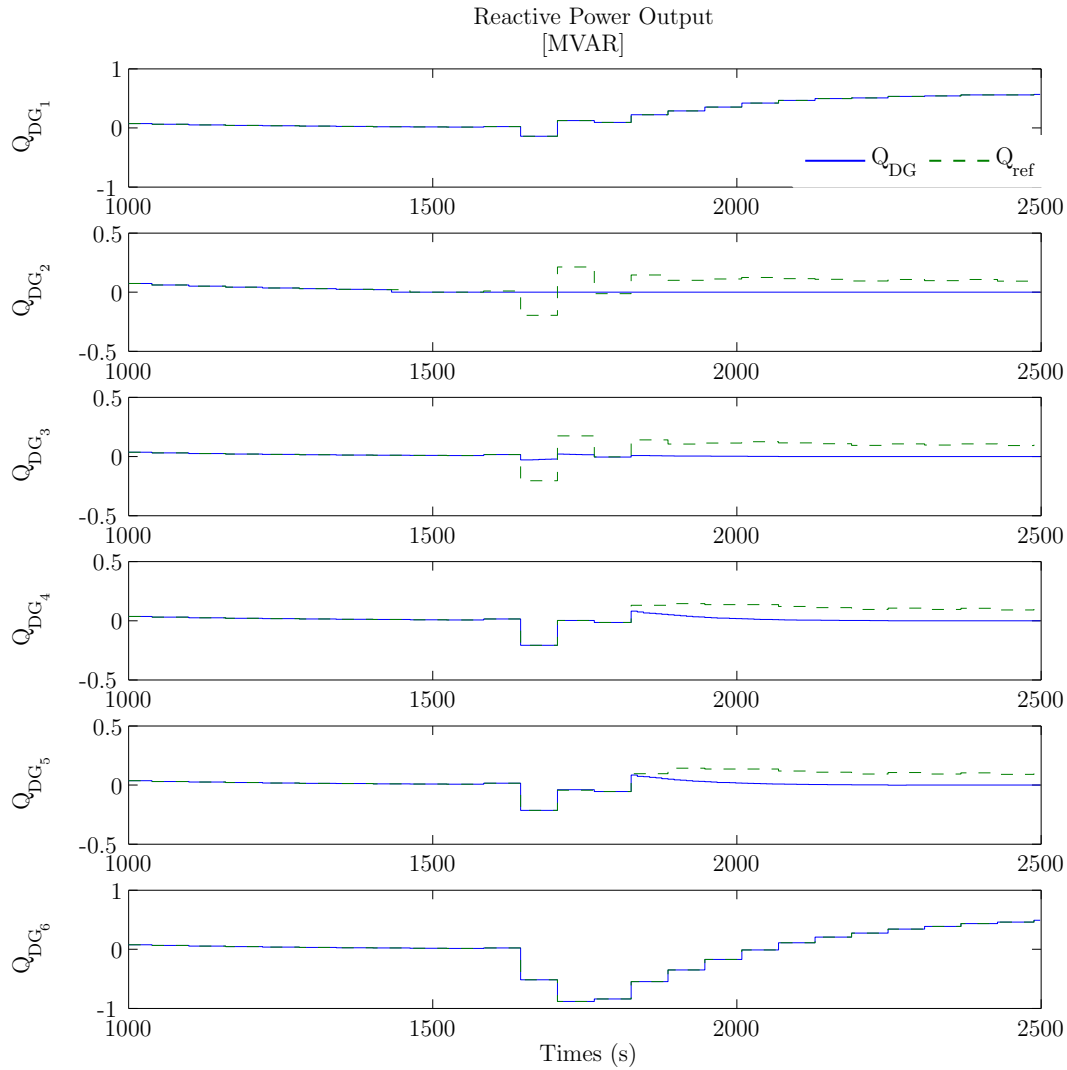


Figure V.18: Comparison of DGs reactive power output and DG reactive power reference, case B, MPC1

V.3.4 Conclusion and recommendations

To conclude, the MPC controller exhibits a high robustness to external disturbances as illustrated in the previous simulations even with noisy measurements and inaccurate sensitivity matrices. However, there are some concerns regarding the robustness to the parametric uncertainties and more specifically to the accuracy of the actuators modeling.

It has been shown that if the OLTC or the reactive power availability of DGs is not accurately modeled, the MPC controller can fail to enforce the constraints on the MV voltages or the $\tan_{HV \rightarrow MV}$. Such cases of failure more specifically occurs when the MPC controller yields an inappropriate set of references for the actuators, and when a possible alternative solution is

more expensive.

On the other hand, the inaccuracies on sensitivity matrices affect only the speed of convergence of the VVC controller.

As a consequence, when designing a predictive controller, we recommend to exercise great care over the modeling of actuators. In any case, such models are in principle more easy to obtain and well-known. Next, the ability of the MPC to deal with various type of constraints enables to consider whenever a complex model is needed.

Other robustness studies could be performed to further investigate the possible benefit to consider load and production pattern forecast within the predictive controller as well as the influence of having a non accurate forecast.

V.4 Adequacy of the predictive VVC for a real 20 kV grid

The effectiveness of the proposed predictive VVC controller has been assessed only on a simplified MV network. Also, simulations have been carried out on the real 20 kV grid (introduced in Section III.1) to illustrate the performances of the method.

V.4.1 Case study: a severe perturbation on the HV grid

Since distribution grids have been designed to face most critical situations, in order to activate the VVC controller, this grid should be affected by a large disturbance.

In this study, it is assumed that the 20 kV network is at low loading condition (20 % of the maximal loading) and at a maximal level of production. Given the level of production, the voltage reference of one of the HV/MV transformer was deliberately poorly chosen: also the voltage at DG_2 grid supply point is at 1.056 pu at the beginning of the simulation. Then, at $t = 300$ s, a severe disturbance occurs in the HV system leading to an increase up to 1,08 pu of the voltage at the HV busbar of the HV/MV substation.

The objectives of the control are :

- Maintain the MV voltages within the range:[0.95, 1.05] pu;
- Maintain the $\tan_{HV \rightarrow MV}$ within the range: [0, 0.2].

V.4.2 Conclusion: a method suitable for large scale distribution grids

The results are illustrated in Figure V.19. The figure gives the 10 s measurements. The first graph (a.) shows the evolution of the MV voltage at the MV busbar of the two HV/MV transformers (namely T_1 and T_2) and at the HV side of the substation. The maximal and minimal MV voltages are also given. The next graph (b.) illustrates the voltage at the DGs point of connection, DG_2 is connected to a dedicated feeder while DG_1 and DG_3 are in mixed feeders. Graph (c.) shows the evolution of the $\tan_{HV \rightarrow MV}$.

The two last graphs (d. and e.) give the control actions: the reactive power output of DGs and CB as well as the evolution of the tap position of the two HV/MV transformers.

From the results, the VVC controller succeeds to meet its twofold objective. During the corrective process, the constraints on the $\tan_{HV \rightarrow MV}$ are temporarily overshoot to speed up the convergence of the MV voltages. Then, the $\tan_{HV \rightarrow MV}$ exponential convergence can be observed in graph (c.).

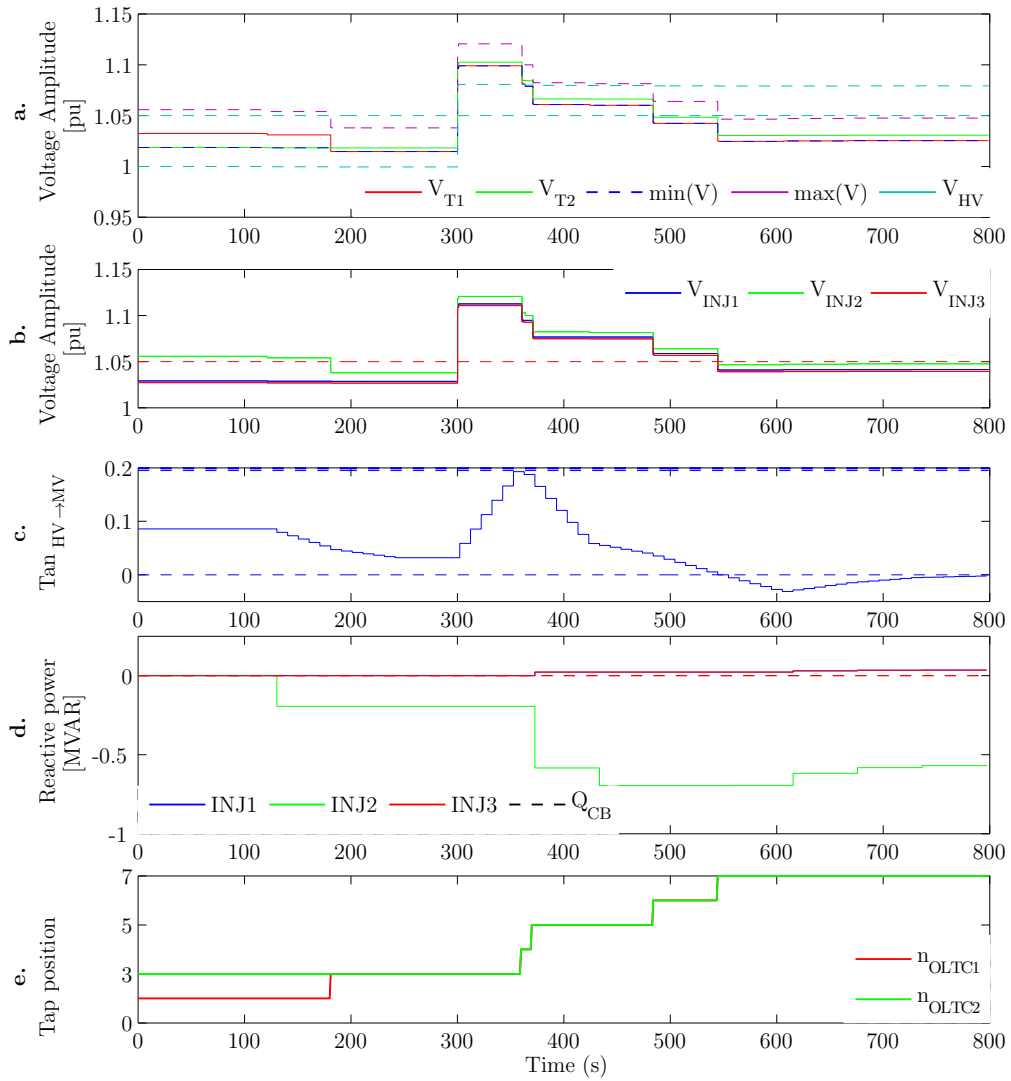


Figure V.19: Results and control actions in the 20 kV grid in case of a large HV disturbance

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Chapter VI

Comparison of the predictive VVC performances compared to other standard methods

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VI.1 A qualitative comparison of VVC schemes

In this section, a qualitative comparison between the three VVC methods is proposed. In the sequel:

- **R-VVC** stands for the rule-based VVC introduced in Chapter IV, IV.2.1;
- **O-VVC** stands for the optimization-based VVC introduced in Chapter IV, IV.2.2;
- **MPC-VVC** stands for the predictive VVC introduced in Chapter V;

Table VI.1 summarizes the needs in requirements for communication, measurements and references. To sum up, O-VVC and MPC-VVC require a model of the network, and assume there is a communication link between the DGs (even in mixed feeders) and the DNCC. Then, the DNCC is able to send new references every minute (every 5 minutes for the R-VVC). Furthermore, the tap position of the OLTC should be known for the O-VVC and MPC-VVC controllers.

Table VI.1: Requirements for each VVC controller

Communication	R-VVC	O-VVC	MPC-VVC
DNCC ↔ DG	Only with dedicated DG	Yes	Yes
DNCC ↔ CB	Yes	Yes	Yes
DNCC ↔ OLTC	Yes	Yes	Yes
Measurements	R-VVC	O-VVC	MPC-VVC
DG	P, Q, V	P, Q, V	P, Q, V
MV voltages	DSE	DSE	DSE
CB	Switching statuses	Switching statuses	Switching statuses
OLTC		Tap position	Tap position
References	R-VVC	O-VVC	MPC-VVC
Δt	5 min	1 min	1 min
Modeling	R-VVC	O-VVC	MPC-VVC
Network	No model, but requires specific	Yes	Yes
Actuators	expertise from the designer	No	Yes

With these additional requirements, both O-VVC and MPC-VVC are able to explicitly minimize the cost of the corrective process and to prioritize secondary objectives. R-VVC could nonetheless considers secondary objectives as well. Moreover, contrary to the R-VVC, the minimization of the periods of non-compliance with specified constraints is guaranteed: they are handled as hard constraints that are relaxed only in case of constraints infeasibility.

The compliance with constraints is even better in the case of the MPC-VVC since it embeds an accurate model of the OLTC. Next, the control of the convergence is made possible in a predictive scheme (See Chapter V), and an exponential convergence has been defined herein. Table VI.2 summarizes all of aforementioned points.

Table VI.2: Comparison of some features of the VVC

Features	R-VVC	O-VVC	MPC-VVC
Reactive power minimization	No	Yes	Yes
OLTC tap change minimization	No	Yes	Yes
Prioritized objectives	No	Yes	Yes
Control of the convergence	No	No	Yes

Then, there is one feature of the MPC that was not used in our work but should be mentioned: the ability to anticipate for any predictable disturbances that can be a load profile or production profile for instance. Also, when more data will be available in order to have prediction on the consumption or production pattern, they could be easily integrated within the MPC approach.

VI.2 A quantitative comparison of VVC schemes on a case study

The three schemes have also been further compared from a quantitative point of view. We will first analyze the uncontrolled network configuration and then show the results for the network equipped with rule-based, optimization-based and predictive VVC.

VI.2.1 Case study and simulations without real-time VVC

Also, for illustrative purposes, the following study-case was considered: the simplified MV network (introduced in Chapter III, Section III.1, Figure III.4 and used in Chapter V to assess the MPC-VVC performances) is assumed to be at low loading (20 % of the maximal loading) and high production (100 %) conditions.

At the initial stage, the voltage reference of the OLTC is poorly chosen: due to the low loading conditions, some buses are facing over-voltage. Then two disturbances are considered:

- Deconnexion of DG6, in dedicated feeder at $t = 800$ s;
- Severe disturbance on HV side of the network, leading to an increase by 0.08 pu of the voltage at the HV busbar of the HV/MV substation at $t = 1600$ s.

The objectives of the VVC controller are the following:

- Maintain the MV voltages within the range $[0.95; 1.05]$ pu;
- Maintain the $\tan_{HV \rightarrow MV}$ within the range $[-0.2; 0]$.

Results obtained without any VVC controller are given in Figure VI.1. Graph a. illustrates the voltage at specific nodes of the 20 kV network, that is the evolution of the minimum ($\min(V)$), maximum ($\max(V)$) voltages, and the voltage at both the MV (V_{MV}) and HV busbar (V_{HV}) of the HV/MV substation. Graph b. gives the evolution of the $\tan_{HV \rightarrow MV}$. The reactive power output of DGs are illustrated in graph c. while the tap position of the HV/MV OLTC is shown in graph d.

From the results, the voltage reference of the OLTC and the power factor ($\tan(\phi)_{DG}$) of DGs have been poorly chosen and the system is subjected to over-voltages during the full simulations. Yet, the MV networks have some control adjustment possibilities: there is one tap position left before the saturation of the OLTC, and the reactive power of DGs is not exploited. Also, several passive solutions can be considered as corrective actions which consist in either adjusting the reactive power output of DGs or the voltage reference of the OLTC. However, for each passive solution, one should check that the solutions are effective also for other operating conditions (in particular here for high loading conditions with a low level of production).

On the other hand, using a real-time solution can increase the control possibilities by automatically adjusting the voltage and reactive power references of the MV network actuators depending on the real-time measurements.

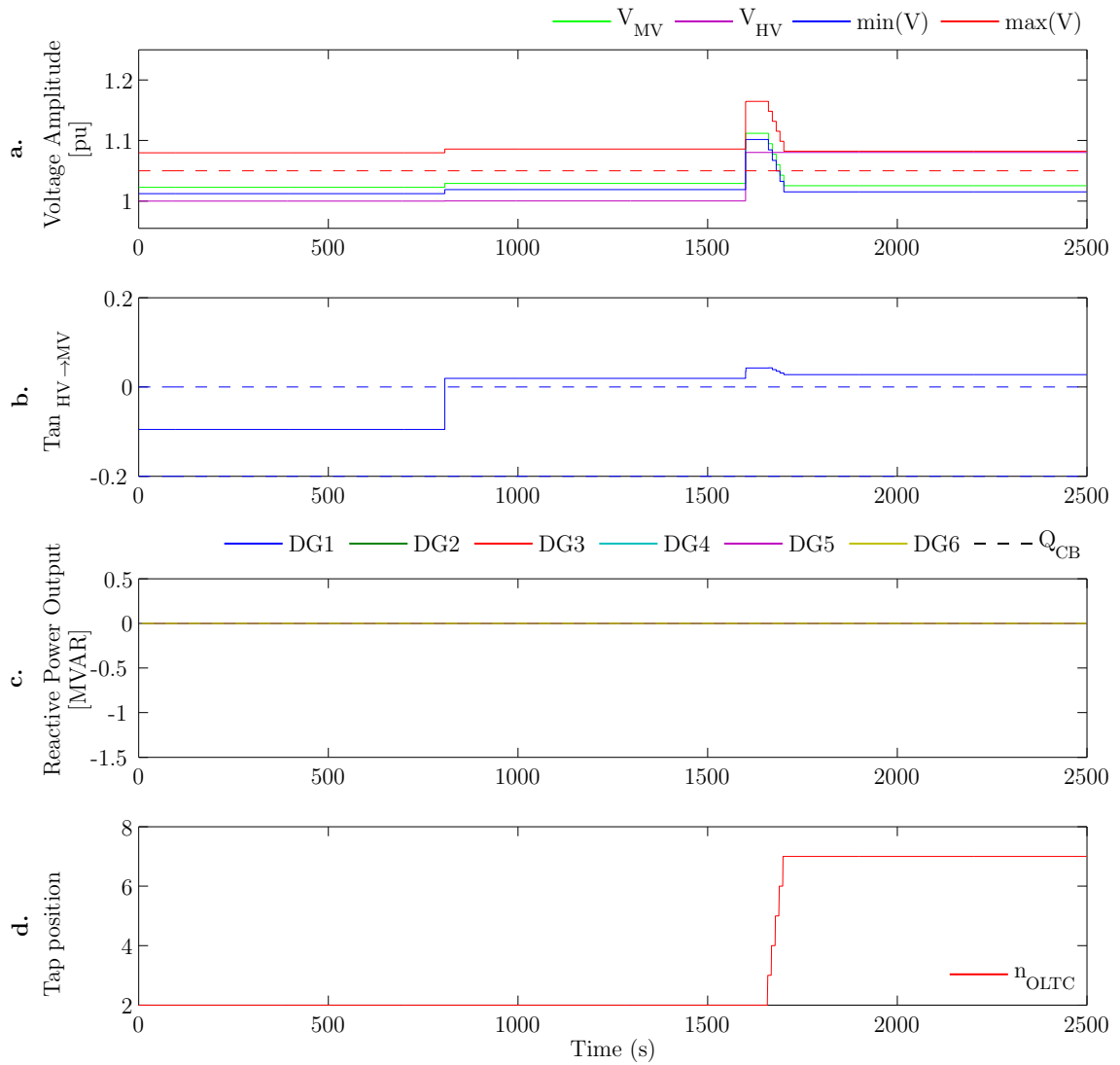


Figure VI.1: Results without a VVC

VI.2.2 Illustration of results with real-time VVC schemes

VI.2.2.a Results with R-VVC

The first real-time solution considered herein is the rule-based VVC. The results are given in Figure VI.2 that follows the same structure as Figure VI.1.

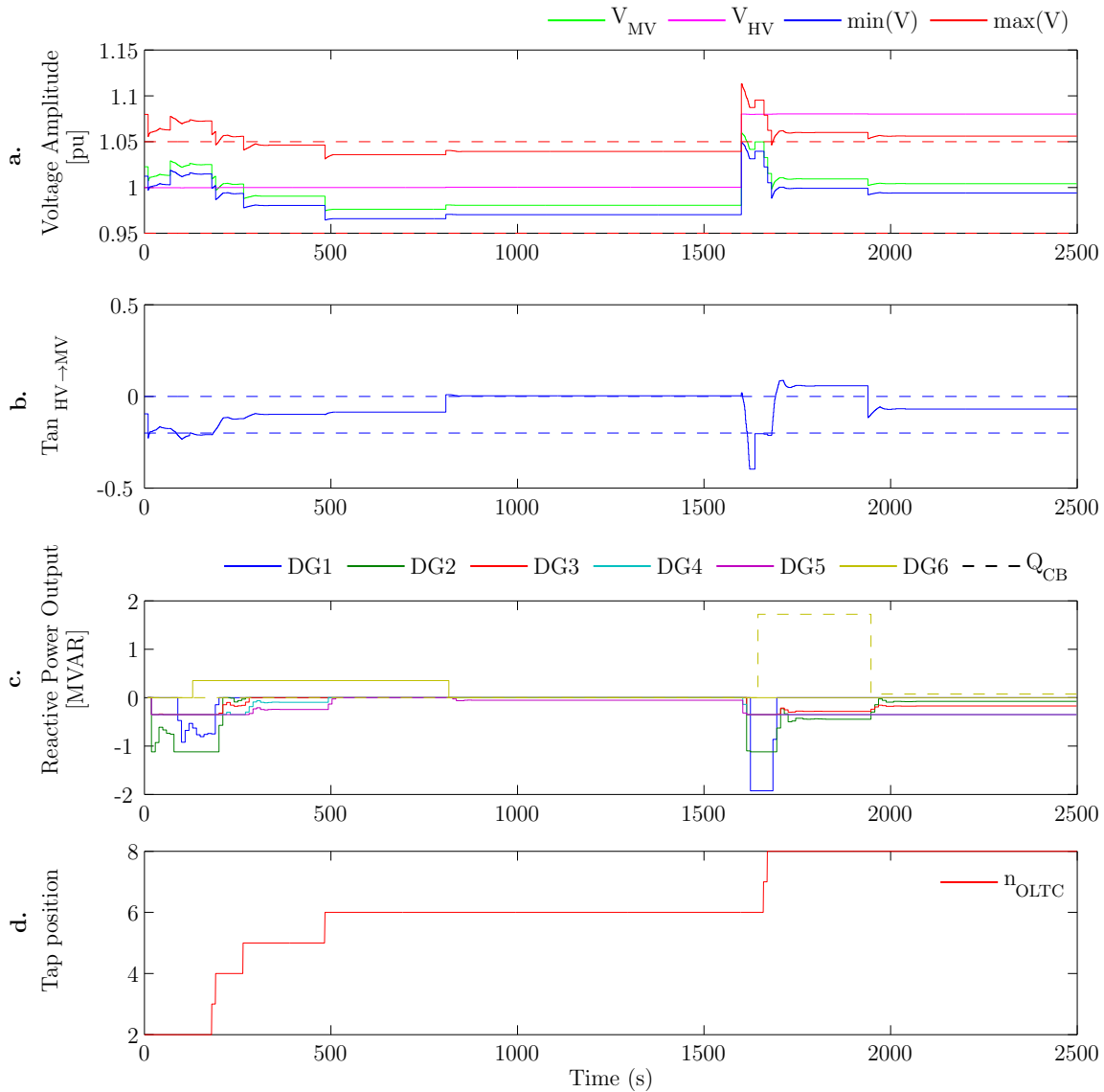


Figure VI.2: Results with R-VVC

The reactive power and voltage rules are activated every 300 s, the first action starting at $t = 120$ s (See the results in Figure VI.2). From the results, the R-VVC succeeds in correcting the MV voltages and the $\tan_{HV \rightarrow MV}$ until the severe disturbance in the HV side of the network

occur. The reactive power of mixed DGs, that follows a $Q = f(U)$ rule, is used temporarily to decrease the MV voltages until the actions triggered by the voltage rule are carried out. This behavior is illustrated for instance, by the evolution of the reactive power requested during the period $t = [0 - 500]$ s and $t = [1600 - 2000]$ s. One major advantage of such a local rule lies in its fast response.

However, this local voltage rule is not coordinated with the reactive power rule, as a result, the actions of the dedicated DG (DG6) are not optimal, and this also leads to the on/off switching of one CB step around $t = 1600$ s, and transient violations of the constraints on $\tan_{HV \rightarrow MV}$ at the beginning of the simulation and around 1700 s.

Moreover, after the disconnection of the only DG connected to a dedicated feeder (DG6), no reactive power of DG is available for the correction of the $\tan_{HV \rightarrow MV}$ even if the reactive power from mixed DGs is available.

Next, the local $Q = f(U)$ rule is not coordinated with the voltage rule playing on the voltage reference of the OLTC. Also it is not well adapted for the grid since this generic rule has parameters which are chosen independently from the grid characteristics, and happens to be unfit for the grid considered herein. Moreover, when the OLTC has reached its saturation point at the end of the simulation, even if there is theoretically reactive power available from mixed DGs to mitigate the voltage rises, the set of rules does not consider to request this reactive power. As a result, the maximum MV voltage overshoots the threshold value of 1.05 pu.

VI.2.2.b Results with O-VVC

The results of the optimal-based controller are illustrated in Figure VI.3. The VVC controller starts running at $t = 120$ s, and then, acts every minute until the end of the simulation is reached. From the figure, the O-VVC controller succeeds in enforcing the MV voltages and $\tan_{HV \rightarrow MV}$ constraints even after the severe HV side disturbance through the optimal coordination of every actuators. Some transient violations can be observed in the $\tan_{HV \rightarrow MV}$ evolution in graph b.

In this simulation, in order to avoid oscillations in the OLTC tap position, the technique developed for the MPC-VVC introduced in Chapter V was used: the optimization yield the optimal tap change and then the voltage reference of the OLTC is derived to ensure that the optimal tap change will be enforced.

Next, since the optimization is a one-step ahead method, the control action are rather abrupt, as it can be especially observed at $t = 1800$ s, since the controller is not able to anticipate the OLTC saturation.

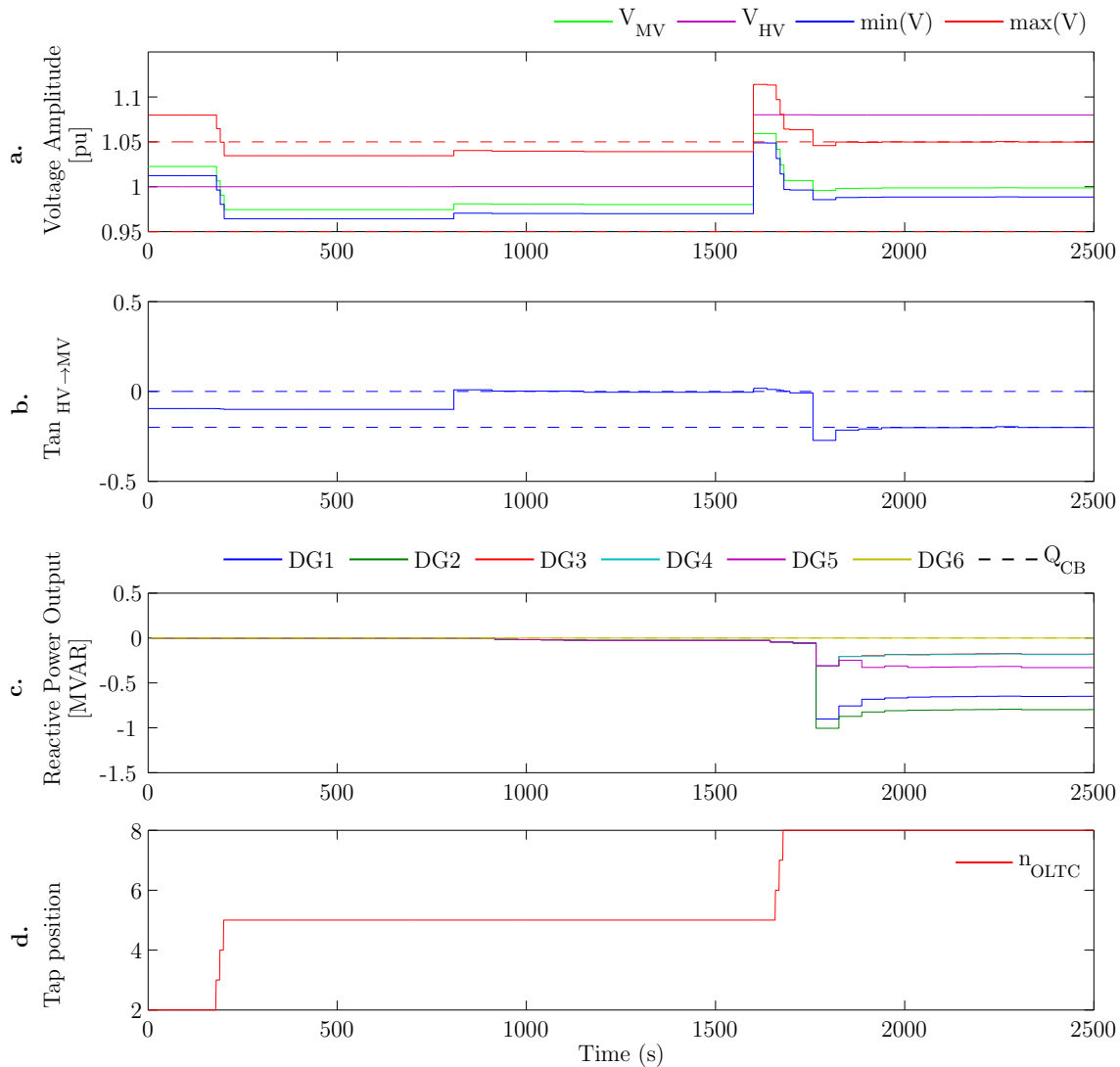


Figure VI.3: Results with O-VVC

VI.2.2.c Results with MPC-VVC

At last, the results obtained with the predictive controller, MPC-VVC, are given in Figure VI.4. The MPC control is activated at $t = 120$ s and then, as for the O-VVC, acts every minute. From the figure, the MPC-VVC succeeds to enforce the specified constraints. Comparing with the control actions yielded by the O-VVC, since the MPC-VVC controller is able to anticipate the future behavior of the system, a smoother and more efficient control policy is obtained. The exponential convergence can be observed in graph b. that illustrates the evolution of the $\tan_{HV \rightarrow MV}$ for instance, and the smooth corrective process in graph c. that gives the evolution of the reactive power of DGs. Next, the transient constraints violations in the $\tan_{HV \rightarrow MV}$ that

were obtained with the O-VVC have been partially corrected using the predictive method. One can note that this reactive power is used during the first sequence ($t = [0 - 800]$ s) to mitigate the MV voltage rise until the OLTC takes over. Also, the reactive power is used only if needed. Due to the small adjustments based on the latest available measurements, the MPC-VVC enables to call for the reactive power in an optimal and coordinated manner with the OLTC tap changes.

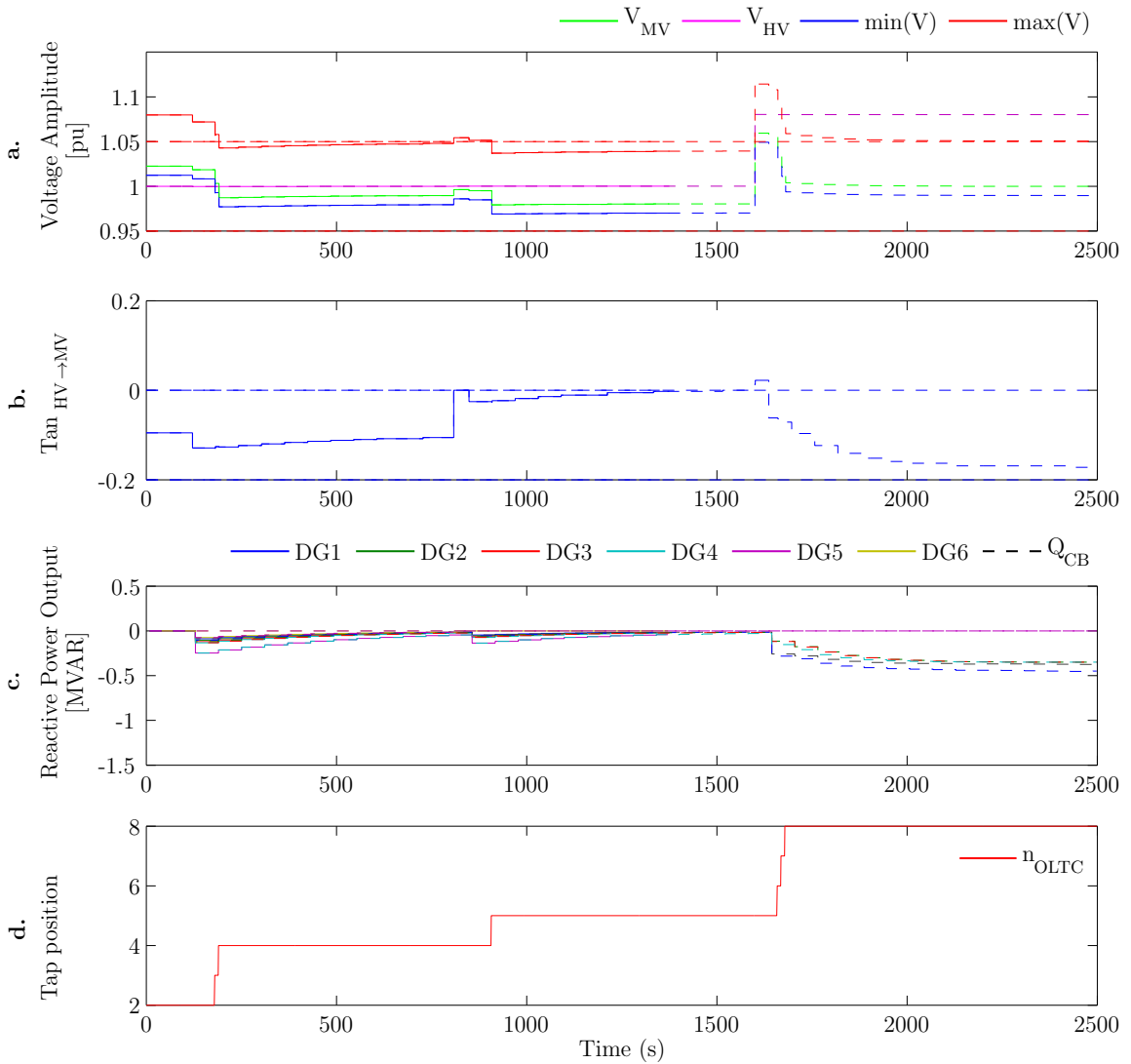


Figure VI.4: Results with MPC-VVC

VI.2.3 Comparison of simulations results from constraints enforcement and costs points of view

To compare the results, the simulation can be divided in three main sequences:

- **Sequence 1:** $t = [0 - 800]s$, correction of the MV voltage (set point tracking);
- **Sequence 2:** $t = [800 - 1600]s$ after the disconnection of DG6 (disturbance rejection);
- **Sequence 3:** $t = [1600 - 2500]s$ after the severe disturbance (HV disturbance rejection) affecting the HV grid and leading to an increase of 0.08 pu at the HV voltage at the HV busbar of the HV/MV substation.

Table VI.3: Comparison from the constraints enforcement point of view

<i>sequences</i>	constraints	without control	R-VVC	O-VVC	MPC-VVC
1+2+3	MV voltages	x	x	√	√
	$\tan_{HV \rightarrow MV}$	x	√	√	√
1	MV voltages	x	√	√	√
	$\tan_{HV \rightarrow MV}$	x	√	√	√
2	MV voltages	x	√	√	√
	$\tan_{HV \rightarrow MV}$	x	x	√	√
3	MV voltages	x	x	√	√
	$\tan_{HV \rightarrow MV}$	x	√	√	√

According to Table VI.3, that summarizes the constraints enforcement for each sequences and each VVC controller, only the O-VVC and the MPC-VVC are able to meet the specified objectives. To sum up, using an optimal coordination of the actuators enables to increase the control performances and thus to face more various situation compared with a 20kV grid without a VVC controller, or equipped with a semi-coordinated VVC such as the R-VVC.

VI.2.3.a Voltage constraint violation

To further investigate the results, the distribution of the constraints violation during the simulation can be plotted as in Figure VI.5. In this Figure, the abscissa corresponds to the value (in per unit) of the maximal constraint violation of the maximal MV voltages for each VVC solutions, while the ordinate indicate the percentage of measurements (on the whole simulation time).

For the sake of simplicity, the results have been split according to the three sequences defined before. Graph b. gives the distribution of the maximum voltage voltage violation for the first sequence, graph c. and d. for sequences 2 and 3 respectively.

From the figure, the O-VVC and MPC-VVC exhibit the best results. There is a slight difference between the MPC-VVC and the O-VVC due to the smooth enforced convergence of MPC. Indeed, since the control efforts are distributed within a prediction horizon, the convergence to the voltage target is very slow, and there are more (in percentage) voltage overshoots than with the O-VVC, however such overshoots exhibit very little amplitude compared with the overshoots

obtained with the O-VVC (See graphs a., b. and d. for instance). To enhance the MPC-VVC strategy, a simple way consists in decreasing to specified range of MV voltages value inside the predictive constraints (to $[0.951 - 1.0499]$ p.u. for example) to speed up the voltage convergence.

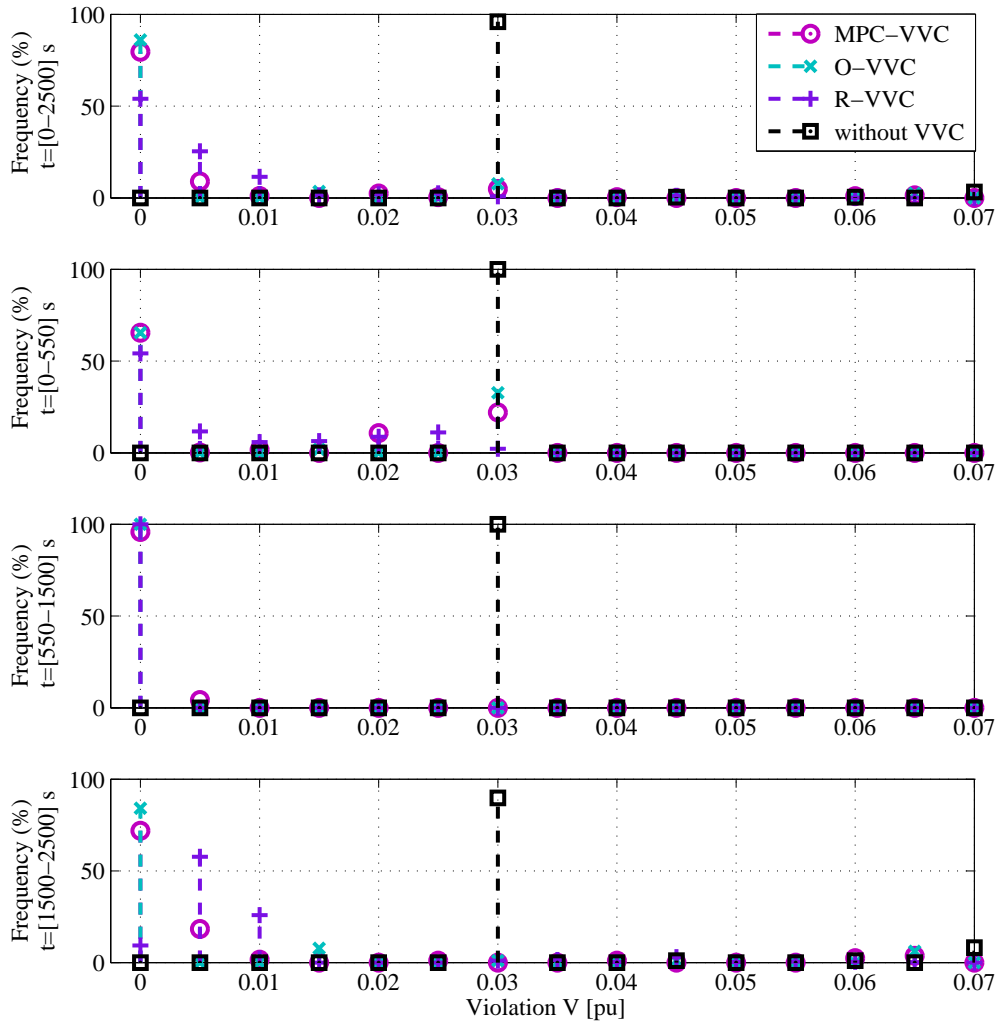


Figure VI.5: Distribution on the MV voltage constraint violation depending on the control algorithm

VI.2.3.b $\tan_{HV \rightarrow MV}$ constraint violation

The same analysis has been performed regarding the violation of the constraint on the $\tan_{HV \rightarrow MV}$. The results are given in Figure VI.6.

From this figure, one can observe that the overshoots on the $\tan_{HV \rightarrow MV}$ are linked with the MV voltage corrective process since the case without VVC exhibits no overshoot.

Next, the MPC-VVC shows the best results compared with the other VVC controllers. This is due to the anticipation capability of the predictive control strategy.

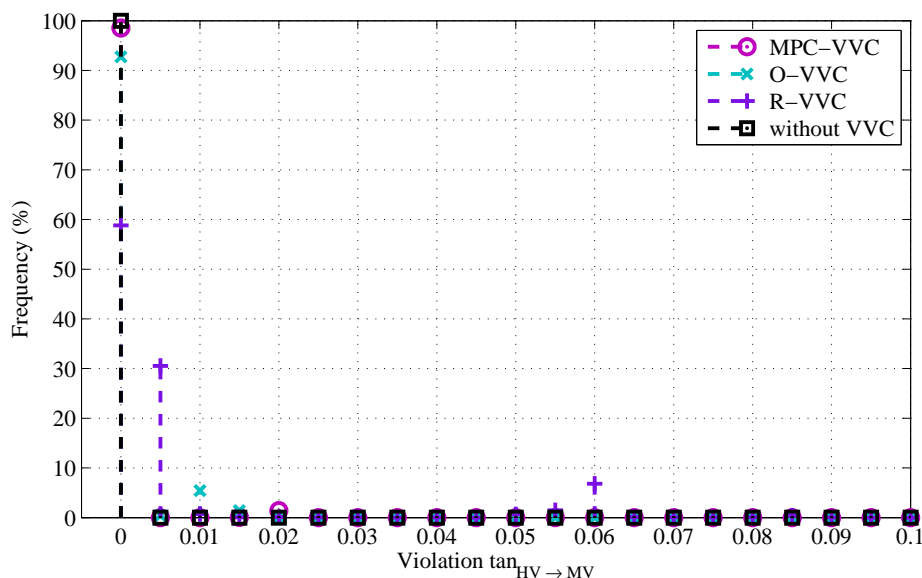


Figure VI.6: Distribution on the $\tan_{HV \rightarrow MV}$ constraint violation depending on the control algorithm

VI.3 Conclusion

In this chapter, the predictive controller introduced in Chapter V has been further compared with two other classical VVC strategies, namely a rule-based and an optimization-based controller described in Chapter IV.

The comparison consists of a qualitative comparison and quantitative comparison on a specific case study.

To sum up, provided that the DNCC are able to retrieve and send measurements every minutes, and can collect real-time measurements of the OLTC tap position, the MPC-VVC exhibits the most attractive performances. Both MPC-VVC and O-VVC reach similar results, and since they are based on a proper coordination between actuators, it is possible to increase the control possibilities (in other words, the number of situations that can be dealt with) and to ensure a minimization of the control costs. Due to the anticipation capability of the MPC method, the MPC-VVC is able to anticipate accurately the future behavior of the grid and of the actuators. Also, the convergence is smoother and accurately controlled. Next, the proposed controller preserves the distribution network from transient constraints violations insofar as possible contrary to R-VVC and O-VVC.

Conclusion on Part B: A predictive real-time VVC to correct MV voltages and control HV/MV reactive power flows

In Chapter IV, based on a bibliographic and state-of-the-art analysis, the relevance of coordinated control structures for real-time Volt Var Control (VVC) of active distribution networks has been established. Indeed, the real-time VVC controller should coordinate several actuators that exhibit various behavior to enforce a twofold objective:

- Maintain the MV voltages;
- Limit the $\tan_{HV \rightarrow MV}$ (HV/MV reactive power exchange).

Among the myriad methods of VVC that can be found in the literature, few methods are dealing with the concern of the HV/MV reactive power exchange, that is one of the points of novelty of our work.

A particularly attractive approach is the Model Predictive Control (MPC) which consists of an optimal multi-step algorithm that can deal with various constraints, time delays and can anticipate predictable disturbances. The receding horizon approach allows the system to track smoothly the desired state, as the introduction of slack variables helps to handle constraints infeasibility whenever needed. Then, contrary to single-step approaches, inaccuracies in the models (usually based on sensitivity matrices and constant load models) can be accounted for through this closed-loop approach.

Next the infrastructures required for most of the controls in literature are far from the nowadays technical state of the art solutions used in distribution networks and from the present level of DG penetration.

Also, in Chapter V a VVC based on MPC has been proposed. The classical On Load Tap Changer inner algorithm has been embedded within the predictive controller. Thus, this original procedure contributes to integrate more advanced control methods in distribution networks without changing the current equipment and the operating strategies. Hence, the implementation costs are limited, and the tap change minimization is guaranteed.

The performances of such a controller have been assessed through various and evolving situations, under disturbances and parametric uncertainties, in a simplified and real 20 kV network.

Next, in Chapter VI, the method was further compared with two classical schemes, namely a rule-based and an optimization-based methods. The results corroborate the attractive performances of the proposed controller.

Part C

Coordinated reactive power management in a medium scale system

Chapter VII

A DSO-TSO coordinated reactive power management scheme in a medium scale system to support TSO operations

VII.1 Introduction

In Part B, an original real-time VVC scheme has been introduced. This scheme is based on Model Predictive Control and aims to achieve a twofold objective: to maintain both the MV voltage and the value of the $\tan_{HV \rightarrow MV}$ within a specified range of values.

In this part, the choice of the reference value for the $\tan_{HV \rightarrow MV}$ that must be tracked by the real-time VVC is more specifically investigated.

As a reminder, one of the motivation for studying the voltage concerns at the TSO/DSO interface lies in the requirements of the Grid Codes Demand and Connection (DCC) that have been presented in Chapter II. This interface corresponds, in France, to the HV/MV interface, typically 63/20 kV or 90/20 kV. In this code, it is stated that the TSO could require that the distribution systems have the capability to prevent reactive power export at low active power consumption. In this chapter, an alternative solution is proposed. Indeed, it is mentioned in the DCC that alternative solutions based on joint TSO-DSO analysis may be found and considered if technical and economical benefits can be assessed.

First, the interest of a reactive power support from MV grids for TSO operations is investigated in this chapter. It should be noted that until now, the issues of voltage and reactive power exchange were mainly considered from the DSO point of view. Theoretical results are given as well as the results of static simulations on a medium scale system for illustrative purposes. As a reminder, the medium scale system introduced in Chapter III, Figure III.5 consists of several MV grids connected to the same part of a HV system.

Then, a rule-based algorithm for the tuning of the MV grids reactive power reference is proposed. The association of this reactive power management with the predictive VVC of distribution systems is studied through dynamic simulations on the medium scale system.

Chapter VII discusses the interest of designing a coordinated reactive power management between DSO and TSO within a HV medium-scale system. In this chapter, the specific simulation tools developed for this study are also introduced.

VII.2 How distribution systems may support TSO operations through reactive power

The undergoing changes of distribution systems have consequences on TSO operations as already stated in Part A. Indeed, due to these changes, the following consequences can be observed:

- Decline and even reverse reactive power flows at the HV/MV interface that can be linked with the evolution of the load and the replacement of overhead lines by underground cables [1, 2];
- Decline and even reverse active power flows at the HV/MV interface due to the insertion of DGs in the distribution systems;
- High variability (in both time and space) of active and reactive power flows at the HV/MV interface correlated with the variability of weather-dependent DGs production and loading conditions.

To sum up, the power flows (and de facto the interactions) between transmission and distribution systems have become more erratic (in time and space), dynamic and hardly predictable. Also, TSO can face difficulty to ensure a suitable regional reactive power provision [3, 4] or difficulty to mitigate voltage rises. Such voltages rises have been observed for instance in the south of England, at the 400 kV level [5, 6]. Voltage excursions have also been reported in the Romanian transmission system according to [7].

To deal with the aforementioned issues, new solutions for regional reactive power balance should be found especially if large traditional power plant units are taken out of service to be replaced by renewable distributed energy resources. In the literature and as requested in the European Grid Code, Demand and Connection, distribution systems are generally considered as a lever for supporting the transmission system by adjusting the reactive power at the HV/MV interface. Thus, new schemes and methods are proposed to investigate how and to what extent the distribution systems can contribute to maintain the HV voltages [5, 8–13].

VII.2.1 Theoretical consequences of MV reactive power exports on HV and EHV voltages

In this section, the theoretical influence of a change in the reactive power flows downstream a specific HV/MV substation on the HV voltage of this substation is studied. As a reminder, the HV voltage level in France maintained by the means of EHV/HV OLTC while the EHV level is managed through a three-level voltage control as detailed in Chapter I, also the voltage control is quite limited.

The influence of the reactive power from MV networks on the HV voltages is roughly proportional to S_{cc} .

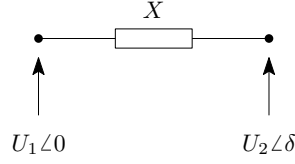


Figure VII.1: Two nodes lines

The reactive power flowing through a line without losses (as depicted in Figure VII.1) connecting two nodes is theoretically given by (in per unit):

$$Q_{1 \rightarrow 2} = -\frac{U_1 U_2}{X} \cos(\delta) + \frac{U_2^2}{X} \quad (\text{VII.1})$$

Differentiating equation (V.18) with respect to U_2 gives:

$$\frac{\delta Q_{1 \rightarrow 2}}{\delta U_2} = -\frac{U_1}{X} \cos(\delta) + 2 \frac{U_2}{X} \quad (\text{VII.2})$$

Then assuming that $U_1 \simeq U_2$, $\delta \simeq 0$ and considering that $U_1 = 1$ pu is stiff leads to:

$$\frac{\delta U_2}{\delta Q_{1 \rightarrow 2}} \simeq \frac{U_1}{X} = \frac{1}{S_{cc}} \quad (\text{VII.3})$$

This equation gives the sensitivity of voltage to reactive power support depending on the short-circuit power. This influence is rather low for HV/MV substations with medium to high S_{cc} . Taking a realistic example, if $S_{cc} \geq 500$ MVA then $\frac{\delta V}{\delta Q} \leq 0.002$ pu/MVAR. As a result, a reactive power support to maintain the corresponding voltage would turn out to be inefficient. However, considering weak transmission system ($S_{cc} \leq 500$ MVA), typically rural ones, such a support could be worth considering. Moreover, HV/MV substation short-circuit powers can be highly impacted by disturbances such as line outage. In this specific condition, a reactive support could be helpful.

Next, if several MV networks (even with high short-circuit power) connected within the same region exhibit reactive power exports upwards a HV grid, this reactive power can turn out to be significant at the EHV/HV interface. This can, in turn, disturb the EHV voltage profile and the reactive power management at the EHV level of the network. Indeed, the EHV voltage are more sensitive to reactive power flows due to X/R ratio of EHV lines and cables.

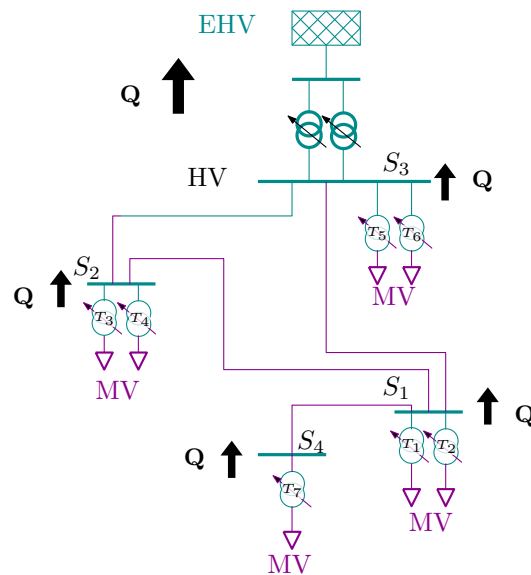


Figure VII.2: High reactive power flowing upwards at EHV/HV interface

To sum up, there are two situations where a reactive power support from MV grid can be helpful for the TSO operations at the HV level (typically 63 kV or 90 kV in France):

- for voltages purposes for weak HV system, that is HV/MV substation with low short-circuit power;
- for EHV/HV reactive power exchange purposes in case of high reactive power flowing upwards the same vicinity of a HV grid.

VII.2.2 Illustration of worst-case situations on the medium scale system

VII.2.2.a A rural medium-scale system

For illustrative purposes, several load flows have been carried out on the medium-scale system introduced in Chapter III and further described in Appendix B (See Figure VIII.15). In short, the HV system is a meshed network that embodies a rural network. Specifically, the real distribution systems connected to this grid exhibit long feeders, and except from substation 3 which is very close to the EHV network (225 kV), their short-circuit powers are rather low. The average length of feeders as well as the conductor types distribution of each HV/MV substation are detailed in Table VII.1 and the short-circuit powers are described in Table VII.2.

With such a level of underground cables in the distribution systems, high reactive powers may flow upwards the transmission grid, especially at a low level of consumption. As a result, this transmission grid is prone to over-voltage and could face difficulty to manage the reactive power exchange at both HV/MV and EHV/HV interfaces. Next, saturations of HV/MV OLTCs are likely to occur. As a result, in the case of an outage of a line, this specific system will turn to be weaker regarding reactive power and voltage concerns.

Table VII.1: Details of lines and cables distribution in MV grids

Substations	Average feeder length (km)	Overhead lines total length (km)	Underground cables total length (km)
<i>S1</i>	20.54	314.82	284.85
<i>S2</i>	21.61	397.31	180.50
<i>S3</i>	24.42	457.05	223.26
<i>S4</i>	31.18	331.60	240.76

Table VII.2: Short-Circuit Power S_{cc} of HV/MV substations at 100 % of production and loading

Substations	S_{cc} (MVA)
<i>S1</i>	407
<i>S2</i>	368
<i>S3</i>	2695
<i>S4</i>	206

VII.2.2.b Assessment of the worst-case conditions

First, several load flows with various production and loading scales have been performed to illustrate the evolution of the EHV/HV reactive power exchange (See Figure VII.3). The same study was also performed for the maximum HV voltage as illustrated in Figure VII.4. Also, it is possible to have a first insight in the MV reactive power reserve needed to face the two aforementioned issues: either HV voltage control, and/or EHV/HV reactive power exports limitation.

The loading scale varies between 20% to 100% while the production scale is varying between 0% and 100 %. It has been assumed in this study that all MV grids have the same load and production percentage levels. In each MV grid, the distribution of the load and production is performed according to the maximal active power of loads and DGs within the grid that is assumed to be known. Next, the HV voltage set-point of EHV/HV transformers was set to 1.01 pu. Regarding the distribution network, no VVC was considered, but the OLTC of HV/MV transformers have been taken into account.

From, these figures one can observe that there is no correlation between the maximum reactive power export upwards the EHV grids and the maximal HV voltages, although both of them occur at low loading conditions. In other words, there are two specific cases where reactive power support can be needed.

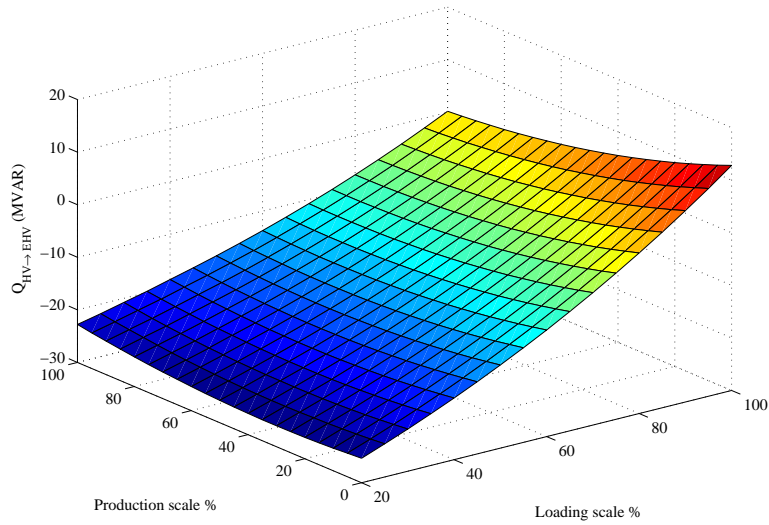


Figure VII.3: Evolution of the reactive power at EHV/HV interface depending on the loading and production scale

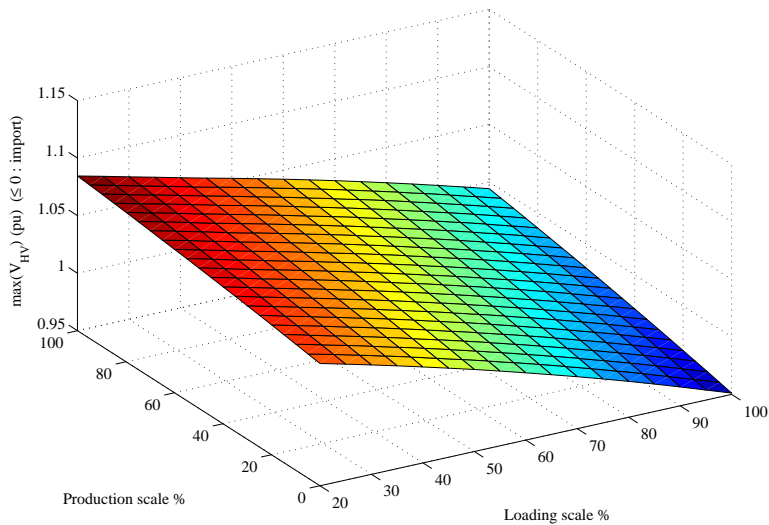


Figure VII.4: Evolution of the maximal HV voltage depending on the loading and production scale

The maximal HV voltage (1.084) is obtained at full DGs production and at the minimal loading condition (20 %). The maximal HV voltage increases while the loading condition is decreasing and the level of production is increasing.

The maximal EHV/HV reactive power export is reached when the DGs production compensates for the active power of loads, that is when the net consumption of MV networks viewed by the HV grid is close to zero. This situation happens when the production scale is at 30.25 % for the specific grid considered herein under a 20 % loading scale. Indeed, for the reactive power exchange at the EHV/HV interface, the reactive power contribution of the HV lines should be taken into account. Yet, this contribution depends on the current flowing through the lines and the voltage at their terminals.

Here, the reactive power exchange varies between -26 MVAR and +11 MVAR according to Figure VII.3. Also, in order to prevent reactive power flowing upwards EHV system, a first coarse estimation of the reactive power reserve needed is of 26 MVAR, which is quite a significant amount if relying only on MV grids.

Table VII.3 summarizes the HV voltages at the different substations $S_{i \in [1,4]}$ and the reactive power flowing upwards the EHV grid for the worst-case conditions.

Table VII.3: EHV/HV reactive power exchange and HV voltage for two specific production scales and with 20 % load for the medium-scale system

Production scale (%)	100%	30,25%
Q_{HV} (MVAR)	-22.78547	-26.01637
V_{S1} (pu)	1.063565	1.047513
V_{S2} (pu)	1.050204	1.039145
V_{S3} (pu)	1.01012	1.010142
V_{S4} (pu)	1.084445	1.066109

Note that the contractual range of values of the HV voltage is of $[0.92, 1.08]$ pu. Also, at 20% loading conditions, and with full production, the maximal HV voltage overshoots the contractual limitation. Next, at this specific condition, two HV/MV OLTC have reached there saturation point (transformers T_2 and T_7), and the MV networks could face difficulties to manage the MV voltages.

VII.2.2.c Sensitivity of HV voltage to the HV/MV reactive power exchanges

In order to roughly estimate the reactive power support needed to correct the HV voltage, one can perform a sensitivity study, that is the variation of HV voltages induced by a change of reactive power at the HV/MV interface. The results of such a study are given in Table VII.4 at 20% loading scale and 100% production scale. From this table, one can observe that there exists a cross-sensitivity between the substations. For instance, a change in reactive power upstream S_1 will influence the voltages of every substations, and more particularly substations S_1 , S_2 and S_4 . The substation S_3 , which is close to the EHV/HV substation and thus exhibits a high short-circuit power, is barely affected by a change in reactive power flows.

Table VII.4: Cross-sensitivity of HV voltages with respect to HV/MV reactive power exchange in the medium scale system

$\frac{\delta V}{\delta Q} (pu/MVAR)$	Q_{S_1}	Q_{S_2}	Q_{S_3}	Q_{S_4}
V_{S_1}	0.00252462	0.00171829	0.00038736	0.00251753
V_{S_2}	0.00171321	0.00253932	0.00038367	0.00171106
V_{S_3}	0.00038005	0.00037657	0.00037653	0.00038167
V_{S_4}	0.00258264	0.00175778	0.00039627	0.005036

Also, since there exist cross-sensitivities, there are several solutions to correct the HV voltage V_{S_4} at the HV busbar of substation S_4 :

- Consume 0,883 MVAR downstream substation S_4 that is calculated according to the following :

$$(V_{S_4} - 1.08) \left(\frac{\delta V_{S_4}}{\delta Q_{S_4}} \right)^{-1}; \quad (\text{VII.4})$$

- Consume 11,22 MVAR downstream substation S_3 according to the following formula;

$$(V_{S_4} - 1.08) \left(\frac{\delta V_{S_4}}{\delta Q_{S_3}} \right)^{-1}; \quad (\text{VII.5})$$

- Consume 2,529 MVAR downstream substation S_2 ;
- Consume 1,721 MVAR downstream substation S_1 ;
- ...

Next, a combination of the contributions from several substations can also be considered. The solutions leading to the minimal amount of requested reactive power is to consume reactive power downstream the substation S_4 . However, the other solutions can be worth considering if there is not enough available reactive power downstream S_4 .

In the end, the reactive powers needed to correct the HV voltages and the EHV voltage appear to be quite different. In order to assess the relevance of the solutions, the true dynamics and behaviors (including the real-time VVC) of MV grids should be taken into account.

VII.2.3 Needs for joint TSO-DSO analysis and dynamic simulations on medium scale systems

To design a cost-effective and relevant support, there are several points to consider. First, it is crucial to hold estimates of the reactive power availability, that is the theoretical amount of reactive power that can be either absorbed or provided by the distribution system at the interface. Such an estimate is indeed necessary to assess the possible requirements in reactive power levers, or to carry out network planning studies. Next, TSO can use these estimates for short-term forecasts in order to anticipate the reactive power management and dispatch within its own network. The study of reactive power reserve assessment is beyond the scope of our work. Indeed, such a study is not straightforward since there are a lot of stochastic variables to consider (active production of DGs correlated with the meteorological data, loading conditions associated

with the high uncertainty of load models in distribution system...) and this reserve is dependent on the prevailing conditions within the distribution systems. In literature several studies can be found and are based on Optimal Power Flow techniques [3, 4, 14] and conclude on the difficulty to obtain a high quality forecast.

Second, assuming a reactive power reserve exists and is well-known, DSO should be able to call for this reserve depending on the TSO needs and requirements. Note that the second part of this report (Part B) is dedicated to the introduction of a VVC that is able to control the reactive power at the HV/MV interface.

Third, it also implies that there exists a communication system between TSO and DSO as required in the Grid Codes Operational Planning and Scheduling and in the code Demand and Connection (DCC). In our work, it will be assumed that TSO and DSO are able to communicate and exchange relevant information regarding the reactive power capability and needs. An example of such a communication scheme is described in [15].

Also in this work, we will focus exclusively on the real-time dispatch of the reactive power of distribution systems coordinated with HV reactive power levers within a HV system. Next, the association of such a reactive power support with the real-time VVC of distribution systems is to be studied.

Generally, the topic of a reactive power support from the distribution systems is addressed from the transmission system point of view only. The contingent constraints in the distribution network are often disregarded and the simulations are reduced to the HV grids and consist of static studies (load flow simulations). These constraints are namely the MV voltages, the MV lines thermal constraints, the amount of reactive power that can be requested from DGs...

Next, there are several approaches to manage the reactive power at TSO/DSO interface. A constant solution for each period of time of the year can be targeted, or constant solution for a specific period of time (winter/summer, day/night), or a solution evolving with the grid loading and production scale. In [12], these three options are further investigated and compared. The article concludes that using either fixed constant solution or several fixed solutions depending on the time period of the year are not relevant to significantly reduce the number of hours of reactive power exports towards the HV system. Note that the first simplified studies detailed in Chapter III have concluded on the relevance of using real-time solution to deal with the high variability and unpredictability of reactive power exchanges. Also, in the literature, the solutions are found based on the real-time states of the HV network.

For instance, in [9] distribution systems are viewed as classical power plants that can achieve reactive power control for the Swiss TSO. It is assumed that the available reactive power of distribution systems is both measurable and controllable at any instant. Hence, distribution systems are able to follow a day-ahead reactive planning. In [10], a co-simulation is developed to study the dynamic exchange of reactive power between a HV and MV grids. The exchange is optimized every 15 minutes. In [11] the problem of real-time active and reactive power regulation for a transmission (subtransmission) grid is investigated. distribution systems are viewed as controllable loads to achieve such a regulation. In [16], a comparison of several strategies using tap stagger techniques is carried out. A genetic-algorithm-based solution as well as a rule-based and a branch-and-bound optimization are considered and are proven relevant for the HV voltage support. However, the MV networks are modeled as constant power load connected to the MV

busbar of the HV/MV transformers. Also, the influence of the loads and DGs is not investigated and more generally the dynamic and behavior of the MV grids is neglected.

Also, there is a clear need to develop simulations combining both transmission and distribution systems. Indeed, in the literature, the problem is often considered from the TSO point of view only as stated before with simplified and inaccurate MV grid model, or from the DSO point of view only. Indeed, among the myriad of new real-time VVC strategies that can be found, few methods address the issue of a reactive power exchange limitation at the HV/MV systems interface. Usually, the transmission grid voltages are supposed to be stiff (i.e. assuming the HV network is strong). This assumption is questionable in degraded operating conditions [17] and when there exists a tighter interdependence between HV and MV grids [18]. Therefore, in order to investigate the relevance of a reactive power support from MV grids and the subsequent consequences for distribution systems, it is of interest to study a medium scale system involving part of a HV network connected to several distribution systems for which these conditions are met.

To sum up, when reactive power support is needed, it seems irrelevant to rely on distribution grid VVC alone, or consider only a supervisory control of the TSO. Next, the dynamic simulations should be carried on a medium-scale system combining both transmission and distribution systems with their own needs and control schemes in order to reach a greater coordination between TSO and DSO.

Compared to other methods proposed in literature, the original features of the control and the method we are proposing are:

- Both MV voltage and reactive power exchange at HV/MV networks interface are controlled;
- Reactive power flowing through HV/MV substation is restrained only if requested by the TSO, and this reactive power is called in a coordinated manner with the possible HV levers;
- HV voltage are not assumed to be stiff, and the cross interactions between HV and MV voltages can be investigated;
- Simulations are performed for a medium scale system.

VII.3 Simulation tool overview for joint DSO-TSO reactive power management

VII.3.1 A joint TSO-DSO coordination: needs and requirements

The objective is to propose a joint TSO-DSO coordination for a reactive power management within a HV grid. The main difficulty lies in the fact that TSO and DSO have different specifications and requirements listed in Table VII.5 that can even be antagonistic.

Table VII.5: TSO and DSO objectives

Operators	TSO	DSO
Primary objectives	Maintain HV voltage profile Limit EHV/HV reactive power exchanges	Maintain MV voltage profile
Secondary objectives	Limit active losses	Provide a reactive support at HV/MV interface Minimize the reactive power requested Avoid saturation of the HV/MV OLTCs

Moreover, DSOs are blind to the TSO operations and more specifically of everything happening upstream HV/MV substations. Next, the DSO has no information on possible cross-sensitivities between two MV grids. On the other hand, TSO have no idea of the possible constraints and requirements downstream HV/MV substations. In other words, both TSO and DSO have local knowledge about their own model but have little information regarding the power flows and the voltage at the HV/MV interface.

Since there is cross-coupling between the MV grids through the HV system, it is barely thinkable to have uncoupled and independent reactive power references for each MV grid. That is why a coordination taking explicitly or implicitly this coupling into account should be targeted. This coupling is reduced after the actions of the HV/MV OLTC, that occur with a delay (time-delay of the OLTC) and if the OLTC has not reached its saturation point. That is why such a coupling can induce unsuitable changes of tap. Also, in this work a coordination based on communication between TSO-DSO was selected in order to account for the possible interactions while considering there is information that TSO and DSO may not be willing to disclose.

The communication framework is illustrated in Figure VII.7. It is assumed that the reactive power management within the HV grid is slower than the real-time VVC of MV grid, and the control sampling time is of ten minutes. A reactive power support can be requested from the MV grid by the TSO. Then, the VVCs of distribution grid are updated in order to meet the TSO and DSO objectives insofar as possible.

In the sequel, it is assumed that the TSO is able to send a reactive power request to the DSO. The DSO can in turn try to follow to this reference insofar as possible through the real-time predictive VVC.

VII.3.2 Simulations and practical aspects

The whole medium scale system has been created in the RAMSES framework to allow performing dynamic simulations. The network is first initialized using ARTERE which is a software performing power flow computation by Network method ¹.

Several Matlab functions have been designed for the control purposes: a set of functions for the MV voltage control and a second set for the HV grid control. Also, each set of functions has access to a restricted data base allowing to reproduce the local knowledge of grid operators. Next, it may happen that the TSO needs to carry out load flows to take his decision. Also, a link between Matlab and PowerFactory Digsilent was created based on the exchange of csv files.

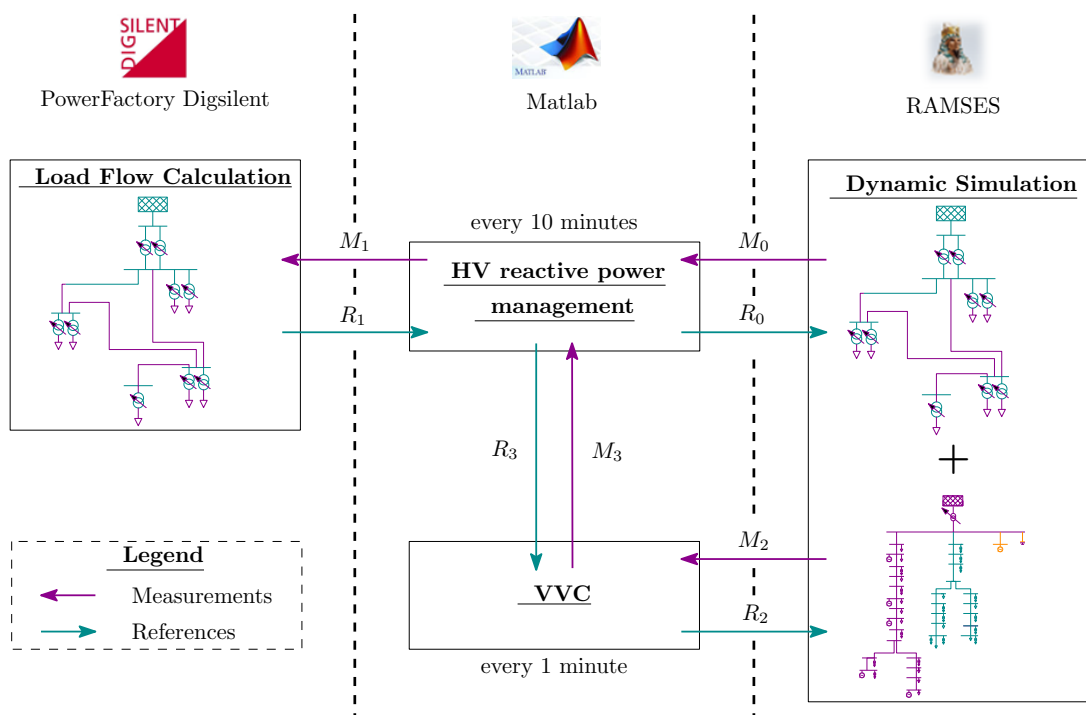


Figure VII.5: Practical realization of the dynamic simulations

The practical realization of the dynamic simulations is illustrated in Figure VII.5. The whole grid (HV+ MV systems) is modeled using RAMSES. To simplify the simulations and make the results analysis more readable, the real MV grids were replaced by the three-feeders grid that exhibits a simplified topology. For the initialization, each MV network has been scaled to respect the initial reactive and active power exchange at the HV/MV interface. As the simplified model exhibits short lines and cables a constant power load was added at the MV busbar of the HV/MV substation to replicate the actual lines and cables contributions of the real grid. More details about this network are given in Appendix VIII.3.6. Next, in the sequel it is assumed that MV grid are equipped with the predictive controller introduced in Part B.

¹More information and download can be found at <http://www.montefiore.ulg.ac.be/vct/software.html>

Only the HV part of the grid including HV/MV transformer is known in the PowerFactory Digsilent model.

The measurement and communication links between the different softwares shown in Figure VII.5 are described hereafter:

- M_0 and M_1 :
 - Active and reactive power flows at the HV/MV interface and in the HV system;
 - HV voltages.
- M_2 , measurements necessary for the predictive real-time control:
 - Active and reactive power flows at the HV/MV interface;
 - MV voltage profile;
 - Tap position of the HV/MV transformer OLTC;
 - Switching statuses of CBs;
 - Active and reactive power of DGs.
- M_3 : the reactive power reserve of MV grid at HV/MV interface.

For the references:

- R_0 and R_1 :
 - Reactive power references at the HV/MV interface;
 - Reactive power references of possible HV reactive power levers;
 - Voltage reference of the EHV/HV OLTC.
- R_2 , References sent by the predictive VVC:
 - Reactive power references of DGs;
 - Number of activated step of CBs;
 - Voltage reference of HV/MV OLTC.
- R_3 : Reactive power references at HV/MV interface.

VII.4 A rule-based algorithm for reactive power management within a HV system

VII.4.1 Enhancing control strategy through a TSO-DSO coordination in case of a HV line outage

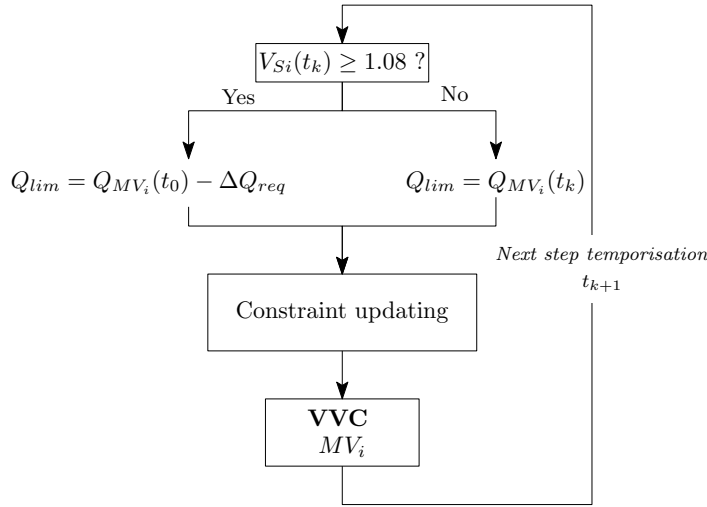
VII.4.1.a A rule-based solution to control the reactive power at the HV/MV interface

There are different methods to derive the reactive power needed at the HV/MV interface. One can use for instance an optimal power flow or a rule-based method. For the sake of simplicity, in a first step, a basic rule has been selected herein which is depicted in Figure VII.6.

In case of a HV voltage overshoot at the HV/MV substation S_i , at a time t_0 ($V_{HV_i} \geq 1.08$ pu), the TSO can send a reactive power request (ΔQ_{req}) to the corresponding distribution grid. This request aims to increase the initial MV reactive power consumption $Q_{MV_i}(t_0)$ to mitigate the HV voltage rise. The activation of the aforementioned constraint (V.4) within the VVC controller will lead to a progressive reduction of the reactive power flowing through the substation S_i .

If, at a time $t_1 \geq t_0$, the voltage level is acceptable (i.e. $V_{HV_i}(t_1) \leq 1.08$ pu) while the reactive power $Q_{MV_i}(t_1)$ is above $Q_{MV_i}(t_0) - \Delta Q_{req}$, then the reactive power limit is updated: $Q_{MV_i} \leq Q_{MV_i}(t_1)$.

This limit should be enforced insofar as possible until the TSO deactivates the constraints on the reactive power exchange.



t_0 : TSO asks for reactive power support

Figure VII.6: State-flow of the proposed reactive power support

The communication scheme between TSO and DSO is depicted in Figure VII.7. The main and non negligible advantage of such a method lies in its simplicity while avoiding to request more reactive power support from the MV networks than truly needed. This is due to the im-

explicit coordination achieved by the predictive VVCs and the proposed scheme. The predictive VVCs gradually meet the specified constraints (the effort is distributed over the horizon) that are updated once the HV voltage are back in the targeted range of values, also the cross-coupling is indirectly taken into account.

The reactive power support ΔQ_{req} required by the TSO is evaluated while considering the sensitivity of voltage with respect to reactive power as given by (VII.3). Also, this value is evaluated with a limited TSO knowledge of the system and the future behavior of distribution systems is not anticipated.

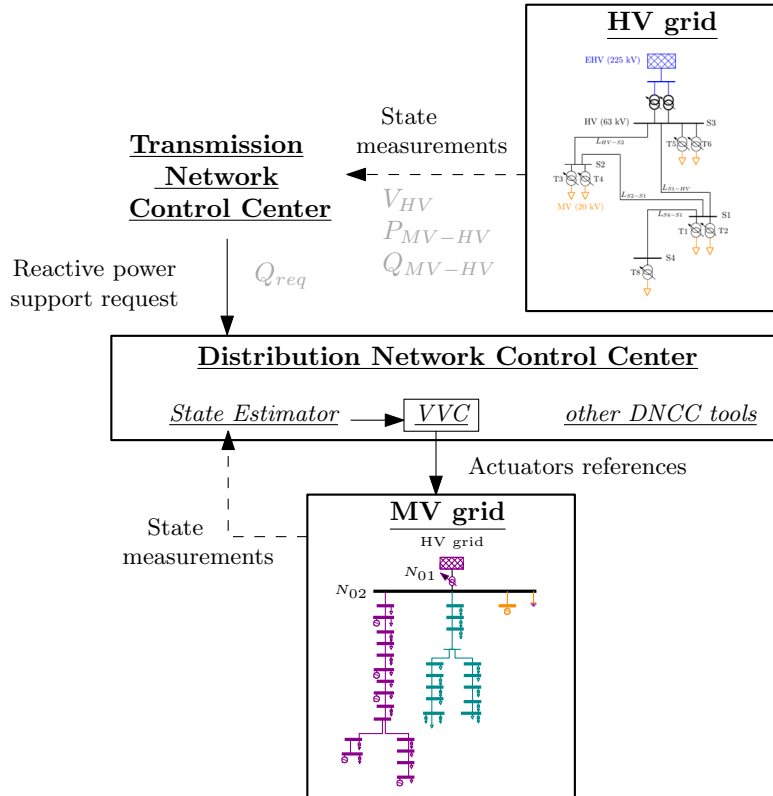


Figure VII.7: Schematic of the proposed control

VII.4.1.b Case study: outage of a HV line

The initial voltages, active and reactive power flows at the primary side of the HV/MV substations are detailed in Table VII.6. From this table, one can observe that the system is at low loading conditions and with high production level (100 % of the overall production). However, the MV voltages and HV voltages lie within the suitable respective range of values.

Regarding the distribution systems, two OLTCs (T_2 and T_7) have reached their saturation point. In case of disturbances further increasing the HV voltages would therefore lead to an overshoot in MV voltages downstream these two specific transformers. That is why, the reactive power of DGs is necessary to be able to correct the corresponding MV grids voltage profiles. Moreover the

voltage reference of EHV/HV transformer is equal to 1.00 pu and cannot be further decreased.

Table VII.6: Initial voltage, active and reactive power flows at the primary side of HV/MV substations

Substations	$V(pu)$	$P(MW)$	$Q(MVAR)$
S_1	1.0541	-16.63	-9.15
S_2	1.0388	-2.00	-5.21
S_3	0.9951	-15.23	-1.17
S_4	1.0722	0.4321	-7.50

In this case, an outage of the line $L_{S_2-S_1}$ will occur and will consequently lead to an overshoot of the HV voltages at the substations S_1, S_2 and S_4 while the voltage at S_3 is barely altered. At the same time, the sensitivity of the HV voltages with respect to the MV reactive power flows would increase.

Table VII.7: Case studies to investigate the relevance of the DSO-TSO coordination

Cases study	
20% loading - 100% generation	
Line outage	
Case A	without TSO-DSO coordination
Case B	with TSO-DSO coordination

Two simulations cases have been considered herein as described in Table VII.7. In case A, the TSO does not send any reactive power request to the DSO. In this case, if needed, the reactive power of DGs will be adjusted jointly with the HV/MV OLTCs to correct only the MV voltages. In case B, the TSO sends a reactive power request to the DSO. This request corresponds to a decrease of the reactive power exchange by a step of 2 MVAR. We recall that this value was evaluated according to the sensitivity of voltage to reactive power. Then, the aforementioned reactive power constraint is activated inside the predictive MV real-time VVC controller and the bounds value at the HV/MV interface follows the scheme previously introduced (See Figure VII.6. Thus, the DG reactive powers is used to correct both the MV voltages and the reactive power exchange. Results are further compared for the HV and the MV grids.

VII.4.2 Comparison of results with and without the proposed reactive power support

Figure VII.8 shows the HV voltages obtained for both cases while Figure VII.9 gives the reactive power exchange downstream each HV/MV transformer. The solid curves correspond to

case A, while the dotted curves correspond to case B. These results consist of the measurements that are taken every 10 s (the controller is fed with 60 s average measurements).

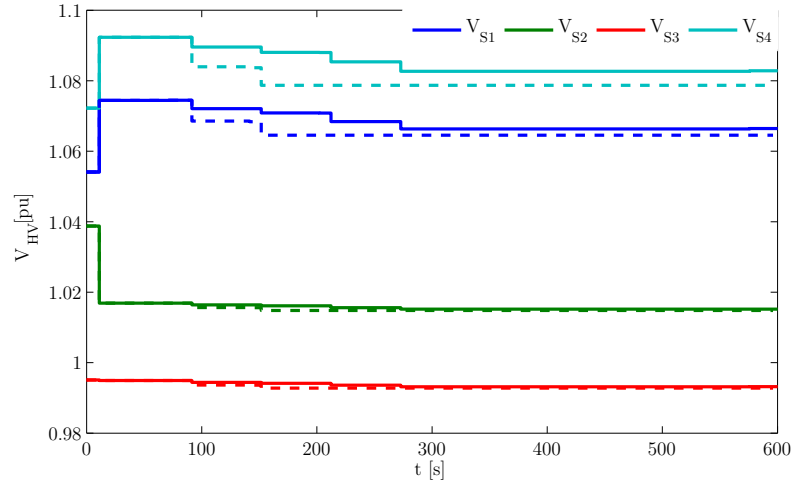


Figure VII.8: Comparison of the evolution of HV voltages, Case A solid lines and Case B in dotted lines

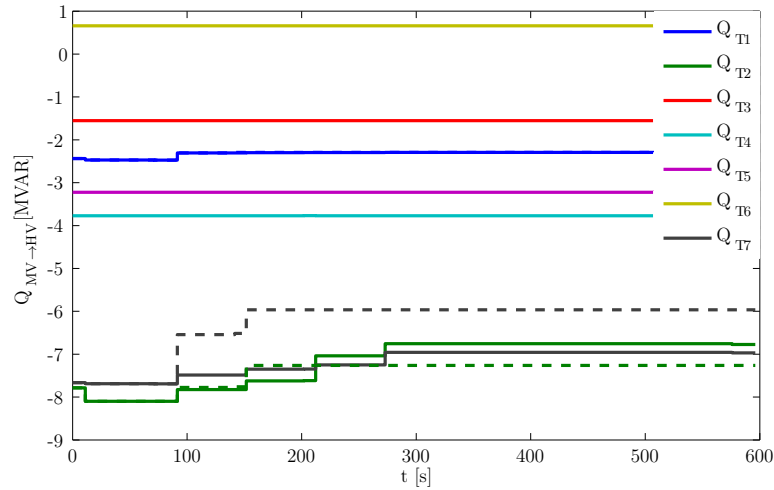


Figure VII.9: Comparison of the evolution of the reactive power flowing through HV/MV transformer at HV side, Case A solid lines and Case B in dotted lines

The line outage can be noticed at $t = 10$ s. As a result, an overshoot in HV voltage occurs: S_4 voltage level reaches 1.0923 pu. The MPC controllers are activated at $t = 80$ s and then act every minute until the constraints are enforced. Only the voltage of the MV grids downstream S_1 and S_4 are impacted by the disturbance while S_2 and S_3 are barely altered. In case B, the TSO requires a reactive power support of $\Delta Q_{req T_7} = 2$ MVAR from the MV grid downstream the substation S_4 once the line outage is detected. Indeed, only the HV voltage up-

stream the substation S_4 overcomes the threshold value 1.08 pu. The constraint (V.4) is already activated at the first VVC control action.

Networks VVCs naturally tends to correct HV voltages

From Figure VII.8, it can be observed that following the TSO reactive power request, the HV voltages are corrected. After 2 control actions, $V_{S4} \leq 1.08$ pu for case B, while at the end of the corrective process of case A, that only aims to adjust the MV voltages, the voltage V_{S4} is equal to 1.083 pu. It should be noted that even in case A, the MV voltage corrective process led by the VVC naturally contributes to decrease the HV voltages. The VVC schemes are requesting reactive power from DGs connected to the MV grid downstream transformers T_1 , T_2 and T_7 in order to correct the corresponding MV voltages that indirectly decrease the HV voltages.

Voltage and reactive power interactions within the system

One can also remark that there are cross-sensitivities between the HV voltages and the reactive power of HV/MV substations: calling reactive power from S_4 induces a modification of the voltages V_{S1} , V_{S2} , V_{S4} and in return reactive power flows from these substations have an influence on the HV voltages. There is no significant influence however on V_{S3} which is closer to the EHV/HV substation and hence exhibits a higher S_{cc} .

The existence of these cross-interactions accounts for the necessity of medium-scale simulations in order to investigate the usefulness of a reactive power support and assess the corresponding needs in reactive power levers.

Additional costs needed to correct the HV voltages

Table VII.8 compares the total amount of reactive power requested by the VVC for cases A and B and the total number of HV/MV OLTCs tap changes. In total, an additional amount of 0.524 MVAR is called for in case B while no additional tap changes are triggered.

Table VII.8: Comparison of the reactive power requested from DG and HV/MV OLTCs tap changes in cases A and B

Case	Q_{Ti} (MVAR)			Tap changes
	Q_{T1}	Q_{T2}	Q_{T7}	
A	0.18	1.32	0.72	5
B	0.177	0.837	1.73	5

Performances of the association of the reactive power support with the predictive VVC

One major advantage of the proposed joint strategy is to avoid requesting more reactive power from MV grids than truly needed. Indeed, the MPC scheme results in distributing smoothly the control effort within a temporal horizon; also the need in reactive power is adjusted at each control step depending on the last real-time measurements. For instance, compared to the 2 MVAR initially required by the TSO downstream transformer T_7 , only 1.73 MVAR are proven to be necessary to correct the HV voltages. Indeed, the TSO request ΔQ_{req} consists

of a rough estimate of the reactive power needed at the HV/MV systems interface. Since MV grids are equipped with a MPC-based VVC, the corrective process will gradually lead to the sufficient amount of reactive power to be provided at the HV/MV interface to enforce a suitable HV voltage profile.

Next, using the reactive power from T_7 to correct the HV voltage indirectly helps the VVC of the MV grids downstream T_1 and T_2 to correct the MV voltage. As a result, in case B less reactive power is required from the DGs connected to downstream the substation S_1 than in case A.

It can also be noted that the sensitivity matrices of each distribution network (that are used in the distribution grid VVC design) were evaluated once and for all by considering only a distribution grid, with constant power loads and assuming that the HV voltage was stiff. The coupling between HV and MV grids has thus been neglected at the control design stage. Hence, this example illustrates again the robustness of the predictive control approach with respect to inaccuracies in the model.

VII.4.3 Focus on the behavior of a low short-circuit power grid

Figures VII.10 and VII.11 illustrate the detailed results for the MV grid downstream T_7 . This grid, that exhibits the lowest short circuit power, is the most affected by the disturbance. The sub-figure a. gives the maximal and minimal MV voltages reached during the simulation updated every 10 s as well as the 60 s average value of voltage at the secondary side of the substation. The sub-figure b. shows the evolution of \tan_{HV-MV} at the DSO-TSO interface, while the last graph c. gives details of the reactive power injection of DG.

With the activation of the constraints on reactive power exchange, the VVC corrective process is speeded up. From graph c. of the Figures VII.10 and VII.11, the reactive power distribution among the DGs can be compared. Indeed, in case B, DGs are used in a coordinated manner in order to decrease the reactive power flowing upwards the HV grid. As a result, more reactive power is needed and the control effort is distributed depending on the DG maximal absorption capacity, while in case A, DGs are used to correct the MV voltages only (there is no TSO-DSO coordination). Thus, in case B, the contribution of DG_{N04} is equal to the contribution of DG_{N11} and DG_{N18} . Likewise, $Q_{DG_{N08}} = Q_{DG_{N14}}$. This difference comes from the maximal amount of reactive power that can be provided. The final MV voltages of case B are lower than those of case A since more reactive power is requested from each DG.

However, the concern of the reactive power availability has not been addressed herein. Since the active power injection is assumed to be at its maximal level P_{max} , it was assumed that DGs can in turn either absorb or produce reactive power in the range $[-0.35, +0.4]P_{max}$. Depending on the level of production and the DG technology, the TSO could not require the same level of reactive power from the MV grids. This issue of reactive power availability can be addressed using a more coordinated approach. For instance, if reactive power is not available from one distribution network S_i , taking advantage of the sensibility of the voltage V_{S_i} to reactive power $S_{\delta V_i / \delta Q_j}$ this request can be shifted to another network S_j . Moreover, if a distribution network is not able to control its own voltage profile, it may request a reactive power support from another MV network.

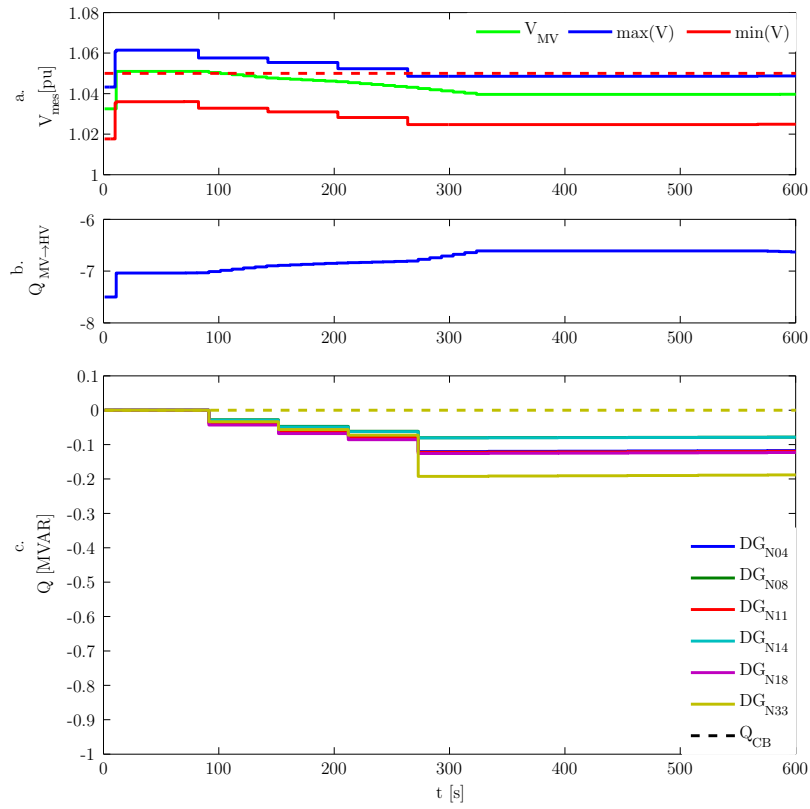


Figure VII.10: Simulation results for the MV grid downstream T_7 , case A

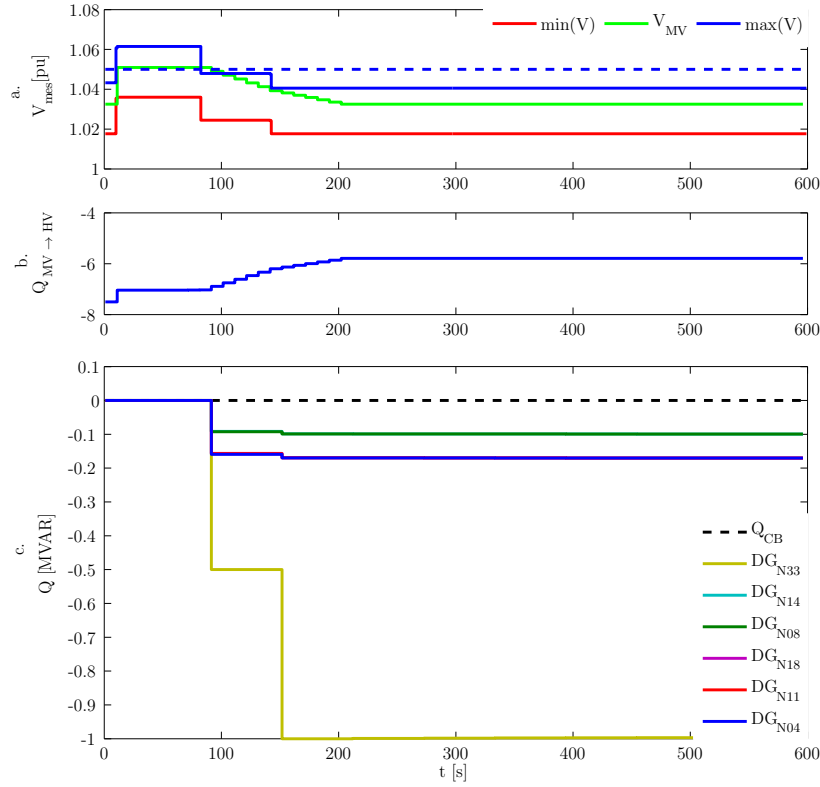


Figure VII.11: Simulation results for the MV grid downstream T_7 , case B

VII.4.4 Conclusion: Motivation for an OPF based coordination

To sum up, it has been shown that due to the adaptability properties of MPC, the predictive VVC controllers are able to effectively support the HV voltages with a limited knowledge and a coarse estimate of the reactive power needed by the TSO.

To enforce a more accurate control of reactive power within a HV system, a coordination of several distribution systems can be considered. Next, by using an Optimal Power Flow technique it will be possible to reach secondary objectives such as to control the reactive power exchange at EHV/HV interface and to take the reactive power limitation of each MV grid into account. EHV voltages are indeed more sensitive to reactive power flows compared to HV and MV voltages.

It was shown that there are cross-sensitivities between the HV/MV reactive power exchange of a HV/MV substation and the HV voltages of other substations in the previous section VII.2. Consequently, there are several alternative solutions to maintain a suitable HV voltage profile. As a result, using an OPF enables to select the most appropriate solution, that is an optimal solution with respect to a specific cost function.

The last chapter of this report is dedicated to the definition of an OPF to realize such a coordination.

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Chapter VIII

Derivation of an optimal reactive power flow in a HV grid considering support from MV grids

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VIII.1 Definition of an Optimal power Flow for the DSO-TSO coordination

The main goal of this chapter is to propose a TSO-DSO coordinated reactive power management for a HV system. This alternative strategy is based on a real-time control, at the level of the TSO. The main objective of the control is to fulfill requirements for the TSO by considering among others, a reactive support from the DSO for voltage and reactive power control purposes. Indeed, it is rather complex to include such requirements in a rather simple scheme as the rule-based introduced in the previous chapter. Next, other levers could be considered to this end and are described hereafter. In order to reach a win-win situation, the reactive power reserve of distribution networks should be used sensibly and sparingly.

The advantages of using optimal power flow over a rule-based method are the common advantages of optimization methods that have been discussed in Chapter IV, that are optimality (according to the selected cost function), ability to deal with multi-input/output system, ability to handle multi-objectives or to be easily generalized.

Eventually, the selection of the OPF cost function is of paramount importance to reach the aforementioned win-win coordination and should be negotiated by the TSO and DSO. The definition of the cost function is described hereafter.

It is recalled that the concerns of network planning and connection studies is beyond the scope of our work. As a result, only a real-time control solution is studied herein. However, special care was taken to ensure the solution is flexible enough if new devices are to be connected to the HV system.

In the sequel it will be assumed that the distribution grids have a reactive power reserve and are equipped with the predictive VVC introduced in Chapter V. Next, DSO and TSO are supposed to be able to exchange information regarding the reactive power reserve of distribution network. This is of paramount importance to ensure that the reactive power support demands from the distribution networks can truly be met.

VIII.1.1 OPF strategies for HV reactive power management

The OPF strategy is illustrated in Figure VIII.1. It is assumed that this control is hosted inside the TNCC (Transmission Network Control Center). In this Figure, the control is presented from the TSO point of view. This figure will be more particularly described in detail throughout this section.

The interest of using an Optimal Power Flow (OPF) technique has been stated in the previous chapter. As a reminder this technique was introduced in 1962 by J. Carpentier [1] and considers a both electrical (solving the classical load flow equations, that can be found in [2]) and economical problem. It consists in solving an optimization problem aiming to minimize costs (related to losses or generation for instance) while satisfying the load flow equations. This problem is non-convex and exhibits both continuous and discrete/binary variables.

This widespread technique is used to assess the reliability and safety of the power system under disturbances (such a loss of a generation unit, line...); for investment planning studies; or to help the system operators taking decisions depending on the real-time system events.

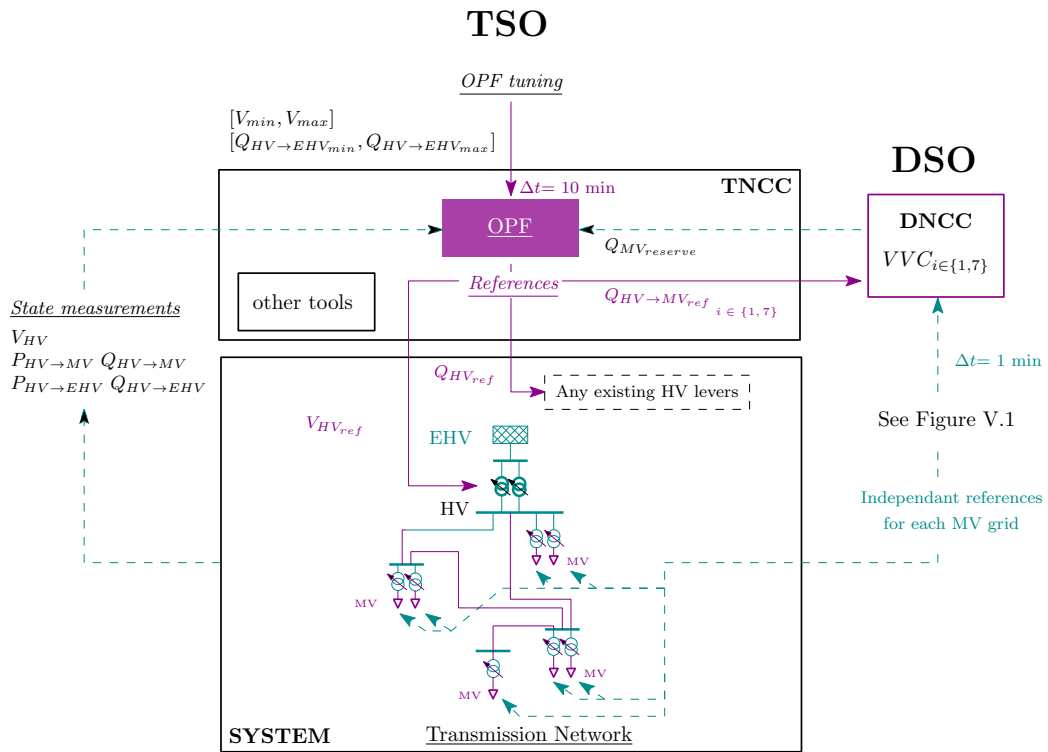


Figure VIII.1: Schematic of the proposed OPF control strategy

Contrary to the naive rule-based approach proposed in the previous chapter, the TSO plays a role of coordinator. One of its assignment is to distribute the reactive power support among the distribution networks.

OPF control targets

The goals of the control are first to enforce a suitable HV voltage profile while limiting the reactive power exchange at the EHV/HV system interface. This second target must be consistent with the reactive power management and voltage control at the EHV level and is assumed to be set by the TSO.

It will be assumed that the twofold objective (HV voltage and EHV/HV reactive power exchange targets) of the control is necessary to ensure a both reliable and safe operations of the power system. Hence, such goals are included in the problem as hard constraints introduced hereafter. In other words, these goals should be enforced at any costs.

Levers

To this end, several levers (U) can be considered within the HV system as illustrated in Figure VIII.1:

- Reactive power references ($Q_{HV_{ref}}$) of possible existing voltage levers connected to the HV system, that could be for instance:
 - Shunt reactances;
 - DGs connected to the HV system;
 - Tap stagger technique using EHV/HV OLTC;
- Voltage reference of the OLTC of EHV/HV transformers ($V_{HV_{ref}}$);
- Reactive power requests ($Q_{HV \rightarrow MV_{ref}}$) at each HV/MV system interfaces.

The TSO gives a reactive power reference for each MV grid (a reactive power target to meet at the HV/MV system interface). Then, each VVC hosted within the DNCC of the DSO acts independently from the others to enforce a suitable MV voltage profile, while trying to reach its own reactive power target assigned by the TSO.

Cost function

In order to reach a coordination between TSO and DSO, the following cost function to be minimized has been considered:

$$J_{OPF} = R_{MV}|Q_{HV \rightarrow MV_{ref}}| + R_{HV}|Q_{HV_{ref}}| + R_{Loss}P_{Loss}; \quad (\text{VIII.1})$$

Where R_{MV} is the cost related to the MV reactive power support, R_{HV} to the HV reactive power, and R_{Loss} to the active power losses within the HV system (including the HV/MV transformers).

Also, in this cost function, the main concerns of both TSO (cost of HV levers support and active losses) and DSO (cost of MV reactive power support) are included. The influence of the weights of this function ($R_{HV}, R_{MV}, R_{losses}$) is investigated in Section VIII.2. It is clear that these weights have to be defined jointly by the DSO and the TSO to reach a fair coordination.

In the sequel, it will be assumed that the existing reactive power assets within the HV grids are reduced to the reactive power reserve of distribution grids, and that the voltage reference of the EHV/HV OLTC transformer can be continuously adjusted within the range [1.0; 1.05] pu. Since the proposed strategy is rather flexible and generic, it can be easily adapted if new devices are to be considered.

Definition of the OPF constraints

The first constraints to be satisfied are the classical load flow equations.

Then, the following constraints focusing on the control objectives should be considered:

$$V_{HV_{min}} \leq V_{HV} \leq V_{HV_{max}}; \quad (\text{VIII.2})$$

$$Q_{HV \rightarrow EHV_{min}} \leq Q_{HV \rightarrow EHV} \leq Q_{HV \rightarrow EHV_{min}}. \quad (\text{VIII.3})$$

The physical limits of actuators $U = [Q_{HV \rightarrow MV_{ref}}, Q_{HV_{ref}}, V_{HV_{ref}}]$ should also be taken into account:

$$U_{min} \leq U \leq U_{max}; \quad (\text{VIII.4})$$

$$\Delta U_{min} \leq \Delta U \leq \Delta U_{max}; \quad (\text{VIII.5})$$

The reactive power limit that can be required from the MV grids ($Q_{HV \rightarrow MV_{ref}}$) is not constant but depends upon the prevailing conditions of the considered MV grid and of the HV voltage at the primary side of the HV/MV substation.

Also, it will be assumed that the MV networks are able to provide their real-time reactive power reserve. This reserve should be frequently updated by the DNCC of the DSO and sent to the TNCC of the TSO. Thus, it is possible to ensure that the reactive power references yielded by the resolution of the OPF will not jeopardize the enforcement of suitable MV voltage profiles especially if the HV/MV OLTCs have reached their saturation point. Next, it also enables the TSO to anticipate if preventive or corrective actions should be taken to ensure the reliability and stability of the system.

VIII.1.2 Network modeling

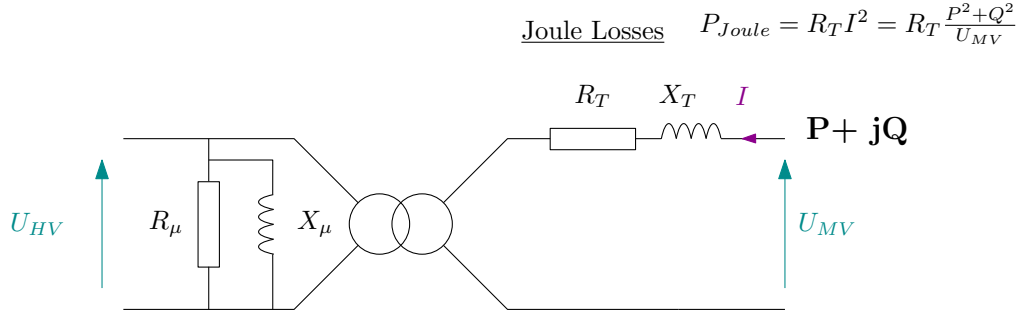
The HV system model considered within the OPF calculation, as shown in Figure VIII.1 consists of:

- EHV/HV stations with OLTC transformers;
- HV lines and cables;
- HV/MV substations with OLTC transformers;
- Constant power loads that embody the MV grids, connected to the MV busbar of HV/MV substations;
- Constant power loads with adjustable reactive power that represent the distribution grid reactive power reserve at the MV busbar of HV/MV substations.

Since a constant load model is used for the MV grids, this means that the active and reactive power consumed by the MV grids is assumed to be independent of the OPF solutions (and the actions of the considered levers) and that these powers remain constant between two control actions.

It could be found surprising that the HV/MV OLTCs are included within the model, since they are located at the interface of TSO and DSO. This choice enables to incorporate the iron and Joule losses within the HV/MV transformers. Indeed, the cost function to be minimized considers the active losses. Yet, the active losses of the HV system can be divided into two main categories:

- Joule losses (in HV lines and EHV/HV and HV/MV transformers) that are proportional to $RI^2 = R \frac{P^2+Q^2}{V}$ and that are minimized when increasing the voltages as illustrated in Figure VIII.2;
- Iron losses in both EHV/HV and HV/MV transformers. These losses are represented by the magnetizing resistance of transformers, and are proportional to the square of the voltage divided by R_μ .



Iron Losses

$$P_{iron} = \frac{U_{HV}^2}{R_{\mu}}$$

Figure VIII.2: Illustration of Iron and Joule losses inside a transformer

Also, when minimizing the active losses, every type of losses should be taken into account to ensure an effective losses reduction: if the active losses of lines are minimized at the expense of an increase in iron losses, the solution is not suitable.

Another advantage of considering the HV/MV substations, is to directly account for the reactive power contribution of HV/MV transformers, that may not be negligible as demonstrated in Chapter III.

VIII.1.3 Resolution and infeasibility cases

It may happen that the constraints (VIII.2) and (VIII.3) are too strict (i.e. the reactive power reserve is not sufficient) and thus cannot be fulfilled. This is the case for instance, if the amount of reactive power needed cannot be provided by the distribution grids and other HV levers. Also in order to avoid a situation of constraints infeasibility a hierarchical relaxation (See Figure VIII.3) using slack variables ($\epsilon_V \geq 0, \epsilon_Q \geq 0$) of the constraints have been introduced:

$$V_{HV_{min}} - \epsilon_V \leq V_{HV} \leq V_{HV_{max}} + \epsilon_V; \quad (\text{VIII.6})$$

$$Q_{HV \rightarrow EHV_{min}} - \epsilon_Q \leq Q_{HV \rightarrow EHV} \leq Q_{HV \rightarrow EHV_{min}} + \epsilon_Q. \quad (\text{VIII.7})$$

Note that such a method has already been considered to prevent infeasibility cases for both the optimization-based and the predictive VVC controller (See Chapter V, V.1.3.c). If slack variables are needed, there are heavily penalized within the objectives functions as given by Table VIII.1.

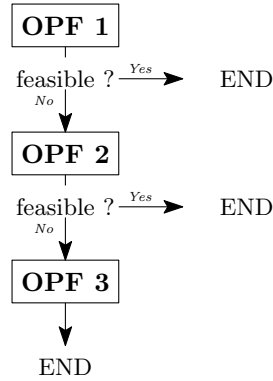


Figure VIII.3: Principle of the hierarchical relaxation for the OPF resolution

Table VIII.1: Hierarchical relaxation of constraints to prevent the OPF resolution from constraints infeasibility

OPF	Cost function	Relaxed constraints
OPF 1	$J_1 = R_{MV} Q_{HV \rightarrow MV_{ref}} + R_{HV} Q_{HV} + R_{Loss}P_{Loss}$	-
OPF 2	$J_2 = J_1 + R_{\epsilon_Q} \epsilon_Q $	(VIII.3)
OPF 3	$J_3 = J_2 + R_{\epsilon_V} \epsilon_V $	(VIII.2),(VIII.3)

For the resolution of the problem, the classical optimization routine `fmincon` of Matlab has been used. This function is suitable to handle constrained nonlinear multivariable optimization. More specifically the algorithm `active-set` has been selected.

As for the load flow equations, they are solved using PowerFactory DigSilent. The resolution of the optimization is thus an iterative process based on a communication through Matlab and PowerFactory DigSilent.

VIII.2 Assessment of the performances of the proposed OPF through static simulations

The simulations carried out in this part aim:

- To illustrate the principle of the control illustrated in Figure VIII.4 below;
- To investigate the influence of the weights in the cost function (VIII.1);
- To investigate the influence of constraints set by the TSO regarding the HV voltages and the reactive power within the HV system.

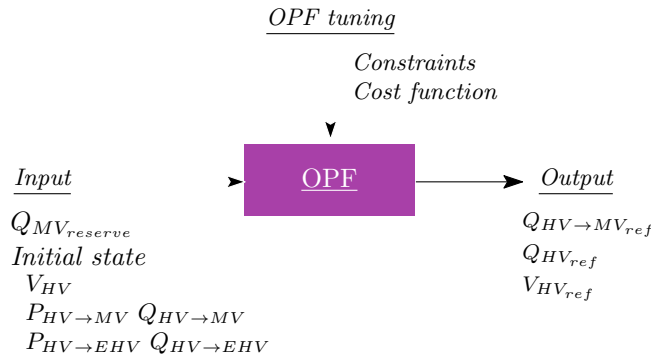


Figure VIII.4: Principle of the OPF strategy

Hence, the evolution of the steady-state solutions yielded by the OPF (level of losses and total amount of reactive power requested from the MV grids) are studied depending on these weights and for several TSO requirements. Indeed these two points (objectives of the OPF, and cost function) have a high influence on the solution.

To do so, the OPF problem has been solved from a specific situation of the medium scale system. Several weighting factors in the cost function have been considered to enforce several sets of constraints.

Since a specific HV system and a specific case have been considered, the results are not to be generalized but head in the direction of the need to define suitable DSO-TSO coordination and perform joint analysis.

VIII.2.1 Simulations overview

VIII.2.1.a Loading and production situations

In order to allow comparisons with the naive rule-based control proposed in Chapter VII, the loading and production scales have been set to the value right after the outage of the line L_{S2-S1} while the VVCs of the MV grid have not yet taken any action.

Table VIII.2 gives the HV voltages, active and reactive power flows at the secondary side of each HV/MV transformer after the disturbance. Two OLTCs have reached their saturation point: T_2 and T_7 . Downstream these two transformers, there are overshoots in the MV voltage profiles after the line outage.

Table VIII.2: Voltage, active and reactive power at MV busbar of HV/MV transformer after the L_{S2-S1} line outage

Transformer	V_{HV} (pu)	V_{MV} (pu)	P (MW)	Q (MVAR)
T_1	1.0744	1.0198	-10.64	-2.47
T_2	1.0744	1.0469	-5.89	-8.10
T_3	1.0174	1.0196	-0.87	1.55
T_4	1.0174	1.0296	-1.14	-3.77
T_5	0.996	1.0195	-0.85	-3.23
T_6	0.996	1.0197	-14.38	0.66
T_7	1.0921	1.0505	0.45	-7.70

VIII.2.1.b Investigation on the influence of the cost function weights and the constraints

In order to select an appropriate cost function, several weighting factors have been considered in the function (VIII.1) that was previously defined, by introducing a parameter α :

$$J_{(\alpha)} = (1 - \alpha)|Q_{HV \rightarrow MV_{ref}}| + \alpha P_{Loss}; \quad (\text{VIII.8})$$

The case, $\alpha = 0$, is, in theory, beneficial for the DSO, while having $\alpha = 1$ favors the TSO. In this objective function, $Q_{HV \rightarrow MV_{ref}}$ and P_{Loss} have been normalized according to the minimal total amount of reactive power requested from MV grids to meet the OPF constraints (solution obtained while minimizing $J_{(\alpha=0)}$), and $P_{Loss_{min}}$ to the minimal active losses level that is reached when considering $J_{(\alpha=1)}$. In other words, minimizing $J_{(\alpha=0.5)}$ is tantamount to find a trade-off between the cost minimization of losses and the reactive power support from MV grids. It could constitute a good agreement between TSO and DSO.

The objective function with α varying in $[0; 1]$ by step of 0.1 has been used to meet three different set of requirements (considered to define the constraints):

- **Set 1**, $C_{V_{HV}}$: Correct the HV voltages only, in this case only the constraints (VIII.2), (VIII.4) and (VIII.5) are activated;
- **Set 2**, $C_{V_{HV}, Q_{EHV-HV}}$: Correct the HV voltages and cancel the reactive power exchange at EHV/HV systems interface by considering constraints (VIII.3);
- **Set 3**, $C_{V_{HV}, Q_{HV-MV}}$: Correct the HV voltages and ensure the reactive power exchange at HV/MV systems interface is in compliance with the DCC requirement (*viz.* given the loading condition, no export upwards HV grid is authorized). In this latter case, the constraint (VIII.3) is replaced by:

$$if P_{HV-MV} \geq 0.25P_{max}, then Q_{HV-MV} = 0; \quad (\text{VIII.9})$$

It is clear that depending on the considered set of constraints, the needs in reactive power would result to be quite different. Also, by considering the aforementioned sets of constraints, it is possible to have a first insight regarding the needs in reactive power and depending on the cost function that has been selected. Furthermore, the reactive power reserve of each MV grid was assumed to be equal to 10 MVAR, which constitutes a significant reserve and enables to investigate a trend for the use of such a reserve.

VIII.2.2 Recommendation for the definition of a relevant cost function

Figure VIII.5 gives the total amount of reactive power obtained for each simulation depending on the cost function that has been selected, while Figure VIII.6 compares the active losses level within the HV system.

From these Figures, it can be observed that depending on the cost function and the selected constraints, the solutions yielded result in quite different level of losses and amount of reactive power requested. In short, the reactive power effort required from MV grid is immoderate when considering the losses minimization only ($J_{(\alpha=1)}$), or when too hard constraints on the reactive power flows within the HV system are required.

Reactive power reserve requirements

More specifically, from the results of Figure VIII.5, obtained with several values of $0 \leq \alpha \leq 1$, the needs in MV reactive power reserve shoot up when tightening the constraints on the reactive power flows within the HV system. The DCC requirements (embodied by the black curves) is the most greedy case regarding the reactive power reserve. For instance, comparing the results obtained with $J_{(\alpha=0)}$, there is a difference in the total amount of MV reactive power support of 18.7 MVAR when enforcing no EHV/HV reactive power export, and of 23.9 MVAR when enforcing the DCC requirements (no reactive power export at HV/MV interface).

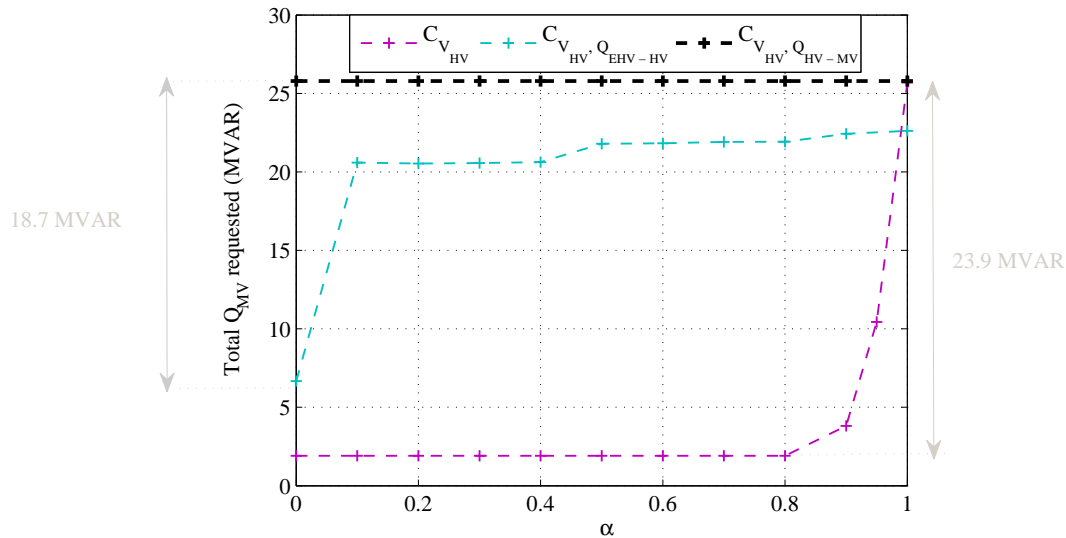


Figure VIII.5: Total amount of reactive power requested depending on the OPF problem definition

When considering $\alpha = 1$, and without constraints on the HV reactive power flows (set of constraints $C_{V_{HV}}$ embodied by the violet curves) the needs of a MV reactive power support is quite increased. From Figure VIII.5, considering the set of constraints $C_{V_{HV}}$, there is a difference in the total amount of MV reactive power support of 27.6 MVAR between $J_{(\alpha \leq 0.8)}$ and

$J_{(\alpha=1)}$, and this difference starts to decrease when α is above 0.8.

Hence, minimizing only the active losses while disregarding the cost of using the MV reactive power reserve is an irrelevant cost function.

Evolution of active losses

It should be noted that in any cases, the active losses after the corrective process are below the initial value of 1.18 MW (See Figure VIII.6). Next, the more the reactive power is constrained, the less the reduction in active losses is possible. Indeed, there are no significant differences in the level of active losses reached with several value of α in the objective function $J_{(0 \leq \alpha \leq 1)}$ and either the set of constraints $C_{V_{HV}, Q_{HV-MV}}$ or $C_{V_{HV}, Q_{EHV-HV}}$.

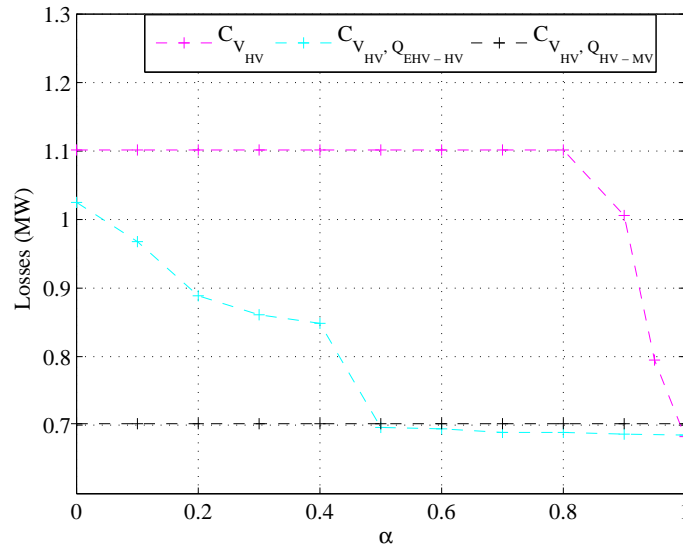


Figure VIII.6: Active losses within the medium-scale system depending on the OPF problem definition

Possibility to reach a trade-off ?

Considering the first set of constraints $C_{V_{HV}}$ (where the constraints are only on HV voltages), the objectives of minimizing either the reactive power requested from MV grids and the HV system active losses are quite antagonistic. However, the differences are reduced especially for the third set of constraints $C_{V_{HV}, Q_{HV-MV}}$.

It is possible to reach a trade-off between the amount of reactive power requested and the level of losses within the HV system (See the results obtained with the cost function $J_{(0 < \alpha < 1)}$).

Recommendations for the definition of the cost function and the constraints of the OPF problem

To sum up, in order to define an appropriate coordination between TSO and DSO, that implies to find a trade-off for the common good, a sensitive and moderate effort should be requested from the MV grids, and the cost function should be negotiated considering every

costs. From the results, the minimization of the active losses is not relevant especially if it is considered that the MV grid support is for safety and stability purposes.

In the sequel, the optimization function will consist in minimizing the reactive power requested while trying not to increase the level of losses, compared to the initial losses level P_{Loss_0} :

$$\min(J_{OPF}) = \beta |Q_{HV \rightarrow MV_{ref}}| + (1 - \beta) \frac{(P_{Loss} - P_{Loss_0})}{P_{Loss_0}}. \quad (\text{VIII.10})$$

In the sequel, $\beta = 0.5$, assuming the costs have been normalized.

The previous results have been obtained while considering the steady-state solutions in open-loop. The behavior and requirements of MV grids should be taken into account as well. Indeed, since the MV grids are equipped with VVC, the constraints are not instantaneously met, and the evolution of the HV/MV reactive power exchanges is also correlated with the prevailing constraints within the MV grids. For instance, it may happen that a specific MV grid cannot meet the reactive power demand at its HV/MV interface, and hence, the TSO may need to find an alternative solution.

VIII.3 Association of the OPF-based coordinated reactive power management and the predictive VVC of distribution networks

VIII.3.1 Joint TSO-DSO coordination

Figure VIII.7 recalls the principle of the association of the OPF-based reactive power management and the VVC of active distribution networks.

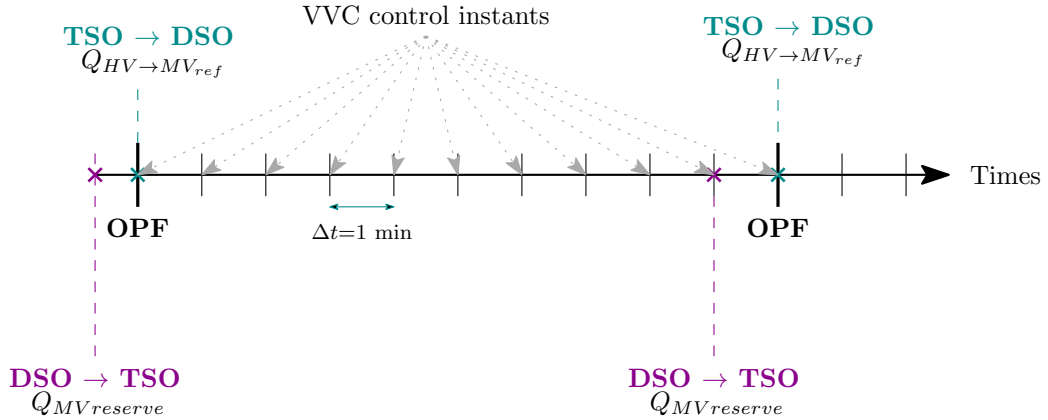


Figure VIII.7: Association of the OPF strategy with the VVC of distribution grids

Every 10 minutes, the resolution of the OPF problem yields the reactive power reference to be tracked at the HV/MV interface by the VVCs. To perform the OPF studies, the TSO uses the latest available measurements of the HV voltages and the power flows at the MV busbar of the HV/MV substations. It is also assumed that the DSO sends to the TSO a forecast of the reactive power reserve for the next 10 minutes.

Then, after the TSO has called for the optimal reactive power support from the DSO, the VVCs act every minute in order to enforce a suitable MV voltage profile and try to meet insofar as possible an appropriate reactive power at the HV/MV interface. At the end of the 10 minutes horizon, the DSO sends the new forecast of the reactive power reserve. Next, if the constraints on HV voltage or EHV/HV reactive power are not met, new references of HV/MV reactive power exchanges are to be calculated by the TSO.

VIII.3.2 Case study

For comparative purposes, the same case studies introduced in Chapter VII, VII.4 have been considered herein and have already been briefly recalled in VIII.2.

As a reminder, the simulations are performed on the medium-scale system. It is assumed that the loading conditions are low, while the production scale is at its maximum. Next, an outage of the line L_{S2-S1} occurs at $t = 10$ s, that leads to an overshoot of the voltage upstream the substation S_4 . At the beginning of the simulations two transformers have already reached their

saturation point (T_2, T_7). However, this is not an issue before the disturbance since these grids exhibit sufficient amount of reactive power to enforce a suitable MV voltage profile.

Two cases studies have been considered to assess the performances of the association of the OPF-based strategy and the predictive VVCs of MV grids. The reactive power support is for considered for:

- **Case A:** HV voltages control purposes only;
- **Case B:** Both HV voltages and EHV/HV reactive power exchange control purposes.

In both cases, the first OPF method is applied as $t = 20s$ (right after the line outage) and at $t = 620s$ that is 10 minutes after the first OPF control action. The first actions of the VVCs of distribution grids take place at $t = 80s$, and then every minute.

VIII.3.3 Coordination of MV grids to support the HV voltages

Suitability of the association predictive VVCs and the OPF-based strategy

Figure VIII.8 gives the evolution of the HV voltages, while Figure VIII.5 shows the evolution of the reactive power at the the MV busbar of each HV/MV transformer. In Figure VIII.5, the dotted lines embody the reactive power support requested by the TSO and yielded by the OPF strategy.

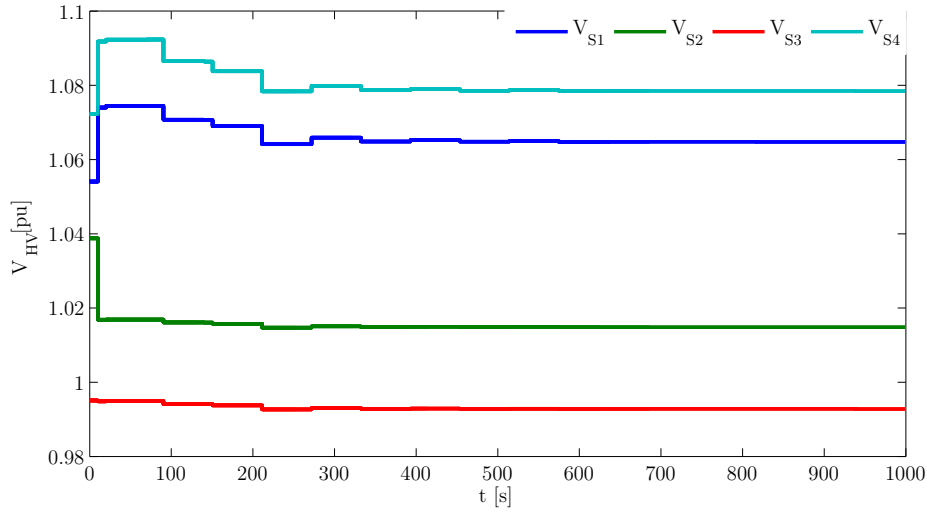


Figure VIII.8: Evolution of the HV voltages with the association of the OPF-based reactive power strategy and the predictive VVC of distribution grids

Thanks to the VVCs of distribution grids, at the end of the simulation, a suitable HV and MV voltage profiles are enforced. A degraded (compared with the OPF solution) but appropriate situation has been reached according to the results. The suitability of using a predictive methods for the VVCs in a joint DSO-TSO reactive power management has already been shown in chapter VII. Once again, the adaptability attributes of the proposed method (including more

specifically the hierarchical relaxation procedure) are assessed: the VVCs are able to find alternative degraded solutions depending on the prevailing MV grid conditions. Since the HV voltage is appropriate at the end of the first 10 minutes, the OPF does not require any change in the HV/MV reactive power exchanges.

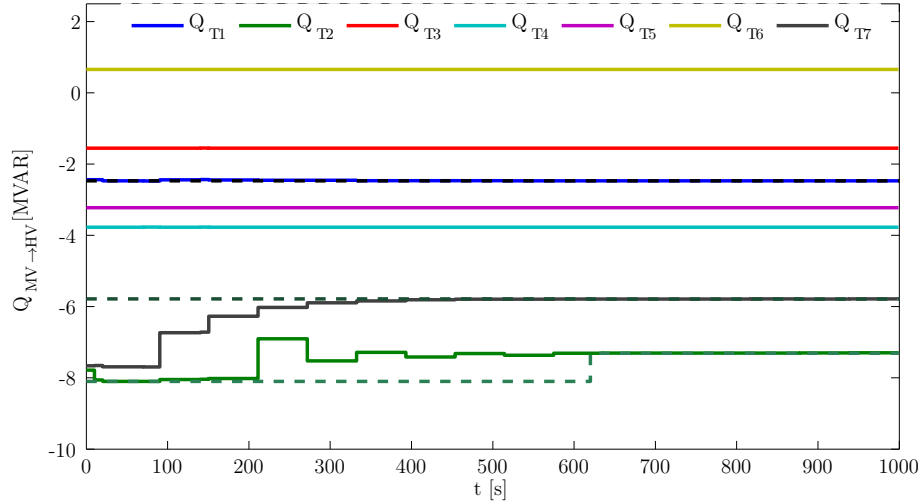


Figure VIII.9: Evolution of the HV/MV reactive power exchange with the association of the OPF-based reactive power strategy and the predictive VVC of distribution grids

Degraded solution to enforce both HV and MV constraints

The OPF solution that does not take into account the reactive power necessary to enforce a suitable MV voltage profile, consists in absorbing 1.903 MVAR downstream the substation S_4 . As a result, at the end of the simulation, the reactive power distribution proposed by the OPF strategy is not enforced. Indeed, the VVC of the distribution grid downstream T_2 has moved away from the OPF solution in order to be able to meet its own constraints as it could be observed from Figure VIII.10.

Table VIII.3: Comparison of the reactive power requested from DGs and HV/MV OLTCs with the rule-based and the OPF reactive power management

Association	Q_{Ti} (MVAR)			Tap changes
	Q_{T1}	Q_{T2}	Q_{T7}	
Rule-based + VVC	0.177	0.837	1.73	5
OPF-based + VVC	0	0.8016	1.9035	5

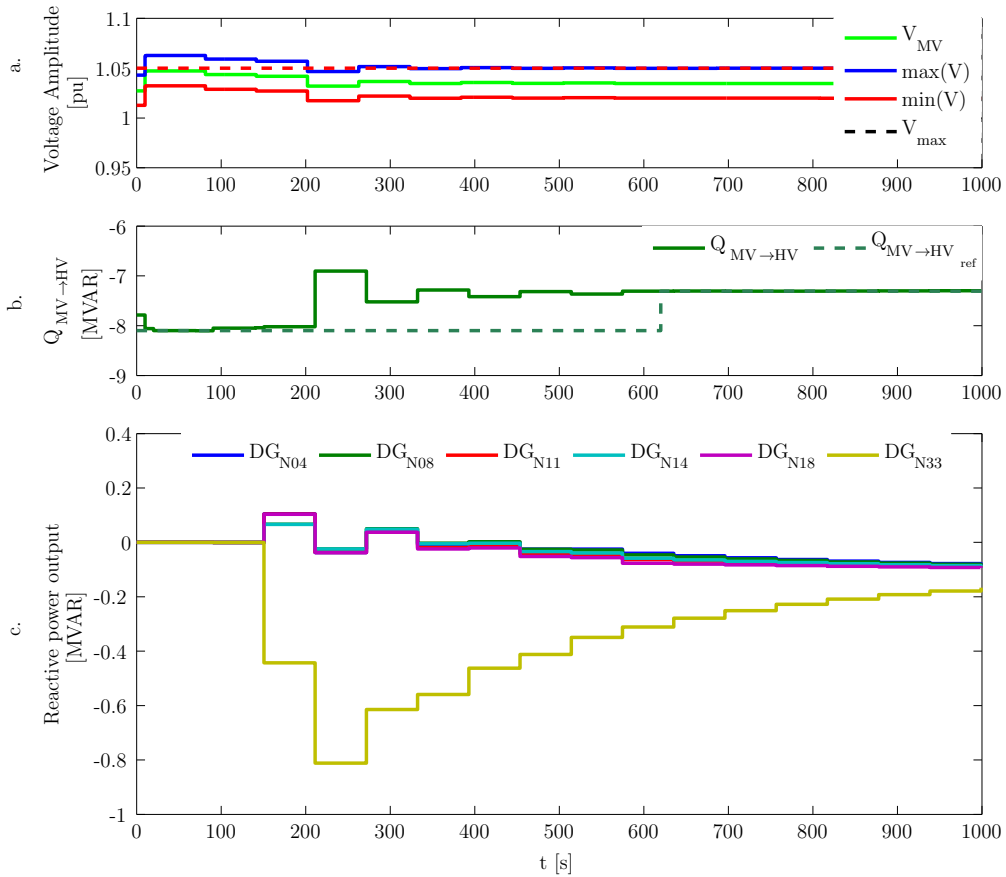


Figure VIII.10: Focus on the results of the MV grid downstream T_2

Comparison with the rule-based algorithm: a steady state situation closer to the optimal solution

Table VIII.3 compares the results obtained with the rule-based and the OPF-based reactive power management. The results are quite similar. The solution obtained with the OPF-based strategy is closer to the optimal solution, yet the difference between the total amount of reactive power requested is only of 0.037 MVAR.

To conclude, when considering constraints on HV voltage only, the rule-based algorithm and the OPF algorithm exhibit similar performances. However the rule-based algorithm is not a generic solution and is not flexible especially if other constraints on reactive power flows are considered.

VIII.3.4 Coordination of MV grids to support the HV voltages with EHV/HV reactive power limitation

In this second set of simulation, it has been assumed that the reactive power flowing upwards the EHV network should be reduced to 15 MVAR. This is a sensitive constraint that can be reached while using only the reactive power of DGs connected to the MV grids. The results are given by Figure VIII.11 for the HV voltages and by Figure VIII.12 regarding the reactive power.

Success of the association of the OPF-based strategy with the predictive VVCs

From the figures, the association of the OPF-based reactive power management and the proposed real-time control of distribution grids succeeds in enforcing suitable HV and MV voltages profiles while reducing the EHV/HV reactive power export.

In the figure the dotted lines embody the reactive power exchange that should be targeted by the VVC at the HV/MV interfaces. The first solution of the OPF-based strategy yielded at $t = 20$ s is realized. This solution consists in absorbing 3.5 MVAR downstream T_1 , 1.75 MVAR downstream T_2 and 1.75 downstream T_7 .

It could be found surprising that a different contribution for the MV grids downstream T_1 and T_2 is requested by the OPF, as both T_1 and T_2 are hosted within the same substation S_1 . However, these two specific MV networks exhibit quite a different level of active and reactive power flows, as a result, the active and reactive power losses inside each transformer (and the evolution) are quite different. And this difference constitutes a non negligible contribution for the minimization of active losses or to meet the EHV/HV reactive power target.

Possible enhancement of the reactive power management through a multi-step optimization methods ?

There is a small overshoot in the HV voltage upstream T_7 during the corrective process around $t = 400$ s. This overshoot is induced by a tap change of the EHV/HV transformer. Since the OPF strategy consists of a one-step-ahead optimization, it is not possible to anticipate that the corrective process can cause such a transient constraint violation.

However, it is possible to handle this concern by using a multi-step optimization that is to say by computing optimal trajectories for the HV/MV reactive power exchanges and the voltage reference of EHV/HV transformers.

Unwanted tap operations at MV side

The results of a specific MV grid (downstream the transformer T_2) are shown in Figure VIII.13. These results are more particularly interesting because one can observe inappropriate tap operations from the graph d.: a tap change up is immediately followed by a tap change down around $t = 140$ s.

Such inappropriate tap operations are induced by the incapacity of the predictive VVC to anticipate the true evolution of the HV voltage of the substation S_1 (and thus of the MV voltage profile). Indeed, the evolution of V_{S_1} is partly linked with the evolution of the HV/MV reactive power exchanges within the HV system. Since the short-circuit power of S_1 is rather low, and non negligible reactive power support are requested from the other networks, more specifically downstream T_1 , T_2 and T_7 , unsuitable tap changes are triggered.

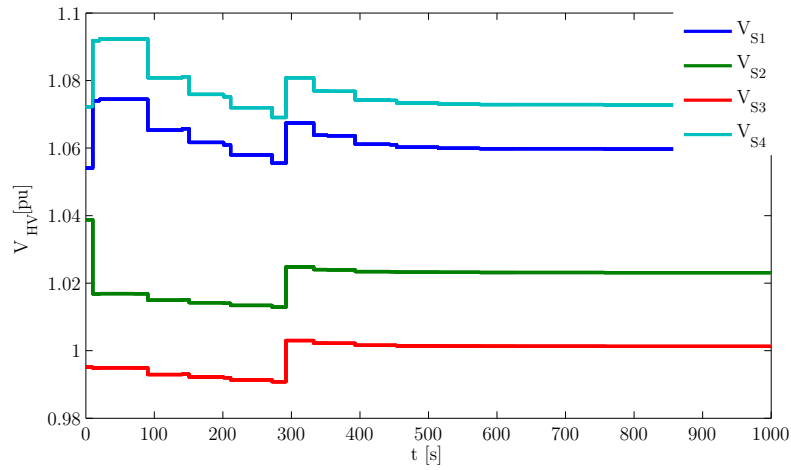


Figure VIII.11: Evolution of the HV voltages with the proposed reactive power management considering a EHV/HV reactive power limitation

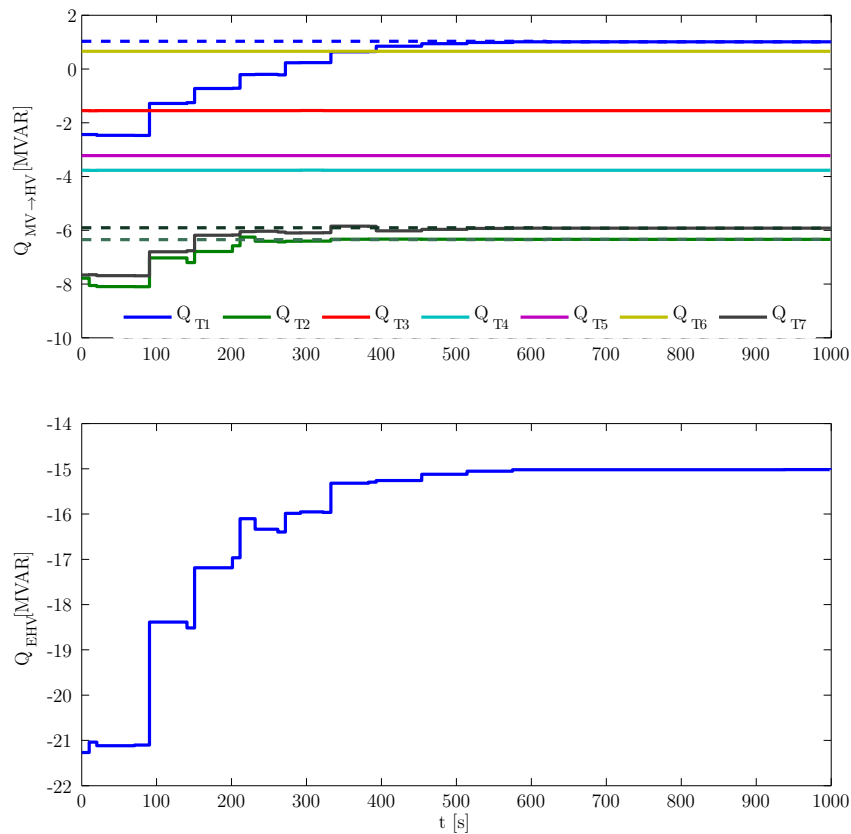


Figure VIII.12: Evolution of the reactive power flows within the HV system with the proposed reactive power management considering a EHV/HV reactive power limitation

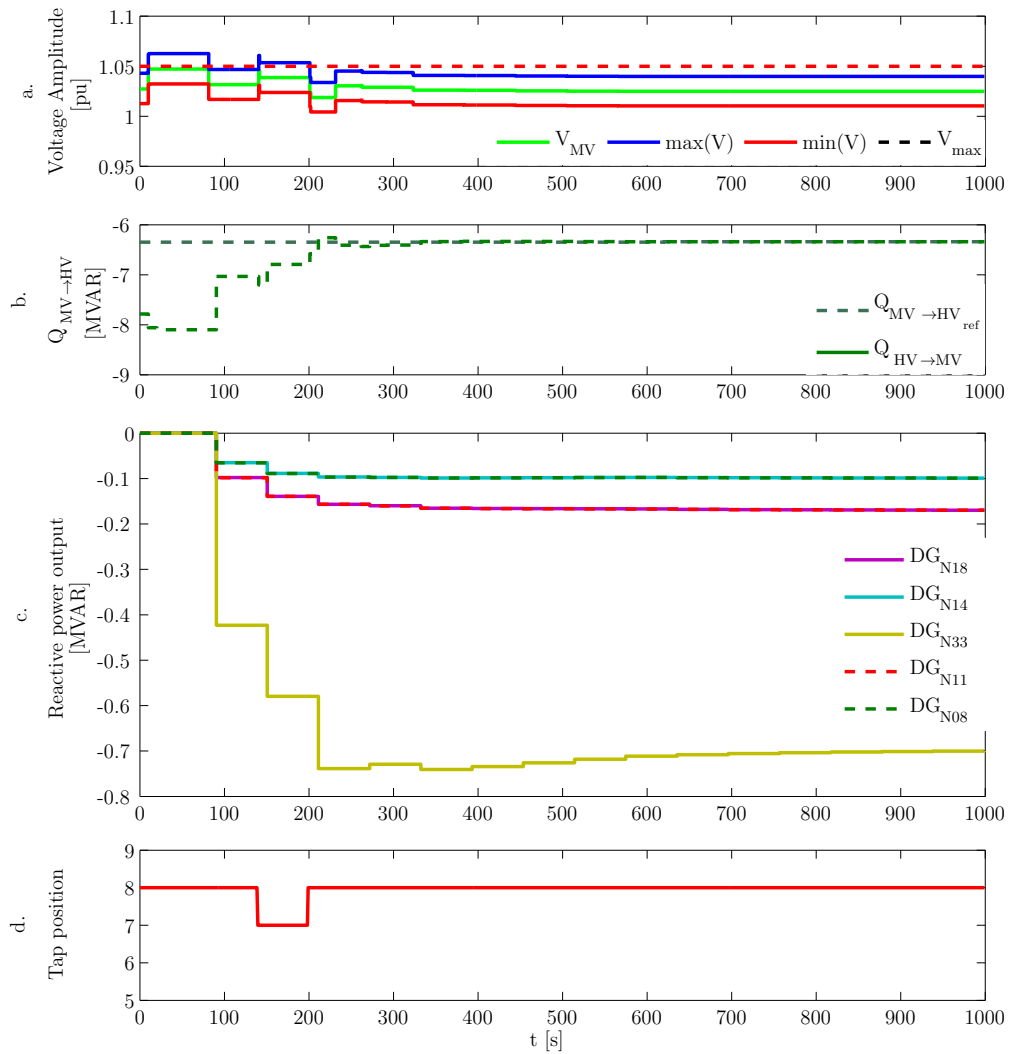


Figure VIII.13: Focus on the results of the MV grid downstream T_2 to illustrate the issue of inappropriate tap operations

VIII.3.5 Conclusion Performances of the OPF management and the MPV-VVC

It was shown through simulations that the proposed association of the OPF strategy and the predictive VVCs is suitable to maintain both appropriate HV and MV voltage profiles, while limiting the reactive power exports upwards the EHV network.

With the proposed hierarchical relaxation principle, it can be guaranteed that the steady state solution is admissible or close to an admissible solution for both TSO and DSOs. Indeed, the VVCs of MV grids give priority to the DSO objectives in the proposed scheme, and act independently from the others. Sometimes, it may happen that a given VVC fosters its MV voltage profile target at the expenses of the TSO objective (that can consider either a HV voltages target or a EHV/HV reactive power exchange target). In this case, at the next OPF control instant, the

reactive power reserve of MV grids is updated, and the OPF is able to find another alternative solution if needed.

Note that the solution is flexible enough if new devices are to be connected to the HV system, such new levers can be easily embedded in the optimization problem. Indeed, there are several solutions that can be considered to solve the HV voltage issues. One solution consists in using the reactive power reserve of distribution networks. However, when this reserve does not exist (or can barely be used by the DSO) as in present distribution networks, it implies that DSO should select and design new reactive power devices to be installed within its own networks, that can turn to be expensive. Since there exists alternative solutions, cost benefit analysis (taking both investments and operating costs into account) solutions should be performed to select an appropriate solution. For instance, enhancing the HV/MV OLTC procedure or connect shunt reactors at HV side of the power system can be considered

VIII.3.6 Perspectives: Possible enhancements of the OPF strategy

Nonetheless, the OPF-strategy can raise two concerns. First, it does not control the trajectory and the dynamic behavior of the HV levers and HV/MV reactive power exchanges. As a result, transient constraint violations within the HV system may happen. Next, since the local MV grids, that are controlled by independent VVCs, are coupled by their outputs and inputs through the HV system, the proposed association, that requires a limited communication between TSO and DSO, may trigger undesirable disturbances (such as inappropriate tap operations) within the MV grids.

The transient constraint violations can be handled by the means of a multi-step optimization to yield suitable references trajectory. On the other hand, it is difficult to deal with the issue of couplings between the VVCs of MV grids. Indeed, in a way, the VVCs of MV grids act in a coordinated manner to enforce the solution given by the OPF-based reactive power management. There are also coupled by their outputs and inputs through the HV system. If the HV voltages are stiff (in other words if the short-circuit powers of the neighboring HV/MV substation are rather high), this coupling is negligible [3]. Note that in the case of a stiff HV system, a possible reactive power support to ensure a suitable HV voltage profile is not really relevant. In other words, when there are strong couplings between MV grids (for instance in emergency situation), the proposed association could be enhanced by increasing the coordination between the VVCs. This would require an increased exchange of information [4].

More generally, the problem consists of several sub-systems (that are the distribution grids owned by one or several DSOs) that are coupled (through the HV system only that is operated by a TSO) that should be coordinated to meet common goals. There are several structures that can be considered: centralized, decentralized or distributed [5–7].

Since the system is rather complex and with various actors (TSO, DSOs...) and given that there are both global (reactive power support) and local objectives (MV voltage profile), it is relevant to target a coordination between TSO and DSOs based on the exchange of information. There are several way to realize the coordination among a distributed structure (i.e. a structure with some level of communication between the different sub-systems) through negotiation [5] or cooperation for instance. To ensure a suitable solution, each VVC controller should have a knowledge of:

- Future control actions of other VVCs (evolution of the neighboring HV/MV reactive power exchange) and HV levers (EHV/HV OLTC tap changes, reactive power output of any HV reactive power levers...);
- Model of the cross-couplings (that could be a priori known by the TSO). Such a model can consist of a linear sensitivity based model for instance.

For example, in [4], a coordination among several MPC controllers (more specifically HV parts of a power system owned by different TSOs) is proposed to maintain the multi-area power system voltages within acceptable bounds. The coordination is based on a distributed model predictive control structure. The application of such a method can be a way to enhance the proposed joint coordination between TSO and DSO.

Next, an increased coordination can also be reached by considering that TSO through the HV operations can also help the DSO to correct the MV voltage profiles in stressed conditions. For instance, if an OLTC has reached its saturation point, and the reactive power reserve is not sufficient downstream this specific OLTC, the DSO can send a request to the TSO in order to decrease the voltage at the HV busbar of this HV/MV substation. To meet this demand, the TSO can take advantage of MV networks cross-sensitivities or consider adjusting the voltage reference of EHV/HV OLTC.

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Conclusion on Part C: Recommendation for a joint DSO-TSO real-time reactive power management

In this last part, the consequences of the evolution of the reactive power flows at the interface between HV and MV systems on the HV system have been studied. The influence on HV voltage is correlated with the short-circuit power of HV/MV substation. The lower the short-circuit is, the more significant the influence on the HV voltages. Next, if there is reactive power export upwards from MV grids within the same area, there could be consequently a non negligible reactive power export upwards the EHV system at a specific EHV/HV substation. This may, in turn, jeopardize the voltage control at the EHV side of the network.

As a result, a reactive power support from the MV grids to mitigate the HV voltage drop or rises is relevant for weak HV/MV substations, namely rural networks that exhibit low short circuit powers or in case of an emergency. On the other hand, for HV/MV substations with a high short circuit power, such a reactive power support can still be of interest to help the EHV system.

Therefore, in this part, two methods have been proposed to set up a real-time reactive power management for a HV system that do not necessarily coincide with the requirements of the European Grid Codes, Demand and Connection. Indeed, it is considered in this code, that other solutions may exist and the technical and economical benefits should be assessed by TSO and DSO through joint analysis. The proposed reactive power management is assumed to be hosted within the Transmission Network Control Center that belongs to the TSO, and that the MV grids are equipped with the predictive VVC introduced in Part B. The TSO should define constraints on HV voltages and/or on the reactive power flows within the HV system to be enforced by the reactive power control. The control yields among others a reactive power target for each HV/MV interface, that are sent to the DSO and that should be achieved by the predictive VVC of the corresponding distribution grids.

A rule-based approach and an OPF-based approach have been proposed to realize such a support. The attractiveness of both methods has been shown through dynamic simulations on the medium-scale system that consists of several MV grids connected to the same HV system. In short, the second method, based on an OPF calculation is more flexible and generic and can easily handle lack of reactive power reserve, or find the best solutions according to a selected cost function.

It stands to reason that other solutions, that may not consist of real-time control or that do

not consider the use of reactive power from MV grids may exist to solve the possible voltage and reactive power issues at the interface between transmission and distribution networks. Next, since these concerns are specific to the considered system and may vary in time or in space, it might not exist a generic solution. At the end of the day, cost benefits analysis, taking both investments and operating costs into account, should be performed to compare the solutions. The main objective of our approach is to propose a generic method for the design of real-time joint reactive power management. Since the simulations have been carried out on a specific system, under specific conditions, the results are not to be generalized but enable to raise recommendations to set up a relevant and appropriate real-time DSO-TSO coordination. Several concerns are indeed of paramount importance:

- The constraints on the reactive power flows may require a significant reactive power support from MV grids. Networks planning studies should be jointly performed by TSO and DSO to ensure that the constraints are relevant and achievable;
- The management of the reactive power should result from a negotiation between TSO and DSO. For instance, in the case of an OPF-based strategy, the cost function to be minimized should be co-defined to find a trade-off that should correspond to a common-good solution;
- The reactive power reserve should be accurately known and shared in real-time to the TSO by the DSO in order to prevent lack of reactive power support and avoid constraints infeasibility.

General conclusion

Distribution networks are undergoing major physical evolutions. One of the main changes is the insertion of Distributed Generation within the distribution systems at Medium and Low Voltage level. Next, for safety and security purposes, more than 30 % of the French MV overhead lines have been replaced by underground cables. Then, the load is also changing these past few years, and a decrease in the reactive power consumption has been observed.

As a result, new operational concerns arise in the MV networks. The MV voltage profile is indeed more complex, since voltage rises are induced with the active production of DGs. Furthermore, a high level of underground cables along with low power consumption could lead to reactive power flowing upwards from MV networks to HV networks contributing to increase HV voltages and leading to the saturation of some existing HV/MV On Load Tap Changer. More generally, the active and reactive power exchanges at the HV/MV interface are more and more erratic and difficult to estimate. The HV/MV interface (typically 63/20 kV or 90/20 kV) embodies in France the Transmission System Operator and Distribution System Operator interface. However, an overall reduction even reversed power flows is to be expected with a high variability and uncertainty depending on the loading and production level.

This trend is also a concern with the requirements including in the European Grid Code on Demand and Connection. According to this code, new distribution system installations connected to the transmission system are required to have the capacity to restrain reactive power flows upwards at the TSO/DSO interface, especially at low active power consumption. As a consequence, alternative solutions to the traditional voltage control in distribution networks can be found relevant to mitigate the voltage rises and deal with the aforementioned operational constraints while keep increasing the level of DGs penetration. The traditional voltage and reactive power control methods have been introduced in Chapter I while the consequences of the technical and regulatory changes have been presented in Chapter II.

In Chapter II, the new drivers and technological limitations for voltage control and reactive power exchange management are further discussed. In short, the recent breakthroughs in communication technologies are paving the way for smart grid solutions and foster real-time control. Therefore, there could be several advantages of improving existing real-time control in order to get a more flexible and adaptive solution that would enable a better coordination of voltage and reactive power control. However one needs to make sure that the reliability of such a solution does not worsen the quality of supply compared to common solutions based on grid reinforcement and reactive power levers investments. Hence, real-time control and grid reinforcement should be combined together to optimize investments and quality of supply.

In our work, an original strategy based on the evolution of the real-time Volt Var Control (VVC) of distribution systems and on an increased coordination between DSO and TSO to handle the reactive power exchanges concern has been developed as explained in Chapter III. Chapter III is also dedicated to the presentation of the methodologies and tools that have been considered in this work.

Evolution of the real-time VVC of distribution network

It should be borne in mind that there exists a substantial literature on real-time voltage control for distribution networks. Chapter IV consists of a concise survey on real-time VVC for distribution networks. In this conclusion, we would like to emphasize the motivations and reasons for selecting and designing the proposed real-time VVC.

Admittedly, not every distribution networks necessarily require a real-time control solution. Actually, the penetration level of DGs and the replacement of overhead lines by underground cables can be quite different from an area to another. Consequently, it is of paramount importance to design a method that is flexible and adaptive enough. A solution towards active distribution networks have been proposed in this work, by adding a coordination algorithm to the actual operation of the distribution grids.

In short, in Chapter IV, the relevance of coordinated over decentralized strategies has been established in particular for multi-objective control. To handle the design of the control law, two methods are generally considered: either rule-based or optimization-based methods. The main advantage of selecting an optimization-based solution lies in the fact that such a method is generic and the optimality according to a chosen cost function is guaranteed. Next, a multi-step optimization approach such as Model Predictive Control exhibits attractive performances: it can deal with time-delays and can anticipate predictable disturbances. The receding horizon approach allows the system to track smoothly the desired state, as the introduction of slack variables helps to handle constraints infeasibility whenever needed. Then, inaccuracies in the models (usually based on sensitivity matrices and constant load models) can be easily accounted for through this closed-loop approach.

In this work, an original predictive real-time VVC (MPC-VVC) has been proposed in Chapter V. This controller is assumed to be hosted within the Distribution Network Control Center. In this DNCC, local measurements are retrieved in real-time (every minutes). The measurements consist of the power injections of DGs, and the power flows within the HV/MV substation. Next, it is also assumed that the DNCC host a Distributed State Estimator, thus the MV voltage is known. The DNCC is supposed to be able to send references every minute to several actuators: the OLTC, the DGs and CBs. At last, the topologies and a simplified model (based on sensitivities matrices) of the MV grids are assumed to be available in the DNCC. Note that such assumptions are closed to the technical capacities of present distribution networks.

The objectives of the control is to enforce a suitable MV voltage profile and limit the reactive power exchange at the HV/MV interface through the control of the $\tan_{HV \rightarrow MV}$ following a TSO demand. It should be noted that the concerns of reactive power exchange is generally not considered in the literature on coordinated real-time voltage control.

To this end, the VVC adjusts in a coordinated manner the voltage reference of the HV/MV OLTC, the reactive power references of DGs and Capacitor Banks. Compared to the literature the key points of the control are:

- The coordination of many actuators for both voltage regulation and reactive power exchange purposes;
- To guarantee the minimization of tap changes during all life of the OLTC since the criterion is explicitly considered in the cost function;
- Keeping and considering the classical OLTC inner control to avoid fundamental modifications of the existing control devices and operating process.

Next, a hierarchical relaxation of constraints has been developed in order to prioritize the different objectives and to tackle infeasibility issues. Moreover, the two sub-problems (voltage control and reactive power exchange regulation) can be partially uncoupled by separately tuning the convergence speed of each objective. A robustness study has concluded on the high robustness of the method in case of disturbances and the needs to have accurate models of actuators (OLTC, DGs, CBs) within the predictive controller.

Then, the performances of the proposed MPC-VVC compared to two other standards methods, that are a rule-based and an optimization based method have been assessed through simulations in Chapter VI.

Otherwise, the choice of controlling the $\tan_{HV \rightarrow MV}$ at the TSO/DSO interface is questionable. Indeed, this parameter can turn to be no longer an appropriate indicator for the characterization of the MV grids consumption. With the evolution of the distribution grids, the $\tan_{HV \rightarrow MV}$ exhibits a high variability and is hardly predictable. Next, in the case of a high DGs penetration level, the active power flows can change throughout the day from negative to positive values. When such a change of sign occurs, the value of $\tan_{HV \rightarrow MV}$ cannot be calculated. As a result, the reactive power value $Q_{HV \rightarrow MV}$ should be used instead.

A joint DSO-TSO coordination for reactive power management

The last part of this dissertation regards a reactive power support from MV grids for the TSO purposes, at the HV level (corresponding to 63 kV or 90 kV in France). More specifically, the choice of the reference values for the reactive power at the TSO/DSO interface to be tracked by the proposed VVC of distribution grids is investigated.

As a reminder one of the motivations for studying the voltage and reactive power exchange concerns at the TSO/DSO interface lies in the requirement of the European Grid Codes, Demand and Connection. In this code, it is mentioned that alternative solutions may exist and can be selected if the technical and economical benefits are jointly assessed by the TSO and the DSO through concerted analysis. Therefore two real-time methods have been proposed to set up a real-time reactive power management for a HV system that do not necessarily coincide with the DCC requirements.

In Chapter VII, the consequences for the HV system of the evolution of the reactive power flows at the HV/MV interface are discussed. Then, the expediency of using reactive power

support from MV grid is further investigated. Hence, the reactive power support from MV grid can be appropriate for:

- HV voltage control purposes when the short-circuit power of HV/MV substations is low, more specifically for rural networks or in case of emergency;
- EHV reactive power purposes. Indeed, when several MV grids are exporting reactive power within the same local area, the reactive power flows upwards EHV grids can become significant and in turn jeopardize the operations of the TSO.

To set up an appropriate and efficient reactive power support from MV grids, there are some prerequisites:

- MV grids should have a reactive power reserve and should be able to ascertain the real-time amount of reactive power reserve that depends on the prevailing conditions of both HV and MV networks;
- MV grids should have the capacity to call for such a reserve. In our work, it was assumed that the MV grids are equipped with the real-time predictive VVC introduced in Chapter V;
- TSO and DSO should be able to exchange relevant information and a communication infrastructure between their Control Centers (TNCC and DNCC) has been developed.

Next, the voltage and reactive power concerns are often considered from the TSO or the DSO point of view only. Also, either the requirements or true dynamic behavior of MV grid or HV system is neglected. As a result, to propose a relevant and efficient coordination between TSO and DSO, it is of paramount importance to develop co-simulation on a medium scale system, combining both transmission and distribution systems considering their own needs and control schemes.

The implementation of such a co-simulation is discussed at the end of Chapter VII and the tools and methodology developed within our works is more specifically detailed.

A first reactive power management based on a local naïve rule has been proposed. The reactive power support is assumed to be hosted within the TNCC. A reactive power request can be demanded by the TSO to the DSO according to a $Q = f(U)$ rule.

It was shown through dynamic simulations that this rule is appropriate for rural networks under emergency (line outage). More specifically, the relevance of the predictive VVC scheme was assessed. However, there are some limitations that cannot be handled by such a simple rule, for instance a lack of reactive power reserve. Next a rule-based solution is not generic and hardly adaptable. As a result, considering a common objective of reactive power at the EHV/HV interface can turn to be difficult.

In the last Chapter of this dissertation (Chapter VIII), an Optimal Power Flow based solution to overcome the aforementioned limitations of a rule-based approach has been proposed and tested through dynamic simulation on a medium scale system with several MV grid and a DNCC equipped with the predictive VVCs.

Again, the control designed in this last chapter is for a specific HV system and under specific conditions (a line outage) and can hardly be generalized. Nonetheless, several recommendations for designing such coordination can be given:

- A special attention should be given to the assessment of the reactive power reserve of distribution networks, and an updated reactive power reserve should be frequently sent to the TSO;
- The objectives of the control (HV voltage support or reactive power target at EHV/HV interface) should be realistic and achievable;
- The cost function should be negotiated by both TSO and DSO to avoid an immoderate effort from the MV grids.

Such a coordination (compared to the requirements of the DCC) enables to spare reactive power support from MV grids. Thus, the need in reactive power reserve is decreased when considering the coordination, even with strict constraints on HV voltages and reactive power flows at the EHV/HV interface. The size of the reactive power reserve depends on the needs and requirements of the TSO. If the objective is to only correct the HV voltages, the needs are quite reduced. However, when a reactive power limitation at the EHV/HV interface is required, the reactive power reserve can significantly increase. Next, this need vary depending on the considered HV and MV grids (short-circuit power, rural or urban areas, lines and cables parameters, level of DGs penetration...). Consequently, in our view, having the same reactive power requirements at each HV/MV systems interface is not an optimal nor a cost-effective solution.

Future works

As a conclusion, there are several future work opportunities to this study. Our work was indeed more specifically focused on proposing real-time solutions for voltage and reactive power control at the distribution level and at the interface of HV/MV system that embodies in France the boundary between TSO and DSO. The proposed solution are flexible enough to consider any new levers if needed.

However, the network planning and connection studies were beyond the scope of our work. These concerns are yet of paramount importance. Indeed, it is clear that there are alternative solutions from using the reactive power from MV grids to support the HV voltage and reactive power management.

It was shown that the need in reactive power reserve is strongly correlated with the objectives of the control at the TSO side. For instance, the needs are quite limited if the only purpose is to enforce a suitable HV voltage profile in a rural network. And in the case of a stronger and stiffer HV transmission network, there is no point using the reactive power of MV grids to mitigate voltage rises or droop. Also, a generic solution may not be found. In order to select the most appropriate solution, cost benefit analyses that take both operational and investment costs into account, should be performed.

A second point regards the assessment of the reactive power reserve of distribution grids. Indeed, in our work, it was assumed that such a reactive power reserve exists and that the DSO is able to evaluate accurately and call for this reserve in real-time. This constitutes a quite strong assumption since the reactive power reserve varies in time and depending on the active power injections of DGs. The study of the reactive power reserve and modeling is one of the topics of PhD work at the L2EP in partnership with Enedis that has started in September 2015.

Then, regarding, real-time VVC for active distribution networks, in order to assess the adequateness of the proposed linear model for the MPC prediction equation based on sensitivity matrices, an a-posteriori verification can be considered. For instance, the auto-correlation function analysis might be included with respect to the residuals of the predicted voltages versus the obtained voltages, active and reactive powers.

Another perspective for real-time control, is to further investigate hybrid strategies, that are a combination of a global centralized control and several local controllers, typically for small DG unit. Thus, it could be possible to reduce the needs in communication equipment.

At last, using a real-time control based on the reactive power of DGs for the MV grids can lead to radically change the dynamics of distribution networks. Also, it should be checked that such a change would not affect the overall stability of the power system or the usual operations of HV and EHV systems.

To sum up, in this work, we have tackle the concerns of Enedis regarding the consequences of the evolution of the distribution systems on voltage and reactive power control at the HV/MV systems interface. To address the issue raised by this evolution, two real-time control schemes have been proposed and associated for voltage regulation and reactive power management. One control is dedicated for MV grids and consists of a predictive real-time VVC hosted in the DNCC and compliant with present industrial requirements. This control is able to enforce a suitable MV voltage profile and limit the reactive power exchange at the HV/MV interface by using in a coordinated manner the OLTC, the DGs and CBs of a specific MV grid. The second control is a reactive power management within a HV grid located in the TNCC that relies on a reactive power support from MV grids. The objectives of the control are to enforce a suitable HV voltage profile and to control the reactive power exchange at the EHV/HV interface. This second control is assumed to be slower than the predictive VVC of MV grids; it more specifically adjusts the reactive power reference at the TSO/DSO interface to be targeted by the VVC of MV grids. The relevance of using an OPF based strategy for the reactive power management has been shown through dynamic simulations in a medium-scale systems and considering the VVC of MV grids.

The main contributions of this work lie in the recommendations given that enable Enedis to consider several solutions for the future industrial choices to set up an efficient real-time control for distribution networks and an appropriate joint TSO/DSO reactive power management for the HV system purposes.

Appendix

Appendix A: Simplified three feeders 20 kV grid

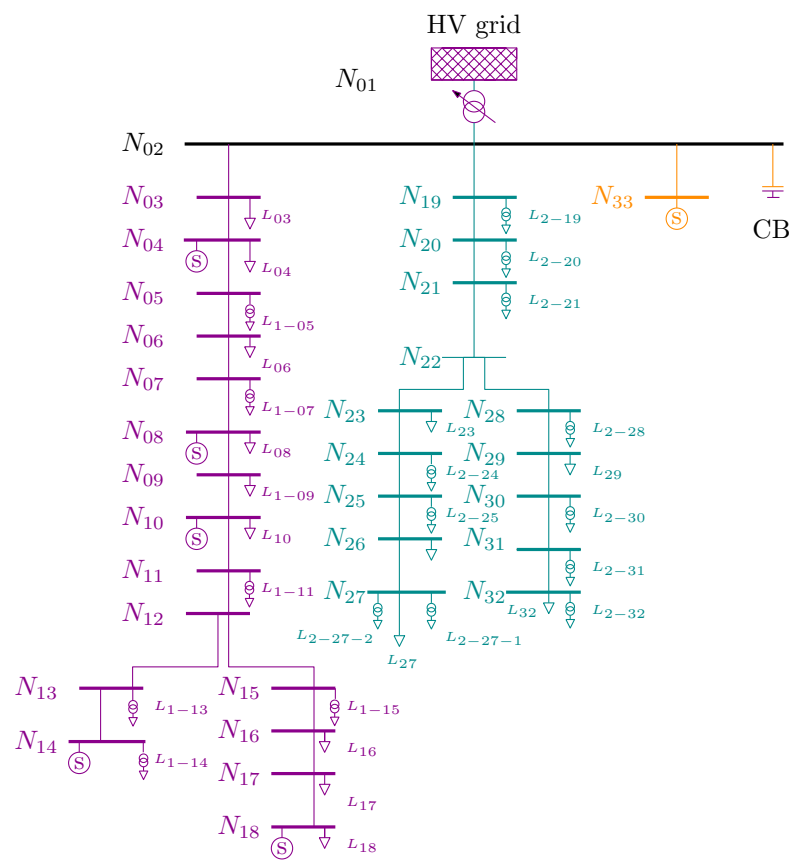


Figure VIII.14: One-Line Diagram of the 3 feeders MV grid

The simplified MV network that encompasses three types of feeders (dedicated, mixed and with only load) is illustrated in Figure VIII.14.

In this feeder, there are 6 DGs further described in Table VIII.5. The loads are given by Table VIII.6. Three load models have been considered in the dynamic simulations:

- **Z**: constant impedance;
- **I**: constant current;
- **Small motor**.

The parameters of the small motor model are given in Table VIII.4 below.

Table VIII.4: Small motor parameters

RS	LLS	LSR	RR	LLR	H	A	B	LF
0,013	0,067	3,8	0,009	0,17	1,5	0,5	0	0,8

Table VIII.5: Description of DGs associated with the 3 feeders MV network

Name	Bus	P_{max} (MW)
DG1	N04	5,5
DG2	N08	3,2
DG3	N10	1
DG4	N14	1
DG5	N18	1
DG6	N33	14,2

Table VIII.6: Description of loads associated with the 3 feeders MV network

Name	Bus	P_{max} (MW)	Q_{max} (MVAR)	Model P	Model Q
L03	N03	0,525368	0,2101473	Small motor	
L04	N04	0,412204	0,1648816	I	Z
L06	N06	0,3753633	0,1501453	Small motor	
L08	N08	0,3829167	0,1531667	I	Z
L1_05	N1_05	0,2504086	0,1001635	I	Z
L1_07	N1_07	0,1479127	5,92E-02	I	Z
L1_09	N1_09	0,1146974	4,59E-02	I	Z
L1_11	N1_11	7,66E-02	3,07E-02	Small motor	
L1_13	N1_13	0,1337008	5,35E-02	I	Z
L1_14	N1_14	0,1217701	4,87E-02	Small motor	
L1_15	N1_15	9,57E-02	3,83E-02	I	Z
L10	N10	8,81E-02	3,52E-02	Small motor	
L16	N16	0,1533161	6,13E-02	Small motor	
L17	N17	0,403419	0,1613676	I	Z
L18	N18	0,2735921	0,1094369	I	Z
L2_19	N2_19	7,13E-02	2,85E-02	Small motor	
L2_20	N2_20	0,1713438	6,85E-02	I	Z
L2_21	N2_21	0,1713609	6,85E-02	I	Z
L2_24	N2_24	0,1603307	6,41E-02	I	Z
L2_25	N2_25	5,37E-02	2,15E-02	Small motor	
L2_27_1	N2_27_1	0,8238742	0,3295497	I	Z
L2_27_2	N2_27_2	0,3042654	0,1217062	I	Z
L2_28	N2_28	0,1327954	5,31E-02	I	Z
L2_30	N2_30	7,27E-02	2,91E-02	Small motor	
L2_31	N2_31	0,138299	5,53E-02	I	Z
L2_32	N2_32	0,770677	0,3082708	I	Z
L23	N23	0,1845203	7,38E-02	I	Z
L26	N26	0,3908069	0,1563227	I	Z
L27	N27	0,2866366	0,1146546	I	Z
L29	N29	5,23E-02	2,09E-02	Small motor	
L32	N32	0,1564431	6,26E-02	I	Z

Table VIII.7: MV/LV transformers of the 3 MV feeders network

Name	From Bus	To Bus	R (%)	X (%)	Ratio	S_{nom} (MVA)
Tr2_20	N20	N2_20	1,15	3,831122	102,5	0,4
Tr2_31	N31	N2_31	1,15	3,831122	102,5	0,4
Tr2_30	N30	N2_30	1,031746	3,864647	100	0,63
Tr2_27_1	N27	N2_27_1	1,031746	3,864647	100	0,63
Tr2_28	N28	N2_28	1,3	3,782856	102,5	0,25
Tr2_27_2	N27	N2_27_2	1,031746	3,864647	100	0,63
Tr2_25	N25	N2_25	1,15	3,831122	102,5	0,4
Tr2_19	N19	N2_19	1,031746	3,864647	100	0,63
Tr1_05	N05	N1_05	1,031746	3,864647	100	0,63
Tr1_09	N09	N1_09	1,3	3,782856	102,5	0,25
Tr2_24	N24	N2_24	1,15	3,831122	102,5	0,4
Tr2_21	N21	N2_21	1,15	3,831122	102,5	0,4
Tr2_32	N32	N2_32	1,15	3,831122	102,5	0,4
Tr1_07	N07	N1_07	1,15	3,831122	102,5	0,4
Tr1_13	N13	N1_13	1,3	3,782856	102,5	0,25
Tr1_11	N11	N1_11	1,3	3,782856	102,5	0,25
Tr1_15	N15	N1_15	1,3	3,782856	102,5	0,25
Tr1_14	N14	N1_14	1,3	3,782856	102,5	0,25

Table VIII.8: Lines of the 3 MV feeders network

Name	From Bus	To Bus	R (Ω)	X (Ω)	WC/2 μS	S_{nom} (MVA)
D3_02_33	N02	N33	1,09	0,549779	227,765472	60
D2_30_31	N30	N31	1,508	0,338161	85,765472	60
D2_28_29	N28	N29	1,276	0,286136	72,570786	60
D1_12_13	N12	N13	1,3464	0,816007	2,438033	60
D1_10_11	N10	N11	0,749916	0,27026	88,435837	60
D1_13_14	N13	N14	0,9216	0,55855	1,668814	60
D1_03_04	N03	N04	0,35316	0,178128	73,796013	60
D2_24_25	N24	N25	0,442365	0,666615	2,332633	60
D1_15_16	N15	N16	0,2664	0,096007	31,415928	60
D2_26_27	N26	N27	0,58982	0,888819	3,110177	60
D2_31_32	N31	N32	1,566	0,351167	89,064148	60
D1_11_12	N11	N12	0,164808	0,083127	34,438137	60
D2_20_21	N20	N21	0,64344	0,969621	3,39292	60
D1_04_05	N04	N05	0,115976	0,058496	24,234245	60
D1_12_15	N12	N15	0,39627	0,142811	46,731194	60
D2_19_20	N19	N20	0,720272	0,363294	150,507416	60
D1_06_07	N06	N07	0,538794	0,194174	63,538715	60
D1_09_10	N09	N10	0,5232	0,263894	109,327431	60
D2_22_28	N22	N28	1,392	0,312149	79,168137	60
D2_29_30	N29	N30	1,392	0,312149	79,168137	60
D2_22_23	N22	N23	0,8043	1,212026	4,24115	60
D2_23_24	N23	N24	0,825748	1,244347	4,354247	60
D1_05_06	N05	N06	0,279912	0,141183	58,490173	60
D2_02_19	N02	N19	0,7848	0,395841	163,991135	60
D1_02_03	N02	N03	0,410712	0,207157	85,822021	60
D1_08_09	N08	N09	0,436	0,219911	91,106186	60
D1_17_18	N17	N18	2,88	1,745469	5,215044	60
D2_21_22	N21	N22	0,96516	1,454432	5,08938	60
D2_25_26	N25	N26	0,48258	0,727216	2,54469	60
D1_16_17	N16	N17	2,16	1,309102	3,911283	60
D1_07_08	N07	N08	0,177156	0,063845	20,891592	60

Appendix B: Medium scale system

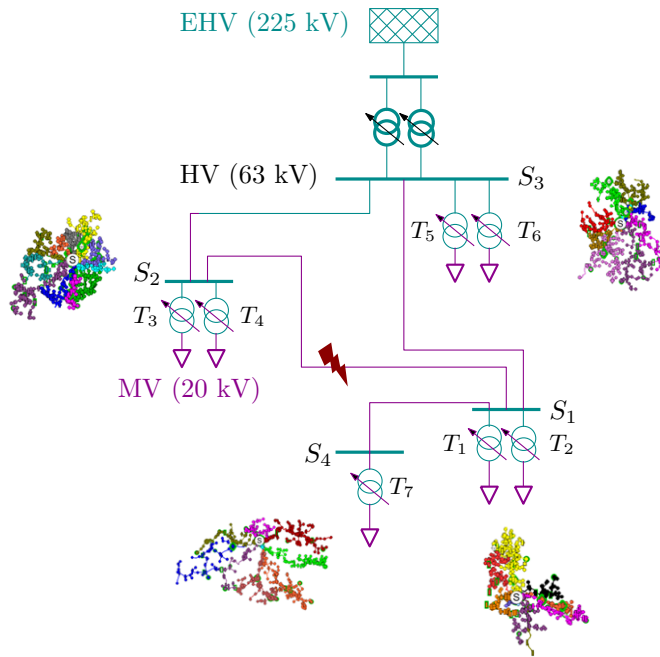


Figure VIII.15: Medium scale system combining HV grid and several MV networks, visualization of the real 20 kV network topology

Table VIII.9: HV Lines parameters

Line	R (Ω)	X (Ω)	WC/2(μS)	S_{nom} (MVA)
L_{HV-S2}	5.94	14.487	22.462	189
L_{S2-S1}	5.168	8.925	30.00	189
L_{S4-S1}	4.452	10.39	37.542	189
L_{S1-HV}	6.216	13.796	49.48	189

Table VIII.10: HV Transformers' parameters

Transformers	V_{1nom} (kV)	V_{2nom} (kV)	R (%)	X (%)	S_{nom} (MVA)
T_9, T_{10}	225	63	0.232966	11.99774	70

Table VIII.11: MV Transformers' parameters

Transformers	V_{1nom} (kV)	V_{2nom} (kV)	R (%)	X (%)	S_{nom} (MVA)
T_1, T_2	63	21	0.06125049	18.742400775	36
T_3, T_5, T_6	63	21	0.0826875	13.229746425	20
T_4	63	21	0.0937125	13.22966925	20
T_7	63	21	0.052062255	13.229900775	36

Appendix C: Résumé en Français

L'objectif de cette partie est de proposer une synthèse en français du manuscrit de thèse. Aussi, seule la méthode ainsi que les principaux résultats sont présentés de manière concise, avec un renvoi vers les parties correspondantes du mémoire complet.

Les travaux ont été financés par le principal gestionnaire du réseau de distribution français : Enedis, et ont été menés au sein de l'équipe réseau du laboratoire d'électronique et d'électrotechnique de puissance de Lille (L2EP). Les objectifs de la thèse étaient de mesurer en quoi les évolutions des réseaux de distribution pourraient modifier les problématiques de réglage de la tension à l'interface entre les réseaux de transport et les réseaux de distribution, puis de proposer et de comparer des solutions permettant d'améliorer, pour le futur, la coordination des moyens de réglage existants ou à développer.

Dans un premier temps, les conséquences des évolutions du réseau de distribution, plus spécifiquement relatives au maintien du plan de tension, sont étudiées. Ces études permettent de dresser les objectifs des travaux de doctorat et de présenter la démarche de travail qui a été entreprise. La seconde partie de cette synthèse est dédiée à la définition d'une commande temps réel pour le réglage de la tension dans les réseaux de distribution également capable de limiter les échanges de puissance réactive à l'interface HT/MT. La dernière partie est consacrée à la proposition d'une gestion commune GRT/GRD des échanges de puissance réactive. Cette gestion définit notamment les valeurs de puissance réactive qui doivent être respectées par les fonctions temps réel des réseaux de distribution.

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Chapitre I

Réglage de la tension dans les réseaux de distribution et contrôle des échanges de puissance réactive à l'interface réseaux de distribution/réseau de transport

I.1 Structure et contrôles traditionnels des réseaux électriques

Le réglage de la tension est d'une importance capitale pour assurer le bon fonctionnement des réseaux électriques. Ce contrôle vise à maintenir les tensions dans des plages acceptables qui sont définies notamment par des normes. En effet, une tension trop élevée peut endommager les équipements électriques tandis qu'une tension anormalement basse peut conduire à des dysfonctionnements. Les Gestionnaires des Réseaux de Transport et de Distribution (GRT, GRD) sont plus spécifiquement responsables du maintien de plan de tension sur leur propre réseau.

Cette section (correspondant au Chapitre I du mémoire complet) est dédiée à la présentation des réglages traditionnels de tension dans le système électrique. Un tel réglage peut être réalisé notamment par une gestion adéquate de la puissance réactive. Après des considérations générales sur les réseaux électriques, le rôle du GRT et du GRD sont rappelés (I.1.1) ainsi que les structures traditionnelles de contrôle (I.1.2).

I.1.1 Les réseaux publics d'électricité

I.1.1.a Structure générale du système électrique

Les réseaux électriques peuvent être séparés en trois grandes catégories fonctionnelles avec des tensions d'exploitation distinctes [1] comme illustré dans la Figure I.1 :

- Réseau de transport exploité à Très Haute Tension (THT) ce qui correspond à un niveau de tension de 400 kV en France, encore appelé HTB3 ;
- Réseau de répartition correspondant à la Haute Tension (HT) qui est supérieure à 36 kV d'après les normes Européennes. En France, la tension d'exploitation est dite HTB1 (63 kV, et 90 kV) ou HTB2 (150 et 225 kV) suivant le niveau de tension ;
- Réseau de distribution à Moyenne Tension (MT) (entre 1 et 36 kV) et Basse Tension (BT) inférieur à 1 kV. En France, le niveau MT ou HTA correspond à une tension d'exploitation de 20 kV (parfois 15 kV), tandis que la tension BT correspond à une tension 400 V.

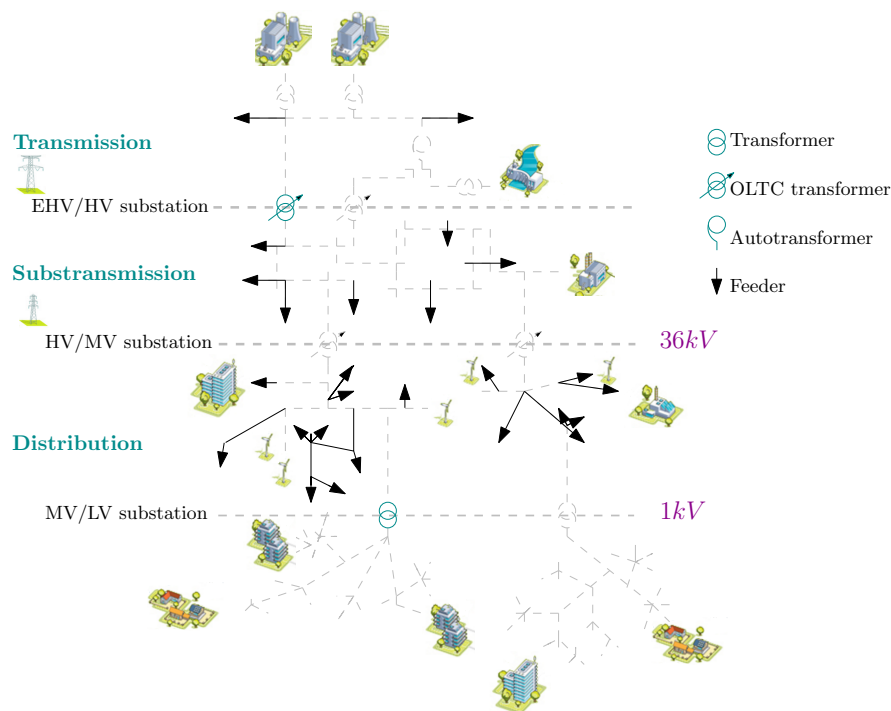


FIGURE I.1 – Structure du système électrique [1]

La plupart des grandes unités de production (Centrales nucléaires, fossiles ou hydroélectriques...) sont raccordées sur le réseau de transport. Ce réseau, très étendu, constitue la principale structure du réseau électrique. Les réseaux HT sont connectés au réseau THT via des postes haute tension dans lesquels des transformateurs THT/HT abaissent la tension. Le rôle du réseau de répartition est de transporter l'électricité depuis le réseau de transport jusqu'au réseau de distribution et aux grands consommateurs industriels. Généralement, le terme réseau de transport désigne à la fois le réseau de transport et de répartition.

La tension HT est transformée en tension MT dans les postes sources via des transformateurs. Les postes sources marquent donc une frontière physique entre réseaux de transport et de distribution. La fonction du réseau de distribution est d'acheminer l'électricité aux consommateurs finaux à deux niveaux de tension. Les réseaux MT auxquels sont connectés les clients industriels de taille moyenne, ainsi que les productions décentralisées ou Générations d'Énergie Dispersée (GED) avec une production significative, ainsi que les postes de distribution. La puissance MT est transformée dans les postes de distribution en puissance BT. Les réseaux BT alimentent ensuite tous les clients résidentiels, commerciaux et industriels de petites tailles, ainsi que les GEDs de faible puissance active.

I.1.1.b Le réseau public de distribution français

Le réseau français de distribution MT comporte 2 240 postes sources HT/MT (qui sont généralement du type HTB1/HTA voire plus rarement HTB2/HTA), 1.3 millions kilomètres de lignes

et de câbles, et 751 000 postes de distribution MT/BT (HTA/BT)¹. 30 Agences de Conduite Régionales (ACR) sont responsables de la bonne conduite du réseau de distribution dans une région prédéfinie. Les outils de conduite sont hébergés dans ces centres de contrôle. Enfin, 232 636 sites de production sont raccordés au réseau de distribution.

Comme dans la plupart des réseaux de distribution européens, le réseau HTA a une structure bouclée mais est exploité de manière radiale afin de simplifier, entre autre, la mise en place des plans de protection ou encore la détection d'éventuels incidents.

Enfin, en France, la majeure partie du réseau de distribution est détenue par les autorités locales.

I.1.1.c Gestionnaires du réseau de distribution et de transport

Par définition, le gestionnaire est responsable de "la conception, de la construction, de l'exploitation, de l'entretien et du développement d'un réseau de transport ou de distribution d'électricité [...], assurant l'exécution des contrats relatifs à l'accès des tiers à ces réseaux"². Aussi, l'une des prérogatives des GRT et GRD est-elle donc d'assurer le maintien d'un plan de tension acceptable dans leurs propres réseaux. En France, Enedis est l'un des principaux GRD, et est notamment responsable de près de 95 % du réseau de distribution français, tandis que le GRT est RTE.

I.1.2 Réglages traditionnels de la tension dans les réseaux de transport et de distribution

I.1.2.a Stratégie de contrôle dans les réseaux de distribution

Afin de satisfaire aux exigences normatives, législatives et contractuelles relatives au maintien de la tension, Enedis a mis en place des politiques industrielles qui reposent sur des études de dimensionnement. Les principaux leviers considérés dans ces études sont : le régleur en charge, les régleurs hors charge, ainsi que les bancs de condensateurs. Ces actionneurs possèdent des lois de contrôle locales, dont la consigne est définie par les études de dimensionnement et de planification. La Figure I.2 schématise le principe du réglage de la tension dans le réseau de distribution.

Actuellement le réglage de la tension est réalisé au moyen de :

- **Régleurs en charge** situés au niveau des transformateurs HTB/HTA par pas d'environ 1% pour ajuster la tension au secondaire du transformateur autour d'une tension de consigne. Dès que la tension dépasse la tension de consigne au delà d'une certaine valeur (la demande morte), un changement de prise est initié par l'algorithme de contrôle interne du régleur en charge. Finalement, les plans de tensions HTB et HTA sont décorrélés par l'action du régleur en charge tant que celui-ci n'est pas en butée.
- **Les régleurs hors charge** au niveau des transformateurs HTA/BT. Dans l'enroulement primaire des transformateurs quelques prises peuvent être manuellement ajoutées ou sup-

1. <http://www.erdf.fr/fonctionnement-du-reseau>.

2. Selon la définition de la CRE, <http://www.cre.fr/glossaire/gestionnaire-de-reseau-de-transport-ou-de-distribution>

primées. Ce réglage est effectué hors tension, aussi il reste rare et est effectué à l'occasion de travaux.

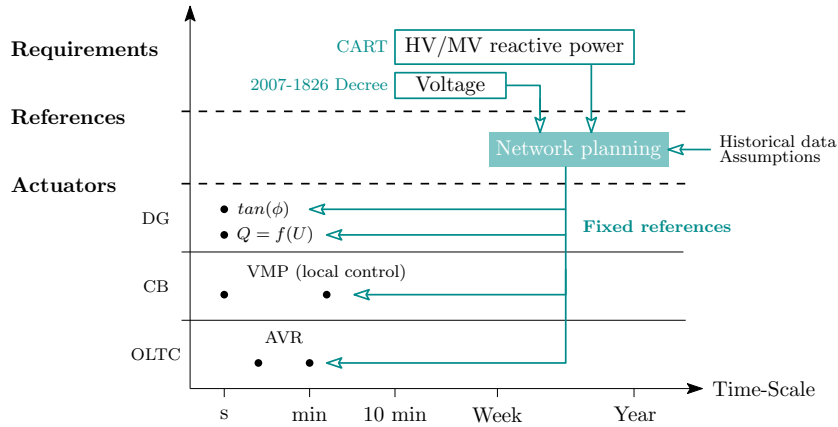


FIGURE I.2 – Stratégie actuelle du réglage de la tension et de la puissance réactive dans les réseaux français de distribution

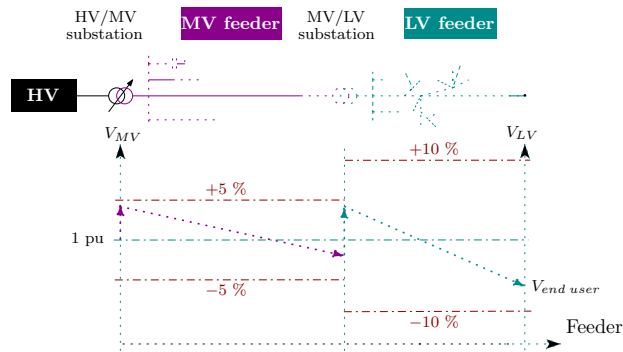


FIGURE I.3 – Evolution de la tension le long d'un départ MT sans production significative

Ces deux moyens de réglage ne peuvent être dissociés, car si la tension HTA est plus ou moins indépendante de la tension HTB, ce n'est pas le cas de la tension BT qui est directement reliée au plan de tension HTA comme illustré dans la Figure I.3 ci-dessus.

Dans les réseaux de distribution, il n'y a pas de lien fort entre la tension et la puissance réactive. Cependant, la puissance réactive reste nécessaire au bon fonctionnement du réseau [2]. Généralement, pour réaliser une compensation de puissance réactive, le moyen le plus couramment utilisé est le gradin de condensateurs. En France, les gradins de condensateurs ont principalement été installés au secondaire des postes sources HTB/HTA pour compenser la consommation en puissance réactive en aval des réseaux de distribution.

Les politiques industrielles développées par Enedis sont des solutions telles que le renforcement de réseau ou encore des solutions du type "fit and forget". C'est-à-dire que tout nouvel

équipement à connecter au réseau de distribution est dimensionné pour éviter des sur/sous tensions et ce dans les conditions les plus critiques (pires cas possibles, c'est-à-dire à forte consommation et faible production, ou inversement à faible consommation et forte production). Puisque les réseaux de distribution ont été conçus au départ pour la distribution d'électricité exclusivement, c'est à dire avec seulement des clients consommateurs d'électricité, seuls des transits unidirectionnels étaient possibles. Aussi, le maintien du plan de tension se limitait alors à atténuer d'éventuelles chutes de tension le long des départs. Avec l'insertion des productions décentralisées, le choix de la tension de consigne $V_{OLTCref}$ des régulateurs en charge HTB/HTA est un peu plus délicat, il faut également s'assurer qu'il n'y a pas de surtension. Enedis a développé la politique suivante :

- $V_{OLTCref} = V_{nom} + 4\%$ pour les départs avec un niveau faible de pénétration de GEDs ;
- $V_{OLTCref} = V_{nom} + 2\%$ pour les départs avec un fort taux de pénétration de GEDs ;

Par ailleurs, dans les études de planification, Enedis vérifie que l'élévation de tension dans un départ est inférieur à 2 %.

Aujourd'hui, la puissance réactive des productions décentralisées est utilisée pour minimiser les coûts associés au renforcement de réseau. Pour ce faire, un facteur de puissance de l'installation $\tan(\phi_{DG})$ est imposé pour les producteurs en départ mixte. Aussi, ce réglage n'est pas à proprement parler un levier de réglage de la tension, mais un moyen de réduire les coûts de connexion des installations GED dans le réseau de distribution. Enedis a également mis en place une loi $Q = f(U)$ qui module en temps réel l'injection de puissance réactive d'une installation donnée en fonction de la tension à ses bornes. Aussi, par rapport à une solution où un facteur de puissance constant est imposé, l'installation est sollicitée seulement lorsque c'est nécessaire pour assurer un plan de tension HTA acceptable.

I.1.2.b Stratégie de contrôle à l'interface HT/MT

Le lien entre le réseau de distribution et de transport est défini par le décret du 6 Octobre 2006. Ce décret stipule que les GRT et le GRD doivent agir conjointement pour assurer le bon fonctionnement du système électrique. Aussi, la gestion des plans de tension et de la puissance réactive sont des objectifs primordiaux. Le lien est également défini par le CART (Contrat d'Accès au Réseau de Transport). Dans ce document, la valeur du facteur de puissance à respecter pour la période hiver, entre 6h et 22h, à l'interface HTB/HTA est spécifiée.

Enfin, les exigences qui peuvent être demandées par le GRT en cas de situations d'urgence sont également détaillées :

- Abaissement de 5 % de la tension de consigne des régulateurs en charge HTB/HTA pour diminuer temporairement la consommation ;
- Blocage des régulateurs en charge pour éviter le phénomène d'écroulement de la tension ;
- Délestage des départs HTA.

I.1.2.c Stratégie de contrôle dans le réseau de transport en France

Comme pour la plupart des pays Européens, le réglage de la tension dans le réseau THT Français est un réglage hiérarchisé, organisé en trois grands niveaux.

En bref, le réglage primaire de tension (PVC) régule automatiquement l'injection de puissance réactive des générateurs afin de respecter un plan de tension déterminé. Ce plan de tension est défini par le réglage secondaire (SVC) dont l'objectif est de coordonner les ressources en puissance réactive pour respecter la tension en des noeuds pilotes. Un noeud pilote est un noeud représentatif de la tension dans une zone géographique particulière et électriquement indépendante. Enfin, le réglage tertiaire (TVC) de tension, est un réglage manuel effectué dans le centre de dispatching pour coordonner les plans de tension des noeuds pilotes.

La Figure I.4 schématise le principe du réglage de la tension dans le réseau de transport.

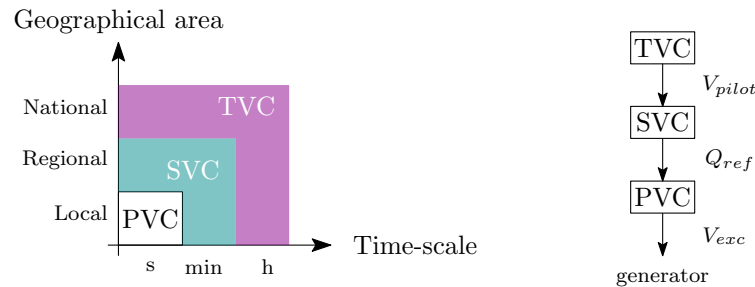


FIGURE I.4 – Structure du réglage hiérarchisé de tension dans le réseau de transport français

Dans le réseau HTB1, le réglage de la tension est peu développé. Le plan de tension est maintenu à l'aide de régulateurs en charge THT/HTB1 dont la tension de consigne peut être ajustée à distance.

I.2 Évolutions physique et réglementaire des réseaux de distribution : le besoin de nouvelles solutions

Ces dernières années, les réseaux de distribution ont connus des évolutions majeures qui remettent en question les solutions traditionnelles pour le réglage de la tension et la gestion de la puissance réactive.

I.2.1 Problématiques liées aux évolutions du réseau de distribution et aux nouvelles exigences réglementaires

I.2.1.a Conséquence des changements des réseaux de distribution

L'insertion de la production décentralisée

L'insertion massive de GEDs principalement au niveau des réseaux MT et BT a modifié le fonctionnement des réseaux de distribution [3–7]. En premier lieu, l'hypothèse de transit unidirectionnel de la puissance n'est plus forcément valide, et on peut observer des inversions de puissance au niveau des postes sources HTB1/HTA. Sans être exhaustif, ces évolutions ont notamment un impact sur le maintien du plan de tension et la gestion des flux de puissance réactive :

- Impact sur le plan de tension : élévation de tension avec l'injection de puissance active des GEDs à leur point de connexion et au voisinage de l'installation ;
- Impact sur les flux de puissances qui deviennent de plus en plus difficilement prévisibles et qui peuvent s'inverser au niveau des postes sources HTB1/HTA. En effet, dans le cas particulier des productions renouvelables qui dépendent des conditions météorologiques, il peut exister des fluctuations importantes de puissance plus ou moins rapides. Par ailleurs, cela réduit l'observabilité de la charge en aval des transformateurs HTB1/HTA, et a notamment conduit à l'abandon de la technique de compoundage utilisée pour régler les tensions de consigne des régulateurs en charge HTB1/HTA.

A noter qu'en France, le raccordement de toute unité de production supérieure à 36 kA implique une étude complète de planification afin de déterminer les conséquences possibles sur le réseau (notamment sur le plan de tension) et s'il est nécessaire de réaliser un renforcement de réseau qui peut alors s'avérer un investissement important. D'un autre côté, si de tels investissements ne sont pas réalisés, une saturation de la capacité d'accueil du réseau peut se produire [8]. Afin de soutenir l'insertion des GEDs sans compromettre les opérations du GRD et du GRT, des solutions alternatives et moins coûteuses que le renforcement de réseau peuvent être imaginées. Ces solutions doivent en particulier pouvoir faire face aux problématiques d'élévation de tension ainsi que l'incertitude et la variabilité des flux de puissance.

Remplacement des lignes aériennes par des câbles souterrains

Depuis plusieurs années, un remplacement des lignes aériennes par des câbles souterrains a été effectué dans les réseaux de distribution pour des questions de sûreté et de maintenance. Aujourd'hui près de 40 % du réseau HTA et 25 % du réseau BT est constitué de câbles souterrains. Cependant, ce changement modifie les flux de puissance réactive. En effet, si un conducteur (ligne ou câble) est chargé au delà de sa puissance naturelle, celui-ci aura un comportement inductif, tandis que chargé en deçà de sa puissance naturelle, son comportement sera capacitif [9]. Or, la puissance naturelle d'une ligne aérienne est supérieure à celle d'un câble souterrain comme en témoigne la Table I.1. Aussi, à faible charge, la présence de câbles souterrains peut induire de forts refoulements de puissance réactive vers le niveau HTB1, ce qui peut alors provoquer l'entrée en butée des régulateurs en charge.

TABLE I.1 – Paramètres typiques des câbles et lignes MT

Conductor	Details	X (Ω/km)	R (Ω/km)	C (nF/km)	S_{nat} (MVA)
Lignes aériennes	75 ² Almelec	0.35	0.44	5	0.845
	148 ² Almelec	0.35	0.22	5	0.845
Câbles Souterrains	95 ² Alu	0.13	0.32	177	8.33
	150 ² Alu	0.13	0.206	250	10

Un nombre accru d'acteurs et une charge en évolution

Avec la libéralisation du marché de l'électricité, une forte augmentation du nombre d'acteurs du système électrique s'est opérée, avec des objectifs pas forcément complémentaires voire anta-

gonistes. D'autre part, il faut s'attendre à l'apparition de nouveaux acteurs tels que les véhicules électriques au niveau du réseau de distribution qui vont contribuer à faire évoluer le fonctionnement du réseau et à la complexification de la conduite des réseaux de distribution. Enfin, se pose également la question des nouveaux rôles des GRDs qui doivent alors gérer de véritables systèmes de distribution.

Enfin, la composante réactive de la charge évolue également. En effet, un déclin persistant de la consommation de puissance réactive à été observé en Europe [10]. Ce phénomène exacerbe les refoulements de puissance réactive vers les niveaux de tensions supérieurs, ce qui peut alors provoquer l'entrée en butée des régleurs en charge HTB1/HTA [11].

I.2.1.b Mise en place d'un nouveau cadre réglementaire : les Codes de Réseau Européen

A ces changements physiques, s'ajoutent des nouvelles exigences réglementaires portées par les Codes de Réseaux Européens. Ces codes sont rédigés par l'ENTSO-E (European Network of Transmission System Operators for Electricity) et sont validés par l'ACER (Agency for the Cooperation of Energy Regulators). Ils constituent un ensemble de règles visant à faciliter l'harmonisation, l'intégration et l'efficacité du marché Européen de l'électricité. Ce marché est vu comme l'un des leviers pour atteindre les objectifs Européens "20-20-20" d'ici à 2020³.

Il y a trois grandes catégories de Codes qui recouvrent l'ensemble du secteur de l'électricité : les codes de connexion, les codes opérationnels et les codes relatifs au marché de l'électricité.

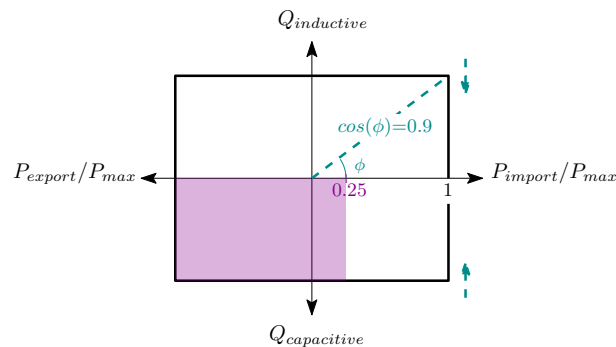


FIGURE I.5 – Illustration des exigences du code DCC relatives aux échanges de puissance réactive à l'interface réseau de distribution/ réseau de transport

En particulier, parmi les codes de connexion, le code "Demand and Connection" (DCC), définit des règles pour les clients quant à la puissance réactive à leur interface avec le réseau de transport. Le DCC stipule notamment que toutes les nouveaux systèmes de distribution doivent :

- Être en mesure de maintenir, en régime permanent, une puissance réactive dans des plages définies par le GRT à leur point de connexion, comme illustré dans la Figure I.5. Cette plage ne doit pas excéder 0.9 en terme de facteur de puissance à la puissance maximale en exportation ;

3. <http://ec.europa.eu/energy/en/topics/energy-strategy/2020-energy-strategy>

- Avoir la capacité constructive si requis par le GRT de ne pas exporter de puissance réactive lorsque la puissance active au point de connexion est inférieure à 25 % de la puissance active maximale. La zone interdite est symbolisée par la plage rouge dans la figure ci-dessus.

A ces exigences constructives, s'ajoute également une exigence plus dynamique : le réseau de distribution doit être capable de contrôler activement les échanges de puissance réactive à l'interface avec le réseau de transport.

A titre de comparaison, les règles constructives qui s'appliquaient jusqu'à présent étaient relativement limitées. En effet, la valeur maximale de la $\tan(\phi)$ au point de livraison est contractualisée dans la convention de raccordement et les pénalités financières associées à son non-respect dans le CART. On voit donc se dessiner une évolution importante, des règles tarifaires en vigueur pour la consommation de réactif à forte consommation vers des exigences de capacité constructive valables quel que soit le transit. Cependant des compromis pourraient être atteints dans les situations où des bénéfices techniques et économiques seraient trouvés.

Certes, il y a un intérêt évident afin de garantir une sûreté et sécurité d'exploitation du système électrique d'imposer des règles claires et harmonisées quelque soit le client raccordé au réseau de transport. Toutefois, il est probable que cela ne constitue pas toujours l'optimum économique. Aussi dans le code DCC, il est prévu que des solutions alternatives puissent être trouvées. En effet, il est raisonnable de penser qu'il n'existe pas une solution générique optimale puisque les réseaux de distribution peuvent avoir des comportements sensiblement différents selon les zones géographiques (réseaux ruraux ou urbains) et le taux de pénétration des GEDs par exemple.

I.2.2 Nouvelles opportunités et verrous pour le réglage de la tension et la gestion des échanges de puissance réactive

Pour faire face aux nouveaux enjeux techniques et réglementaires, le GRD peut considérer d'utiliser de nouveaux leviers permettant d'augmenter la contrôlabilité des réseaux de distribution. Les principaux leviers que l'on peut envisager sont :

- Contrôle à distance de la tension de consigne des régulateurs en charge des postes sources HTB1/HTA ;
- Utilisation de la puissance réactive des productions décentralisées suivant un contrôle à distance ou une loi locale ;
- Amélioration des lois d'enclenchement des gradins de condensateurs ;
- Connexion de nouveaux leviers encore non présents sur le réseau de distribution telles les solutions basées sur l'électronique de puissance (FACTs par exemple) ;
- Technique de décalage de prises de transformateurs exploités en parallèle ("tap stagger technique" [12]). Il est à noter que cette technique ne pourrait pas être considérée pour les réseaux Français, car les transformateurs ne sont pas opérés en parallèle pour des questions notamment de plan de protection.
- ...

Afin d'assurer que la solution retenue soit envisageable pour les réseaux de distribution actuels, nous nous sommes volontairement limités aux leviers existants aujourd'hui, à savoir :

régleur en charge, GED et banc de capacité au niveau MT.

Utilisation de la puissance réactive des GEDs

En effet, il est généralement admis que les GEDs peuvent être un levier du réglage de tension en modulant leur injection de puissance réactive. Pour rappel, la formule (I.1) de la chute de tension le long d'un conducteur montre le lien entre tension et puissance réactive.

$$\Delta V = \frac{R(P_L - P_{DG}) + X(Q_L - Q_{DG})}{V_2} \quad (\text{I.1})$$

Pourtant, cette réserve de puissance réactive depuis les GEDs est difficile à estimer pour le GRD. En effet, la capacité en puissance réactive d'une installation donnée dépend de sa technologie, de son injection de puissance active mais est également limitée par les conditions d'exploitation du réseau. Il ne faut pas que l'utilisation de cette puissance réactive engendre l'apparition de contraintes (contraintes thermiques par exemple) sur le réseau de distribution. Finalement, cela soulève la préoccupation de la disponibilité d'une telle réserve. On peut se limiter à la capacité contractuelle (i.e. le digramme (P,Q) spécifié dans les exigences de connexion d'Enedis) schématisé dans la Figure I.6. Avec un tel diagramme, contrairement à un diagramme idéal, la réserve de puissance réactive est limitée à faible injection de puissance active.

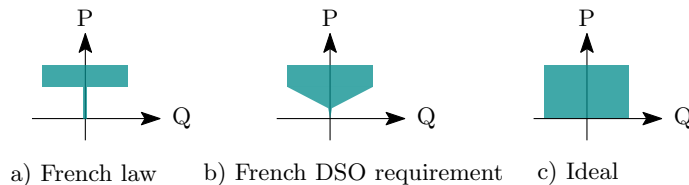


FIGURE I.6 – Différents diagrammes (P,Q) des producteurs connectés au réseau de distribution

Développement des réseaux « intelligents » et actifs de distribution

Les développements actuels dans les domaines de la communication et des mesures ouvrent la voie à des solutions "intelligentes" basées sur des contrôles temps réels. Pour mettre en place de telles solutions, l'observabilité du réseau de distribution doit être améliorée. L'un des principaux freins à la mise en place de solutions dites « smart » est leur coût élevé. Il faut en effet investir dans des capteurs et des réseaux de communication. De manière plus générale, cela pose également le problème de la protection des données, l'interopérabilité des différents équipements communicants. Enfin, cela suppose également de repenser et de mettre en place de nouvelles méthodes pour les études de planification ou de connexion. Finalement, le GRD peut se voir attribuer de nouveaux rôles : il s'agit alors de gérer un système avec des leviers qu'il ne possède pas directement (puissance réactive des GEDs par exemple ou agrégateurs). Enedis a déjà investi dans des solutions avancées de contrôle plus spécifiquement pour la localisation des défauts et la reconfiguration automatique de réseau pour le niveau MT. Ces fonctions sont localisées dans les ACR.

I.3 Objectifs et positionnement des travaux

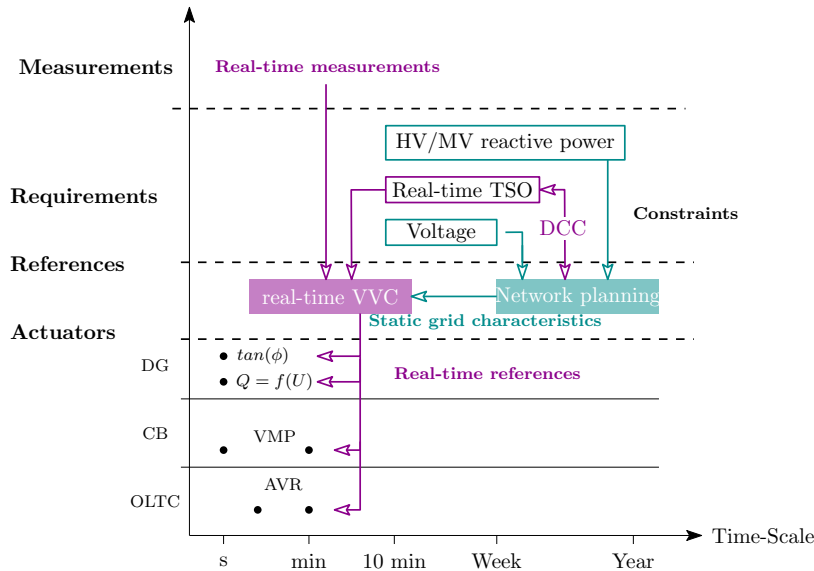


FIGURE I.7 – Illustration de l'évolution proposée pour le réglage de la tension et la gestion de la puissance réactive des réseaux de distribution

Du fait des changements actuels des réseaux de distribution, et avec l'entrée en vigueur des codes de réseau européen, il y a une réelle opportunité de réfléchir à la mise en place de nouvelles stratégies de contrôle de la tension et de la puissance réactive dans les réseaux MT, et à l'interface HT/MT (qui correspond à la frontière GRT-GRD en France). Ce besoin implique d'une part une évolution du réglage de la tension MT, et d'autre part d'approfondir les coordinations entre les GRT et GRD.

Les nouvelles stratégies de contrôle pour les réseaux de distribution doivent répondre à deux objectifs : le maintien du plan de tension MT, et le contrôle des échanges de puissance réactive à l'interface. Pour cela, deux approches principales peuvent être considérées et combinées : le contrôle temps réel et le renforcement/développement du réseau. Cette seconde solution est souvent estimée comme coûteuse et conservatrice, mais permet d'assurer une fiabilité très élevée dans les conditions normales d'exploitation. D'un autre côté, les récentes avancées des technologies de contrôle et de communication ouvrent la voie aux réseaux dits « intelligents » et favorisent le réglage temps réel. Il pourrait y avoir plusieurs avantages à l'amélioration des réglages temps réel actuels pour obtenir une solution flexible et adaptative. Ensuite, le contrôle temps réel permet de faire face à des situations d'urgence qui pourraient théoriquement se produire mais sont en réalité peu probables (quelques heures par an seulement par exemple). Pour garantir que le choix d'une telle solution ne dégrade pas la qualité de fourniture ou ne conduise à des investissements trop importants, il faut combiner solution temps réel et solution de dimensionnement.

Dans nos travaux, nous nous sommes plus particulièrement focalisés sur l'amélioration du

réglage temps réel des réseaux de distribution, également appelé Volt Var Contrôle (VVC). L'un des points d'originalité de notre approche réside dans la gestion de la puissance réactive à l'interface qui est généralement non considérée parmi la myriade de solutions VVC que l'on peut trouver dans la littérature (voir l'état de l'art proposé en II.1). Par ailleurs, un soin tout particulier a été apporté pour assurer que nos travaux sont théoriquement et technologiquement viables pour les réseaux de distribution d'aujourd'hui. Dans cette solution, illustrée par la Figure I.7, les références des actionneurs pour le réglage de la tension et de la puissance réactive sont ajustées en temps réel en fonction des conditions du réseau, contrairement à la solution actuelle où les références sont fixées lors des études de planification (voir Figure I.2).

Comme les flux de puissances à l'interface GRT/GRD sont de plus en plus variables et imprévisibles, avec des conséquences tant sur les réseaux de distribution que de transport il est judicieux de mettre en place une plus grande coordination entre gestionnaires. Pour ce faire, il y a un besoin de conduire des études conjointes sur un système intégrant à la fois une boucle de transport et des réseaux de distribution. Ainsi, il est alors possible de prendre en compte les besoins et contraintes des gestionnaires qui peuvent parfois être antagonistes. Dans la littérature, il n'y a que peu d'études conjointes ou sur un système de moyenne échelle comme évoqué précédemment. Le problème de la gestion de la puissance réactive et de la tension à l'interface est généralement traité soit du point de vue du GRD soit du GRT uniquement, ce qui conduit à des solutions pas toujours acceptables ou réalisables.

I.3.1 Démarche de travail

La démarche de travail peut être résumée par les trois grands points suivants :

- **1.** Évaluation des conséquences des évolutions des réseaux de distribution et des exigences réglementaires sur l'ensemble du système électrique (distribution, interface, transport) ;
- **2.** Proposition de nouvelles solutions temps réel pour le réglage de la tension dans les réseaux de distribution, intégrant une limitation des échanges HT/MT de puissance réactive ;
- **3.** Mise en place d'une gestion conjointe GRT-GRD de puissance réactive au sein d'une boucle de transport en s'appuyant notamment sur les réseaux de distribution via les contrôles VVC temps réel proposés.

Les besoins en simulation étaient à la fois la simulation statique et dynamique ainsi qu'un degré d'ouverture suffisant pour permettre la mise en œuvre d'un algorithme de contrôle commande. D'autres caractéristiques ont également été prises en compte comme le format des données. Deux outils ont été sélectionnés pour réaliser les études de simulation dans le cadre de la thèse : Powerfactory Digsilent et RAMSES (« Relaxable Accuracy Multithreaded Simulator of Electric power System »). Le premier – PowerFactory Digsilent - est couramment utilisé à Enedis pour différents types d'études. Le second a été mis au point à l'université de Liège dans le cadre du projet européen PEGASE. Il est destiné aux systèmes de très grandes tailles. Son principal atout est sa rapidité ainsi qu'un fort degré d'ouverture : possibilité de s'interfacer avec d'autres logiciels notamment avec Matlab. Le logiciel RAMSES a été retenu pour effectuer les simulations dynamiques et pour son degré d'ouverture. Par ailleurs, aucune étude dynamique n'a encore été effectuée à Enedis avec Powerfactory. Le logiciel Powerfactory sera dédié aux

analyses statiques –principalement des études de load flow et des modifications topologiques des données Enedis.

Trois grands types de réseau ont été utilisés dans le cadre de la thèse. Pour l'étude des conséquences des évolutions des réseaux de distribution un réseau réel HTA a été gracieusement fourni par Enedis. Pour la mise en place d'une nouvelle fonction VVC temps réel, il y avait un intérêt clair de posséder un réseau simplifié afin de faciliter la lecture des résultats et de déterminer les stratégies les plus pertinentes. Par ailleurs, les réseaux réels ont été dimensionnés pour faire face aux situations les plus critiques, aussi l'étude d'une fonction temps réel n'a que peu d'intérêt sans modifications ou alors sous hypothèse d'une perturbation majeure et donc peu probable. Aussi, un réseau académique avec trois départs types a été utilisé. Enfin, pour l'étude d'une gestion conjointe de puissance réactive, une boucle de transport associée à des réseaux MT a été considérée. Pour plus de détails sur les différents réseaux, se reporter au Chapitre III, Section III.1 du mémoire complet (également aux Annexes A et C).

I.3.2 Première étude prospective : illustrations statiques des conséquences des évolutions du réseau de distribution

La question de l'impact des évolutions du réseaux de distribution sur les réseaux MT a déjà été largement traitée [3, 5, 6, 13]. Aussi, dans cette partie, les conséquences à l'interface HT/MT ont été plus particulièrement étudiées.

I.3.2.a Evolution des échanges de puissance réactive à l'interface HTB1/HTA

Les études menées sur les évolutions des échanges de puissance réactive à l'interface ont conduit à la publication des travaux [11] présentée lors de la conférence CIRED. Aussi, seul un résumé concis soulignant les principales conclusions obtenues est proposé ici. Pour plus de détails, se reporter au Chapitre III du mémoire complet.

A l'interface, les flux de puissance réactive résultent de :

- La consommation de la puissance réactive par les charges connectées au réseau de distribution ;
- La consommation / production de puissance réactive dans les lignes aériennes et les câbles souterrains ;
- Des pertes réactives dans les transformateurs HTB1/HTA et HTA/BT ;
- De la puissance réactive fournie/consommée par d'éventuels compensateurs connectés au réseau de distribution ;
- De la puissance réactive fournie/ consommée par les GEDs suivant leur injection de puissance active et la valeur contractuelle imposée pour leur facteur de puissance.

La contribution en puissance réactive des câbles et des lignes dépend des charges dans le réseau, tandis que celle des transformateurs dépend de leur état de charge. Aussi, la valeur des flux de puissance à l'interface HTB1/HTA n'est pas directe et simple à évaluer.

Pour avoir une estimation précise, il est nécessaire de conduire des calculs de load flows. Pour déterminer l'influence de l'insertion de la production décentralisée, du remplacement des lignes aériennes par des câbles souterrains, ou encore de la diminution de la composante réactive

des charges, plusieurs calculs de load flows ont été menés sous des hypothèses différentes, et avec des échelles de production et de consommation variées.

Les principales conclusions obtenues sont les suivantes :

- Suite aux évolutions des réseaux de distribution, une diminution des transits de puissance réactive (voir un refoulement) peut être constatée à l'interface HTB/HTA ;
- Le facteur principal de cette tendance à la diminution de la puissance réactive à l'interface est le remplacement des lignes aériennes par des câbles souterrains. A titre d'exemple, 100 km de câbles souterrains produisent environ 5 MVAR à faible charge. Cette contribution est par ailleurs variable suivant le niveau de production/charge du réseau.
- La contribution en puissance réactive des transformateurs HTB1/HTA n'est pas négligeable, et en particulier à forte charge.
- Si les GEDs connectés dans des départs mixtes ont un facteur de puissance non nul, alors leur contribution est difficile à évaluer car dépendante de leur injection de puissance active.

En conclusion, une tendance générale de diminution de la puissance réactive consommée aux interfaces transport/distribution est à prévoir, avec une probabilité accrue de refoulement vers le réseau HT. Par ailleurs, ces flux dépendant des conditions de charges et de production qui peuvent varier significativement au cours d'une journée, et qui sont donc de plus en plus variables et imprévisibles.

I.3.2.b Conséquences d'un refoulement de puissance réactive en amont des réseaux de distribution et besoin de solutions actives

Détermination du diagramme (P,Q) et évaluation du besoin en leviers pour répondre aux exigences du DCC

L'une des premières conséquences de l'évolution des flux de puissance réactive est la difficulté d'obtenir un diagramme (P,Q) à l'interface HTB1/HTA, et ce d'autant plus si les GEDs suivent des lois locales (du type $Q=f(U)$ par exemple).

Dès lors, comment déterminer le besoin en leviers de puissance réactive pour satisfaire des exigences comme celle du code DCC à l'interface, et déduire un pilotage de ces leviers ? Il semble pertinent d'utiliser une solution temps-réel pour résoudre d'éventuelles contraintes en puissance réactive à l'interface HT/MT, et non une solution figée. La question du dimensionnement des leviers pour la solution temps-réel reste une tâche ardue, mais en dehors du cadre de notre étude. En effet, il n'y a pas une homogénéité des besoins en absorption de réactif pour une période de l'année (été/hiver) comme cela pouvait être le cas par le passé. L'intermittence et les incertitudes liées à la production décentralisée est une explication, ainsi que le comportement du réseau avec l'enfouissement des lignes aériennes. Les câbles peuvent produire plus ou moins de réactif suivant la valeur de la charge. De même il est difficile d'incorporer les variations de pertes dans le réseau suite à l'utilisation d'un levier réactif.

Entrée en butée des régleurs en charge HTB1/HTA

Par ailleurs, les refoulements de puissance réactive vers le réseau de transport peuvent également engendrer l'entrée en butée des régleurs en charge HTB1/HTA. En France, un nombre accru d'alertes butée a été relevé, généralement associé à des situations de tension haute.

En effet, les régulateurs en charge ont été dimensionnés par le passé pour faire face des à situations de tension basse (en considérant que le réseau de distribution était exclusivement consommateur). Lorsque la butée est atteinte, le découplage en tension entre le réseau de distribution et transport n'est alors plus assuré. Il existe une limite de puissance réactive maximale vers la HTB1 avant l'atteinte de la dernière prise. Cette valeur dépend des caractéristiques des transformateurs, de la tension côté HTB1 ainsi que de la valeur de la tension de consigne du régulateur. Ces différents aspects ont été étudiés dans [11] et également rappelés dans la Section III.3 du mémoire de thèse complet.

Seule la conclusion de ces études est donnée ici ; à savoir que le risque d'entrée en butée des régulateurs en charge est favorisé par :

- Une tension HTB1 « haute » ;
- Une faible puissance nominale du transformateur ;
- Une faible amplitude de réglage du régulateur en charge ;
- Une tension de consigne « basse » au secondaire ;
- Le centrage actuel des prises, dimensionné pour faire face à des situations de basse tension.

En conclusion, il nous apparaît judicieux de proposer une solution temps réel et basée sur une plus grande coordination entre GRT et GRD. Le contrôle temps réel des réseaux de distribution est l'objet de la seconde partie des travaux, tandis que la coordination est l'objet de la troisième partie.

Chapitre II

Mise en place d'une fonction Volt Var Contrôle temps réel pour les réseaux actifs de distribution avec une limitation de la puissance réactive échangée à l'interface HT/MT

II.1 Étude bibliographique et état de l'art sur les réglages VVC temps réel pour les réseaux de distribution

II.1.1 Stratégies de contrôle centralisé avec gestion des échanges de puissance réactive dans la littérature

Il existe une littérature très riche sur le réglage de la tension temps réel pour les réseaux de distribution, avec de nombreuses méthodes dont la Table II.1 propose un récapitulatif.

TABLE II.1 – Etat de l’art sur le réglage de la tension et de la puissance réactive pour un réseau MT

Method	Details
Contrôle global	<ul style="list-style-type: none"> · Expert-system / rule-based control [6, 14–17] · Multi-agent system [18, 19] · Multi-level, hierarchical control [20–22] · Optimal Control [4, 6, 23–26] · Model Predictive Control [20, 27–30]
Contrôle local	<ul style="list-style-type: none"> · rule-based [31–37] · Optimization-based [38, 39]

II.1.1.a Pertinence des stratégies coordonnées

Les différentes méthodes que l’on peut trouver dans la littérature peuvent être grossièrement divisées en deux grandes catégories : les solutions globales ou coordonnées et les solutions locales. Historiquement, afin de pallier les conséquences des évolutions du réseau de distribution (plus spécifiquement l’insertion de la production décentralisée), des méthodes locales ont d’abord été imaginées ([31–37]).

La table montre les avantages et inconvénients de chacune de ces approches.

TABLE II.2 – Comparaison d’une stratégie locale ou globale

Structure	Avantages	Inconvénients
Locale	<ul style="list-style-type: none"> Peu de difficultés techniques ; Besoin de communication et d’équipement limité ; Besoin limité en terme de connaissance et de modèle du réseau. 	<ul style="list-style-type: none"> Risque de conflits entre les lois locales ; Pas d’objectifs globaux mais des objectifs locaux.
Globale	<ul style="list-style-type: none"> Contrôle d’un ensemble d’entrées et de sorties ; Possibilité d’atteindre des objectifs globaux et locaux (sans conflits). 	<ul style="list-style-type: none"> Difficulté technique accrue ; Coût d’investissement éventuels (système de communication) ; Besoin d’une connaissance détaillée du réseau.

Dans notre cas, il s’agit d’atteindre à la fois des objectifs locaux (réglage de la tension) mais aussi un objectif nécessitant la coordination des leviers en puissance réactive (assurer un niveau de puissance réactive à l’interface). C’est pourquoi une structure coordonnée a été retenue. Par ailleurs, une telle structure permet d’avoir des possibilités de contrôle accrues. Afin de limiter les besoins en terme de communication, nous nous sommes limités à un réglage centralisé, sans besoin de communication entre les actionneurs, et un tel contrôle serait situé au niveau des ACR.

II.1.1.b Méthodes classiques pour un réglage coordonné

Il y existe plusieurs méthodes pour la mise en place des lois de commande. Généralement, les méthodes développées sont basées sur le savoir faire et l'expertise des opérateurs et ingénieurs de réseaux. Aussi, trouve-t-on deux grandes familles de méthodes :

- **Système de règles** qui consiste en une automatisation des règles techniques et des processus industriels ;
- **Optimisation** basée sur la minimisation d'une fonction coût prenant en compte des considérations technico-économique.

Systeme expert

Historiquement, les systèmes experts (règles préétablies) ont été proposés dès le début des années 1980 avec l'essor des techniques d'intelligence artificielle. Ce contrôle, assez intuitif, est relativement aisé à mettre en œuvre et peu coûteux en termes de temps de calcul à condition d'avoir un système relativement simple. En effet, pour les systèmes de grande échelle, il existe un risque d'explosion combinatoire. En cas de re-calibration du réseau, des outils complexes sont nécessaires tels que des outils d'optimisation ou de self-learning. Lorsqu'un changement de topologie survient ou encore lorsque de nouveaux producteurs et consommateurs sont raccordés, ou si de nouveaux renforcements du réseau sont effectués, il faut alors reconfigurer entièrement le système et repenser toutes les règles suivant tous les nouveaux cas de figure. En ce sens, cette approche est peu flexible aux modifications de la base de données générale. De plus, aucune stabilité n'est garantie.

Commande optimale

D'un autre côté, les méthodes basées sur une commande optimale sont plus génériques et plus flexibles. La commande optimale consiste à déterminer la commande d'un système tout en minimisant une fonction coût et en assurant le respect de certaines contraintes. Cependant, la mise en place d'une telle commande nécessite un travail de modélisation du réseau et requiert une certaine précision dans les modèles.

Un type particulier de la commande optimale est la commande prédictive (MPC) qui a été proposée notamment par les auteurs de [20, 28–30] pour un VVC temps réel d'un réseau de distribution. Cette approche optimale appartient à la classe des algorithmes de contrôle avec horizon fuyant. Il s'agit de « prendre en compte dès l'instant présent, le comportement futur du système en utilisant explicitement un modèle numérique du système afin de prédire la sortie dans le futur et sur un horizon fini » d'après la définition donnée dans [40]. Le principe de MPC, également illustré par la Figure II.1, repose sur l'existence d'un horizon fuyant, et peut être expliqué comme suit :

- 1. Prédiction de la sortie sur un certain horizon, l'horizon de prédiction. On utilise classiquement pour le réseau de distribution les matrices de sensibilité.
- 2. Définition d'une trajectoire de référence sous un horizon de consigne pour définir le ralliement à la consigne. Ainsi ce ralliement peut-il être choisi pour respecter une certaine dynamique.
- 3. Élaboration d'une séquence de commandes optimales selon un critère choisi, ce critère pouvant être par exemple la minimisation des écarts entre consigne et entrée, le coût économique de la solution...

- 4. Application du premier élément uniquement de la séquence optimale. Et, après une mise à jour du système via des mesures ou estimations, l'ensemble du processus est entièrement réitéré, on parle d'horizon fuyant.

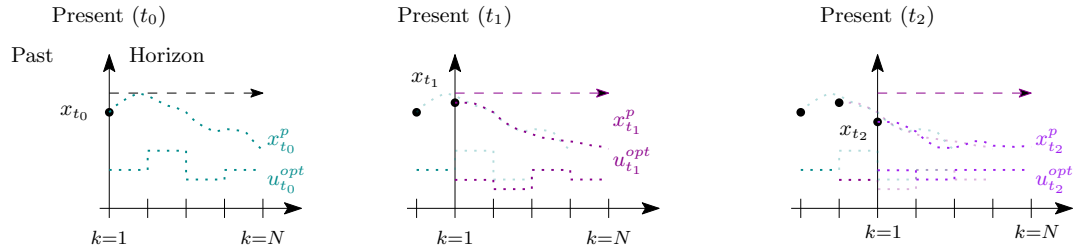


FIGURE II.1 – Principe d'une commande de type MPC

Les principaux atouts de cette commande sont d'abord ceux relatifs à toute commande optimale : optimalité (par rapport au critère choisi), multi-variables, multi-objectifs, généricité. Les avantages spécifiques de la commande prédictive sont d'une part la capacité d'anticipation de toute perturbation connue, mais aussi la possibilité notamment d'anticiper le comportement dynamique des actionneurs ainsi que de gérer des contraintes complexes variant sous l'horizon de prédiction. Ainsi il est possible d'imposer des trajectoires de convergence. Enfin, un avantage conséquent est la robustesse naturelle de la commande prédictive car elle constitue une approche en boucle fermée, permettant de pallier dans une certaine mesure les erreurs et imprécisions des modèles.

En conclusion, la commande prédictive nous semble particulièrement intéressante pour le développement de nouvelles fonctions de contrôle temps réel. A des fins de comparaison, deux autres fonctions plus classiques ont également été considérées dans ces travaux de doctorat : à savoir une commande basée sur un ensemble de règles et une commande basée sur une commande optimale.

II.1.1.c Possibilités technologiques actuelles des réseaux de distribution quant à un réglage VVC temps réel

Nous avons affirmé notre volonté de proposer des fonctions qui pourraient être envisagées pour les réseaux actuels de distribution. En effet, les infrastructures requises pour la plupart des stratégies de contrôle proposées dans la littérature sont loin des possibilités techniques actuelles. Peu de méthodes abordent la question de la mise en oeuvre concrète de la commande comme indiqué dans [41]. Ensuite, les performances des commandes proposées sont souvent démontrées avec des réseaux présentant un taux de pénétration très élevé des GEDs. Par conséquent, il existe un écart manifeste entre les projets démonstrateurs et les fonctions VVC que l'on trouve dans la littérature.

Pour justifier les hypothèses prises quant aux capacités techniques des réseaux de distribution, nous avons étudié plusieurs solutions de projet démonstrateurs de différents GRD Européens (Flexible Plug and Play [42, 43], Aura-NMS [44], ZUQDE¹, se reporter à la Section IV.1.3 du

1. <http://www.igreengrid-fp7.eu/scope-of-work/demonstrators/austria/zuqde.aspx>

mémoire). Dans ce résumé, nous ne reviendrons que sur la solution développée par Enedis. Il s'agit des fonctions FAR (Fonctions Avancées de Réseau) dans le cadre du projet démonstrateur VENTEEA.

Ce projet démonstrateur est mené conjointement par EDF R&D et Enedis. Il s'agit d'expérimentations sur un réseau rural, exploité en 20 kV, auquel est raccordé plusieurs fermes éoliennes. La stratégie de contrôle de la tension suppose l'existence d'un estimateur d'état (DSE, Distributed State Estimator). Ce DSE permet d'évaluer en temps réel la valeur de l'amplitude de la tension dans l'ensemble des noeuds du réseau.

Ensuite, deux règles sont dédiées au réglage de la tension. Une loi globale ajuste la tension de consigne du régulateur en charge en fonction de l'estimation des amplitudes de tension du réseau. Cette loi est localisée dans les outils des centres de conduite des réseaux de distribution (ACR). La seconde loi, locale, est une loi de type $Q = f(U)$ spécifique au GED connecté en départ mixte. Ces deux lois sont plus particulièrement présentées dans la section suivante. En effet, la fonction VVC à base de règles considérée dans nos travaux s'inspire largement de ces deux fonctions.

En conclusion, il est nécessaire d'avoir une certaine observabilité des réseaux de distribution pour l'amélioration des lois de commande. Un point important est l'existence d'un estimateur d'état (DSE) suffisamment précis. Dans les travaux de thèse, nous avons fait l'hypothèse d'une existence de capteurs de mesures avec une fréquence d'échantillonnage de 10 s, et que les moyennes sur 1 minute étaient envoyées au centre de conduite (ACR). La précision des estimations/mesures est supposée être de 1% pour les mesures de puissance (active ou réactive), et de 0.5 % pour l'amplitude de la tension. Il est à noter que si ces niveaux de précisions ne sont pas atteints, il est difficilement envisageable de mettre en place un pilotage temps réel des leviers, notamment du régulateur en charge dont la précision est de 1% (ordre de grandeur de la valeur d'une prise).

Par ailleurs, nous avons fait l'hypothèse que l'ensemble des mesures suivantes était disponible au niveau de l'ACR :

- P,Q au primaire et secondaire des transformateurs HTB1/HTA ;
- P,Q produite par chaque producteur HTA ;
- Amplitude des tensions de l'ensemble du réseau ;
- Statut des gradins de condensateurs (enclenché/déclenché)
- Tension de consigne et prise des régulateurs en charge ;
- Topologie temps réel et configuration du réseau ;

D'autre part, il a été considéré comme possible d'envoyer depuis l'ACR des consignes de puissance réactive aux GEDs, de tension au régulateur en charge, et des télécommandes pour les gradins de condensateur.

II.1.2 Présentation de deux fonctions VVC classiques et conformes aux contraintes industrielles

Dans cette partie, les deux fonctions R-VVC (basée sur des règles) et O-VVC (basée sur une optimisation), sont simplement introduites. Des illustrations du principe de ces deux commandes sont données dans le Chapitre VI du mémoire complet, lors de la comparaison avec la commande

prédictive développée ci-après. Pour plus de détails, consulter la Section IV.2 du chapitre IV du mémoire de thèse.

De manière générale, le système à contrôler est un réseau HTA radial. Dans ce réseau l'existence de régulateurs en charge au niveau des transformateurs des postes sources est prise comme hypothèse d'étude. Par ailleurs, des productions décentralisées (GED) ainsi que des gradins de condensateurs (CB) peuvent être connectés sur ce réseau. Les objectifs du contrôle sont doubles. Il s'agit d'une part de maintenir la tension V_{MV} dans l'ensemble du réseau de distribution HTA et d'autre part de réguler les transits de puissance réactive $Q_{MV \rightarrow HV}$ à l'interface réseau de distribution / réseau de transport tout en respectant les contraintes nécessaires au bon fonctionnement du système électrique. Rappelons que le second objectif demande d'assurer une coordination entre les différents acteurs en réactif (i.e. les productions décentralisées), et justifie le choix d'une commande centralisée dont l'intelligence est située au niveau des outils de conduite du distributeur (à l'ACR).

Par ailleurs, il a été choisi de contrôler la valeur de la tangente (i.e. le ratio entre la puissance réactive consommée par la puissance active consommée par le réseau de distribution) à l'interface réseau de transport/réseau de distribution plutôt que de contrôler directement la valeur de la puissance réactive. En effet, le facteur de puissance est une illustration claire du comportement en réactif. C'est d'ailleurs cette valeur qui est aujourd'hui contrôlée à l'interface.

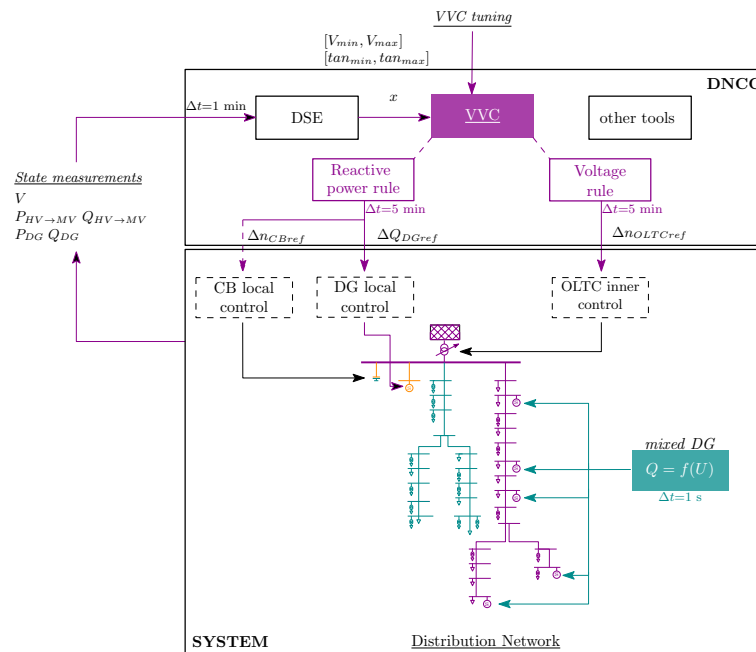


FIGURE II.2 – Illustration de la fonction R-VVC basée sur des règles

II.1.2.a R-VVC : une fonction basée sur un système de règles

Ce contrôle, dont la stratégie est illustrée par la Figure II.2 est basé sur l'existence de trois fonctions indépendantes. Deux fonctions ($FAR U$ et $Q = f(U)$) ont pour objectif le main-

tion du plan de tension, la troisième, *FAR Q* le contrôle des échanges de puissance réactive à l'interface HT/MT.

Loi FAR U

Cette fonction ajuste la tension de consigne du transformateur selon les valeurs extrêmes de tension mesurées dans le réseau de distribution. Elle suppose donc l'existence d'un système de mesures et d'un estimateur d'état. La Figure II.3 donne le principe de fonctionnement de cette fonction. Dans ce cas, le long du départ bleu où doit être situé un producteur, la tension augmente de telle sorte qu'elle dépasse la valeur limite autorisée, aussi la tension de consigne du régulateur en charge est abaissée pour rétablir un plan de tension acceptable. Certaines limites à ce réglage peuvent être mentionnées, notamment lorsqu'il existe des contraintes en tension haute sur un départ et en tension basse sur un autre départ. L'association à la loi locale $Q = f(U)$ présentée ci-après permettrait de s'affranchir de ce problème dans la limite de capacité de réglage du producteur et du régulateur en charge.

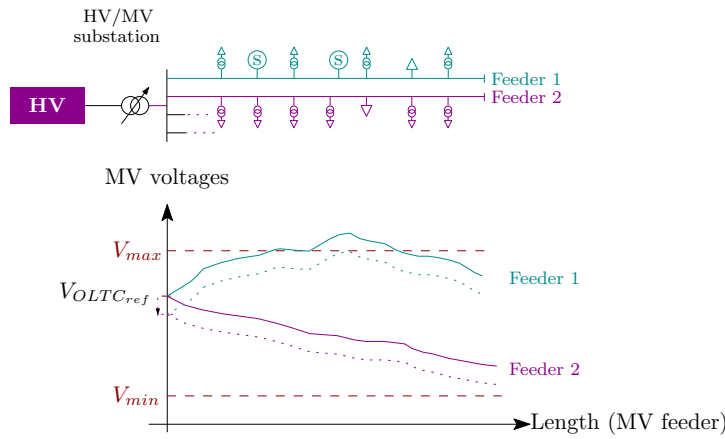


FIGURE II.3 – Loi *FAR U* pour le choix de la tension de consigne du régulateur en charge

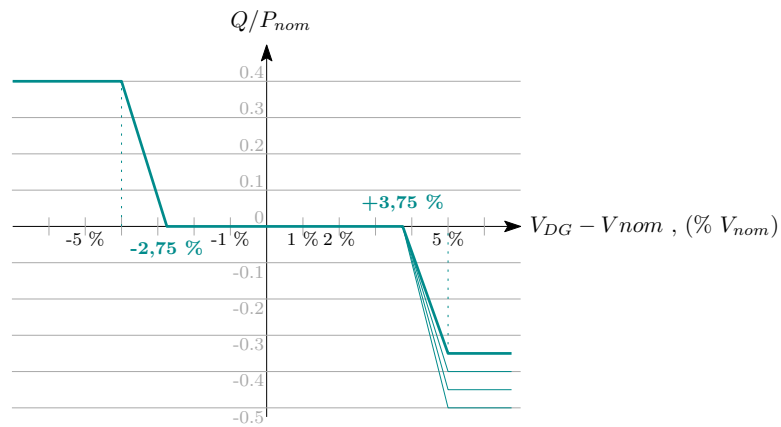


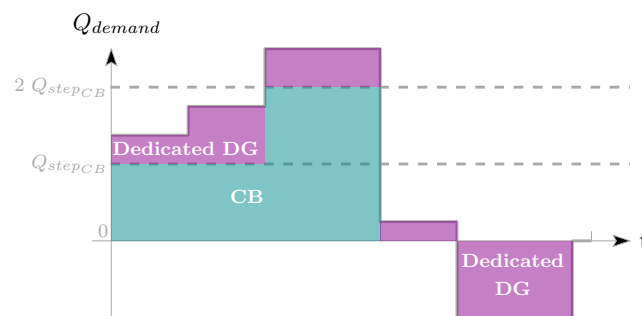
FIGURE II.4 – Principe de la loi $Q = f(U)$ pour les producteurs en départ mixte

Loi $Q = f(U)$

Il s'agit de prendre avantage des producteurs en départ mixte, et d'imposer en fonction de la tension à leur borne une certaine valeur de réactif à fournir (dans le cas de tension basse) ou à absorber (dans le cas de tension haute). Cette loi (visible dans la Figure II.4) est une loi avec bande morte pour éviter une trop grande sollicitation des producteurs, avec saturation. Les différents paramètres (bande morte, pentes de réglage, valeurs maximales..) résultent de compromis technico-économiques.

Loi $FAR Q$

Enfin, la fonction $FAR Q$ a pour but de répondre à une certaine demande en réactif à l'interface avec le réseau de transport. Différentes stratégies sont aujourd'hui envisagées par Enedis. Dans l'esprit, il s'agit de privilégier les gradins de condensateurs, et d'ajuster au besoin avec la production en départ dédié si possible

FIGURE II.5 – Loi $FAR Q$

Actuellement, il est envisagé de faire appel à la fonction $Q = f(U)$ toutes les secondes, et les capacités de mesures et communication actuelles permettraient de faire appel à $FAR U$ ou $FAR Q$ toutes les 10 minutes. Ces fonctions sont schématisées dans la Figure II.2. Notons que sans coordination, alors s'il existe des couplages entre les problèmes de tension et de transit de réactif, il y a un risque de conflit entre ces différents réglages.

II.1.2.b O-VVC : un fonction basée sur une optimisation

Cette deuxième fonction (O-VVC), basée sur la commande optimale, est par essence très semblable à la commande prédictive développée dans la section suivante. En effet, sous certains aspects, une commande optimale peut être vue comme une commande prédictive avec un horizon de prédiction égale à 1. Aussi, par souci de concision, cette méthode n'est pas développée dans ce résumé du mémoire de thèse.

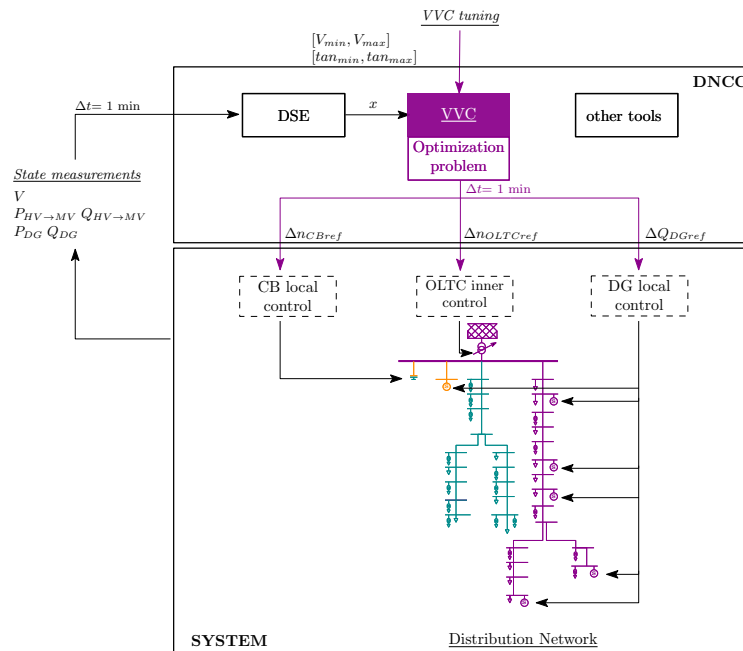


FIGURE II.6 – Illustration du contrôle O-VVC basé sur la résolution d’une optimisation

II.2 Définition d’une fonction VVC temps réel basée sur la commande prédictive avec limitation d’échange de puissance réactive

La commande prédictive pour la mise en place de fonctions VVC temps réel pour un réseau actif de distribution a été proposée notamment par [20, 28–30]. Par rapport à la littérature, l’originalité de notre démarche réside dans plusieurs points :

- la coordination de plusieurs actionneurs en vue d’assurer le maintien du plan de tension (similaire à ce qui peut être trouvé dans la littérature aujourd’hui) ainsi que le réglage de la puissance réactive à l’interface réseau de distribution / réseau de transport ;
- la garantie de minimiser le nombre de changements de prise des régulateurs en charge, car les changements sont explicitement intégrés dans la fonction coût ;
- l’avantage de garder sans modification le contrôle classique du régulateur en charge ou d’autres processus industriels traditionnels. Finalement, l’approche développée est une solution intermédiaire vers des réseaux de distribution plus actifs.

En effet, le régulateur en charge possède un algorithme interne de commande qui a été mis au point afin d’optimiser sa durée de vie. Notamment, le changeur de prise est un équipement fragile dont les frais de maintenance sont assez coûteux. Aussi, il est judicieux de vouloir conserver ce contrôle interne et de l’intégrer dans de nouvelles stratégies de contrôle. Il est à noter que cet algorithme de contrôle est fortement non linéaire, et comporte notamment des temporisations (60 s puis 10 s pour les transformateurs HTB1/HTA) ainsi qu’une bande morte.

Peu d'articles prennent en compte cette nature non-linéaire du régleur en charge (et de manière plus générale des différents actionneurs) lors de la conception des contrôleurs temps réel. D'une manière générale, il y a une vraie difficulté à mettre en place des méthodes MPC hybrides (i.e. avec des variables continues et discrètes), et non linéaires ; cela soulève notamment des problèmes numériques ou de complexité par exemple [45, 46].

II.2.1 Stratégie de contrôle MPC de la tension et de l'échange de puissance réactive entre les réseaux HT et MT

II.2.1.a Définition du problème MPC

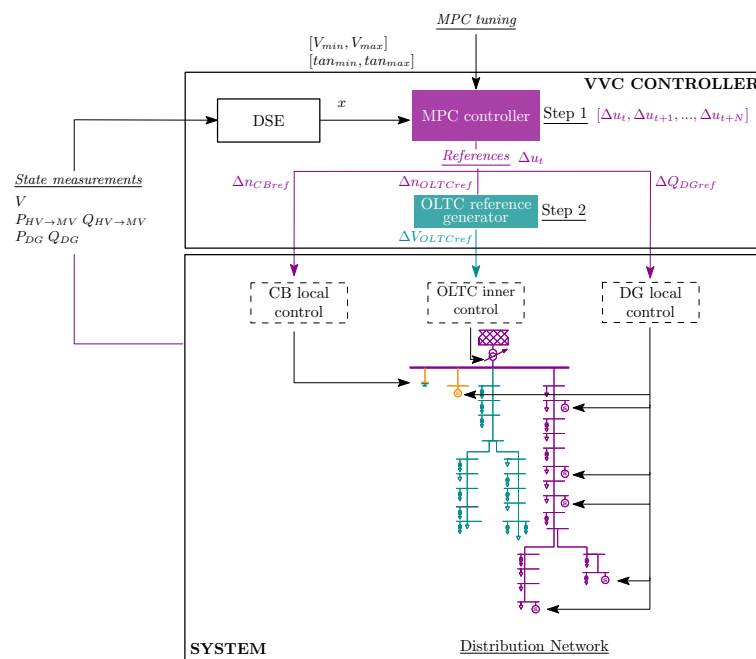


FIGURE II.7 – Illustration du contrôle MPC-VVC basée sur une commande prédictive

La stratégie de contrôle MPC est illustrée dans la Figure II.7. Le contrôleur VVC est supposé être intégré aux outils des centres de conduite du GRD (ACR). Dans ce schéma, les contrôleurs locaux des actionneurs (GED, OLTC, CB) figurent car ils sont pris en compte dans la commande MPC. Il s'agit de déterminer les références temps réel à envoyer à ces contrôleurs locaux.

A nouveau, l'objectif est double : maintenir un plan de tension HTA acceptable ainsi que des échanges de puissance réactive dans une plage de valeurs spécifiques à l'interface GRT/GRD. Pour ce faire, le contrôleur produit une séquence optimale de contrôle Δu sous l'horizon de prédiction sélectionnée :

$$\Delta u_{k \in \{1, N\}} = [\Delta Q_{DG_{ref}}, \Delta n_{CB_{ref}}, \Delta n_{OLTC_{ref}}]_{k \in \{1, N\}}. \quad (\text{II.1})$$

$$\min(J)_{\Delta u} = \sum_{k=1}^N [\Delta u(k) R_{\Delta u} \Delta u(k)^T + \alpha P_{loss}(k)^2] + u(N) R_u u^T(N), \quad (\text{II.2})$$

Objectifs et contraintes

Les objectifs du contrôle doivent être réalisés à tout prix, aussi ont-ils été traduits par des contraintes dures et n'ont pas été directement intégrés dans la fonction coût :

$$V_{min} \leq V(N) \leq V_{max}, \quad (\text{II.3})$$

$$\tan(\phi)_{min} \leq \tan(\phi)_{HV \rightarrow MV}(N) \leq \tan(\phi)_{max}. \quad (\text{II.4})$$

Ensuite, les contraintes physiques des actionneurs doivent être prises en considération sous l'horizon de prédiction i.e. $\forall k \in \{1, N\}$:

$$u_{min} \leq u(k) \leq u_{max}, \quad (\text{II.5})$$

$$\Delta u_{min} \leq \Delta u(k) \leq \Delta u_{max}. \quad (\text{II.6})$$

$$V_{min}(k) \leq V(k) \leq V_{max}(k), \quad (\text{II.7})$$

$$\tan_{min}(k) \leq \tan_{MV \rightarrow HV}(k) \leq \tan_{max}(k). \quad (\text{II.8})$$

Convergence exponentielle et hiérarchisation des objectifs

Il est également possible de préciser la convergence souhaitée pour la réalisation des objectifs du contrôle, en faisant évoluer le long de l'horizon de prédiction les contraintes portant soit sur le plan de tension V ou le réactif à l'interface $\tan_{MV \rightarrow HV}$.

Ici, nous avons choisi de mettre en place une convergence exponentielle, avec une vitesse différente pour les deux objectifs. Cela permet de faire, lorsque c'est possible, un découplage entre ces deux objectifs. Pour plus de détails, se reporter au Chapitre V du mémoire ou encore à [47].

Modélisation du réseau et des actionneurs

L'une des principales difficultés liée à la mise en place d'une commande basée sur un modèle, ici servant à la prédiction pour l'approche MPC, est l'obtention d'un modèle répondant à des exigences de précision et de simplicité. La plupart du temps, un modèle de type statique via des matrices de sensibilité est utilisé [23, 29, 36, 48]. Les matrices de sensibilité permettent d'anticiper l'état final du système en exprimant la variation des états du système induite par une variation d'une entrée (commande ou perturbation).

Dans notre cas, il s'agit plus précisément de lier les variations de puissance réactive des GEDs, les variations de tension de consigne de l'OLTC et l'état des CB au plan de tension du réseau de distribution et à la valeur de la tangente à l'interface transport/distribution et ce, connaissant l'état du système, et en négligeant les entrées de perturbations. Pour simplifier le problème, et pour rendre compte de l'état des connaissances actuelles, nous avons fait l'hypothèse que les matrices de sensibilité étaient constantes, évaluées une fois pour toute en supposant que les charges du réseau de distribution pouvaient être modélisées par des charges à puissance

constante. Par ailleurs, nous avons considéré que les puissances actives des charges et des GED étaient constantes le long de l'horizon de prédiction. Cette dernière hypothèse n'a que peu d'influence car les mesures seront recalées à l'instant de contrôle suivant.

La prédiction se réalise sur un horizon temporel, ici nous avons choisi pour des considérations techniques, de faire appel au contrôleur toutes les minutes. Par rapport à cette constante de temps, l'action des productions décentralisées et des CBs peut-être considérée comme instantanée, i.e. leur action sera réalisée à l'instant de contrôle suivant. Ce n'est pas le cas pour le régleur en charge qui possède une temporisation, égale à 60 s. Aussi, en prenant en compte le délai de communication et cette temporisation, l'action du régleur en charge (c'est à dire un changement de prise) sera effectivement détecté deux instants de contrôle plus tard. Ce qui nous conduit aux équations de prédiction suivantes :

$$x(k+1) = x(k) + \frac{\delta x}{\delta Q_{DG\ ref}} \Delta Q_{DG\ ref}(k) + \frac{\delta x}{\delta n_{CB\ ref}} \Delta n_{CB\ ref}(k) + \frac{\delta x}{\delta n_{OLTC\ ref}} \Delta n_{OLTC\ ref}(k-1), \quad (\text{II.9})$$

x représentant alors sans distinction le plan de tension, la puissance active ou réactive à l'interface HT/MT.

Il a été montré à travers diverses simulations sous perturbations et avec incertitudes paramétriques, que le contrôleur, en dépit de toutes les hypothèses prises, est capable d'atteindre les objectifs fixés.

II.2.1.b Résolution et gestion des cas d'infaisabilité

Nous avons déjà brièvement évoqué la difficulté de résolution de problème MPC mixte (continu-discret), et non linéaire. Différentes méthodes pour pallier ce problème peuvent être trouvées. Dans notre cas, nous avons utilisé le solver "BNB" (branch and bound) de Yalmip ([49]).

Il est possible que le problème formulé comme proposé ne soit pas soluble. Cela peut être le cas lorsque le système a subi une forte perturbation l'amenant dans un état loin de l'état ciblé, ou lors d'une défaillance de l'un des actionneurs. Pour pallier le risque de dysfonctionnement, le contrôleur doit, même en cas d'infaisabilité, amener le système dans une situation la plus proche d'une situation stable et satisfaisante. Une solution classique consiste à utiliser des variables dites de "relaxation", car elles permettent de relâcher les contraintes [20, 29] :

$$x_{min}(k) + \varepsilon_{min}(k) \leq x(k) \leq x_{max}(k) + \varepsilon_{max}(k) \quad (\text{II.10})$$

x correspond ici soit à V ou $\tan_{HV \rightarrow MV}$. Pour éviter d'avoir une compétition entre la relaxation des contraintes et les objectifs du contrôle (qui doivent être réalisés à tout prix), une hiérarchisation des relaxations a été mise au point. En effet, lorsqu'il n'y pas de solution au problème initial :

1. Une relaxation de la contraintes portant sur la convergence exponentielle de la $\tan_{HV \rightarrow MV}$ est d'abord envisagée (II.8) $_{1 \leq k \leq N-1}$, avec $1 \leq k \leq N-1$. Ensuite, si et seulement si,

le problème n'a toujours pas de solution, les contraintes sont relâchées les unes après les autres :

2. Une relaxation de la contraintes portant sur $\tan_{HV \rightarrow MV}$ à la fin de l'horizon (contrainte (II.8)_N with $k = N$);
3. Relaxation de la convergence exponentielle de V ((contrainte(II.7)_{1 ≤ k ≤ N-1}));
4. Relaxation de la contrainte terminale portant sur V ((contrainte (II.7)_N).

A chaque étape de relaxation, les variables de relaxation sont fortement pénalisées dans la fonction coût comme indiqué dans la Table II.3. L'avantage de cette méthode de hiérarchisation, est de s'assurer que les contraintes ne sont pas respectées si et seulement si le problème n'est pas soluble. Par ailleurs, cela permet d'introduire une notion de priorité entre les contraintes, ici portant sur le plan de tension HTA (objectif prioritaire pour le GRD). Une autre structure de relaxation pourrait aisément être envisagée si besoin. Notons qu'à la fin du processus de relaxation précédemment décrit, le problème possède obligatoirement une solution car toutes les contraintes ont été relâchées.

TABLE II.3 – Fonctions coûts associées associée à la relaxation des contraintes

Problem	Cost function	Relaxed constraints
0.	$J_0 = \sum_{k=1}^N [\Delta u(k) R_{\Delta u} \Delta u(k)^T] + u(N) R_u u^T(N)$	None
1.	$J_1 = J_0 + \sum_{k=1}^{N-1} [\varepsilon_{\tan}(k) S \varepsilon_{\tan}(k)^T]$	(II.4) _{1 ≤ k ≤ N-1}
2.	$J_2 = J_1 + \varepsilon_{\tan}(N) 2S \varepsilon_{\tan}^T(N)$	(II.4) _{1 ≤ k ≤ N}
3.	$J_3 = J_2 + \sum_{k=1}^{N-1} [\varepsilon_V(k) S \varepsilon_V(k)^T]$	(II.4) _{1 ≤ k ≤ N} , (II.3) _{1 ≤ k ≤ N-1}
4.	$J_4 = J_3 + \varepsilon_V(N) 2S \varepsilon_V^T(N)$	(II.4) _{1 ≤ k ≤ N} , (II.3) _{1 ≤ k ≤ N}

II.2.1.c Choix des paramètres

II.2.2 Intégration des non-linéarités du régleur en charge dans la commande

Le contrôleur MPC calcule, entre autre, la séquence des changements de prise optimaux. Or, le régleur en charge est contrôlé par sa tension de consigne selon son algorithme de contrôle interne.

Cette loi de contrôle interne présente des non-linéarités : une bande morte, des variables discrètes (les prises du régleur), ainsi qu'une temporisation. Une inversion explicite de cette commande n'est donc pas possible. L'approche proposée ici, afin de prendre en compte les non-linéarités du régleur en charge dans la commande consiste en une approche en deux étapes :

- Résolution du problème MPC, et calcul de la séquence des changements de prise optimaux ;
- Détermination d'une séquence de tension de consigne pour respecter la séquence de changements de prise optimaux.

L'intégration des non-linéarités du régleur en charge a fait l'objet d'un article [50] et est également l'objet de la Section V.2 (Chapitre V) du mémoire de thèse. Aussi, dans ce résumé substantiel, nous ne proposons qu'une synthèse concise des conclusions de cet article. En bref, il a été mis en évidence que l'utilisation d'un modèle simplifié pour le régleur en charge n'est

pas pertinent pour le contrôleur VVC, qui peut alors, sous certaines conditions être incapable de maintenir la tension dans les plages contractuelles.

Il s'agit de trouver une stratégie, parmi les toutes les possibilités existantes, qui permet de réaliser les changements de prises optimaux.

Si l'on utilise la tension de consigne suivante :

$$V_{OLTC\ ref}(k) = \widehat{V}_{MV}(k+1) + \Delta n_{OLTC\ ref}(k)V_{tap}, \quad (\text{II.11})$$

cette tension de consigne est telle que la tension prédite $\widehat{V}_{MV}(k+1)$ reste dans la plage :

$$[V_{OLTC\ ref}(k) - d, V_{OLTC\ ref}(k) + d].$$

La tension prédite $\widehat{V}_{MV}(k+1)$ est la tension de consigne théorique, si toutes les actions de contrôle sont réalisées sauf le changement de prise $\Delta n_{OLTC\ ref}$. Suivant l'algorithme interne du régulateur en charge, les changements de prise souhaités seront alors réalisés s'il n'y a pas de perturbation extérieure. En effet, puisque la prédiction de la tension n'est jamais exactement réalisée (à cause d'imprécisions dans le modèle ou encore par des perturbations extérieures, telles qu'une variation de production ou de consommation), ce choix limite les changements de prises qui ne seraient pas souhaités. En effet, tant que l'erreur de prédiction est inférieure à la demi-bande morte, d , les changements de prise optimaux seront générés par une telle commande.

Le risque principal lié à l'utilisation d'un modèle simplifié pour le régulateur en charge, par exemple, en négligeant l'existence de la bande-morte, est de créer des situations où l'action du régulateur en charge ne suit pas celles prévues par le contrôleur MPC. Aussi, parfois, alors qu'il existe des solutions alternatives, le système se trouve bloqué dans une situation où l'ensemble des contraintes n'est pas respecté. En effet, il peut par exemple se produire des situations où un changement d'une valeur non entière (0.2 par exemple) de prise puisse résoudre toutes les contraintes. Le contrôleur, avec un modèle continu, envisage qu'un tel changement (pourtant impossible) peut être réalisé, et ne va alors pas converger vers une autre solution acceptable, et ce, même si les contraintes ne sont pas respectées [50].

II.2.3 Résultats de simulations : illustrations des performances de la commande proposée

II.2.3.a Etudes de robustesse pour évaluer les performances du contrôle

La démonstration formelle de la robustesse et de la stabilité de la commande proposée est une tâche malaisée, notamment parce qu'il s'agit d'une commande MPC hybride (variables continues et discrètes), non-linéaire. Pour contourner cette difficulté, les performances des commandes prédictives pour les fonctions VVC des réseaux de distribution sont généralement uniquement illustrées via des simulations [20, 27–30]. Dans ces simulations, le contrôleur doit faire face à des perturbations extérieures non anticipées, et montrer sa capacité à respecter les contraintes en présence d'incertitudes ou d'erreurs de modèle.

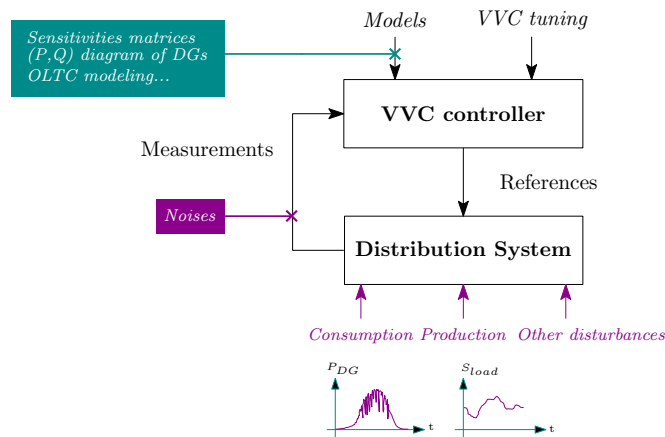


FIGURE II.8 – Incertitudes paramétriques (bleu) et perturbations extérieures (magenta) qui peuvent affecter le contrôleur

Finalement, une étude de robustesse de la commande afin de montrer que la commande proposée est capable de faire face à diverses perturbations et erreurs, ainsi que de quantifier le niveau de ces perturbations/erreurs a été développée. Il s'agit de montrer que le contrôleur est capable (jusqu'à un certain niveau de perturbation/erreur) de remplir ses objectifs. Ces tests de robustesse, illustrés dans la Figure II.8, peuvent être divisés en deux grands types :

- Perturbations extérieures non anticipées par le contrôleur :
 - Variations d'injections de puissance active des GED entre deux instants de contrôle,
 - Variations des consommations actives et réactives des charges entre deux instants de contrôle,
 - Bruits de mesure,
 - Incident sur le réseau de transport en amont...
- Incertitudes paramétriques, c'est à dire des erreurs de modèle, qui peuvent plus particulièrement se situer au niveau du :
 - Modèle du réseau (via les matrices de sensibilité),
 - Modèle des actionneurs, par exemple utilisation d'une approximation continue pour le régulateur en charge.

II.2.3.b Cas d'études et hypothèses

Afin de limiter les tests à mener, nous avons décidé de considérer uniquement les cas critiques pour le réseau de distribution, à savoir une situation de charge extrême associée à une production nulle, et une situation de production importante associée à des conditions de faible charge. Par ailleurs, il est peu probable de corriger certaines erreurs et perturbations qui existent dans la réalité, comme par exemple, l'existence de bruits de mesure. Par contre, nous avons

connaissance des précisions des capteurs de mesure. Aussi il paraît judicieux de tester la commande, en ajoutant un bruit de mesure égale en amplitude à la précision des capteurs. Cette précision est de l'ordre de 0.5% pour les amplitudes de tension et de 1 % pour les mesures de puissance active ou réactive.

De même, la question de l'évaluation des matrices de sensibilité est une question épineuse, car cette évaluation dépend non seulement de la connaissance des paramètres du réseau (lignes, câbles), mais également du modèle des charges. Or l'on sait que les modèles de charge restent l'un des principaux points d'incertitudes dans les simulations électriques. Aussi, avons nous considéré un modèle de charge constant pour l'évaluation de ces matrices (alors que les charges étaient modélisées différemment dans les simulations dynamiques), qui n'ont été évaluées qu'une seule fois, et dans une situation de réseau particulière. Notons que la conséquence d'une sur ou sous évaluation des coefficients des matrices de sensibilité avait été partiellement étudiée dans [28]. Il avait été montré que la conséquence d'une telle erreur portait sur la vitesse de convergence vers une situation acceptable.

Enfin, il paraît illusoire d'envisager d'être en possession d'une prédiction exacte de charge ou d'injection des GEDs. Aussi, il faut tester la commande en considérant des variations de consommation et de production. Aussi, un profil de charge et de production a été créé dans cette optique. De plus, un incident relativement sévère va affecter le réseau de distribution : il s'agit d'une forte élévation de la tension côté HTB1.

Dans la section précédente, nous avons évoqué l'importance d'avoir un modèle précis du régulateur en charge pour éviter des situations dans lesquelles les contraintes ne seraient pas respectées. Dans ces travaux, nous avons étudié plus précisément l'influence d'une mauvaise estimation des réserves en puissance réactive des GED et ce, dans les conditions critiques pour le réseau de distribution.

Tous les détails relatifs à la mise en place des études de robustesse pour évaluer les performances du contrôleur proposé sont disponibles dans le Chapitre V, Section V.3 du mémoire complet.

II.2.3.c Conclusion et recommandations

Toujours par souci de concision, seule une synthèse des résultats et de la conclusion des études menées est proposée dans ce résumé.

En bref, le contrôleur proposé est capable d'atteindre ses objectifs alors même qu'il existe des bruits de mesures, des incertitudes sur le modèle du réseau (les matrices de sensibilité), et que le système est soumis à des perturbations variées (variation de production et de charge, perturbation côté HTB1) dans une situation supposée déjà critique. Aussi, il est alors raisonnable et légitime (bien que cela n'est pas été démontré formellement) de penser que ce contrôleur peut faire face à toutes les situations bornées par les situations critiques considérées et sous les conditions précédemment détaillées.

Par ailleurs, l'utilisation d'une commande prédictive pour la mise en place d'un contrôle VVC pour un réseau de distribution est une solution judicieuse à condition que certaines précautions soient prises. Un soin particulier doit être apporté au modèle des actionneurs pour assurer une bonne robustesse de la commande et éviter de converger vers des situations non acceptables. Sous cette condition, nous avons montré via une étude de robustesse dans des cas critiques, et

avec une connaissance raisonnable du système, (il est à noter que le modèle des actionneurs est celui qui peut être connu le plus précisément), que l'approche prédictive est souhaitable, et qu'un tel contrôleur atteint ses objectifs en dépit des imprécisions et des perturbations qui affectent le système.

II.3 Supériorité de la fonction VVC prédictive proposée par comparaison à d'autres méthodes classiques

Afin de compléter l'étude de la commande proposée, il est également important de mener un travail de comparaison avec d'autres commandes, ici celles introduites dans la section II.1 ; qui sont à savoir : la commande R-VVC (basée sur des règles), et la commande O-VVC (basée sur une optimisation en une étape).

Les Tables II.4 et II.5 constituent une comparaison qualitative de ces trois commandes en terme de prérequis pour la mise en place du contrôle et des objectifs possibles.

TABLE II.4 – Exigences pour chaque contrôleur VVC

Communication	R-VVC	O-VVC	MPC-VVC
ACR ↔ GED	GED départ dédié uniquement	Oui	Oui
ACR ↔ CB	Oui	Oui	Oui
ACR ↔ OLTC	Oui	Oui	Oui
Mesures	R-VVC	O-VVC	MPC-VVC
GED	P, Q, V	P, Q, V	P, Q, V
Tension MT	DSE	DSE	DSE
CB	États commutation	États commutation	États commutation
OLTC		Position de la prise	Position de la prise
Consignes	R-VVC	O-VVC	MPC-VVC
Δt	5 min	1 min	1 min
Modèle	R-VVC	O-VVC	MPC-VVC
Réseau	Pas de modèle mais nécessite une	Oui	Oui
Actionneurs	expertise spécifique	Non	Oui

TABLE II.5 – Comparaison des caractéristiques des GED

Caractéristiques	R-VVC	O-VVC	MPC-VVC
Minimisation du réactif	Non	Oui	Oui
Minimisation des opérations de l'OLTC	Non	Oui	Oui
Hiérarchisation des objectifs	Non	Oui	Oui
Contrôle de la convergence	Non	Non	Oui

Ensuite, les trois commandes ont été simulées sous les mêmes conditions de réseau, sur le

réseau académique introduit dans la section I.3. En conclusion, la commande MPC-VVC permet d'obtenir les meilleurs résultats, grâce à ses capacités d'anticipation. Cela permet notamment de limiter d'éventuels dépassement transitoires sur l'objectif, par exemple en terme de puissance réactive à l'interface tout en assurant que la tension reste dans les plages contractuelles.

Ici, seule la conclusion des études est donnée, les résultats complets sont disponibles dans le Chapitre VI du mémoire de thèse.

Chapitre III

Gestion coordonnée des flux de puissance réactive au sein d'une boucle de transport

La commande temps réel présentée dans la section précédente s'inscrit dans un contrôle étendu à une boucle de transport HTB1. Ce dernier contrôle doit permettre une gestion optimale des flux de puissance réactive HTB1 et de définir les plages/contraintes en réactif à l'interface du contrôle temps réel HTA. Cette partie s'intéresse donc à la mise en place d'une gestion optimale d'une boucle de réseau de transport, et en la détermination des références en $\tan_{HV \rightarrow MV}$ à demander à l'interface réseau de distribution/réseau de transport.

III.1 Intérêt de la mise en place d'une gestion de puissance réactive conjointe GRT-GRD pour soutenir les opérations du GRT

Les problématiques soulevées dans cette dernière partie sont la question de l'intérêt (sous quelles conditions) un support en puissance réactive des réseaux de distribution peut-il soutenir les opérations du GRT, et la mise en place d'une gestion pertinente de ce support en puissance réactive d'un point de vue du GRT et du GRD.

En réalité, il y a deux problèmes subsidiaires distincts à considérer lors de la mise en place d'une telle gestion de puissance réactive au sein d'une boucle de transport. L'un concerne le « dimensionnement optimal » des leviers suivant des besoins et critères prédéfinis, tandis que le second problème implique « l'exploitation optimale », i.e. une commande temps réel, de ces mêmes leviers.

La question du dimensionnement optimal n'est pas sans difficultés. En effet, il y a la notion de dimensionnement du levier (i.e. quel serait la capacité en réactif), mais aussi la notion de positionnement optimal du levier sur cette boucle, c'est-à-dire une position qui permettrait de minimiser les besoins en installations de nouveau levier par exemple. Ou encore, qui prendrait en considération certaines limites, comme la possibilité limitée en chaque point du réseau en

raccordement de réactif (place limitée, impact sur la tension etc.). Par ailleurs, l'évolution des réseaux, et donc une stratégie à long terme doit être prise en compte dans les choix de dimensionnement.

Les travaux de doctorat permettent donc de soulever la question du dimensionnement. Cependant, celle-ci reste en dehors du spectre de l'étude de la thèse qui se concentre sur la gestion optimale et temps réel des leviers.

III.1.1 Support potentiel des réseaux de distribution pour les besoins du GRT

Du fait des évolutions du réseau de distribution, le GRT peut faire face à des difficultés à limiter d'éventuelles élévations de tension, ou d'assurer une distribution appropriée de puissance réactive au sein d'une région [51–53].

Pour faire face à ces difficultés, il est souvent envisagé que les réseaux de distribution, en prenant avantage de certaines flexibilités (notamment offertes par l'introduction des GEDs) puissent fournir un support réactif [51, 54–59]. C'est d'ailleurs également l'esprit du code Européen DCC que nous avons introduit dans la section I.2.

Influence théorique de la puissance réactive des réseaux de distribution sur les tensions HT et THT

L'influence d'un transit de puissance réactive à l'interface sur la tension côté réseau de transport est grossièrement inversement proportionnelle à la puissance de court-circuit du poste source HTB1/HTA S_{cc} . Aussi, l'influence des transits de puissance réactive est relativement faibles sur les tensions du réseau de transport pour des postes sources avec des puissances S_{cc} moyennes à élevées. Afin d'avoir un ordre de grandeur, prenons considérons un poste avec $S_{cc} \geq 500$ MVA (ce qui constitue déjà une puissance relativement moyenne voire faible pour le réseau Français). Alors, $\frac{\delta V}{\delta Q} \leq 0.002$ pu/MVAR. On comprend alors, que maintenir la tension HTB1, depuis ce poste n'est pas pertinent, cela demanderait un effort immodéré à fournir au réseau de distribution en amont.

Par contre, pour des réseaux de transport plus faibles ($S_{cc} \leq 500$ MVA), typiquement des réseaux ruraux, un tel support pourrait être envisageable. Il faut également préciser que les puissances de court-circuit S_{cc} ne sont pas constantes, et peuvent être fortement impactées par certaines perturbations comme la perte d'une ligne haute tension. Aussi, dans ces cas d'urgence, un support peut devenir intéressant.

Par ailleurs, même dans le cas d'une boucle de transport "forte", si les exports de puissance réactive en aval du réseau de transport (HTB1) au sein d'une même zone géographique sont plus ou moins importants, ils peuvent engendrer un fort refoulement de puissance réactive vers les niveaux de tension supérieurs (typiquement HTB2). Cela peut alors perturber le profil de tension HTB2 ainsi que la gestion de la puissance réactive à ce niveau qui est intimement liée au réglage hiérarchisé de tension.

Finalement, il y a deux grandes situations pour lesquelles il y a une opportunité à mettre en place un support de puissance réactive depuis les réseaux de distribution pour les besoins du GRT à des fins :

- De maintien de la tension HTB1 dans le cas de réseaux faibles, c'est à dire avec des

- puissances de court-circuit faibles ;
- De limitation des refoulements de puissance réactive vers les niveaux supérieurs de tension (HTB2/HTB1).

Besoin d'études conjointes et de simulations dynamiques sur un système étendu

Pour mettre en place un soutien économiquement et techniquement viable, il y a plusieurs points à considérer :

- Connaissance précise de la réserve en puissance réactive en aval des réseaux MT ;
- Capacité du GRD à faire appel à cette réserve ;
- Existence d'un système de communication entre GRT et GRD.

Rappelons que nous nous focalisons uniquement sur l'appel temps réel des leviers et non pas sur des problématiques de dimensionnement de leviers ou même encore sur les techniques d'évaluation d'une telle réserve de puissance réactive. En effet l'évaluation de cette réserve peut être délicate, car elle n'est pas constante et varie suivant les contraintes éventuelles sur le réseau de distribution, ou encore suivant l'injection de puissance active des GEDs selon les digrammes (P,Q) considérés. On peut toutefois citer différentes méthodes dans la littérature basées sur des calculs de load flows [60–62] mais qui notent la difficulté d'obtenir une estimation précise.

Par ailleurs, nous avons fait l'hypothèse que les réseaux de distribution étaient équipés de la fonction VVC temps réel MPC introduite dans la seconde partie de ce rapport, et que le GRD était capable de communiquer régulièrement avec le GRT, notamment quant à sa réserve de puissance réactive.

L'objet de ses travaux est la gestion temps réel des leviers en réactif pour les besoins du réseau de transport. L'association d'une telle gestion avec les fonctions temps réel des réseaux de distribution a également été plus particulièrement étudiée.

Généralement, comme nous l'avons déjà indiqué, les problèmes à l'interface sont traités soit du point de vue uniquement du GRT, soit uniquement du GRD. Par exemple, les contraintes éventuelles dans le réseau de distribution sont souvent ignorées et les simulations sont réduites à l'étude des réseaux HT, avec des modèles très simplifiés et simplistes pour les réseaux de distribution [55–57, 63]. D'un autre côté, le sujet de la mise en place d'une fonction de contrôle temps réel des réseaux de distribution est traité dans la littérature du point de vue du GRD uniquement, le réseau de transport étant limité à un noeud de tension tenue. Or cette hypothèse peut être remise en question, notamment dans le cas conditions dégradées [64] ou quand il existe une forte dépendance entre les réseaux HT et MT [65].

Aussi, il existe un besoin évident de développer des simulations combinant à la fois les réseaux de distribution et de transport. C'est pour ces raisons que notre étude s'est portée sur un réseau étendu, qui consiste en plusieurs réseaux de distribution connecté à une même boucle de transport. En résumé, lorsque le soutien de puissance réactive s'avère nécessaire, il paraît peu pertinent de ne considérer que les réseaux de distribution ou d'envisager un contrôle exclusivement basé sur la supervision du GRT. Des simulations dynamiques sur un système étendu doivent être menées afin de prendre en compte un comportement plus réaliste du système, et d'intégrer l'ensemble des contraintes et exigences des gestionnaires.

III.1.2 Outils et méthodes

Afin de mettre en place des études conjointes, qui seraient basées sur une communication et des échanges d'informations entre GRT et GRD, un environnement de simulations dédié a été imaginé. Cet environnement est détaillé dans la Section VII.2 du mémoire de thèse.

L'ensemble du système (boucle de transport et réseaux MT) a été modélisé en utilisant RAMSES. Pour simplifier la lecture et l'analyse des résultats, tous les réseaux de distribution possèdent la même topologie (celle du réseau académique) et qui a été mis à l'échelle pour respecter les échanges de puissance à l'interface ainsi que les niveaux de production.

RAMSES peut être couplé à différents logiciels de simulation dont Matlab. C'est ce dernier qui a été sélectionné pour réaliser les contrôles temps réel. Pour reproduire la connaissance limitée des GRT et GRD, deux sets de fonctions de contrôle, un qui serait localisé dans le centre de contrôle du GRD, et l'autre qui serait localisé dans celui du GRT ont été réalisés. Chaque set de fonctions a donc accès une quantité restreinte d'informations. Par ailleurs, le GRT peut faire appel à des calculs de load flow pour estimer les consignes de puissance réactive à imposer à chaque interface transport/distribution. Aussi un lien entre Matlab et Powerfactory a également été créé.

III.1.3 Mise en place d'une première gestion simple au sein d'une boucle HTB1

Dans un premier temps, une fonction de gestion très simple a été proposée dans nos travaux. Cette première gestion est basée sur une loi locale. Le principe est le suivant : en fonction de la mesure de la tension à une interface HT/MT donnée, le réactif de consigne est ajusté au besoin, en connaissant la valeur de la sensibilité de la tension à la puissance réactif en aval. Cette stratégie est illustrée dans la Figure III.1.

Par exemple, faisons l'hypothèse qu'il y a un dépassement de tension V_{HV_i} au poste source S_i , à un instant t_0 , alors le GRT peut demander une demande d'absorption de puissance réactive ΔQ_{req} , en aval du réseau S_i afin de réduire l'élévation de tension. Cette demande du GRT, va activer la contrainte portant sur la valeur de la $\tan_{HV \rightarrow MV}$. Aussi, la fonction VVC associée au réseau en aval de S_i va agir afin de satisfaire dans la mesure du possible, la demande à l'interface et les contraintes propres GRD. La fonction VVC étant la fonction prédictive proposée dans la section II.2, une réduction progressive de la puissance réactive va avoir lieu. Si jamais la tension V_{HV_i} retourne dans les plages contractuelles alors que la consigne en réactif n'est pas encore réalisée, celle-ci est alors mise à jour pour éviter de demander un effort supplémentaire inutile au réseau de distribution. La contrainte à l'interface doit être respectée tant que le GRT ne lève pas sa demande. Si le GRT ne fait aucune demande spécifique, la valeur $\tan_{HV \rightarrow MV}$ n'est pas limitée. En d'autres termes, il n'y a pas de contrainte portant sur la valeur de $\tan_{HV \rightarrow MV}$ dans les VVC des réseaux de distribution.

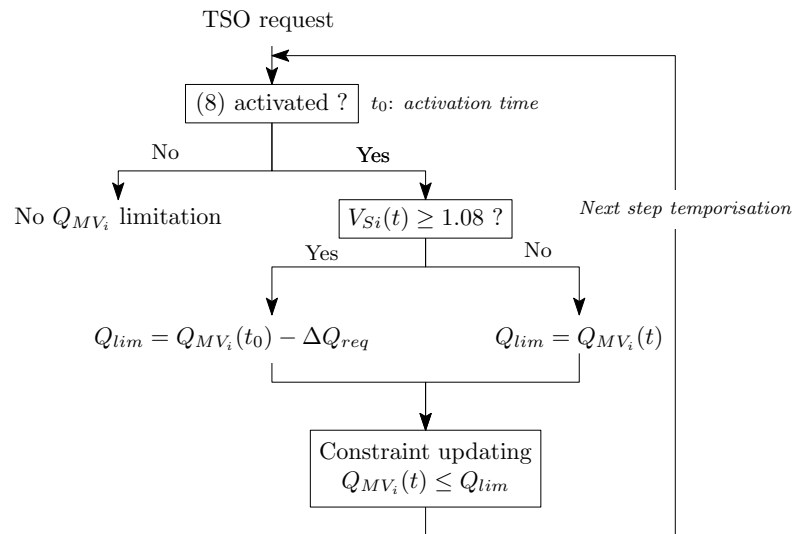


FIGURE III.1 – Schéma de principe du support local de puissance réactive proposé

Pour vérifier l'intérêt et les performances d'une telle loi, des simulations dynamiques, sur le système étendu, ont été menées dans le cas particulier d'une perte de ligne HTB1, ce qui conduit à une élévation de tension. Des comparaisons avec et sans cette loi de contrôle (i.e. avec uniquement les fonctions VVC des réseaux de distribution qui ne considèrent que des objectifs pour le GRD) ont été réalisées.

Ici seules les conclusions des travaux sont présentées mais sont détaillées dans le Chapitre VII du mémoire complet. A noter que cette étude a donné lieu à la rédaction d'un article, qui a été soumis au journal *Sustainable Energy Grid and Networks*. A titre de synthèse, il a été mis en évidence, que grâce aux propriétés inhérentes d'adaptabilité de la commande MPC, les contrôleurs VVC sont capables de soutenir efficacement les tensions HT, et ce, avec une connaissance limitée et une estimation grossière de la puissance réactive dont a besoin le GRT. De plus, ce support en puissance réactive n'induit pas un surcoût important pour le GRD. En effet, l'élévation de tension côté réseau de transport induit également des élévations côté réseau de distribution, que les fonctions VVCs temps réel vont être amenées à corriger, en utilisant entre autres la puissance réactive des GEDs. Autrement dit, la réaction naturelle des VVC tend à fournir un support indirect au réseau de transport. Par ailleurs, l'approche proposée permet de limiter les demandes de puissance réactive si les contraintes sont respectées.

Cependant, les limites importantes de ce premier contrôle sont la difficulté à gérer des situations plus complexes comme : que faire en cas de pénurie de puissance réactive sous un réseau de distribution (la loi est en effet purement locale) ? comment calculer la référence en aval des postes HT/MT pour assurer une limitation des refoulements de puissance réactive vers les niveaux supérieurs de tension ? Finalement, nous sommes confrontés au manque de flexibilité d'une approche basée sur l'établissement de règles, et ce, d'autant plus qu'il existe des sensibilités croisées entre les transits de de puissance réactive d'un poste HT/MT et les tensions HT d'autres postes. Par conséquent, il existe plusieurs solutions alternatives pour maintenir un profil de tension HT approprié. C'est pourquoi, l'utilisation d'un OPF (Optimal Power Flow)

permettait de sélectionner la solution la plus appropriée, i.e. la solution optimale par rapport à une fonction coût spécifique.

III.2 Calcul des flux de puissance réactive optimaux au sein d'une boucle de transport

L'objectif de cette dernière partie est de proposer une coordination GRT-GRD pour la gestion de la puissance réactive au sein d'une boucle de transport HTB1, qui s'appuierait notamment sur les réseaux de distribution. Par rapport à au contrôle assez simple basé sur une règle développée dans la section précédente, un contrôle basé sur une optimisation (via la résolution d'un problème d'Optimal Power Flow [66]) a été considéré dans cette dernière partie.

En effet, le choix de l'optimisation par rapport à celui d'un système de règles, se justifie par la généralité et souplesse d'une telle méthode, il est facilement envisageable de pouvoir remplir les deux objectifs suivants : maintien du plan de tension HTB1, maîtrise des échanges de puissance réactive vers la HTB2 selon les besoins du GRT.

La définition du problème d'optimisation (choix de la fonction coût, choix des contraintes) a été plus particulièrement étudiée pour permettre d'atteindre une coordination "gagnant-gagnant". Pour ce faire, il faut d'une part que les contraintes et exigences des GRT, GRD soient respectées, sans que l'une des parties ait à fournir un effort immodéré et trop important. Par ailleurs, nous avons fait l'hypothèse que les réseaux de distribution étaient équipés de la MPC-VVC proposée dans la Section II.1, et que le GRT et le GRD étaient capable d'échanger à propos de la réserve réactive disponible aux interfaces HTB1/HTA.

III.2.1 Définition du problème d'OPF pour la gestion de puissance réactive

Le principe de la commande est illustré dans la Figure III.2. Nous avons considéré que le contrôle serait localisé dans le centre de contrôle du réseau de transport du GRT.

Les objectifs de la commande sont doubles : maintien du plan de tension HTB1, et limitation des échanges de puissance réactive vers la HTB2.

Pour répondre à ces deux objectifs, le contrôle peut considérer les leviers suivants : le réactif des réseaux de distribution (en envoyant une consigne distincte pour chacune des interfaces HTB1/HTA), la tension de consigne du régulateur en charge HTB2/HTB1. S'il existe d'autres leviers sur le réseau de transport (GED connecté au réseau de transport, self, banc de condensateur HTB1...) ceux ci peuvent aisément être introduits dans le contrôle.

Afin de minimiser les coûts d'un tel contrôle, qui serait utilisé pour assurer la sûreté du système (donc un besoin plutôt dans des cas d'urgence) la fonction de coût suivant a été utilisée :

$$J_{OPF} = R_{MV}|Q_{HV \rightarrow MV_{ref}}| + R_{HV}|Q_{HV_{ref}}| + R_{Loss}P_{Loss}; \quad (III.1)$$

Le terme P_{Loss} représente les pertes dans le système HTB1, transformateurs HTB1/HTA inclus.

Enfin, pour terminer la définition du problème, il convient d'écrire les différentes contraintes que le contrôle doit satisfaire.

Comme pour la mise en place de la commande prédictive, il y a d'une part, des contraintes

physiques, que le contrôleur ne peut pas violer. Il s'agit principalement des contraintes portant sur les limitations physiques des actionneurs. Et d'autre part, les contraintes qui traduisent les objectifs du contrôle.

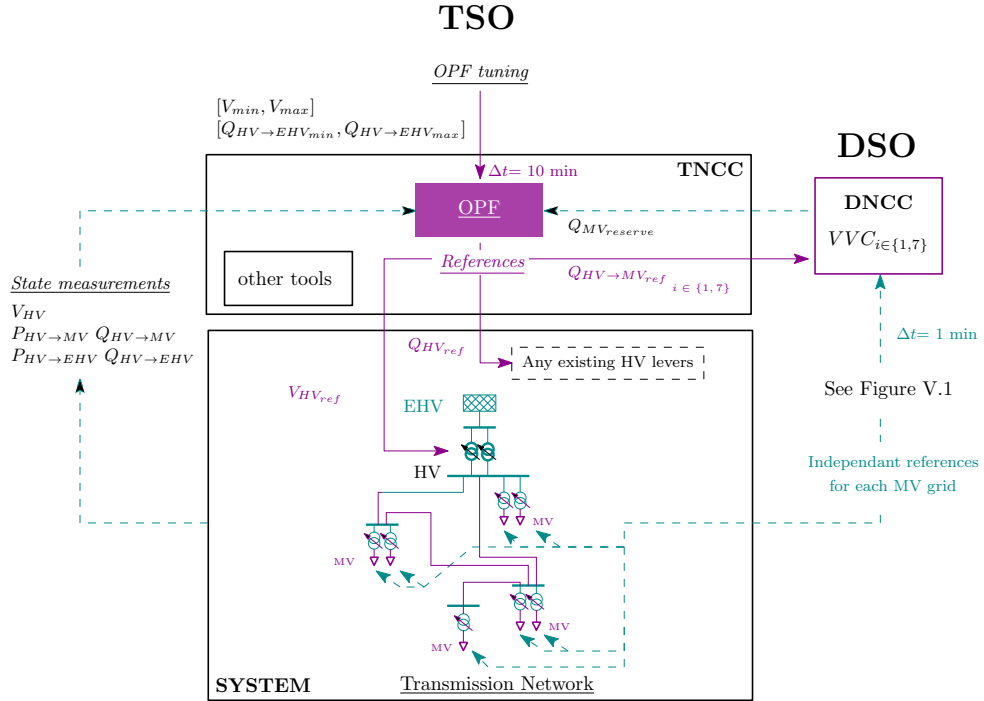


FIGURE III.2 – Schéma de principe de la stratégie de contrôle basée sur un OPF

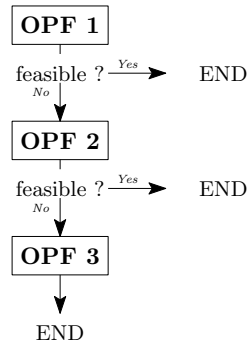


FIGURE III.3 – Principe de structure hiérarchisée de relaxation des contraintes

III.2.1.a Résolution et gestion des cas d'infaisabilité

Les calculs de load flow sont effectués via le logiciel PowerFactory DigSilent, tandis que la résolution de l'optimisation est gérée par la fonction fmincon de Matlab.

Comme dans les contrôles basés sur une optimisation développés pour les VVC des réseaux de

distribution, une relaxation hiérarchisée (voir Figure III.3) des contraintes a été mise en place pour pallier les infaisabilités. Les variables de relaxation sont alors fortement pénalisées dans la fonction coût.

III.2.1.b Recommandation pour la définition de l'OPF

Il est assez intuitif que l'effort demandé aux réseaux MT va dépendre d'une part des exigences du réseau de transport (maintien de la tension, choix de la limite autorisée en puissance réactive vers le niveau supérieur de tension...), et d'autre part des coûts associés à l'appel de chaque levier. Par exemple, si le GRT néglige le coût de l'appel aux leviers en puissance réactive du GRD, alors l'appel à ces mêmes leviers ne sera pas limité par le contrôle (aucun coût associé, donc pas de poids dans la fonction coût).

L'influence des facteurs de pondération de la fonction objectif, ainsi que des contraintes a été étudiée dans le mémoire complet (voir plus particulièrement la Section VIII.2 du Chapitre VIII) et illustrée via des simulations statiques. Il en résulte qu'il est peu intéressant de minimiser les pertes (surtout si l'on considère que le contrôle va servir pour faire face à des situations exceptionnelles qui pourraient mettre en danger la sûreté du système). De plus, il faut que les objectifs à réaliser en terme de puissance réactive soient raisonnables, et que des études de dimensionnement soient conduites conjointement par le GRT et le GRD pour s'assurer de trouver l'optimum économique si besoin.

III.2.2 Association avec les fonctions VVC temps réel des réseaux de distribution

Le principe de l'association des fonctions VVC temps réel et de la gestion du réactif basé sur l'OPF est illustré dans la Figure III.4. Toutes les dix minutes, la résolution de l'OPF donne les consignes de réactif à chaque interface HTB1/HTA, qui sont traduites par les VVCs en objectifs en terme de $\tan_{HV \rightarrow MV}$. Pour mener une telle étude, le GRT utilise les dernières valeurs de mesures des tensions HTB1, et échanges de puissance aux interfaces. Par ailleurs, le GRD communique régulièrement sur la réserve disponible en puissance réactive sous chacun des postes sources HTB1/HTA.

Toutes les minutes, les fonctions VVC des réseaux de distribution agissent et essaient de répondre aux sollicitations du GRT lorsque c'est possible (i.e. si cela est compatible avec leurs propres objectifs du maintien de la tension MT).

Deux cas d'études ont été définis afin de montrer via des simulations dynamiques l'intérêt de l'approche proposée. Les résultats de simulations sont disponibles dans la Section VIII.3 du Chapitre VIII du mémoire de thèse. Ces simulations ont montré que l'association OPF et VVC temps réel permettait d'obtenir des plans de tensions MT, et HTB1 appropriés, tout en limitant dans la mesure du possible les échanges de puissance réactive à l'interface HTB2.

A nouveau, l'intérêt de l'approche prédictive par ses grandes capacités d'adaptation a été démontré. Il se peut que la VVC s'éloigne temporairement de son objectif en terme de puissance réactive à l'interface pour maintenir les contraintes du GRD. Cela ne constitue pas un problème si une bonne communication sur la réserve de puissance réactive est disponible. L'utilisation d'une relaxation hiérarchisée permet de s'assurer que la meilleure situation possible est atteinte grâce au contrôleur.

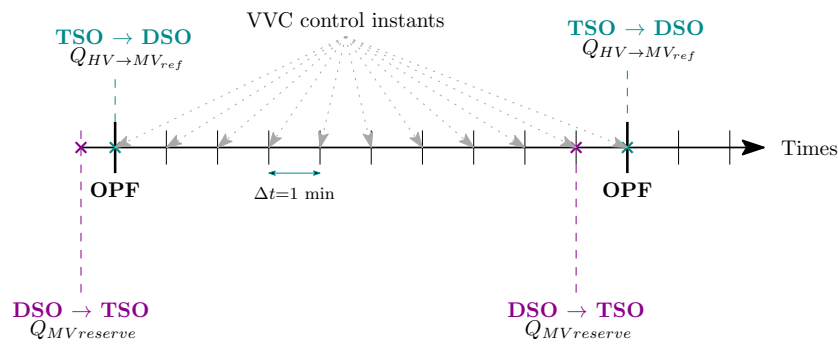


FIGURE III.4 – Association de la stratégie de contrôle OPF avec la commande VVC des réseaux de distribution

Des pistes d'amélioration de la commande peuvent être envisagées :

- Utilisation d'une commande prédictive pour éviter des violations transitoires ;
- Améliorer les échanges d'informations, notamment entre VVC (prendre en compte l'action future des autres VVC) ;
- Envisager que le GRT puisse venir en aide au GRD via la coordination dans le cas d'un éventuel problème de tension dans un réseau de distribution.

Conclusion générale et perspectives

Les réseaux de distribution connaissent actuellement des évolutions majeures. Ces évolutions sont par exemple l'insertion de la production décentralisée (les GEDs), l'enfouissement des lignes aériennes, ou encore l'évolution de la charge. En conséquence, des nouvelles problématiques opérationnelles sont susceptibles d'apparaître sur l'ensemble du système électrique. Ces problématiques peuvent être plus spécifiquement relatives au maintien du plan de tension, souvent lié à la gestion de la puissance réactive. Sans être exhaustif, les conséquences sont un risque accru de tension anormalement haute, un déclin des flux de puissance aux interfaces HT/MT, avec une grande variabilité et imprévisibilité, un risque d'entrée en butée des régulateurs en charge HT/MT...

Par ailleurs, les gestionnaires des réseaux de distribution doivent également répondre aux nouvelles exigences réglementaires, portées par l'entrée en vigueur des codes de réseau européens. En conséquence, des solutions alternatives au réglage traditionnel de la tension dans les réseaux de distribution peuvent être proposées pour atténuer les élévations de tension et faire face aux contraintes opérationnelles.

Dans ces travaux de doctorat nous nous sommes concentrés sur la mise en place de solutions temps réel pour répondre à ces nouveaux enjeux autour de deux axes : évolution du réglage temps réel des réseaux de distribution, mise en place d'une gestion conjointe GRT/GRD des échanges de puissance réactive

Amélioration du réglage temps réel des réseaux de distribution

Il existe une littérature très riche sur le réglage temps réel de la tension dans les réseaux de distribution. Dans cette conclusion, nous tenons à souligner les choix effectués ; i.e. de développer plus particulièrement une commande prédictive, centralisée. Cette commande est un pas en avant vers un système de distribution plus actif, dans laquelle nous avons tenu à conserver par exemple l'algorithme de contrôle du régulateur en charge, pour ne pas bouleverser le fonctionnement du réseau. En effet, il nous semble que l'utilisation d'une solution temps réel n'est pas forcément pertinente et nécessaire pour chaque réseau de distribution. Par exemple, le niveau de pénétration des productions décentralisées (GEDs), ou le taux de câbles souterrains par rapport aux lignes aériennes peuvent être très différents d'une région à l'autre.

Dans cette optique, une commande temps réel pour la gestion des réseaux de distribution a été présentée. Les objectifs de cette commande sont doubles : le maintien du plan de tension HTA et le contrôle du réactif à l'interface réseau de transport / réseau de distribution. Pour la réalisation de cette commande, une approche centralisée, coordonnée et basée sur la commande prédictive (MPC) a été mise au point. L'une des particularités de ce contrôle est la gestion du réactif à l'interface, mais aussi la prise en compte des non-linéarités du régulateur en charge grâce à l'approche prédictive. Par ailleurs, un soin particulier a été apporté pour s'assurer que cette commande s'appuie sur une vision réaliste des réseaux de distribution actuels.

Les performances de cette commande ont été montrées via des études de robustesse ainsi que des comparaisons avec des commandes plus classiques (basées sur un système de règles et sur une optimisation en une étape).

Enfin, une telle commande temps réel devait s'inscrire dans un cadre plus large : la gestion optimale d'une boucle HTB1.

Mise en place d'une gestion conjointe GRT/GRD des échanges de puissance réactive

Pour définir une telle commande, des études ont été menées sur une boucle HTB1 afin de déterminer les besoins et les contraintes. Les objectifs et les contraintes du problème d'optimisation ont été posés, et une démarche générale proposée ; l'objectif ultime étant de mettre en perspective les exigences des Codes de Réseau Européens par rapport aux besoins des gestionnaires des réseaux de transport et de distribution.

Il existe deux situations pour lesquelles il y a une vraie opportunité de mettre en place un support en puissance réactive depuis les réseaux de distribution :

- Pour le maintien du plan de tension HTB1 dans le cas d'un réseau faible (i.e. avec postes sources possédant de faibles puissances de court-circuit)

- Pour la limitation des exports de puissance réactive dans le cas de réseaux de distribution avec des refoulements de puissance réactive aux interfaces HTB1/HTA.

Pour la mise en place d'un tel contrôle, tout comme pour la conception des VVC, différentes méthodes peuvent être envisagées. Dans ces travaux, nous avons développés deux approches. La première très simple, est une loi locale qui permet d'ajuster le réactif de consigne en amont d'un poste source donné si la tension HTB1 de ce poste est anormalement élevée. Cette loi ne permet que le maintien du plan de tension, et peut se retrouver en défaut s'il s'avère qu'un réseau de distribution ne peut fournir la demande en puissance réactive. La seconde solution, plus complexe mais plus générique et flexible, permet de pallier les manques de puissance réactive ou encore de facilement considérer un double objectif. Cette dernière solution est basée sur la résolution d'un problème d'OPF.

Des simulations dynamiques, sur un système étendu permettant d'illustrer et de confirmer l'intérêt des associations proposées entre gestion de la puissance réactive et fonctions VVC des réseaux de distribution ont été réalisées. Certes, ces études ne sont pas à généraliser puisqu'elles ont été menées sur un réseau spécifique et dans des conditions spécifiques. Cependant, elles permettent de dresser des recommandations pour la mise en place d'un soutien en puissance réactive pour des besoins du GRT en s'appuyant sur les réseaux MT.

En conclusion, il peut exister des solutions alternatives à la solution du code DCC pour répondre à des exigences du GRT. Pour la mise en place de telles solutions, il est nécessaire d'atteindre une plus grande coordination entre GRT et GRD de mettre en place des :

- Échanges d'information (une information de première importance est une estimation de la réserve de puissance réactive en amont de chaque poste HTB1/HTA) ;
- Études communes (études de dimensionnement et analyses dynamiques), pour atteindre un accord quant à l'effort auquel peuvent raisonnablement consentir les réseaux de distribution et pour le coût le plus faible pour la communauté.

Perspectives de travail

Il existe plusieurs perspectives à ces travaux de doctorat. En effet, il a été précisé que la question du dimensionnement et des études de planification était en dehors du cadre de cette étude qui s'est davantage focalisée sur la mise en place des solutions temps réel pour le pilotage des leviers (HTA ou HTB1). Aussi, les points suivant mériteraient d'être approfondis :

- Dimensionnement des leviers pour les besoins de la gestion commune HTB1/HTA. Dans nos travaux, nous avons fait l'hypothèse de l'existence d'une réserve suffisante. Cependant si cela n'était pas le cas, il est clair qu'il n'existe pas une solution générique mais diverses alternatives suivant le système considéré quant aux choix des leviers à raccorder, ainsi que différentes localisations possibles (HTB1 ou HTA). Afin de trouver la meilleure solution possible (la moins chère pour la communauté), il est nécessaire de conduire des analyses coût/bénéfice conjointes entre GRD et GRT ;
- Évaluation de la réserve de puissance réactive HTA disponible à l'interface HTB1/HTA en J-1 et en temps réel. Il a été montré qu'il était nécessaire d'avoir une évaluation assez précise de cette réserve pour mettre en place la gestion commune au sein de la boucle

HTB1. Or l'évaluation de cette réserve n'est pas aisée car elle varie dans le temps et en fonction des conditions de charge et de production du réseau HTA. Ce sujet est l'un des thèmes d'une thèse menée par le L2EP en partenariat avec Enedis qui a débuté en Septembre 2015.

En conclusion, nous avons répondu aux attentes d'Enedis en étudiant les conséquences des évolutions des réseaux de distribution sur les problématiques de réglage de la tension, plus particulièrement à l'interface HTB1/HTA. Pour remédier aux problématiques soulevées par ces évolutions, une stratégie basée sur deux solutions a été développée : d'une part une évolution du réglage temps réel des réseaux de distribution et d'autre part un renforcement d'une coordination GRT/GRD. Pour chacun de ces points, différentes méthodes ont été proposées et illustrées par des simulations dynamiques permettant d'envisager différentes solutions pour les choix industriels futurs.

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COORDINATION DES MOYENS DE REGLAGE DE TENSION A L'INTERFACE RESEAU DE DISTRIBUTION/RESEAU DE TRANSPORT ET EVOLUTION DU REGLAGE DE LA TENSION DANS LES RESEAUX DE DISTRIBUTION

RESUME : Le réglage de la tension et la gestion de la puissance réactive est d'une importance capitale pour le bon fonctionnement du système électrique. Les réseaux de distribution connaissent des modifications profondes qui sont tant techniques avec l'insertion de la production décentralisée ou l'enfouissement des lignes aériennes, que réglementaires avec l'entrée en vigueur des codes de réseaux Européens. Aussi, des alternatives aux réglages traditionnels de tension et la mise en place de contrôle des échanges de puissance réactive à l'interface réseau de transport/distribution peuvent être développées. Dans le cadre de ces travaux de doctorat, une solution basée sur l'amélioration du réglage temps réel des réseaux de distribution ainsi que la mise en place d'une gestion conjointe de la puissance réactive entre les gestionnaires du réseau de transport et distribution a été proposée. Ce réglage temps réel est basé sur une méthode de commande prédictive, et s'appuie notamment sur le régleur en charge ou les productions décentralisées pour réaliser un réglage de la tension au sein d'un réseau de distribution et contrôler les échanges de puissance réactive. Les références de puissance réactive à atteindre à l'interface entre réseau de distribution et de transport sont déterminées par le gestionnaire du réseau de transport pour ses propres besoins et en connaissance des réserves de puissance réactive disponible depuis les réseaux de distribution. Par rapport à la littérature, notre démarche a pour originalité de prendre en compte les problèmes à l'interface des réseaux de distribution et de transport et démontre l'intérêt de mener des études conjointes entre gestionnaires.

Mots clés : Réglage de tension, gestion de la puissance réactive, réseau de distribution actif, interface transport/distribution, contrôle temps réel, commande prédictive.

JOINT TSO AND DSO VOLTAGE AND REACTIVE POWER CONTROL AT HV/MV SYSTEMS INTERFACE AND DEVELOPMENT OF REAL TIME VOLT VAR CONTROL OF DISTRIBUTION NETWORKS

ABSTRACT: Voltage and reactive power control are of paramount importance to ensure safe and reliable operation of the power system. Distribution grids are undergoing major changes, namely the insertion of distributed generation and the replacement of overhead lines. Along with these physical evolutions, new distribution networks should comply with the requirements of the European Grid Codes on the reactive power exchange at the HV/MV interface. To handle these new operational concerns, alternative solutions to the traditional voltage and reactive power control can be found. In our work, a scheme based on the evolution of the real-time Volt Var Control (VVC) of distribution networks and a joint coordination for the reactive power management of a HV system has been proposed. The real-time VVC of MV grids is based on a predictive control method. This control uses in a coordinated manner the on load tap changer, the distributed generation and the capacitor banks to enforce a suitable MV voltage profile and an appropriate HV/MV reactive power exchange. The reactive power targets at the HV/MV interface are determined by the Transmission System Operator for its own requirements but considering the true MV reactive power reserve. Compared to the literature, the novelty of our approach consists in considering the concerns at the HV/MV system interface. Next our works have shown the relevance of performing joint transmission and distribution system operators analysis.

Keywords : Voltage and reactive power control, active distribution grids, HV/MV systems interface, real-time control, predictive control.