OPTIMAL CONTROL OF WIND FARMS FOR TSO-DSO COORDINATED REACTIVE POWER MANAGEMENT

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Ai miei genitori,
Giovanni e Giovannella.
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Nomenclature

List of Acronyms

AEEGSI Autorità per l’Energia Elettrica, il Gas e il Sistema Idrico
AS Ancillary Services
AVR Automatic Voltage Regulator
CP Connection Point
DC Direct Current
DCC Demand and Connection Code
DEA Dezentralen Erzeugungs Anlagen
DEP Data Exchange Platform
DFIG Doubly-Fed Induction Generator
DG Distributed Generation
DPL DigSilent Programming Language
DSO Distribution System Operator
EDSO European Distribution System Operators
EHV Extremely High Voltage
EVs Electric Vehicles
FACTS Flexible AC Transmission Systems
FRCI Fast Reactive Current Injection
GA Genetic Algorithms
GTO Gate-turn-off Thyristor
HV High Voltage
HVDC High Voltage Direct Current
IGBT Insulated Gate Bipolar Transistor
IRENA  International Renewable Energy Agency
ISO  Independent System Operator
IWES  Institute for Wind Energy and Energy Systems
KKT  Karush-Kuhn-Tucker
LCOE  Levelized Cost of Electricity
LP  Linear Programming
MAE  Mean Absolute Error
MINLP  Mixed Integer Non Linear Programming
MIQP  Mixed Integer Quadratic Programming
MO  Multi Objective
MPC  Model Predictive Control
NLP  Non Linear Programming
NSON  North Sea Offshore and Storage Network
OF  Objective Function
OLTC  On Load Tap Changer
OPF  Optimal Power Flow
ORPF  Optimal Reactive Power Flow
PCC  Point of Common Coupling
PSO  Particle Swarm Optimization
PV  PhotoVoltaics
PVR  Primary Voltage Regulation
REI  Radial Equivalent Independent
RES  Renewable Energy Sources
RPR  Reactive Power Reserve
SCC  Short Circuit Capacity
SCIG  Squirrel Cage Induction Generator
SGUs  Smart Grid Users
SLIB  Single Load Infinite Bus
SM  Synchronous Machine
SSVC  Steady State Voltage Control
STATCOM Static Synchronous Compensators
SVCs Static Var Compensators
SVR Secondary Voltage Regulation
TCR Thyristor Controlled Reactor
TSC Thyristor Switched Capacitor
TSO Transmission System Operator
TVR Tertiary Voltage Regulation
VRES Variable Renewable Energy Sources
VSI Voltage Source Inverter
VVC Volt-Var Control
WEA Wind Energie Anlagen
WPP Wind Power Plant
WRIG Wounded Rotor Induction Generator
WT Wind Turbine

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<tr>
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<td>B</td>
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Lagrangian function  \( L \)
Lagrangian multiplier (equality constraints)  \( \lambda \)
Boundary nodes (EHV side)  \( M \)
Lagrangian multiplier (inequality constraints)  \( \mu \)
Active power  \( P \)
Pareto set  \( P \)
Reactive power  \( Q \)
OLTC tap position  \( r \)
Resistance  \( R \)
Solution space  \( S \)
Time  \( t \)
MPC time horizon  \( T \)
Control variable  \( u \)
Voltage  \( U \)
OF weight  \( w \)
Variable  \( x \)
Reactance  \( X \)
Admittance matrix  \( Y \)
Impedance  \( Z \)

**List of Indexes**

- **ext**  external
- **g**  generator
- **i**  bus
- **j**  bus (alias)
- **k**  bus (alias)
- **max**  Maximum
- **min**  Minimum
- **n**  Number of nodes
- **N**  Number of connection points
- **opt**  optimal
- **set**  setpoint
Abstract

The growing importance of renewable generation connected to distribution grids poses several challenges to traditional grid operation methods, at both distribution and transmission level. Distributed Generation (DG) offers on the other hand also opportunities, especially when it comes to reactive power provision. Voltage and reactive power control in systems with high penetration of Variable Renewable Energy Sources (VRES), require an increased coordination between the Transmission System Operator (TSO) and the Distribution System Operator (DSO) in order to exploit DG potential in the optimal way.

This Master Thesis addresses the coordination between TSO and DSO at the High Voltage (HV)-Extremely High Voltage (EHV) interface in Germany and the optimal use of wind farms for reactive power management. For this purpose, a modular Optimal Power Flow (OPF) tool, featuring Multi Objective (MO) optimization, is developed. The OPF tool is used to build a practical and effective interaction scheme based on sequential optimizations to evaluate the reactive flexibility potential of distribution networks and dispatch them along with traditional synchronous generators. The scheme developed allows taking into account constraints and needs of both systems keeping to a minimum the information exchange.

The proposed method is evaluated for a real German 110-kV grid with 1.6 GW of wind power and the surrounding transmission system. Different types of set points are investigated, showing the feasibility for the DSO to fulfill also individual voltage and reactive power targets over multiple connection points. Different wind farm control modes are also proposed and implemented in the OPF. The results of this work, suggest the feasibility and the convenience of involving distribution grids and connected DG in the voltage control concept of entire grid regions.

The research work was performed through an internship at the Transmission Grid department in the Energy Economy and Grid Operation division of the Fraunhofer Institute for Wind Energy and Energy Systems (IWES) under the supervision of the department leader David Sebastian Stock within the IMOWEN Project, and in cooperation with the Energy department of Politecnico di Milano, under the supervision of Professor Alberto Berizzi.
Abstract in Italiano

La crescente diffusione degli impianti di generazione da fonte rinnovabile connessi alle reti di distribuzione pone diverse sfide ai metodi tradizionali di operazione dei sistemi elettrici, sia a livello di distribuzione sia di trasmissione. La Generazione Distribuita (GD) offre d’altro canto anche diverse opportunità, soprattutto in termini di regolazione della potenza reattiva. Il controllo della potenza reattiva e delle tensioni in un sistema ad alta penetrazione di Fonti Rinnovabili Non Programmabili (FRNP), richiede una crescente coordinazione tra il gestore del sistema di trasmissione (TSO) e i gestori dei sistemi di distribuzione (DSO), al fine di sfruttare in modo ottimale il potenziale offerto dalla GD.

Questo lavoro di tesi si concentra sulla coordinazione tra TSO e DSO in Germania all’interfaccia tra l’alta e l’altissima tensione (AAT), e sul controllo ottimale dei parchi eolici per la gestione dei flussi di potenza reattiva. A tal fine è stato sviluppato un programma modulare di Optimal Power Flow (OPF), con ottimizzazione Multi-Obbiettivo (MO). L’OPF è stato poi usato per costruire uno schema di interazione basato sul calcolo della flessibilità in termini di potenza reattiva fornibile dalla rete di distribuzione e sul successivo dispacciamento della stessa da parte del TSO in coordinazione con generatori sincroni. Il sistema sviluppato permette di tenere in considerazione i vincoli e le esigenze di entrambi i sistemi minimizzando lo scambio di informazioni richiesto.

Il metodo proposto è stato validato tramite simulazioni su una porzione della rete di trasmissione tedesca con connessa una rete di distribuzione a 110-kV collocata nel nord della Germania e avente 1.6 GW di capacità eolica connessa. Diversi tipi di setpoint per il DSO sono stati investigati con successo, dimostrando la possibilità di fornire anche valori di tensione o potenza reattiva specifici per ogni punto di connessione. Anche diversi metodi di controllo per i parchi eolici sono stati sviluppati nell’OPF. I risultati di questo lavoro suggeriscono che è possibile e anche conveniente coinvolgere le reti di distribuzione e la GD ivi connessa nella regolazione di tensione e di potenza reattiva di intere regioni.

Il lavoro di ricerca qui presentato è stato svolto tramite uno stage al dipartimento Transmission Grid del Fraunhofer Institute for Wind Energy and Energy Systems (IWES) in Germania, sotto la supervisione del capo dipartimento David Sebastian Stock nell’ambito del progetto IMOWEN, ed in collaborazione con il Dipartimento di Energia del Politecnico di Milano, sotto la supervisione del Professor Alberto Berizzi.
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Chapter 1

Introduction

“We are the first generation to feel the effect of climate change and the last generation who can do something about it.”

Barack Obama

The present chapter is intended to introduce the thesis topic with a background on the development of renewable energies and wind power in particular, and challenges associated to the grid integration of this energy source, with a particular interest in the aspects related to voltage control. The focus is mainly on Germany since the study presented in this thesis was carried out in this country, which also represents a significant case study due to its high wind power penetration. An overview of the German power system is reported in Section 1.3. A short introduction to the IMOWEN project, is also presented in Section 1.4. Section 1.5 concludes the chapter defining the position and the contribution of this work.

1.1 Development of Wind Power and Renewable Generation in Europe and Germany

Over the past decade, growth in renewable generation has been a main trend in electric power systems in many parts of the world. This growth has been driven by policy regulations aimed at the decarbonisation of electricity production and technological innovations enabling cost competitive Renewable Energy Sources (RES) generation. Europe has been a pioneer in this transition, although currently the leadership in RES investments has moved to China. The development of renewable technologies in Europe has been promoted mainly by the so called “20-20-20” strategy, a regulatory package agreed by European leaders in 2007 under the strong push from German chancellor Angela Merkel and enacted in 2009. The package sets three fundamental targets for the year 2020:

- 20% cut in greenhouse gas emissions (from 1990 levels)
- 20% of EU energy from renewables
- 20% improvement in energy efficiency

The global targets were translated into binding national targets for each country. In particular renewable energy targets helped the development of RES generation, with many countries setting up feed-in tariffs, tax-exemptions or other mechanisms to promote the
Chapter 1. Introduction

Figure 1.1: Cumulative installed wind power capacity in Europe [2]

installation of RES power plants. The decarbonisation goals stated in the 20-20-20 package were re-affirmed on a global scale with the Paris Agreement on climate change reached at COP21 in December 2015. The Paris agreement sets the goal to limit the increase in average global temperatures by 2100 to 2 degrees compared to pre-industrial levels. Wind power is seen as one of the most important renewable energy sources that can be used to achieve these goals. Thanks to its technological maturity and its competitive Levelized Cost of Electricity (LCOE), wind accounts now for the absolute majority of new yearly installations in Europe and its cumulative capacity has overcome coal reaching the second place. Benefits of wind power technology include almost zero CO2 emissions over the lifecycle, zero water consumption for energy generation, one of the lowest energy payback times among generation technologies and fast installation times. Thanks to technological innovation and to the use of bigger turbines, the cost of onshore wind, which LCOE is currently around 70 $/MWh in Europe, could decrease by another 26% to 2025 according to the International Renewable Energy Agency (IRENA) [1]. Even higher cost reductions are possible for offshore wind, which will make up 25% of new installations in Europe to 2020 [2]. Adoption of longer blades has also opened up the exploitation of new low-speed wind sites. In Europe 153.7 GW of wind power plants are currently in operation (141.1 onshore and 12.6 offshore) providing around 300 TWh/yr, equivalent to 10.4% of European electricity demand [3]. In Figure 1.1 the historical growth of wind power capacity between 2005 and 2016, as well as trends to 2020, are shown.

Other important RES technologies are hydro power (11.9% of EU electricity demand), which is however a traditional source with limited margins of expansion in Europe, solar power, accounting for 101 GWp of installed capacity and 107 TWh (3.5% of demand), and generation from biomass. Looking at Figure 1.2, it emerges a clear trend of decarbonisation of the European power system, with the net installations of generation technologies leaded by wind and solar, while nuclear and coal have negative values. In a recent interview, the president of European utilities association, Eurelectric, as well as CEO of Enel, Francesco Starace, has declared that, irrespective of policy support, coal is dead in Europe and no new plants will be probably ever built. He also suggested that soon the debate could move to whether gas plants can still be a profitable investment.

Even before the launch of the 20-20-20 strategy in 2007, some European countries had already started promoting the adoption of renewables at national level. Germany, in par-
1.1. Development of Wind Power and Renewable Generation in Europe and Germany

Figure 1.2: Net additions of generation technologies capacity in Europe[3]

particular, with the adoption of the first EEG (Eneuerbare Energie Gesetz, Renewable Energy Act) on 1st April 2000 provided one of the first examples of legislation in favour of renewables [4]. This piece of legislation, envisioned by the visionary SPD (Sozialdemokratische Partei Deutschlands) politician and President of Eurosolar, Hermann Sheer, guaranteed to renewable power plants the priority of dispatch and a guaranteed feed-in-tariff for 20 years. This legislation prompted the birth of many initiatives from single citizens and local communities to build up solar PV plants and small wind farms. The history of renewable deployment in Germany is mainly made of community owned projects, with big utility companies being for a long time out of the business. The German feed-in-tariff system established with the EEG helped building an industry in the sectors of wind, solar power and other renewable technologies and was one of the first steps towards the impressive cost reduction and exponential growth experienced worldwide by these technologies. Nowadays, Germany is still leading in terms of wind and solar installed capacity at European level, with 50 GW and 41 GW respectively at the end of 2016 [5] (see Figure 1.3). Also in terms of newly installed capacity, Germany is still the biggest market in Europe for wind energy.

In Figure1.4 [6] it is possible to see the electrical energy generated in Germany from the different sources, as well as the total amount coming from renewable and non-renewable sources, in 2016. The renewable quota is equal to one third of total electricity demand with the main contributions coming from wind (14.3%), biomass (8.7%) and solar (6.9%). Germany has instead a limited hydro energy production (only 3.6%), unlike Italy for instance, making it more challenging a complete transition to renewables.

Although many countries in the world are experiencing a transition towards renewable energy, the role played by Germany is quite unique since the pioneering role it had in the beginning to establish this industry and the scope and vision which are peculiar to the German Energiewende, as it is called in the country the energy transition. The reasons for this commitment of Germany to the energy transition arise from the strong grassroots movement against nuclear energy which was born in the ‘80s. Actually, another peculiar characteristic of the German Energiewende is the plan to phase-out not only fossil fuels but
also nuclear generation. This decision was taken by Chancellor Angela Merkel after the Fukushima disaster in 2011, with a sharp political change from previous plans of nuclear expansion.

Eight old reactors were immediately shut down, while the life-extension of existing plants was abolished and plans for the construction of new ones slashed. A gradual phase-out is being performed and in 2022 the last nuclear power stations will close. Currently, nuclear plants provide about 14% of German demand down from 25% in 2011. As we can see wind generation has arrived now on par with nuclear generation and the overtaking is expected in 2017.

The German Energiewende is not coming without challenges and contradictions. The closure of many nuclear plants, for instance, has led to an increase in the use of coal, the worst fossil fuel in terms of emissions. The role of coal, both hard coal and lignite, the most polluting type, is still very important in electricity generation, as shown in Figure 1.4. The German government has faced criticism for supporting coal production, which is
1.1. Development of Wind Power and Renewable Generation in Europe and Germany

Figure 1.5: Investments in different technologies and fuel savings according to a Energiewende roadmap for 100% energy in 2050 developed at Fraunhofer IWES [8]

an important local industry, and said in defense that the increase in coal consumption is a temporary condition due to the fast nuclear phase-out, coupled with a slower renewables deployment, and promised the eventual dismissing of coal plants. A similar criticism is sometimes attributed to the transport sector policy, where the transition to Electric Vehicles (EVs), paramount for a fully sustainable energy system, has been not adequately supported according to some critics in order to protect the interests of the powerful German car industry. Germany is also facing a problem with electricity cost: despite having among the lowest wholesale prices in Europe, final tariffs are among the highest due to feed-in surcharges for renewables. This has led to reforms to the EEG in order to limit costs for consumers and it is currently underway a transition from the feed-in-tariff mechanism to an auction mechanism for renewable technologies. Other problems include the rising rate of curtailment due to bottlenecks in the electrical grid, which could not be expanded fast enough to keep up with renewable installations, and the increasing occurrence of negative prices in the spot market during high wind and solar in-feed hours, due to a relatively inflexible coal and nuclear generation fleet.

In spite of these issues, there is a strong political consensus around the implementation of the Energiewende in Germany. According to a survey carried out in 2015, 90% of the German citizens are in favour with the goals of the energy transition [7]. A study carried out by Fraunhofer IWES in 2016 and titled A business model for the Energiewende, A Rejoinder to the “Cost Argument” [8], shows how the complete transition to 100% renewable energy in all sectors could be achieved by 2050 with a return-on-investment between 2.3-6.7% depending on inflation rates and fossil fuel prices. The transition would require an up-front investment of 300-500 billions of euros and could reach break-even between 2029 and 2035 (see Figure 1.5). Under this scenario a massive generation capacity of renewables would be required in 2050 (180 GW onshore wind, 50 GW offshore wind, 200 GW solar PV), as well as storage technologies, such as batteries (10 GW-8 hours), power-to-gas (78 GW), and power-to-heat (28 GW).

As briefly described in this initial section, the energy transition is an enormous challenge but not an impossible one. Its outcome depends on several factors, technical, economic, social and political. The next decades will tell us whether this exciting story will be also a successful one, in Germany as well as all over the world.
1.2 Challenges of Wind Power Integration in Power Systems

As stated in the previous section, the increasing use of wind power and other renewable sources has many advantages and it represents an established trend also for the future. However, some challenges arise in power systems heavily reliant on wind power. In this section, a short overview of grid integration challenges of wind power is presented. For several aspects, the challenges mentioned apply also to solar PhotoVoltaics (PV).

1.2.1 Variability and Uncertainty of Wind Power

The first challenge is represented by the variable nature of wind, which is a natural phenomenon which cannot be controlled. The variability of wind power, as well as solar power, even though with different characteristics, is also not easy to forecast. The use of forecasts has improved enormously in the last decade and it is a scientific field of paramount importance for the energy transition. As mentioned in Section 1.4, it is also part of the IMOWEN research activity. As a general consideration, forecast accuracy is also improved when a short time horizon is used and a wider spatial scale is considered with several wind farms aggregated. The first point is quite intuitive and due to this reason, a much better value of forecasts can be obtained close to real-time compared to the day-ahead. Thus, this is an incentive for moving markets close to real time. The second point is also called smoothing effect and implies a benefit in the distributed location of wind generation. Nonetheless, moving from a dispatchable generation to a stochastic power in-feed is a challenge at medium-high penetration levels. It can be solved improving the controllability of variable plants (e.g., through curtailment), and improving predictability through better forecast systems. Reported values of Mean Absolute Error (MAE) of wind forecasts for Germany were equal to 1% for 1 hour-ahead and 3% for 1 day-ahead as of 2014 [9]. Offshore power plants, where a considerable capacity is concentrated in a small area can lead to higher errors.

1.2.2 Transmission Expansion Planning

The increase in wind power can determine the need to reinforce the grid due to congestions at several levels. The main difference compared to conventional fossil generation is that the location of wind farms is mainly determined by the availability of a good wind resource. However, this holds also for other traditional energy sources, such as hydro power. Furthermore, transmission expansion can also be beneficial in a highly wind-penetrated system to smooth variability of wind resource and improve the system operation. However, it is actually hard to determine which amount of new transmission lines are directly deployed due to wind power. A different case is the one of offshore wind plants, which need a dedicated grid connection to shore. With the increase of distances from the shore, High Voltage Direct Current (HVDC) technology is preferable. Due to the massive amount of offshore capacity that is expected to be built in the next decades, grid operators in countries facing the North Sea are also considering to build a meshed offshore HVDC grid (instead of currently prevailing point-to-point connections), to connect several offshore wind farms to several countries and increase the reliability of offshore energy. This expansion should be optimally coordinated to minimize the cost and maximize benefits of offshore wind deployment. North Sea Offshore and Storage Network (NSON) is an international research project in which also Fraunhofer IWES is involved. It aims at studying the optimal development of a European offshore grid and its impact on market and system operation. In Germany the problem of transmission expansion is a crucial topic, since most of the wind generation
1.2. Challenges of Wind Power Integration in Power Systems

Potential (both onshore and offshore) is located in the north of the country, while biggest load areas are concentrated in the south and west. The problem of congestions is a rising issue, especially considering future dismantling of nuclear reactors in the south, and an ambitious plan to build several HVDC corridors between the north and the south of the country is under development (see Figure 1.6).

Figure 1.6: Planned HVDC corridors in Germany to connect the wind potential of the North Sea with load centers in the south. Source: IEEE Spectrum

1.2.3 Wind Power and Generation Adequacy

The impact of wind power is also reflected in electricity markets where it represents a generation source with zero or close to zero marginal cost. Due to the merit order system, this causes the supply curve to be shifted rightwards decreasing the average spot price values. However, in the long-run, this effect can cause an insufficient return on investment for some traditional plants, which are consequently retired from operation. The issue is that these plants could be necessary to meet demand in certain times, since wind generation is variable and it is not always available when necessary. This problem is called generation adequacy, i.e. the ability of the existing generation plants to meet demand in all scenarios. To evaluate generation adequacy of a wind penetrated system, the capacity value of wind power should be estimated. The capacity value is the amount of generation that can be accounted for meeting peak demand with high reliability. The task of assessing the capacity value of wind power is not of easy determination. It depends on the penetration level, the size and interconnection of the system, and the correlation between load and wind patterns. However, realistic capacity values can be assumed around 20% for onshore and 40% for offshore.

1.2.4 Short-term Reliability

Wind power can also have an impact on power system dynamics, balancing and voltage control. The main difference of wind power plants compared to traditional generators is the presence of a power electronics interface in all modern wind turbines. This changes
the dynamic behaviour of the power system posing some challenges but also offering new opportunities.

**Transient stability**

Transient stability concerns the response of the power system to severe contingencies and the ability to avoid loss of synchronism of synchronous generators. Transient stability can be ensured also in presence of large shares of wind power, provided that low-voltage and fault-ride-through capabilities are present to avoid the disconnection of wind turbines during fault events. Also the decrease in system inertia due to the large amount of non-synchronous generation can adversely affect transient stability. This aspect is already an issue in Ireland, a small power system with high wind penetration. Dynamic frequency considerations pushed the local TSO Eirgrid to limit instantaneous non-synchronous penetration (wind plus HVDC imports) below the 50% limit. Power electronics in wind power plants can also be used to mitigate this issue: thanks to advanced control techniques a Wind Power Plant (WPP) can provide synthetic inertia or fast frequency response, even though it is still not a common practice.

**Frequency stability**

Frequency stability concerns the ability to preserve adequate frequency levels after major imbalances between load and generation. Wind power can adversely affect frequency stability since it decreases the system inertia and usually does not provide up-regulation. The risk is that in case of a loss of generation asset, the frequency decreases too much before the primary control is able to stabilize it. As previously mentioned, this aspect is already an issue in the Irish system, even though small-signal stability is not as problematic as transient stability. Use of synthetic inertia from WPPs is a possible mitigation to the problem.

**Reserve requirements**

The TSO should procure reserves to cope with real-time demand and generation imbalances due to load variations and possible contingencies. The impact of wind power on reserve requirements is due to its variable nature, which should be considered along with load variability in reserve determination. Contingency reserves are usually not increased by wind power presence, since WPPs are small in size compared to traditional plants. Also short term reserves (seconds to minutes) are not significantly affected by wind generation, since wind variability on this short time horizon is very low for a large area. The need of longer time reserves (e.g., secondary and tertiary reserve) is instead increased by wind generation. According to [9], 1-hour ahead reserves increase between 2-5% at 30% wind penetration. Values are higher for reserves determined on a day-ahead basis.

**Voltage stability**

Voltage stability concerns the ability to keep nodal voltages within a prescribed range both in steady-state and after disturbances (e.g., load increase or grid faults). Voltage stability largely depends on reactive power balances and instability mechanisms may arise where insufficient reactive power is available at local level. Wind power impact on voltage stability can be positive, since wind turbines have a reactive power capability and fast control possibilities, which can be used to provide reactive support both in steady-state (Steady State Voltage Control (SSVC)) and in fault conditions (Fast Reactive Current
Injection (FRCI). However, increased wind power penetration is often implying a decrease in operating hours of traditional synchronous generators. This can produce a lack of reactive power in some regions, especially if WPPs are not involved in the voltage control task. The need of installing additional regulating equipment and define “must-run” units for voltage regulation, are possible consequences in this case. This issue represents the central topic of this master thesis, and therefore will be widely analyzed in the following chapters.

1.3 The German Power System

In order to understand the voltage control methods reported in Chapter 2, the power system architecture has to be introduced. The general architecture of a power system is made of a transmission system, which represents the highest voltage network and the backbone of the whole system used for long distance power transmission, and the distribution system, made of lower voltage grids used to deliver power to local consumers. The distinction is usually also referring to the assets ownership: the transmission system is the one owned and operated by the TSO, which is usually a monopolist within a country, while the distribution system is operated by DSOs, which are local monopolists in each city or region. According to voltage levels, the power system can also be divided between low voltage (LV), medium voltage (MV), high voltage (HV) and extremely high voltage (EHV). The values assigned to each level change significantly from country to country and region to region also within Europe, except for LV where 400 V is the common standard (to facilitate appliances commercialization). Also the boundary between transmission and distribution is not univocally defined at a specific voltage level.

![Figure 1.7: German TSOs and respective control areas. Source: PSI Energie](image-url)
The German power system architecture is made of an highly meshed transmission system (Übertragungsnetze) comprising the EHV grid (220 and 380-kV). Due to historical reasons, four different TSOs are present in Germany: Amprion, EnBW, TenneT and 50 Hertz (see Figure 1.7). The distribution system (Verteilnetze) comprises the HV, MV and LV level as shown in Figure 1.8). The HV level (Hochspannung Verteilnetze), where voltage can be either 60 or 110 kV, is particularly crucial since it has a large share of RES installed, especially big wind farms, and is characterised by a meshed structure. It corresponds to the subtransmission level, which in many countries, such as Italy, is managed by the TSO along with the EHV grid. This particularity of the German power system poses several challenges to RES integration due to the need of coordinating different system operators and it will play an important role in this work.

![Figure 1.8: Voltage levels in the German power system. Source: Verein Deutscher Ingenieure](image)

### 1.4 The IMOWEN Project

The IMOWEN project was launched in 2014 with the sponsorship of the German Federal Minister of Economy and Energy in the framework of the research initiative Forschungs Stromnetze. Project partners are Fraunhofer IWES in Kassel, Senvion, a leading wind turbine manufacturer, and Avacon, one of the biggest German DSOs.

![Figure 1.9: Project partners participating in the IMOWEN project](image)
1.5 Thesis Position and Contribution

The project name IMOWEN is the German acronym for Integration großer Mengen On- und Offshore erzeugter Windenergie in das elektrische Netz durch intelligente Netzanalyse und Clusterbetriebsführung, which means integration of large on- and offshore wind power plants in the electrical grid through intelligent network analysis and clustering techniques. The project is concerned with intelligently integrating a large number of wind farms connected to the 110-kV level, within the voltage and reactive power control concept of the grid operator. A 110-kV grid located in north-west Germany with a high wind power penetration (1.6 GW) has been used as study case for this project (see Figure 1.10). Here, several wind farms no more than 80 kilometres apart are being grouped together to form a wind farm cluster in terms of the grid operation.

The project activities are divided in three main thematic areas:

- Optimization tools for wind farm cluster management
- Short-term wind forecast improvement
- Stability assessment of wind farm control methods

The first topic is developed at the Transmission Grids department of Fraunhofer IWES, where the present thesis work was completed. The scientific work included the grid modelling of the region under study and the development of optimization models in GAMS for reactive power management of wind farms in coordination with OLTC transformers and other generators, in order to achieve a coordinated voltage control and automatically adapt the reactive power fed into the grid by the wind farms so that wind energy can help balance the reactive power requirement of the entire grid region. The second topic is studied at the department of Forecasts for Energy Systems at IWES, where innovative techniques based on statistical models and machine learning are adopted to improve forecast accuracy in the time horizon up to three hours. Finally, the Control Systems department is in charge of the third task, with a particular focus on wind park modelling and stability assessment of wind farm clusters with Q(U) control.

1.5 Thesis Position and Contribution

Over the past decade, growth in renewable generation has led to substantial increase in decentralized generation located in distribution grids [10]. In classical power system operation, reactive power has been mainly balanced by large generation units in the transmission grid, in addition to compensating equipment and Flexible AC Transmission Systems (FACTS). The Transmission System Operator (TSO) has been in charge of coordinating different reactive sources (mainly synchronous generators and compensation units) to ensure the reactive power balance of the entire system. In the future, this bulk generation capacity will likely decrease and reactive power provision by distributed generation (DG) will gain a significant role [11]. Moreover, voltage control and reactive power management have been traditionally addressed in a rather uncoordinated way between distribution and transmission system. Distribution systems acted mainly as passive networks and the possible use of On Load Tap Changer (OLTC) transformers together with load power factor correction were the main methods for the Distribution System Operator (DSO) to perform local voltage control.

With the current capacity of distributed generation mainly installed under DSO control, challenges to traditional voltage and reactive power management methods arise both at local and system level. At local level, active and reactive power injections of DG modify the voltage profile and require coordination with traditional OLTC control methods. At
the DSO-TSO interface, reactive power flows can change significantly due to DG presence. In the transmission grid, in addition to the displacement of synchronous generators, DG can lead to additional reactive power demand for long-range AC transmission, if the renewable energy source is located far from consumption centers (e.g., wind power plants are located mainly in the north of Germany and load mainly in the south).

Therefore, to successfully integrate large shares of DG in power systems, active participation mechanisms to voltage and reactive power control should be identified. This requires taking into account the reactive needs and constraints of several voltage levels, the interaction of DG with other reactive sources, and considering the need to coordinate different system operators, with their own objectives, control variables and data security concerns. The complexity of evaluating the real potential of DG reactive power provision and the need to use it in the optimal way from a system perspective require introducing novel control methods and innovative operational procedures.

This master thesis investigates the optimal use of wind farms connected to 110 kV distribution grids to contribute to local and regional reactive power management. A coordination mechanism between TSO and DSO based on an Optimal Power Flow (OPF) tool featuring Model Predictive Control (MPC) and multi-objective (MO) optimization is presented. The mechanism involves the coordination between two real-time OPF running in the control centers of the TSO and DSO respectively. An interaction chain based on sequential optimizations and exchange of relevant data and set points is defined. Different control modes ($\cos\varphi$, $Q$ and $Q(U)$) for wind farms are also compared. The performance of the proposed mechanism is evaluated through simulations on a regional-scale grid model featuring a portion of the German transmission system and the Avacon 110 kV distribution...
grid coming from the IMOWEN project. The final goal is to assess whether and how, controlling wind farm clusters, distribution grids can act supporting the transmission voltage in a similar way to conventional synchronous generators. Figure 1.11 shows a scheme of the proposed interaction between TSO and DSO for an optimal coordinated operation.

The thesis is structured as follows: Chapter 2 includes a review of the voltage and reactive power control task, addressing the main equipment and control systems used, as well as the potential role of wind power in providing this service. The chapter concludes on the importance of wind power participation in voltage support and identifies optimization methods as the state-of-the-art technique to achieve such real-time control. Chapter 3 is divided in two main parts: the first provides a background on Optimal Reactive Power Flow (ORPF), while the second describes in detail the mathematical model of the OPF tool developed. Chapter 4 is devoted to the description of the proposed coordination scheme for TSO-DSO coordination. It also includes a state-of-the-art review on the topic and some considerations on market mechanism to facilitate a fair coordination. Chapter 5 provides insights on the simulation setup used, including grid models, time-series data and scenarios analyzed and shows the results of simulations performed. Finally, Chapter 6 is the conclusion.
Bibliography


Chapter 2

Reactive Power and Voltage Control

2.1 Introduction

Voltage control is a critical task for system operators in order to ensure a secure and reliable operation of the power system. An efficient voltage control system should fulfill the following goals [1]: maintain voltages in all system nodes within acceptable limits not to damage connected equipment, preserve system stability margins to avoid voltage collapse maximizing the utilization of the transmission system, minimize reactive power flows in order to limit active ($R_i^2$) and reactive losses ($X_i^2$). Voltage control is highly dependent on reactive power flows, especially in transmission systems where the reactance/resistance ratio ($X/R$) is quite high. This is due to eq. (2.1), where a linear model is used corresponding to small variations in nodal voltages:

$$\Delta \dot{U}_i = R_i \dot{P}_i + X_i \dot{Q}_i \tag{2.1}$$

In transmission systems where $X/R$ ratio is around 7-10, voltage variations mainly depend on reactive power injections:

$$\Delta \dot{U}_i \approx X_i \dot{Q}_i \tag{2.2}$$

Therefore, the voltage control in these systems is mainly performed adjusting reactive power injections, while in lower voltage systems, such as at medium and low voltage, active power injections become more important due to the non-negligible term $R_i$. Therefore voltage control methods differ significantly between transmission and distribution level.

Another important difference is represented by the meshed or radial nature of the system. In meshed systems, each nodal voltage depends on all nodal reactive injections, while for radial systems the voltage depends only on the substation voltage and on loads (and DG) behaviour along the feeder. Our attention will go to meshed systems since these are mainly used at HV and EHV levels. Another peculiarity of voltage control is that reactive power cannot be efficiently transmitted over long distances since this would imply unacceptably high active and reactive losses. The main aim of the whole transmission system is efficiently transferring active power, thus it is important that reactive power is produced and consumed on a local basis. The reactive power provision for voltage control is an ancillary service which needs to be performed at specific locations, unlike active power provision for frequency control in which the injection point is not important. The reactive power balance is determined by injection and absorption by several components present in power systems, such as:
**Synchronous machines**: generate or absorb reactive power depending on the excitation. They are the backbone of voltage control systems.

**Overhead lines**: can generate or absorb reactive power depending on loading status. Capacitive behaviour prevails at low loading while inductive behaviour is predominant above the natural loading.

**Underground cables**: due to the high capacitance they generate reactive power in most conditions.

**Transformers**: transformers always absorb reactive power, at low loading due to the magnetizing inductance and at high loading mainly due to the leakage inductance.

**Loads**: usually operate at lagging power factor absorbing reactive power. Shunt capacitors can be used for power factor correction.

**Compensating devices**: are series or shunt devices added to control reactive power flows.

In this chapter we will provide an overview of voltage control with particular attention to voltage stability phenomena (Section 2.2), regulating equipment (Section 2.3) and methods for power system voltage control at both transmission (Section 2.4) and distribution level (Section 2.5). Section 2.6 analyzes capabilities of WPPs to provide voltage support and grid code requirements. Section (Section 2.7) reviews control methods for distribution grids under DG penetration. Finally, Section 2.8 concludes the chapter.

### 2.2 Voltage Stability

Admissible voltages should be ensured both in steady-state operation and after credible disturbances. In case a post-disturbance equilibrium cannot be reached the system is said to be voltage instable.

“Voltage stability refers to the ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance from a given initial operating condition.” [2]

A simple criterion for voltage stability is that at each bus the derivative of reactive injection with respect to the voltage must be positive:

\[ \frac{dQ_i}{dU_i} > 0 \]  

\[ \frac{dQ_i}{dU_i} = 0 \] represents the critical point, after which voltage collapse may happen. Voltage instability usually occurs in heavily stressed systems and can be caused by a gradual increase in the load without adequate reactive power support (slow instability), or a sudden change in the network (e.g. a component contingency or a change in network topology) which makes impossible to provide enough reactive support to some node of the system (fast instability). Voltage stability can also be distinguished in small-disturbance and large-disturbance voltage stability. They require different simulation tools to be studied appropriately both in the short and in the long-term. Different methods to assess voltage stability and stability margins are:
2.2. Voltage Stability

- **Contingency analysis**: evaluates a set of different contingencies to see if they may lead to instability or voltage collapse. It can employ load-flow or time-domain simulations.

- **Loadability limit**: is a measure of how far the system can move from its current operating point without incurring in instability. It can use the singularity of the Jacobian or continuation power flows. In some cases it can be obtained also as the result of an OPF. PV and VQ curves are also used to establish the stability margin.

> Figure 2.1: SLIB system [2]

If we consider the simple Single Load Infinite Bus (SLIB) system in Figure 2.1 and the power transfer equations:

\[
P_L = \frac{U_N U_L}{X_{eq}} \sin(\theta_L) \tag{2.4}
\]

\[
Q_L = -\left( \frac{U_L^2}{X_{eq}} - \frac{U_N U_L \cos(\theta_L)}{X_{eq}} \right) \tag{2.5}
\]

The following PV and PQ curves can be derived. The PV curve is also called nose curve and the point corresponding to \( P_{L_{\text{max}}} \) is called tipping point, where the \( \frac{dQ_L}{dU_L} = 0 \). On the left of this point, two solutions exist for each \( P_L \) value, one with high voltage and the other with low voltage, the first one is the desired one and assumed to correspond to a stable operating condition. As we can see the amount of reactive power produced or consumed by the load impacts the amount of active power that can be transferred over the line. The difference between the actual active power transfer and the maximum value corresponds to the stability margin. Its computation for large meshed systems is not easy. The same aspect can be seen using VQ curves, which are useful to assess the reactive power margin at a given bus, i.e. the amount of increase of reactive load that can be accommodated before incurring in voltage collapse.

> Figure 2.2: Examples of PV curve (left) and PQ curve (right) for a SLIB used for voltage stability assessment[2]
Voltage stability is of paramount importance in power system operation and in the
design of voltage control systems also dynamic aspects need to be taken into account.
Cases of reported voltage collapse leading to large blackouts are several in history. Among
the most important ones the blackouts of July 1987 in Japan and August 2003 in North
America.

2.3 Voltage Control Equipment

As described in the previous section, voltage control can be performed controlling reactive
power injections and flows. The equipment used to achieve such a goal can belong to three
main categories:

- **Sources or sinks of reactive power**: synchronous generators and compensators,
  shunt capacitors and reactors, Static Var Compensators (SVCs) and Static Syn-
  chronic Compensators (STATCOM).

- **Line reactance series compensators**: series capacitors.

- **Regulating transformers**: tap-changing and boost transformers.

Another distinction can be made between active (synchronous machines, SVCs and STAT-
COM) and passive devices (series and shunt capacitors and reactors): the former contribute
to voltage regulation adjusting their reactive power exchange, while the latter act modi-
fying the network characteristics. Finally, controlling devices can also belong to the static
or dynamic class depending on their response time to disturbances.

2.3.1 Synchronous Generators and Compensators

The backbone of voltage control systems have traditionally been synchronous generators
placed in power plants. A synchronous generator is able to control the reactive power
injection or absorption controlling the field excitation current $I_f$ and consequently the in-
ternal voltage $E_f$ (see Figure 2.3). When the internal voltage is higher than the terminal
voltage $V_t$, the machine produces reactive power (over-excitation), while in the opposite
case absorbs reactive power (under-excitation). The field current is controlled by an au-
tomatic system called Automatic Voltage Regulator (AVR) based on the terminal voltage
measurement.

![Figure 2.3: Equivalent circuit of a synchronous machine](image)

The advantages of reactive power provision by SGs are: unaltered effectiveness also
at low voltage (compared to passive devices which reactive output is equal to $BV^2$) and
also much faster and more accurate responses (inferior only to power electronics based equipment). The reactive power limits of synchronous generators depend on thermal limits of both the field and armature windings. Armature current limits are particularly binding at high real power loading. Finally, an under-excitation limit is present and a limit related to the maximum active power of the prime mover. Capability limits also depend on the terminal voltage of the SG.

![Figure 2.4: Capability curve of a synchronous machine](image)

When a generating power plant is not present in the area but voltage control is required, a synchronous compensator can be installed. It is nothing else than a synchronous machine which is not connected to a prime mover (e.g., hydro or steam turbine) but withdraws active power from the grid to compensate for its losses and provides the required amount of reactive power.

### 2.3.2 Shunt Reactors

Shunt reactors are often used to limit overvoltages that may happen at low load (for instance during night time) due to line capacitance. They are required especially for long overhead lines longer than 200 km, shorter lines supplied by weak systems or in presence of cables [1]. Shunt reactors can be permanently connected or switched on and off according to system needs. Another typical use is for limiting voltages during lines energizing.

### 2.3.3 Shunt Capacitors

Shunt capacitors are used to supply reactive power and increase nodal voltages. They are widely used in distribution systems to control feeder voltages and for load power factor correction. Many domestic and industrial loads have a lagging power factor and can absorb huge amounts of reactive power. Therefore, system operators require in many countries to limit the minimum power factor in order to decrease the reactive power transfer in the system. Also in the transmission system, switched shunt capacitors can be used to support the voltage during high loading conditions.

### 2.3.4 Series Capacitors

Series capacitors are placed in series with line conductors. They actually modify the line impedance decreasing its reactance. Their main goal is to increase the active power transfer which follows from eq. 2.4 and decrease reactive power losses ($X I^2$), but they also provide voltage control in an automatic way since their reactive output increases with the
line loading. They can be used both at transmission and distribution level, even though resonance issues should be carefully considered.

### 2.3.5 Static Var Compensators (SVCs)

Static var compensators are power electronics based devices used to absorb or provide a controlled amount of reactive power. They belong to the wider family of Flexible AC Transmission Systems (FACTS) devices. The adjective static is due to their property of having no moving parts in contrast with synchronous generators and compensators. Similarly though, they are active control devices. There are several types of SVCs, but they are all derived from the combination of thyristor switches and passive elements (capacitors or reactors) connected in series or parallel (see Figure 2.5):

- Thyristor Controlled Reactor (TCR), also with a fixed capacitor configuration (FC-TCR)
- Thyristor Switched Capacitor (TSC)

Controlling the firing angle of the back-to-back thyristor switch, it is possible to adjust the reactive power current fundamental value. The full theory and mathematical equations governing this type of devices are not here reported, since this is not the main scope of this work. For a detailed explanation the reader can refer to [1] or [3].

![Figure 2.5: FC-TCR (left) and TSC (right)](image.png)

These devices can be combined together and also with passive elements to form an SVC system (Figure 2.6). This should ideally behave as a variable capacitor in parallel with a variable reactor providing an horizontal V-I characteristic (constant voltage). The realistic characteristic is somehow closer to the one reported in Figure 2.7 due to the limited values of capacitance and reactance available.

SVCs are usually employed for a variety of applications [1]:

- Control of temporary overvoltages
- Prevention of voltage collapse
- Enhancement of voltage stability
2.3. Voltage Control Equipment

2.3.6 STATCOM

Static synchronous compensators (STATCOM) are basically Voltage Source Inverter (VSI) which are used to provide a desired reactive power controlling the terminal voltage. The Direct Current (DC) voltage source is usually represented by a capacitor, but also a battery storage system can be used. The converter is usually a 6-pulse 2-levels inverter employing Insulated Gate Bipolar Transistor (IGBT) or Gate-turn-off Thyristor (GTO) valves (Figure 2.8). A filter inductance is placed at the interface with the grid to limit transient peak currents. The name derives from the similarity with the Synchronous Machine (SM): the filter inductance can be seen as the equivalent of the series reactance of a SM, while the inverter output voltage as the internal SM voltage (compare Fig. 2.3 and Fig. 2.8). Assuming that no active power is exchanged between STATCOM and the grid (lossless operation) the output voltage is in phase with the grid voltage. If the inverter terminal voltage magnitude is smaller than the voltage at the connection point, reactive power will flow from the grid to STATCOM. In this case the reactive power will be consumed. In the opposite situation the reactive power is injected into the grid.

STATCOM can be controlled with different techniques, the most used are sinusoidal

- System oscillations damping
- Elimination of voltage flickers (at subtransmission or distribution level)
PWM, multi-pulse converters switched at line frequency and cascade converters [4]. The deriving reactive power capability is shown in Figure 2.9.

STATCOM have several advantages, such as fast and accurate control, low losses and harmonics, and also a moderate cost [5]. Generally, STATCOM are more effective than SVCs in voltage regulation during undervoltage situations, while SVCs are more effective than STATCOMs during overvoltage situations [6].

### 2.3.7 OLTC Transformers

On Load Tap Changer (OLTC) transformers are an important component in voltage control at many voltage levels. An OLTC transformer is able to change the voltage level at the secondary side by changing the turn ratio adjusting the tap position. It allows a discrete regulation: since tap positions can only assume discrete values, the voltage can be changed only through discrete steps (see Figure 2.10). The allowed voltage range is usually ±10\% or ±15\%. The tap changing process happens through mechanical commutation. The mechanism is usually installed at the primary side since the higher voltage implies lower currents which are favourable for the commutation process. It is a delicate and costly component and tap operations should be minimized in order to reduce maintenance costs and extend the lifetime of the device. OLTC transformers are used both at distribution and transmission level. At transmission and subtransmission level, transformers and autotransformers are usually equipped with OLTC to regulate the reactive power flow between
2.4 Transmission System Voltage Control

different voltage levels and thus regulate the voltage and reduce P and Q losses. At distribution level, OLTC transformers installed in the substation help keeping a suitable voltage profile along the feeders. Tap operations are performed when the load varies significantly to keep the voltage around a predefined profile, for instance between day and night.

![Mechanical tap changer mechanism](image)

Figure 2.10: Mechanical tap changer mechanism

Tap operations can be manually activated or automatically activated by a local AVR system. In the second case, the OLTC receives a voltage setpoint to be kept at the secondary side (lower voltage level) and a deadband of regulation. The AVR monitors the voltage at the secondary side and compares it with the target value, as shown in Figure 2.11. If the error exceeds the deadband, after a certain time-delay, a tap operation is triggered. The voltage setpoint can be updated manually or derived through some automatic control function. A typical example used in Italy at HV-MV interface is the compound control [7], which uses the measurement of the current through the transformer to estimate the voltage drop along the MV feeder and determines the optimal voltage at the MV side of the OLTC transformer thanks to eq.(2.6), where $V_B$ is the substation voltage, $V_L$ is the desired voltage at the end of the feeder, $I_l$ is the transformer current and $\phi_l$ is the measured power factor at the primary substation (see Figure 2.12).

$$V_B^* = V_L^* + \sqrt{3}I_l (R_l \cos \phi_l + X_l \sin \phi_l)$$  \hspace{1cm} (2.6)

### 2.4 Transmission System Voltage Control

In the previous section, relevant equipment traditionally used for voltage control has been introduced. In the present section, the control methods used by different transmission system operators in Europe to coordinate the different devices are briefly introduced. In the next section also an overview of traditional voltage control methods in distribution systems is described.

The main scope of transmission system voltage control is to ensure a secure operation of the power system, providing that all voltages are within an acceptable range both
Chapter 2. Reactive Power and Voltage Control

Figure 2.11: AVR system for OLTC transformer [8]

Figure 2.12: Traditional compound control applied to HV-MV OLTC transformers in Italy [7]

in normal operation and after credible contingencies (voltage stability). The mentioned objective should be achieved minimizing system losses and ensuring adequate reactive power reserves. The voltage control task spans several stages: from power system planning, to operational planning and scheduling, up to real-time. State-of-the-art voltage control methods are based on a hierarchical classification. Such a classification is described in the following subsection. However, such a system is not used by all TSOs, thus a classification based on different TSOs practices is reported in subsection 2.4.2, with a special focus on Germany, Italy and Switzerland.

2.4.1 Hierarchical Voltage Control

Voltage control is rather a local problem and should be managed with local resources. But instability arising from one area could propagate to other areas and in general, for the sake of optimization, coordination between different local controllers should be achieved. For large systems is however not practical to run a complete optimization considering at the same time all control variables and constraints. This is the reason why many TSOs have established a hierarchical voltage control usually based on three levels [9]:
2.4. Transmission System Voltage Control

- Primary Voltage Regulation (PVR)
- Secondary Voltage Regulation (SVR)
- Tertiary Voltage Regulation (TVR)

The primary voltage control (PVR) acts locally and it is based on the automatic response of generators (AVR) and other controllable devices. Its goal is to maintain the assigned bus voltage close to a defined set point. The secondary voltage regulation (SVR) has the goal of coordinating several reactive sources located in the same area providing setpoints to the PVR. Usually the power system is divided in several areas with a separate controller each. The ensemble of regional controllers forms the SVR [10]. The scope of SVR is to keep the voltage at a particular bus, the pilot node, close to a set-point, coordinating the available reactive resources. The pilot node is usually chosen as the strongest load bus in the area (for instance the one having the highest Short Circuit Capacity (SCC)), and it should well represent the voltage profile across the whole area. Pilot nodes and controlling generators should also be chosen in order to decouple as much as possible the voltage of different areas, for instance maximizing the electrical distance of pilot nodes and choosing control generators as the ones having minimal influence on voltage in adjacent areas and maximal influence on the associated pilot node voltage [10]. Finally, in some power systems, a tertiary voltage control (TVR) is used, which has a global scope. TVR coordinates the SVR providing setpoints from a centralized optimization, using as objective functions maximization of Reactive Power Reserve (RPR), minimization of losses or voltage deviations.

In some power systems secondary and tertiary voltage control are merged together: in these cases the classification is only between primary and centralized voltage control [9]. Besides the scope, also the time scale of the different hierarchical levels is different: the PVR operates in times of seconds, while the SVR is generally an order of magnitude slower, and the TVR, when present, is even slower, in the time scale of minutes [9].

The use of a hierarchical voltage control system is expected to increase the transmission capacity and improve voltage stability indicators [11]. An issue connected with this type of architecture is that control areas are usually assumed fixed while they actually change dynamically depending on operating conditions.

2.4.2 Voltage Control Systems in some European Countries

In this subsection we build on the concepts of voltage control architecture explained before, to describe and compare some real significant control methods applied by European TSOs.

Italy

A typical example of a hierarchical control scheme, is the Italian voltage regulation system, in place since 2003 [12]. It is based on all three hierarchical levels as shown in Figure 2.13: on top, the tertiary voltage control, finds the optimal voltage values for pilot nodes in the entire transmission system. The optimal voltages are first computed offline the day-ahead or close to real-time by an ORPF for Losses minimization control (LMC). The main target is to minimize network losses while preserving reactive power control margins. Then in real-time the TVR minimizes the difference between optimal forecasted values and field measurements defining voltage setpoints for pilot nodes taking into account the real-time network conditions. Then, for each control area, the secondary voltage control, or RVR
(regional controller), computes the voltage error and, based on a PI controller logic, defines a reactive level $q$, between 1 and -1, which is sent as control signal to regulating plants. Here the primary voltage control (implemented in a device called SART by the Italian grid code) is performed, adjusting the voltage setpoint for each generator AVR. The use of a reactive power level equal for all area control devices, ensures a fair alignment of reactive power provision and the same relative reactive power margin for all units. The system works automatically in real-time with different time constants for each hierarchical level: from few seconds for PVR to 5 minutes for TVR. The overall Italian power system is divided in 18 areas (regions).

So far distribution grids have not been actively involved in supporting transmission voltage control in Italy. However, thanks to the huge amount of DG connected at distribution level (around 30 GW), the potential participation is of interest. A new joint study, performed by the TSO Terna and Politecnico di Milano, investigates the potential impact of reactive power provision from distribution systems extending the $q$ signal to DSOs [13].

![Figure 2.13: Hierarchical voltage control architecture used in Italy by Terna [14]](image)

Switzerland

In Switzerland a different system is in place belonging to the class of centralized schemes: a centralized off-line OPF (operating the day-ahead) is run for each hour of the following day defining optimal voltage setpoints for regulating devices [15]. A particular feature of the Swiss mechanism, of high relevance for our work, is that also distribution grids can actively participate in the mechanism. In case of active participation, distribution transformers are represented in the OPF through a virtual generator with a predefined reactive capability (and fixed active power) and a voltage setpoint is issued like for synchronous generators. Otherwise, DSOs can opt for passive participation and in this case they have to comply with some reactive power exchange limits, reported in Figure 2.14. These limits are actually stricter than the guidelines prescribed by the Demand and Connection Code (DCC) from ENTSO-E, since the maximum $\cos\phi$ limit (0.9) is multiplied for the actual power imported/exported and not for the maximum exported as in the DCC, thus, at low active power exchange, the reactive exchange limits are very narrow. Penalties are foreseen in case of non-compliance.

As for active regulating devices, a mechanism of reactive power remuneration is in-
2.4. Transmission System Voltage Control

![Figure 2.14: Reactive power exchange limits comparison between Swiss regulation and ENTSO-E DCC](image)

Table 2.1: Summary of reactive power tariffs in Switzerland

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Introduced. As long as the controlled voltage is kept within a specified range, each Mvarh is paid (see Table 2.1 [16]). For active distribution transformers in particular, this range corresponds to:

- ±3 kV (380-kV level)
- ±2 kV (220-kV level)

Key input data for the ORPF are the power plants reactive power limits, which are computed using detailed capability curves on the basis of the market dispatch results, and 220-380 kV OLTC transformers models. For the active distribution grids, fixed reactive power limits are considered, being this a severe limitation of the system as it will be further discussed hereafter. The objective function reflects the market-oriented approach adopted by SwissGrid, being the total cost (TC) for the TSO:

\[
TC = \alpha \cdot P_{\text{loss}} + \beta \cdot \sum |Q_k|
\]  

(2.7)

Here \( \alpha \) represents the cost of active power and \( \beta \) of reactive power from the \( k \) reactive providers. The described method allowed SwissGrid to improve the voltage control in its system limiting the use of enhanced reactive power services. As of 2014, about 20 distribution transformers were involved in the active mechanism, providing an estimate reactive reserve of ± 300 Mvar.
Chapter 2. Reactive Power and Voltage Control

Germany

In Germany a manual dispatch of reactive power is still in use. No centralized or hierarchical system is in place and each TSO controls the voltage in its own area setting some scheduled voltage setpoints for regulating plants via bilateral agreement [17]. Setpoints are then updated in real-time when required. Setpoints can be either based on voltage, reactive power or \( \cos \phi \) values. Reactive power is remunerated based on regulated tariffs. Distribution grids have to respect some reactive exchange ranges also determined via bilateral agreement.

Table 2.2 shows a summary of voltage control methods in some European countries.

Table 2.2: Summary of voltage control practices of some European TSOs

<table>
<thead>
<tr>
<th>System</th>
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<th>Hierarchical voltage control</th>
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2.5 Distribution System Voltage Control

Distribution systems can comprise very different voltage levels, spanning from LV up to HV levels. Radial or meshed networks can be included in distribution. Therefore it is evident that very different techniques are applied in each case. In Figure 2.15 the boundary voltage between transmission and distribution in several European countries is reported.

Focus is here mainly on HV and partially MV distribution grids. DSOs goals are mainly keeping voltage levels within allowed ranges (1 ± 0.1 p.u.) [18] and ensuring a suitable voltage profile in the grid. Losses reduction and tap changer operations minimization are other goals. Instead, the impact of distribution systems on overall voltage stability has usually been marginal. In addition to its own internal objectives, the DSO has usually to fulfill some limits of reactive power exchange at T-D interface (e.g., \( Q_{max} = \tan \phi_{max} \cdot P_{max, export} \) and \( \cos \phi_{max} = \pm 0.9 \) in the DCC). Traditional voltage control equipment available to DSOs is represented by OLTC transformers, capacitor and reactors banks and in some cases SVCs.

In the last decade however, deep transformations in distribution grids have challenged traditional voltage control methods, among the main trends the massive increase in renewable-based DG, mainly installed at distribution level (see Figure 1.8), has been the most important. In particular, main challenges posed by DG are:

- Change in voltage profiles due to DG reactive and active (at LV and MV) power injections
2.6. Wind Power and Voltage Control

- Coordination issues with OLTC control
- Reverse power flows at T-D interface
- Power quality issues due to power electronics converters

Also the increasing use of underground cables and the spread of new load types (e.g., electric vehicles) are posing some challenges. Another peculiarity of distribution grids is that, especially at MV and below, the system operator has a limited observability of the system, due to the limited amount of sensors and measurement units in the field. Therefore, it can be hard to monitor and control the system under DG penetration. These challenges require new control methods to reliably operate distribution grids, involving a transformation towards Smart Grids, with enhanced observability, controllability and communication in place. Section 2.7 provides a review on Volt-Var Control (VVC) for distribution grids with high DG penetration.

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*Voltage level used in a given country

Voltage levels according to European standardisation bodies CEN/CENELEC: LV (42 kV), MV (6–36 kV), HV (36 kV).
** Italy: 650 kV do not operate HV lines directly, but 150 and 165 kV substations including HV lines circuit breakers (on TSO request); ** The Netherlands: 155 kV lines owned by the DSO are operated by the TSO.

Figure 2.15: Voltage levels at T-D interface in European countries, source: Eurelectric

2.6 Wind Power and Voltage Control

2.6.1 Wind Turbine Technologies

The capability of wind power plants to participate in voltage control depends mainly on the turbine type. There are historically four Wind Turbine (WT) types (see Figure 2.16 [5]):
• **Type A (Danish concept):** it is the oldest WT concept. It is made by a Squirrel Cage Induction Generator (SCIG) directly connected to the grid. It works at fixed speed, having thus a low efficiency.

• **Type B (Variable rotor resistance):** it is an upgraded version of type A, using a Wounded Rotor Induction Generator (WRIG) with variable rotor resistance. This allows a little regulation range of the rotational speed (±10%).

• **Type C (DFIG):** it uses a Doubly-Fed Induction Generator (DFIG), where the generator rotor is also connected to the grid via a partial scale converter (usually 30% $P_n$), which can inject a variable frequency rotor current, allowing to modify the slip and thus the rotational speed in the range $[-40,+30] \%$ of the synchronous speed.

• **Type D (Full converter):** it is based on a full scale converter (100% $P_n$) as interface between the generator stator and the grid. It allows to fully decouple the generator and the grid frequency, allowing a full range of speed variation and optimal efficiency. The generator type can be either synchronous or asynchronous, and geared or gear-less (direct-drive).

![Figure 2.16: Different WT generator types](image)

In terms of reactive power capability, type A and B can only absorb reactive power and they also need a capacitor bank with a soft starter in order to improve the power factor and reduce Q absorption at the start. Instead, type C and D can provide reactive power control thanks to the use of power electronic converters. These two concepts are the most diffused in modern wind turbines. Type D has the highest capability. The back-to-back converter works in the following way: the machine-side converter controls the electrical torque, modifying the shaft speed to optimize the energy extraction from the wind (speed control), while the grid-side converter is in charge of controlling the voltage at the dc-link adjusting the reactive power injection of the WT. The reactive power capability corresponds more or less to the inverter capability. A single wind turbine equipped with type D generator is able to provide a wide reactive capability, as shown in Figure 2.17. This capability can be extended also at low or zero active power injection incorporating phase shifting functionality, in this way the WT is able to behave as a real STATCOM (compare with Figure 2.9).

Similar capabilities at low or null active output can be reached also for type C WT, as derived in [20].
2.6. Wind Power and Voltage Control

So far we have talked about individual WT capabilities, but from the system operator point of view it is more important to analyze what can be provided at the Point of Common Coupling (PCC) by the WPP as a whole. This value is also influenced by the electrical cables connecting the turbines and the step-up transformer. They behave as outlined in section 2.1: at high loading the wind farm will have a more inductive behaviour due to the transformer reactance, while at low loading the capacitance of cables will prevail. The mentioned phenomena can have a distortion effect on the capability curve of the WPP as a whole, as shown in Figure 2.18 where the theoretical and actual capability limits at the PCC of a wind park are shown (it represents though an extreme case of an offshore wind park connected through a long AC cable). Some additional equipment can be installed at wind farm level to compensate these effects and comply with grid code requirements, such as OLTC transformers, capacitive or inductive compensators, and FACTS.

However, according to most WPPs developers, the use of WTs capabilities should be the main method of reactive power control at wind farm level. As stated in [19], "wind turbines can act as FACTS devices, which is still quite unknown to many system operators in Europe".

### 2.6.2 Reactive Power and Voltage Control Modes for WPPs

The reactive power potential of WT can be harnessed using different control techniques. They can be generally applied both at WT or WPP level, with the latter requiring more sophisticated controls. In the field of voltage control, two different services can be provided:
• **SSVC** (Steady State Voltage Control): to control the steady-state voltage

• **FRCI** (Fast Reactive Current Injection): to support the bus voltage in case of faults

From now on, the attention is focused on SSVC. Main control modes for reactive power and voltage control are based on:

- Reactive power \( (Q) \)
- Voltage \( \cos \phi \)
- \( Q(P) \)
- \( \cos \phi(P) \)
- \( Q = f(U) \)

The first five modes are quite straightforward, while the \( Q = f(U) \) is an hybrid control mode, based on a voltage setpoint used to get a variable \( Q \) output based on the voltage deviation \( (\Delta U) \) according to the \( Q = f(U) \) law of eq. (2.8),(2.9) and (2.10):

\[
Q_g = -\frac{1}{\text{droop}} \cdot \Delta U \iff Q_{g,min} \leq Q_g \leq Q_{g,max} \tag{2.8}
\]

\[
\Delta U = (U - U_{setpoint}) \tag{2.9}
\]

\[
d\text{droop} = \left| \frac{dU}{dQ_g} \right| \tag{2.10}
\]

Also a non-regulation dead-band (see Figure 2.19) can be included to avoid too frequent changes in reactive power output from the WT, even though not strictly necessary. \( Q(U) \) control can be applied both at WT or WPP level and it is a very promising control technique with increased application. The droop value defines the strength of control on local voltage, common values range from 20 down to 0 (vertical characteristic equivalent to PV node behaviour).

### 2.6.3 Grid Code Requirements

Grid Codes define the minimum requirements for reactive power performances required to WPPs that are connected to a certain voltage level. It is important to point out two facts:

- Grid Code requirements are usually quite conservative in terms of performance required to WPPs compared to their potential. Besides requirements, it is also important to consider actual use of voltage control services: in many systems, although potential is available and required, WPP are still not involved in voltage control.

- The coordinated use of WPPs for voltage control depends not only on reactive power capabilities at WTs or WPPs, but also on communication systems to allow remote control. These Smart Grids systems are not always available, especially for older plants, in this case only local control systems are feasible (this point will be analyzed more in depth in the next section).
2.6. Wind Power and Voltage Control

The requirements and practices differ from individual grid operators, and also within each country between distribution and transmission level. In Scotland and UK, for instance, Q(U) control is used for all wind farms, while in Germany only one third of WPPs is equipped with this control [19]. A good overview of reactive power and other requirements across Europe is reported in [21]. In the following, we describe the cases of Germany and Italy.

Germany

Wind power plants connected to 110-kV level have to follow the requirements stated in [22] where three variants are proposed and can be agreed between the WPP operator and the DSO (see Figure 2.20 and 2.21 [22]). The power factor should be able to change between 0.9 overexcited and 0.925 underexcited depending on the variant. Also a dependency based on the PCC voltage is included. Similar values are requested for power plants connected to the transmission system. As for control modes, the large majority of WPPs is controlled via power factor setpoints, which are manually adjusted by system operators, but mostly kept fixed.

![Figure 2.20: cos(φ)(V) requirements in Germany at 110-kV level for over- and under-excited operation](image)
Chapter 2. Reactive Power and Voltage Control

Italy

In Italy the TSO Terna requires a power factor range between 0.95 leading/lagging to WPPs connected at HV or EHV voltage level. However, WPPs are still mostly operated at unitary power factor [23]. A novel consultation document from the Autorità per l’Energia Elettrica, il Gas e il Sistema Idrico (AEEGSI) proposes an approach to involve DG in voltage regulation based on two control modes [13]:

- Local control based on $Q = f(U)$
- Coordinated control based on Q setpoint from SO (it requires a communication system in place)

The proposed mechanism should be applied to DG plants with nominal capacity larger than 1 MW at HV or EHV level, and 100 kW at distribution level. Reactive power provision would not be remunerated.

2.7 Review of VVC Methods in Distribution Systems with High DG Penetration

The increased amount of distributed generation installed in the DSO grid, the need to coordinate several resources and the necessity of complying with novel grid code requirements such as the Demand Connection Code (DCC) [24], which defines reactive power exchange limits for transmission connected distribution grids, call for additional reactive power management tools. Table 2.3 summarizes the main actuators available to DSOs for Volt-Var Control.

Existing methods can be divided between:

- **Uncoordinated methods**
- **Coordinated methods**

2.7.1 Uncoordinated Methods

Uncoordinated methods are based on local measurements only and aim at local objectives. They include operation of DG with fixed $\cos \phi$, $Q(U)$ or $\cos \phi(P)$. They do not require heavy
2.7. Review of VVC Methods in Distribution Systems with High DG Penetration

Table 2.3: Summary of voltage control equipment for DSOs

<table>
<thead>
<tr>
<th>Actuators</th>
</tr>
</thead>
<tbody>
<tr>
<td>OLTC transformers</td>
</tr>
<tr>
<td>Capacitor and reactor banks</td>
</tr>
<tr>
<td>DG reactive power</td>
</tr>
<tr>
<td>SVCs</td>
</tr>
<tr>
<td>Storage systems</td>
</tr>
<tr>
<td>Load shedding</td>
</tr>
</tbody>
</table>

investments in additional equipment and communication infrastructure. However, they present several shortcomings, such as the possible undesired results of interaction between different DGs locally controlled and with OLTC and other equipment, the impossibility of using resources for controlling other buses voltages, and finally the lack of optimality of the control actions, potentially leading to losses and tap operations higher than necessary. The complexity of the reactive power and voltage control task suggests that, when global objectives are sought (for instance keeping the reactive power exchange of the distribution grid within some limits), coordinated methods are preferable. This result is stated in most of existing literature.

2.7.2 Coordinated Methods

Coordinated methods are based on knowledge of the overall grid topology and global measurements and target global objectives. They require higher investments costs, especially in communication systems, and entail higher complexity but generally achieve better results. They are mainly divided in rule-based methods and optimization-based methods.

Rule-based methods

Rule-based methods, also called intelligent agents, define control actions based on some rules. They entail less mathematical complexity than optimization but are not able to guarantee optimal results and in case of large systems with many actuators it becomes also challenging to define effective rules and the computational burden can become excessive. Moreover, the system is not easily adaptable to changes in topology and number/type of actuators.

Optimization methods

Optimization methods, i.e. based on an optimization process, can instead guarantee optimality given a determined objective function and they are very flexible to changes in the grid topology and have the property of generality. Optimization drawbacks are the need of having a very detailed model of the system and the issues related to the objective function and constraints choice leading to potential infeasibility. Optimization methods can be based on sensitivities or include the full power flow equations. In the former case we can use Linear Programming (LP) while, in the latter, Non Linear Programming (NLP). Other optimization techniques, usually called soft-optimization techniques, are Particle Swarm Optimization (PSO) and Genetic Algorithms (GA). A review is found in Section 3.2.2.
Chapter 2. Reactive Power and Voltage Control

The advantages offered by optimization methods make them the state-of-the-art technique for VVC in distribution grids with high DG penetration [8], even though optimization is today not commonly applied at this level, while it is an important part of transmission system voltage control, as seen in Section 2.4.

2.8 Importance of WPPs and DG Participation in Voltage Control

In this chapter the fundamentals of reactive power and voltage control of power systems have been presented, through an overview of relevant equipment and methods used by SOs at both transmission and distribution levels. It was explained how synchronous generators have traditionally been the backbone of voltage control systems in the transmission grid, while in distribution systems OLTC transformers and shunt compensators represented the main tools. However, these consolidated methods are challenged by several trends, with the main one represented by massive DG installations, mainly at distribution level. Related challenges for voltage control span from local to system level:

- **Distribution System**
  - Distribution voltage profile
  - Coordination with OLTC

- **T-D interface**
  - Unpredictable and reverse reactive power flows

- **Transmission system**
  - Displacement of synchronous generators in sunny/windy hours
  - Increased reactive power demand for long-range transmission
  - Increased risks of voltage instability [25]
  - Increased occurrence of voltage-induced redispatch [26]

All these issues are already concretely present in Germany. On the other hand, as seen in Section 2.6, WPPs offer quite wide capabilities of reactive power and voltage control often unused. Modern wind turbines can be seen as FACTS devices embedded in the power system and the exploitation of their reactive potential comes at null or very low cost [19]. Due to the high number of power plants and their distributed nature, some coordinated control system should be in place to achieve the best result from a system perspective avoiding at the same time local violations: in the end of the previous section we highlighted how optimization tools in the hands of the DSO are the most promising method to achieve such a result. Moreover, the use of DG for voltage control could be extended to consider the requirements of voltage levels different from the one where WPPs are installed, trying to address all the issues presented in the list above. This requires taking into account the reactive needs and constraints of several grid levels, the interaction of DG with other reactive sources, and considering the need to coordinate different system operators, with their own objectives, control variables and data security concerns. All these aspects contribute to the definition of the problem that this work tries to address. Possible advantages of DG active participation in voltage and reactive power control can include but are not limited to:
2.8. Importance of WPPs and DG Participation in Voltage Control

- Exploit the unused reactive capability of distributed generation
- Make available new reactive sources
- Reduce investment costs in additional reactive compensation equipment
- Reduce costs due to voltage induced redispacht
- Reduce grid losses and associated costs
- Reduce the number of must-run units in charge of voltage regulation
- Improve margins for voltage stability

Experiments for participation of WPPs in voltage control at different voltage levels have been conducted in several countries. A study carried out in 2013 within the REserviceS project [27] in Ireland, showed how the expected decrease in reactive power reserves due to increased wind penetration at 2020, could be mitigated using WPPs for reactive power provision. With extended STATCOM capabilities, WPPs could provide almost the same amount of RPR as in the baseline 2010 case (see Figure 2.22).

![Figure 2.22: Reactive power duration curves in Ireland for 2010 and 2020 [27]](image)

In a study published in 2014 by Dena [28] and focused on the Ancillary Services (AS) in Germany in 2030, reactive power provision by WPPs in distribution grids is proposed as an important solution. It is envisioned that each voltage level should become self-sufficient in terms of reactive power needs, and HV grids could also support the transmission voltage if this can be achieved in an economical way. Another important measure suggested is the use of HVDC inverter stations to provide voltage control.

"The available potential of the provision of reactive power by renewable energy sources in the high voltage grid (110kV level) in 2030 can also be used to meet the reactive power demand of subordinate grid levels, in addition to its own demand. In addition to this, the grid regions examined in the study have the potential to provide reactive power from the high voltage grid for the superordinate extra high voltage grid."[28]

In the following chapter, after an overview on optimization theory and ORPF, we will present the modular OPF tool developed to build a coordinated voltage regulation scheme between TSO and DSO for optimal control of DG.
Bibliography


Chapter 3

Optimal Power Flow

This chapter is intended to introduce the OPF theory and explain in detail its application to our problem. Section 3.1 briefly addresses the optimization theory in general, while Section 3.2 explains the ORPF problem and its possible solution methods. In Section 3.4, Section 3.5 and 3.6, three additional features of the OPF problem are analyzed, namely Multi-Objective (MO) optimization, the extension to multiple time steps through Model Predictive Control (MPC) and the handling of multi-area power systems. Finally, in Section 3.7, the mathematical model of the OPF tool used in this work is described in detail.

3.1 Optimization Theory

Optimization theory has the goal to find the optimal solution to a defined problem among all possible (feasible) solutions. The simplest optimization problem is the unconstrained optimization problem: given an Objective Function (OF) $f(x)$ to minimize, which depends on the control variables vector $x$, the optimal solution can be found zeroing the gradient of the objective function:

$$\nabla f(x) = [0]$$  \hspace{1cm} (3.1)

The solution of this system is evaluated looking at the Hessian matrix to assess if the point found is a maximum, a minimum or a saddle point. Most optimization problems belong however to the constrained problem class. Meaning the feasible values of the control variables are limited by equality $g(x)$ and inequality constraints $h(x)$. The problem can be written as follows:

$$\min f(x)$$  \hspace{1cm} (3.2)

$$\text{s.t.}$$

$$g(x) = [0]$$  \hspace{1cm} (3.3)

$$h(x) \leq [0]$$  \hspace{1cm} (3.4)

To find the solution of this optimization problem, it is necessary to build the Lagrangian function $L(x, \lambda, \mu)$ using Lagrangian multipliers $\lambda_i, \mu_j$:

$$L(x, \lambda, \mu) = f(x) + \sum_{i=1}^{M} \lambda_i \cdot g_i(x) + \sum_{j=1}^{L} \mu_j \cdot h_j(x)$$  \hspace{1cm} (3.5)
Chapter 3. Optimal Power Flow

The following step consists in solving the Karush-Kuhn-Tucker (KKT) conditions:

\[
\begin{align*}
\delta L(x,\lambda,\mu) \overline{\delta x}_k &= 0 & \forall k = 1, ..., N \\
\delta L(x,\lambda,\mu) \overline{\delta \lambda}_i &= g_i(x) = 0 & \forall i = 1, ..., M \\
\delta L(x,\lambda,\mu) \overline{\delta \mu}_j &= h_j(x) \leq 0 & \forall j = 1, ..., L \\
\mu_j \cdot h_j(x) &= 0 & \forall j = 1, ..., L \\
\mu_j &\geq 0 & \forall j = 1, ..., L
\end{align*}
\]

(3.6)

The solution of this system of equations provides the globally optimal solution, as long as the problem is convex. If the problem is non-convex (see Figure 3.1), satisfying the KKT conditions is a necessary but not sufficient condition for global optimality. Different locally optimal solutions could be found in this case, depending on the initial search point.

![Figure 3.1: Example of non-convex optimization problem](image)

3.2 Optimal Reactive Power Flow

3.2.1 Introduction

Optimal power flow techniques have been introduced in 1962 by J. Carpentier [1] and are nowadays widely used in several power system applications, from investment planning, to economic dispatch and security assessment. It is a constrained optimization technique where a cost function is minimized subject to the electrical problem constraints. The problem itself is non-linear due to the presence of load flow equations and non-convex. Recent research advances are aiming at convex relaxation of non-convex problems in the field of power system optimization [2]. In case discrete variables are also included, such as OLTC tap positions or switchable components status, the problem becomes a Mixed Integer Non Linear Programming (MINLP).

A simplified version of the OPF problem, the DC OPF, can be considered when only active power optimization is required. The DC OPF assumes that all nodal voltages are equal to 1 p.u. and that angle differences are small, in order to use a linear model of the power flow equations where only active power is considered. This method is widely used in
3.2. Optimal Reactive Power Flow

economic dispatch problems. Our interest is however in ORPF problems, thus the DC OPF is obviously not a viable solution and the AC OPF has to be used. The ORPF problem is used by several TSOs in the deregulated power systems to find the optimal voltage profile, and the consequent reactive power injections, given a pre-defined active power dispatch, coming from the electricity market outcomes. The derived solution should fulfill several constraints, such as limits on operating voltages, limits on reactive power capabilities of control devices, limits on discrete variables (such as OLTC tap positions). Congestions and line loading limits are usually considered in the economic dispatch. The general form of the ORPF problem is described by eq. (3.7)-(3.13).

\[ \min f(x, u) \quad (3.7) \]

s.t.

\[ P_{Gi} - P_{Di} = P_i(x, u) \quad \forall i = 1, ..., N \quad (3.8) \]
\[ Q_{Gi} - Q_{Di} = Q_i(x, u) \quad \forall i = 1, ..., N \quad (3.9) \]
\[ V_{i,\text{min}} \leq V_i \leq V_{i,\text{max}} \quad \forall i = 1, ..., N \quad (3.10) \]
\[ Q_{g,\text{min}} \leq Q_g \leq Q_{g,\text{max}} \quad \forall g = 1, ..., N_g \quad (3.11) \]
\[ Q_{sh,\text{min}} \leq Q_{sh} \leq Q_{sh,\text{max}} \quad \forall sh = 1, ..., N_{sh} \quad (3.12) \]
\[ T_{k,\text{min}} \leq T_k \leq T_{k,\text{max}} \quad \forall k = 1, ..., N_{OLTC} \quad (3.13) \]

Where \( x \) and \( u \) stand for the state and control variables vectors respectively, while in the previous section \( x \) was used to denote generically all variables. \( N \) is the number of nodes, \( N_g \) the number of generators, \( N_{sh} \) of shunt devices and \( N_{OLTC} \) the number of OLTC transformers. As for constraints, eq. (3.8) and (3.9) represent the power flow equations, while eq. (3.10) - (3.13) are limits on bus voltages, generators and shunt devices reactive exchange and OLTC tap positions. Due to the presence of \( T_k \) variables the problem belongs to the MINLP class. The OF in the ORPF problem can be among others [3]:

- Losses minimization
- Reactive power provision minimization
- Quadratic deviation from a voltage profile minimization
- Voltage collapse distance (loadability margin) maximization

Several of the above-mentioned OFs can be also combined in a MO optimization (see Section 3.4), where coefficients \( w_i \) are the OF weights:

\[ OF = F(x) = w_1 \cdot f_1 + w_2 \cdot f_2 + \ldots + w_n \cdot f_n \quad (3.14) \]

3.2.2 Solution Methods

Several computation techniques can be applied to solve optimal power flow problems, Table 3.1 sums up some of the main computational techniques available [4] [5].
### Table 3.1: Summary of OPF solution algorithms

<table>
<thead>
<tr>
<th>Solution Class</th>
<th>Solution Algorithm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Linear Programming (LP)</td>
<td>Simplex Method</td>
</tr>
<tr>
<td></td>
<td>Interior Point (IP) method</td>
</tr>
<tr>
<td>Non Linear Programming (NLP)</td>
<td>Gradient Method</td>
</tr>
<tr>
<td></td>
<td>Newton Method</td>
</tr>
<tr>
<td></td>
<td>Quadratic Programming (QP)</td>
</tr>
<tr>
<td></td>
<td>Interior Point (IP) Method</td>
</tr>
<tr>
<td>Mixed Integer Non Linear Programming (MINLP)</td>
<td>Branch &amp; Bound (B&amp;B)</td>
</tr>
<tr>
<td></td>
<td>Benders Decomposition</td>
</tr>
<tr>
<td>Soft-Computation - Artificial Intelligence(AI)</td>
<td>Genetic Algorithm (GA)</td>
</tr>
<tr>
<td>Techniques</td>
<td>Particle Swarm Optimization (PSO)</td>
</tr>
</tbody>
</table>

### Linear Programming

Since the OPF problem is non-linear, the use of LP is based on a linearization of the problem using the first order derivatives. It is often called also sensitivity-based approach. LP has the advantages to guarantee good convergence properties and fast infeasibility detection. In addition, the non-convexity issue is overcome assuring global optimality. The most common algorithms to solve LP problems are IP method (explained in detail later) and the Simplex method. However, LP application in the AC OPF field has been restricted due to the inaccuracy in the model related to the linearization process compared to a full non-linear model [5].

### Non Linear Programming

Non linear programming is used for OPF when no integer variables are considered. Several algorithms have been introduced to solve this class of problems:

- **Gradient Method**: is based on the first-order derivatives computation to calculate the search direction from a starting point. It is also called first-order method.

- **Newton Method**: this method consists in approximating the function with a quadratic function at each iteration and trying to find its minimum. It requires the computation of the Hessian matrix.

- **Quadratic Programming**: it is a method to solve linearly constrained quadratic problems (where the OF is the product of some variables). Together with the Newton method, it involves the computation of the second-order partial derivatives and the Hessian Matrix. They allow faster convergence close to the solution point.
3.2. Optimal Reactive Power Flow

**Interior Point method:** Interior point is a method alternative to the simplex method that can be extended also to nonlinear problems. It is based on two fundamental concepts: first of all the solution is found at each iteration as a point inside the feasible region, this means that boundary points are not considered from a mathematical point of view. Practically speaking, also points at the boundary of the feasible region are reachable since it is possible to reach the limits with an infinitesimal distance. Second key point is that the problem is solved via the definition of sub problems in which the feasible region is restricted by a logarithmic penalty factor which is decreased at each iteration leading the problem to coincide with the initial one at the end of the optimization process. Advantages of this method are good scalability and high efficiency.

**Mixed Integer Non Linear Programming**

MINLP problems are of interest when discrete or binary variables have to be represented. Typical cases are OLTC tap positions and switching actions.

**Branch & Bound:** Branch-and-Bound is a tree search based on continuous relaxations of the discrete problem. It was firstly introduced by Dakin in 1965. It consists of a systematic definition of candidate solutions by means of state space search. The candidate solutions form a rooted tree. The algorithm explores the different branches of this tree, representing subsets of the solution set. Before enumerating all the possible branch solutions, the branch is compared against the estimated upper and lower bound of the optimal solution. If the branch is not able to improve the best solution found so far, it is discarded and the algorithm considers a new branch. This allows to drastically decrease the number of possible solutions actually evaluated along each branch. The search ends when there is no unexplored portion of the solution space left, and the optimal solution is then the one stored as "current best". In Figure 3.2 we can see the three steps of a B&B algorithm: starting from the root of the tree, possible branches are evaluated and the ones (1 and 4 in this case) which cannot improve the optimal solutions discarded, while branching goes on for the others (2 and 3) [6]. Different techniques can be used for the tree search, among the most important:

- Best First Search
- Breadth First Search
Depth First Search

Figure 3.3 shows a simple tree solved using all the three different techniques. The number in the circle indicates the order according with each node is evaluated. In the Best First Search (a), the algorithm always selects among the remaining sub-problems one of those with the lowest bound. Instead, in the Breadth First Search (b) all nodes at one level of the search tree are evaluated, before proceeding further to nodes at a higher level. Finally, in the Depth First Search (c) strategy, once a node has been positively evaluated against current bounds, one higher level node of the same branch is processed, going in depth in the same branch.

Benders Decomposition: Benders decomposition is a technique introduced for solving complicate stochastic or mixed-integer problems. It is based on a problem decomposition strategy, in which the entire problem and its variables are divided in a master problem, which
3.3 Artelys KNITRO

is solved first, and a set of sub-problems. If the solution found for the first-stage master problem leads to infeasible variable values in the sub-problems, the master problem is solved again adding new constraints.

Soft-computation - Artificial Intelligence Techniques

This class of solutions use heuristic algorithms to solve complicate optimization problems. Several algorithms have been invented belonging to this class. Here some of the most interesting for ORPF applications are reported.

Genetic Algorithm: GA is inspired to the evolutionary theory in biology. Firstly, the solution domain is expressed in terms of genetics, i.e. variable values are translated into a genetic representation. Second, a fitness function is introduced to evaluate each individual in the population: the fitness function usually coincides with the objective function of the optimization problem. The algorithm starts from a random population and finds the individuals who fit best the fitness function. Once selected these individuals, a new generation is created from them using mechanisms also taken from the genetic field, such as selection, crossover and mutation, to change the characteristics of the new generation compared to the previous one (parent)[7]. The algorithm is terminated when a maximum number of generations is reached, or the fitness function has reached a defined value. Applications of GA to ORPF can be found for instance in [3], [8], [9].

Particle Swarm Optimization: PSO is a meta-heuristic algorithm which also takes inspiration from biology. It is based on a set of particles, i.e., a swarm, moving in the solution space. The speed and movement directions are governed by a set of mathematical equations. Each position is evaluated against the fitness function and the best positions are discovered. The algorithm should converge until all the particles occupy the optimal position in the solution space according to the defined fitness function. This algorithm does not employ any gradient method to find search directions, and it is thus suitable for non-differentiable and irregular problems. However, as other heuristic methods, it does not guarantee an optimal solution is found. Examples of PSO application in optimal power flow problems are given in [10] and [11].

3.3 Artelys KNITRO

Several commercial solvers exist today to solve optimization problems employing the algorithms so far described. For solving very large and difficult NLP and MINLP problems one of the best solvers is Artelys KNITRO [12]. KNITRO was employed to solve the OPF model that will be presented later on. It is a very efficient and robust tool and incorporates several useful functionalities, such as automatic tuning of best options, presolver, multi-start to try reaching global optimality also in non-convex problems, parallelism and some specific features for NLP and MINLP problems.

In the NLP class, KNITRO features four different solvers: two belonging to the active set/quadratic programming class and two based on the Interior Point (IP) method. It can also automatically choose the best solver given a certain problem (crossover).

In the MINLP class KNITRO can use three solvers: branch & bound, Quesada-Grossman and Mixed Integer Quadratic Programming (MIQP). The first one was used in the following simulations. Global optimality is ensured only in case of convexity, so not in
the case of our problem which is non-convex. Variables initialization is thus of fundamental importance to achieve a global optimal solution in case of non-convexity. In this case KNITRO uses heuristic methods. It also features a special way of handling complementarity constraints, which are generally particularly complicate to solve.

### 3.4 Multi-Objective Optimization

Multi-Objective (MO) optimization is a technique used when multiple objectives are sought within an optimization problem. The general MO optimization problem can be written as [13]:

\[
\begin{align*}
\min \mathbf{F}(\mathbf{x}) &= (f_1(\mathbf{x}), f_2(\mathbf{x}), \ldots, f_k(\mathbf{x}))^T \\
s.t. & \quad \mathbf{x} \in S \\
& \quad \mathbf{x} = (x_1, x_2, \ldots, x_n)^T
\end{align*}
\]  

where \( \mathbf{x} \) represents the vector of problem variables (of all kinds) and \( S \) the space of feasible values of \( \mathbf{x} \) (solution space), while \( f_1(\mathbf{x}), f_2(\mathbf{x}), \ldots, f_k(\mathbf{x}) \) are the \( k \) OFs of the problem. The values of \( \mathbf{F} \) corresponding to \( S \) are denoted by \( \mathbf{Y} \) (attribute space) and \( \mathbf{F} \) maps \( S \) into \( \mathbf{Y} \), as shown in Figure 3.4.

The utopian solution is defined as \( \mathbf{F}^*(\mathbf{x}) = (f_1^*(\mathbf{x}), f_2^*(\mathbf{x}), \ldots, f_k^*(\mathbf{x})) \), i.e. the minimum of all individual OFs. This solution is rarely achievable due to constraints on variables \( \mathbf{x} \). Therefore, in order to evaluate the function \( \mathbf{F}(\mathbf{x}) \) it is necessary to introduce certain criteria. One criterion commonly used is to request that candidate solutions are non-dominated [13]: a solution \( \mathbf{x} \) dominates \( \mathbf{y} \) if \( \mathbf{x} \) is better or equal to \( \mathbf{y} \) in all attributes, and strictly better in at least one attribute. In mathematical terms, \( \mathbf{x} \) is said to dominate \( \mathbf{y} \), \( \mathbf{x} \succ \mathbf{y} \), if:

\[
\forall i \in \{1, \ldots, k\} : f_i(\mathbf{x}) \leq f_i(\mathbf{y}) \quad \text{and} \quad \exists j \in \{1, \ldots, k\} : f_j(\mathbf{x}) < f_j(\mathbf{y})
\]

Figure 3.4: Solutions (left) and attribute (right) space in a bi-dimensional MO optimization problem [13]

The \( \mathbb{R}^k \) space formed by non-dominated solutions is called Pareto space or Pareto set [14]. It is clear that the optimal solutions of the MO optimization problem must belong to the Pareto space. Figure 3.4, shows the solutions space and the attribute space in the
case of a simple bi-dimensional problem with two variables \((x_1, x_2)\) and two OFs \((f_1, f_2)\). The Pareto set is identified with the symbol \(\mathcal{P}\).

In order to prioritize one OF over the other(s), weight coefficients \(w_i\) are usually introduced, as shown in eq. (3.14). However, challenges arise in the choice of weights due to the different physical quantities and measurement units of the OFs which makes hard a direct comparison and equivalence and due to the high sensitivity of the Pareto set to weights choice.

### 3.5 Model Predictive Control

OPF problems can be either solved as single step optimization problems or using Model Predictive Control (MPC). MPC, also called receding time horizon, is a multi-step optimization technique. The problem is solved for multiple time steps depending on the chosen time horizon \(T\). In this way, the optimal trajectory of control variables over the time horizon is identified, but only the control actions of the contingent time step are applied. More specifically, the steps of MPC optimization are the following:

1. Prediction of the system evolution over the time horizon
2. Computation of the reference (optimal) trajectory
3. Definition of the optimal sequence of control actions to minimize the objective function over the whole time horizon \(T\)
4. Application of the first element in the control actions sequence

MPC was firstly introduced in the petrochemical industry in the 1970s and has found since then application in many fields (aviation, energy,\ldots). Figure 3.5 shows the concept of MPC optimization. Single step optimization can be seen as a particular case of MPC where \(T = 0\).

![Figure 3.5: Concept of Model Predictive Control (MPC) optimization](image)

The ability of MPC to incorporate a forecast of the system evolution is important in order to smooth in time control signals and avoid unwanted or unnecessary control actions. In our context, this is particularly important for tap operations, which should be minimized as much as possible. Examples of MPC application to ORPF are presented in [15], [16], and [17]. The importance of forecast accuracy is paramount. Especially when among control
variables is included DG flexibility, which usually depends on energy source availability, e.g. wind speed. In this case, the performance of deterministic forecasts should be accurately compared against the one of probabilistic forecasts, accounting for the stochastic nature of the phenomenon. MPC is also included in the OPF tool developed, even though it does not represent the main focus of this work.

3.6 Multi-Area OPF

OPF problems have been traditionally solved in a centralized way, since, usually, a single vertically-integrated utility was in charge of managing the whole national system. With the unbundling and liberalization of the power system and the increasing interconnection level at continental scale, the need of coordinating several SOs in the optimization process has become more urgent. The problem arises when the system to be optimized is made of portions, which cannot be optimised individually due to strong cross-dependency, controlled by different entities. The problem at hand is defined multi-area power system optimization and several methods have been developed for it. First of all, it is important to review the main methods employed for network reduction and equivalency, i.e. to represent external portions of the network under study in power flows or OPF computations.

3.6.1 Network Equivalents

Network equivalents are used to represent a portion of a power system with a much lower number of components allowing faster and less onerous computations when dealing with large interconnected systems, such as the European continental network. The main properties of a good reduced network model are accuracy and simplicity of computation. Network equivalents are also clustered in two groups [18]:

Static Equivalents: starting from a load flow scenario, the equivalent model represents a snapshot of the system and can be used for static analysis only, such as power flow calculations or operational and planning analysis.

Dynamic equivalents: they can be used for studies on dynamic effects, such as offline transient stability with large disturbances, off-line dynamic stability analysis with small disturbance, on-line security assessment.

From now on, our attention is focused on static equivalent models. Reduction methods are based on dividing the overall system in two parts: the internal system and the external system to be reduced. Influence of the latter on the former is assumed to be limited. The most diffused network equivalents are the REI and Ward equivalents.

Ward Equivalent

The method with widest application is the Ward equivalent, introduced by J.B. Ward in 1949 [19]. It performs a triangular reduction of the $Y_{bus}$ matrix of the network using the Gaussian method, briefly described in eq. (3.19)-(3.25), where $i$, $b$, and $e$ represent internal, boundary and external buses respectively [20]. $E$ represents voltages and $I$ current injections. $Y_{eq}$ and $I_{eq}$ are the reduced model parameters.

$$YE = I$$  \hspace{1cm} (3.19)
3.6. Multi-Area OPF

\[
\begin{pmatrix}
Y_{ee} & Y_{eb} & 0 \\
Y_{be} & Y_{bb} & Y_{bi} \\
0 & Y_{ib} & Y_{ii}
\end{pmatrix}
\begin{pmatrix}
E_e \\
E_b \\
E_i
\end{pmatrix}
=
\begin{pmatrix}
I_e \\
I_b \\
I_i
\end{pmatrix}
\quad(3.20)
\]

\[
Y_{ee}E_e + Y_{eb}E_b = I_e
\quad(3.21)
\]

\[
\Rightarrow E_e = -Y_{ee}^{-1}Y_{eb}E_b + Y_{ee}^{-1}I_e
\]

\[
Y_{be}E_e + (Y_{bb} + Y_{ib})E_b + Y_{bi}E_i = I_b
\quad(3.22)
\]

\[
\Rightarrow (Y_{bb} + Y_{ib} - Y_{be}Y_{ee}^{-1}Y_{eb})E_b + Y_{bi}E_i = I_b - Y_{be}Y_{ee}^{-1}I_e
\]

With:

\[
Y_{eq} = Y_{bb} - Y_{be}Y_{ee}^{-1}Y_{eb}
\quad(3.23)
\]

\[
I_{eq} = -Y_{be}Y_{ee}^{-1}I_e
\quad(3.24)
\]

\[
\begin{pmatrix}
Y_{bb} & Y_{eq} & Y_{ib} \\
Y_{ib} & Y_{ii}
\end{pmatrix}
\begin{pmatrix}
E_b \\
E_i
\end{pmatrix}
=
\begin{pmatrix}
I_b + I_{eq} \\
I_i
\end{pmatrix}
\quad(3.25)
\]

Thus, the \( Y_{bus} \) matrix is reduced from eq. (3.20) to eq. (3.25) including only admittances between internal and boundary buses and also some equivalent admittances corresponding to the newly created equivalent branches between boundary buses, as shown in Figure 3.6. In order to have the boundary flows matching power flow results, some equivalent current injections for each boundary bus are considered, indicated by arrows in Figure 3.6.

![Figure 3.6: Ward network equivalent and corresponding variables [20]](image)

The classical Ward reduction features two versions, differing from each other in the way the bus power injections are represented. These two versions are usually named the Ward injection method and Ward admittance method. In the Ward injection method, all the bus power injections are handled as constant current injections and later converted back to constant power injections after reduction. In the Ward admittance method, instead, all the nodal power injection are converted to admittance before the reduction. The first one is usually preferred due to its higher reliability [21]. One shortcoming of the classical Ward equivalent is its inability to represent reactive power support from the external area in case of contingency in the internal area. For this reason, the extended Ward equivalent is an attractive alternative.
Extended Ward

The extended Ward is based on the classical Ward equivalent with the addition of some additional generators with no active power output but with a reactive power output based on a PV node behaviour. They are used to model the external system reactive response when voltages change with respect to initial values. It is thus suitable for contingency studies. Figure 3.7 shows and compares the Ward and extended Ward equivalents [22].

![Extended Ward Diagram](image)

**Figure 3.7: Network equivalent using the Ward (left) and extended Ward (right) models [22]**

REI Equivalent

The Radial Equivalent Independent (REI) method is based on the substitution of several generators with an equivalent generator. Therefore, the power injection of these N generators is aggregated in a virtual node where a REI generator is connected. The passive N nodes remaining can be eliminated with the previously shown Gaussian method. The virtual nodes are connected to the boundary nodes using a radial network made of equivalent admittances. These are computed based on the load flow results[18]. REI equivalent and its variants have several limitations, making them less popular than the Ward equivalent [21].

![REI Equivalent Diagram](image)

**Figure 3.8: Network equivalent using the REI model [23]**
3.6. Multi-Area OPF

3.6.2 Distributed Optimization

The use of static network equivalents is suitable when the external system has little influence on the system under optimization, however, when the influence is not negligible and/or both systems should be optimized at the same time, more sophisticated methods are required. These fall within the category of distributed optimization. As a general point, distributed optimization algorithms should exhibit some properties, such as simplicity and robustness, for instance with respect to loss of communication. They should also deliver a close-to-optimal solution, which would be found through a centralized optimization. In the present section a short review of the most important algorithms for distributed OPF is provided.

Update of network Equivalents

One method to achieve a distributed optimization is to add to the local problem solved by each SO in a greedy way some constraints relating the parameters of the reduced network model used to actual measurements. An example of such a method applied to voltage optimization is provided in [23], where a fitting function is developed which uses past observations of current and voltages at the interface to update the reduced model of each TSO at each iteration (see Figure 3.9 [23]). Each measurement is penalized in the fitting function depending on a memory parameter and the time it was taken. In this way no exchange of information or explicit coordination is required. Coordination is achieved implicitly through measurements, which reflect other SOs control actions. Several reduced models are used, from simple PQ and PV models to REI equivalents. However only few combinations of network equivalent and memory parameters gave satisfactory results, underlining the complexity of the problem. Moreover, two important assumptions were made using a time-invariant system and the same objective function for all SOs.

\[
\tilde{g}_A(X_A, X_B) \tilde{g}_B(X_B, X_A) \tag{3.26}
\]

\[
\tilde{h}_A(X_A, X_B) \tilde{h}_B(X_B, X_A) \tag{3.27}
\]

Figure 3.9: Distributed optimization using update of network equivalents [23]

Power Flow Decomposition

Power flow decomposition techniques use another principle: the global optimization problem is decomposed in N sub problems and solved in a decentralised way, where each sub problem is coupled to the others by means of interface coupling constraints (3.26), (3.27), which state that boundary variables should have the same values (see Figure 3.10 [24]).
All the other constraints act only on local variables. An information exchange is required to communicate interface variables and Lagrangian multipliers associated to the coupling constraints. The method is described in detail in [25], and [24]. [26] provide an application of Lagrangian decomposition to a multi-area MPC problem for voltage security. Different variants can be used, based on Lagrangian relaxation or augmentation. The outlined method has the advantage of ensuring global optimality and requires a very little exchange of information. However, major limitations are the number of iterations required and the consequent computation time associated, which is an issue especially for large systems.

![Figure 3.10: Distributed optimization using Lagrangian decomposition [24]](image)

**Cooperation and Negotiation**

Other approaches for distributed optimization are based on intelligent agents theory and the use of cooperation or negotiation mechanisms. For instance, [27] proposes a distributed MPC control where each DSO is a Communicating Agent (CA) and exchanges with its neighbours only information about future control actions. In [28] a mechanism of negotiation between several agents is developed where a common strategy is selected based on negotiation and evaluation of the global cost function. These solutions generally entail a higher amount of data exchanged.

### 3.7 Development of the modular OPF tool in GAMS

Building on the theoretical background described so far, this section will present the mathematical model of the OPF tool developed for this thesis. The model is based on the work presented in [29] and in [15], consisting in a OPF tool with MPC for distribution system VVC based on wind farms and OLTC control. The tool is extended with several major parts, including a new control mode for wind farms, new objective functions, modelling of new components such as synchronous generators and implementing multi-area optimization to deal with a regional grid model comprising both transmission and distribution level and different SOs. The extended OPF tool can thus be used to simulate the proposed coordinated voltage control scheme between TSO and DSO. The description of this scheme is the topic of the next chapter. The tool we describe here is a comprehensive and modular OPF tool, able to deal with several tasks and problems. In each optimization a model is chosen including a subset of variables and equations from the entire set available depending on the task at hand. The model can be configured as a MINLP problem when OLTC
3.7. Development of the modular OPF tool in GAMS

transformers are included. Conversely, a NLP problem is solved when no OLTC is present in the grid under study. In both cases the solver adopted is Artelys KNITRO [12] (for details about this solver refer to Section 3.3) and the optimization problem is modelled in GAMS [30].

3.7.1 Sets and Variables
The grid under study consists of $n$ nodes. The set $A$ is introduced to represent the area of the grid subject to optimization: for instance it can include distribution grid only, transmission grid only or both. Each node in the system is mapped to a grid area, thus the OPF is able to distinguish grid areas and optimize only those indicated by the set $A$. Distribution and transmission grid are connected via grid-coupling transformers. The nodes on the low voltage side of those transformers define the set $M$ and those on the high voltage side the set $K$, respectively. They are mapped to the connection points they belong to through the set $cp$. The sets $i$ and $j$ indicate grid nodes. Set $g$ refers to generators, while set $t$ refers to time instants and the parameter $T$ represents the MPC time horizon. The transformer tap-changer positions are discrete and modeled with binary variables. $G_{ij}$ and $B_{ij}$ are the branch conductance and susceptance. These are dependent on the actual tap-changers configuration.

The state variables are the voltage magnitude $U_{i}$ and angle $θ_{i}$ for PQ buses, the reactive power $Q_{i}$ and voltage angle $θ_{i}$ for PV buses and the active power $P_{i}$ and reactive power $Q_{i}$ for the $Uθ$ bus. The control variables $u$ are the positions of the transformer tap-changers $r_{ij}$ and reactive power set-points $Q_{g}$ of PQ generation units and voltage set points $V_{opt}^{cp}$ in case of Q(U) or PV generators. The problem is written in p.u. notation, with a predefined base.

3.7.2 The Objective Function
The tool is configured to perform a multi-objective optimization. MO optimization was introduced in Section 3.2 and consists in minimizing or maximizing a linear combination of several objective functions, each multiplied by a scalar coefficient, referred as weight. It is often used when several conflicting objectives are sought and it allows to achieve a trade-off between them, provided the weights choice is done wisely. The following objective functions are included in the MO function, where coefficients $w_{i}$ denote the weights:

$$
\min_{u} \left\{ w_{1} f_{\text{profile}} + w_{2} f_{\text{losses}} + w_{3} f_{\text{Tap}} + w_{4} f_{\Delta Q} + w_{5} f_{V_{ext}} + w_{6} f_{\Delta Q_{cp}} \right\} \tag{3.28}
$$

Voltage Profile

$$
f_{\text{profile}} = \sum_{t=0}^{T} \sum_{i \in A} (U_{i,t} - U_{i}^{set})^{2} \tag{3.29}
$$

The function $f_{\text{profile}}$ penalizes the sum of the quadratic deviations of the nodal voltages from a predefined setpoint $U_{i}^{set}$. It is useful to reach a smooth voltage profile in the system around a desired value. Only nodes belonging to the optimization area are considered.
Losses

\[ f_{\text{losses}} = \sum_{t=0}^{T} \sum_{i \in A} \sum_{j \in A} G_{ij,t} \left[ U_{i,t}^2 + U_{j,t}^2 - 2U_{i,t}U_{j,t} \cos(\theta_{i,t} - \theta_{j,t}) \right] \]  

The function \( f_{\text{losses}} \) penalizes active power losses in the branches belonging to the selected area.

Tap Operations

\[ f_{\text{Tap}} = \sum_{t=0}^{T-1} \sum_{i \in M} \sum_{j \in K} [r_{ij,t+1} - r_{ij,t}]^2 \]  

The function \( f_{\text{Tap}} \) penalizes the changes in tap positions quadratically, in order to consider equally an increase or decrease of the tap number.

Reactive Power Sum

\[ f_{\Delta Q} = \sum_{t=0}^{T} \left\{ \sum_{i \in M} \sum_{j \in K} U_{i,t}U_{j,t} \left[ G_{ij,t} \sin(\theta_{i,t} - \theta_{j,t}) - B_{ij,t} \cos(\theta_{i,t} - \theta_{j,t}) \right] - Q_{\text{set}}^t \right\}^2 \]  

The function \( f_{\Delta Q} \) is used to minimize the quadratic deviation of the sum of reactive power flows over boundary branches from a given setpoint. It is useful to ensure a desired reactive power exchange between the distribution and transmission level.

Voltage Targets

\[ f_{\text{Vext}} = \sum_{t=0}^{T} \sum_{i \in K} \left( U_{i,t} - U_{\text{set},i,t} \right)^2 \]  

The function \( f_{\text{Vext}} \) penalizes the sum of the quadratic deviations of the EHV boundary voltages from some given setpoints \( U_{\text{set},i,t} \). It is necessary to control the boundary voltages fulfilling some external targets on EHV voltages.

Reactive Power Targets

\[ f_{\Delta Q_{cp}} = \sum_{t=0}^{T} \sum_{cp} \left\{ \sum_{i \in M_{cp}} \sum_{j \in K_{cp}} U_{i,t}U_{j,t} \left[ G_{ij,t} \sin(\theta_{i,t} - \theta_{j,t}) - B_{ij} \cos(\theta_{i,t} - \theta_{j,t}) \right] - Q_{\text{set},cp,t} \right\}^2 \]  

The function \( f_{\Delta Q_{cp}} \) is similar to \( f_{\Delta Q} \), but penalizes quadratically the deviations of reactive power flows from target values at each connection point \( Q_{\text{set},cp,t} \). Thus, it is intended to control individually the reactive power exchanged from the distribution grid at each CP. \( M_{cp} \) and \( K_{cp} \) are the HV and EHV boundary buses of each CP.

The first three OFs can have general application at both TSO and DSO level, while the last three are specifically introduced in order to allow the DSO to include in its optimization setpoints coming from the TSO.
3.7. Development of the modular OPF tool in GAMS

### 3.7.3 Problem Constraints

State and control variables are bounded by several equality and inequality constraints:

\[
\Delta P_{i,t} = U_{i,t} \sum_{j=1}^{n} U_{j,t} \left[ G_{ij,t} \cos(\theta_{i,t} - \theta_{j,t}) - B_{ij,t} \sin(\theta_{i,t} - \theta_{j,t}) \right] \tag{3.35}
\]

\[
\Delta Q_{i,t} = U_{i,t} \sum_{j=1}^{n} U_{j,t} \left[ G_{ij,t} \sin(\theta_{i,t} - \theta_{j,t}) - B_{ij,t} \cos(\theta_{i,t} - \theta_{j,t}) \right] \tag{3.36}
\]

\[
Q_{g,t}^{\min} \leq Q_{g,t} \leq Q_{g,t}^{\max} \tag{3.37}
\]

\[
U_i^{\min} \leq U_{i,t} \leq U_i^{\max} \tag{3.38}
\]

\[
r_{ij}^{\min} \leq r_{ij,t} \leq r_{ij}^{\max} \tag{3.39}
\]

\[-\Delta r_{ij}^{\max} \leq r_{ij,t+1} - r_{ij,t} \leq \Delta r_{ij}^{\max} \tag{3.40}
\]

\[
U_i^{\text{opt}, \min} \leq U_{i,t} \leq U_i^{\text{opt}, \max} \tag{3.41}
\]

The first two constraints (3.35),(3.36) represent the load flow equations where the terms \( \Delta P \) and \( \Delta Q \) are the nodal power balances, and \( g_i \) indicates the generators connected to bus \( i \):

\[
\Delta P_{i,t} = \sum_{g_i} P_{g,t} - P_{i,t}^{\text{load}} \tag{3.42}
\]

\[
\Delta Q_{i,t} = \sum_{g_i} Q_{g,t} - Q_{i,t}^{\text{load}} \tag{3.43}
\]

The active power output of each generator is always a constant value in the optimization (except for the slack), while the reactive power output is an optimization variable for some generator classes (see subsection 3.7.1). Eq.(3.37) states the reactive power limits of generators, while eq.(3.38) the limits on admissible nodal voltages \( U_i \). Eq.(3.39) and (3.40) resemble limits on OLTC tap positions and operations per time step respectively. Eq. (3.41) defines the limits on voltage setpoints for PV and Q(U) generators.

Additional equations have to be introduced to compute the branches parameters \( G_{ij,t} \) and \( B_{ij,t} \) taking into account tap positions:

\[
G_{i,t} = G_i^{\text{shunt}} + \sum_k (G_{ki}^{\text{branch}} - \frac{1}{2} Y_{ki} G_{ki}^{\text{branch}}) \cdot (\text{tap}_{ki,t})^2 + \sum_k (G_{ik}^{\text{branch}} - \frac{1}{2} Y_{ik} G_{ik}^{\text{branch}}) \tag{3.44}
\]

\[
G_{i,t} = \sum_k -G_{ki}^{\text{branch}} \cdot \text{tap}_{ki,t}^{\text{ratio}} + \sum_k -G_{ik}^{\text{branch}} \cdot \text{tap}_{ik,t}^{\text{ratio}} \tag{3.45}
\]

\[
B_{i,t} = B_i^{\text{shunt}} + \sum_k (B_{ki}^{\text{branch}} - \frac{1}{2} Y_{ki} B_{ki}^{\text{branch}}) \cdot (\text{tap}_{ki,t})^2 + \sum_k (B_{ik}^{\text{branch}} - \frac{1}{2} Y_{ik} B_{ik}^{\text{branch}}) \tag{3.46}
\]

\[
B_{i,t} = \sum_k -B_{ki}^{\text{branch}} \cdot \text{tap}_{ki,t}^{\text{ratio}} + \sum_k -B_{ik}^{\text{branch}} \cdot \text{tap}_{ik,t}^{\text{ratio}} \tag{3.47}
\]
Eq. (3.44)-(3.47) represent the diagonal and off-diagonal real and imaginary parts of the \( Y_{bus} \) matrix. \( G_{shunt}^i \) and \( B_{shunt}^i \) represent the conductance and impedance of shunt devices connected to bus \( i \). \( G_{branch}^{ij} \) and \( B_{branch}^{ij} \) are the series conductance and susceptance of branch \( ij \), using a \( \pi \) line model (see Figure 3.11). They are computed starting from known values of the line resistance and reactance:

\[
G_{branch}^{ij} = \frac{R_{ij}}{\sqrt{R_{ij}^2 + X_{ij}^2}} \tag{3.48}
\]
\[
B_{branch}^{ij} = -\frac{X_{ij}}{\sqrt{R_{ij}^2 + X_{ij}^2}} \tag{3.49}
\]

While parameters \( YG_{branch}^{ij} \) and \( YC_{branch}^{ij} \) represent the branch shunt conductance and capacitive susceptance, which are provided as input data.

Finally, \( tap_{ij,t}^{ratio} \) is a variable which represents the actual transformation ratio of the branch, defined as 1 minus the tap position in time \( t \), times \( dU_{ij}^{tap} \), the voltage variation in p.u. corresponding to a single tap position change:

\[
tap_{ij,t}^{ratio} = 1 - r_{ij,t} \cdot dU_{ij}^{tap} \tag{3.50}
\]

The set of equations (3.44)-(3.50) allows to compute at each time step the \( Y_{bus} \) matrix of eq. (3.51) as a function of OLTC tap positions.

\[
Y_{bus} = \begin{bmatrix}
G_{11,t} + j \cdot B_{11,t} & \cdots & G_{1n,t} + j \cdot B_{1n,t} \\
\vdots & \ddots & \vdots \\
G_{n1,t} + j \cdot B_{n1,t} & \cdots & G_{nn,t} + j \cdot B_{nn,t}
\end{bmatrix} \tag{3.51}
\]

### 3.7.4 Synchronous Generators Model

The OPF tool developed must correctly handle synchronous generators in voltage regulation mode. They can be represented as PV nodes within the model. The difficult aspect is to represents the change to PQ nodes in case the capability limits of synchronous machines are hit (refer to Section 2.3). This is relevant when the generators in voltage control mode are included in the OPF but not optimized (i.e. the voltage setpoint is not a variable). To model this behaviour complementarity constraints are introduced [31]. These constraints, although necessary, are not easy to handle for the solver and they can lead to an increase in the number of iterations.
3.7. Development of the modular OPF tool in GAMS

\[
\begin{align*}
(Q_{g,t} - Q_{g,t}^{\text{max}}) \cdot \Delta U_{i,t} & \leq 0 \quad (3.52) \\
(Q_{g,t} - Q_{g,t}^{\text{min}}) \cdot \Delta U_{i,t} & \leq 0 \quad (3.53) \\
(U_{i,t} - U_{i,t}^{\text{opt}}) = \Delta U_{i,t} \quad (3.54)
\end{align*}
\]

Here $\Delta U_{i,t}$ represents the deviation from the voltage setpoint. If $Q_{g,t}$ has not hit the lower or upper limit, the only possible way for (3.52) and (3.53) to hold is that $\Delta U_{i,t} = 0$, thus the voltage is equal to the setpoint. When one of the two limits is reached, $\Delta U_{i,t}$ becomes different from 0, as shown in eq. (3.55).

\[
\begin{cases}
Q_{g,t} = Q_{g,t}^{\text{max}} & \Delta U_{i,t} \leq 0 \\
Q_{g,t}^{\text{min}} \leq Q_{g,t} \leq Q_{g,t}^{\text{max}} & \Delta U_{i,t} = 0 \\
Q_{g,t} = Q_{g,t}^{\text{min}} & \Delta U_{i,t} \geq 0
\end{cases} \quad (3.55)
\]

When, instead, the generator’s voltage setpoint is an optimization variable, the PV node can be simply represented with (3.56).

\[
(U_{i,t} - U_{i,t}^{\text{opt}}) = 0 \quad (3.56)
\]

In both cases, reactive power limits of synchronous generators, stated in eq. (3.37), are computed using a simplified trapezoidal model of capability curve [32].

\[
\begin{align*}
Q_{g,t}^{\text{max}} & = \alpha_1 \left(1 - \frac{P_{g,t}}{P_{g,t}^{\text{max}} \cdot \beta_1}\right) \quad (3.57) \\
Q_{g,t}^{\text{min}} & = \alpha_2 \left(1 - \frac{P_{g,t}}{P_{g,t}^{\text{max}} \cdot \beta_2}\right) \quad (3.58)
\end{align*}
\]

With the following values for the parameters $\alpha$, $\beta$, the capability curve assumes the shape of Figure 3.12:

\[
\begin{cases}
\alpha_1 = 1 & \beta_1 = 2.5 \\
\alpha_1 = 0.4 & \beta_1 = 2
\end{cases} \quad (3.59)
\]
3.7.5 Wind Farm Model

The behaviour of wind farms in the OPF depends on the chosen control mode, based on the possible solutions presented in Section 2.6. As mentioned there, in Germany the most diffused control mode is based on Q or cosφ setpoints. Two possible control modes for wind farms are considered and modeled in the OPF: Q (or cosφ) set points and Q(U) control. Both modes can be either static, with fixed set points, or dynamic, with set points updated at each time interval by the OPF (see Figure 3.13).

![Figure 3.13: Wind farm control modes implemented in the OPF tool](image)

**Power Factor Control**

Power factor control represents the most widely applied reactive power control for wind farms. In Section 2.6 it was mentioned this is the most common control method also in Germany: the DSO can usually control the cosφ of wind farms equipped with remote control directly from its control centre. In many cases the power factor is the only variable that can be controlled, as in the case of the IMOWEN system. Wind farms controlled through power factor adjustment are simply modelled in the OPF as PQ nodes, which reactive power output can vary in the range $Q^\text{range}_{g,t} = [Q^\text{min}_{g,t}, Q^\text{max}_{g,t}]$. Reactive limits are updated at each time step, depending on the admissible power factor limits considered.

**Q(U) Control**

Q(U) control is instead based on a voltage target and a droop to get a variable reactive power output depending on the voltage deviation, as outlined in Section 2.6. This control mode is also often used, especially targeting local voltage control purposes [33], but also for coordinated [34],[35] or semi-coordinated applications [36]. The development of this control in the OPF is performed adding one additional constraint equation related to the $Q = f(U)$ control law. The complicate part is to represent the discontinuity of this function in a simple mathematical way within the algorithm. In [35] a sigmoid function is used for this purpose. The solution here proposed is to model the Q(U) characteristic using a fifth order polynomial function (3.60), since it allows to intrinsically represent reactive limits in the load flow, whilst ensuring fast convergence. In the OPF explicit reactive limits are added. A polynomial representation of the $Q = f(U)$ law is proposed also in [37].

$$Q_{g,t} = Q^\text{range}_{g,t} \cdot \left( a_1 \cdot \Delta U_{i,t} + a_3 \cdot \Delta U_{i,t}^3 + a_5 \cdot \Delta U_{i,t}^5 \right) \quad (3.60)$$

Generally, both the voltage setpoint and the droop can be variables in the optimization as shown in [36] and [35]. In the present application the droop is kept constant. Thus,
3.7. Development of the modular OPF tool in GAMS

Figure 3.14: $Q = f(U)$ polynomial characteristic

coefficients $a_{1,3,5}$ are found via polynomial fitting when the desired droop has been selected. With the parameters of (3.61) we obtain the characteristic of Figure 3.14 with a droop around 2%. The slight error compared to the original linear characteristic is compensated by faster convergence.

$$\begin{cases} a_1 &= -91 \\ a_3 &= 1.42 \cdot 10^5 \\ a_5 &= -1 \cdot 10^8 \end{cases} \quad (3.61)$$

Nodes with wind farms in the distribution grid are generally represented as PQ nodes. In order to identify controlled wind farms in the OPF, the parameter $\text{gen}_{-}\text{op}_{-}\text{mode}$ is defined in GAMS and set equal to 7 for controllable wind generators. In this way the OPF knows that should handle that generator with power factor or $Q(U)$ control, depending on the specific case, and not as a simple PQ generator.
Bibliography


Chapter 4

Coordinated TSO-DSO Reactive Power Management

4.1 Introduction

In this chapter the proposed coordination procedure between TSO at EHV level and DSO at HV level to achieve a joint reactive power and voltage control in a regional system is illustrated. The first step in our research was to identify the voltage control method used by each SO in its own control area. As shown in Chapter 2, in Germany the transmission system voltage control is still based on a manual dispatch system [1]. In HV distribution systems the voltage control is also performed mainly manually or with uncoordinated local control of regulating devices, such as OLTC transformers. WPPs, which are connected mainly to the MV and HV level, are often still operated at $\cos \phi = 1$ or with a manual adjustment of the power factor. The coordination scheme here proposed is based on the basic assumption that modern optimization tools are available to both the TSO and DSO. This is true in most countries for the TSO, but still very rare for DSOs, even at HV level. In the proposed scheme, the two SOs use the following methods for voltage control:

- **DSO**: real-time OPF-based VVC controlling OLTC and DG
- **TSO**: centralized real-time OPF (similar to the Swiss system but real-time)

Both control systems can be modelled with the optimal power flow tool described in the previous chapter. The choice of a centralized OPF for the TSO has a two-fold justification: it is inspired to the Swiss system, where the DSOs are already actively involved in voltage control, and it is simpler to implement compared to a hierarchical voltage regulation system, such as the one in place in Italy. However, when applied to large systems, centralized schemes have several disadvantages compared to hierarchical systems as described in Chapter 2. In any case, *mutatis mutandis*, the present coordination scheme could be adapted also in presence of the secondary voltage regulation (even though the Italian system is structurally different, since the meshed subtransmission level is under the direct control of the TSO).

Established this, the goal is to develop a coordination mechanism to make these two optimization tools interact. Several complexities arise when considering a real case, such as: how to compute the reactive power flexibility of an HV distribution grid, how to take into account the influence of the transmission system on this flexibility, how to represent distribution grids in the TSO OPF, how to handle several connection points at T-D interface, coupled by the meshed electrical network, which type of setpoints consider, how to
achieve a feasible and fair compromise between TSO and DSO objectives, which are these objectives... and many more issues.

In the next sections a review of state-of-the-art research on TSO-DSO coordination for reactive power and voltage control including control of DG, as well as prescriptions from relevant grid codes are provided.

In conclusion to this introduction, the author would like to clarify a term that could be ambiguous for the reader: we have mentioned a couple of times the word flexibility (and many more will be mentioned in the following) and one may ask what is here meant with this term. It was deliberately used in a generic way, since we still do not know what exactly we define with flexibility, in this context it is for sure related to the ability to modify the reactive power exchange and voltages at T-D interface. But flexibility should be understood first of all as a general concept, of paramount importance in the current transformation of power systems towards a distributed generation paradigm: flexibility is, in the literal definition, the property of being susceptible of modification or adaptation, being adaptable. Flexibility is thus the ability to adapt to a contingent situation modifying some system properties. To be flexible, a system should be able to change some control variables in a certain range. If no margin of modification is present, the system is not flexible. But, an existing margin or potential is not enough: also a complementary concept, controllability, is required to achieve a real flexibility. Translated into our problem, this means to have in place not only flexible hardware, i.e., modern wind turbines with wide reactive capabilities, transformers equipped with OLTC, and on a higher level distribution grids able to modify reactive power exchange with the TSO. It is necessary also to have methods to control and harness this flexibility potential in a coordinated and optimal way for the system as a whole.

4.2 State-of-the-Art

Several studies investigate the reactive power exchange at the transmission-distribution interface, but, in most cases, they see the problem from a single-sided perspective, for instance from the DSO point of view only, considering stiff voltages in the TSO grid and pre-defined ranges of reactive power exchange to be kept [2], or voltage setpoints, however also fixed and assumed a-priori [3], [4]. Conversely, the problem can be studied from the TSO point of view only, neglecting distribution system constraints or assuming fixed flexibility values at the interface, as done in [5]. In [6], a PSO algorithm is proposed to control wind farms at 110 kV level to obtain a desired reactive power exchange with the transmission grid, namely a neutral reactive power balance. Wind farms are controlled in a different way depending on their position: WPPs close to the T-D connection points are controlled through Q setpoints, since their influence on the nodal voltage is very low, while WPPs far from connection points are controlled as PV nodes, with voltage setpoints. However, the transmission grid is modelled as an infinite bus with a stiff voltage at each Connection Point (CP). A neutral reactive power balance with the transmission grid is targeted also in [7], using a simplified version of the tool here presented. The transmission grid is also represented with a fixed equivalent and the performance is compared with the prescriptions of the Swiss regulation for transmission connected distribution grids and the limits of the DCC [8]. MO optimization is used to reach secondary objectives such as losses minimization and voltage profile smoothing. MPC control is proposed to reduce tap operations. However, the external equivalent is not updated and the general approach is still passive, with a fixed and predefined neutral exchange target.
4.2. State-of-the-Art

MPC is used also in [9] to control distributed generation power factor. A first coordination mechanism between TSO and DSO is studied in the TWENTIES project [10], based on a test case in Denmark: here the problem is addressed using updated grid equivalents to find the optimal reactive power flow and voltage values at each CP. However, the equivalents used are very rudimentary and the coupling between different CPs from the DSO point of view is completely neglected. In the Swiss system [5] the TSO perspective is adopted: distribution grids are represented as virtual generators corresponding to each CP in the TSO off-line OPF. These generators have a fixed active power output and a variable Q output, similarly to traditional synchronous generators. In the latter case, however, Q limits are computed using detailed capability curve models once the active power output from market dispatch is known. While for active distribution CPs, "fixed reactive power limits" are adopted [5]. From the OPF results, voltage setpoints \( V_{opt} \) are derived for both distribution CPs and traditional generators. Fulfillment criteria, penalties and remunerations are also applied, as described in Subsection 2.4.2. Notably, given one distribution grid with several CPs, the DSO can also choose to define only a subset of them as active participants in the voltage control; for the others passive participation rules apply.

Voltage setpoints at T-D interface are used also in [3] comparing centralized and autonomous solutions based on \( Q = f(U) \) control. Fixed voltage setpoints for \( Q(U) \), obtained through a scenario analysis, are compared to setpoints coming from an on-line OPF, with the same goal of supporting target voltages at T-D interface. This contribution is interesting because combines a medium-scale scale grid model including distribution and transmission level and the idea of controlling WPPs with \( Q(U) \) optimization to support the transmission voltage. However, the study is based on several simplifications and it does not address a real coordinated optimization: first of all the voltage setpoints at T-D interface are assumed known a-priori and not determined via optimization by the TSO, also the synchronous generators in the TSO grid follow a fixed voltage setpoint determined arbitrarily (1.1 p.u.). In addition to that, the IEEE 30 bus system used as test case is manipulated to obtain several radial distribution networks out of a single meshed network with multiple CPs: therefore the problem of handling several CPs and the coupling between them is totally neglected. This is a non-trivial assumption since at HV level, in Germany, multiple CPs and meshed networks are the standard.

A medium-scale system is used also in [11] to study a joint voltage control between MV DSOs and the TSO at HV level in France. In this work a real-time MPC VVC is first developed to control the reactive power exchange at T-D interface leveraging on DG reactive power, OLTC transformers and capacitor banks at MV-HV substations. This tool is later associated to a OPF in the transmission system in charge of defining the reactive power exchange setpoint for each distribution grid in order to improve the HV voltage and keep a neutral reactive balance at the HV-EHV interface. A coordinated scheme is thus implemented. However, the problem of evaluating the real-time flexibility that the distribution system can provide is skipped, due to the complexity of this task. A fixed value arbitrarily determined is used instead. This work is an important inspiration though, even if the complexity of MV radial networks is much lower than the one faced in our problem.

An approach to compute DSO flexibility is proposed in [4] for a real German 110-kV grid using optimal power flow techniques and test cycles: the maximum overexcited and under-excited behaviour of the WPPs determines the flexibility range in reactive power exchange; OLTCs are also incorporated assuming DSO control and, of course, technical
limits (e.g., on nodal voltages) are considered. The overall distribution network flexibility is thus computed, i.e., the sum of reactive power over the multiple CPs. It is specified that such a global flexibility statement is not very useful in case the TSO needs to incorporate it in its on-line OPF, but it is adequate in case of manual dispatch (as currently possible in Germany). The solution adopted is to find the minimum value of the flexibility range, e.g., over one year, and provide this to the TSO. For instance, in the case of a 24h test cycle, the minimum value of 288 Mvar will be the communicated flexibility range, as shown in Figure 4.1 [4]. This leads to a very conservative result in general, especially if phase shifting capability of WPPs (i.e., STATCOM functionality as explained in Section 2.6) is not available and flexibility depends not only on network conditions but also on wind availability. This work was extended in a follow-up paper [12], where the control of wind farms through the OPF was used to evaluate the voltage support capabilities at T-D interface modelling also a little portion of the connected transmission system. Compliance with the Swiss system is verified, and the importance of controlling in a coordinated way OLTCs and WPPs is shown. However, once again voltage setpoints are defined arbitrarily and no association with a TSO OPF is established.

The problem of computing DSO flexibility is also addressed in other literature sources using optimization techniques, such as in [13], where the equivalent capability chart of a distribution grid is derived using AC OPF to be used as insight for transmission planning studies. Estimation of potential reactive power provision from distribution grids on a day-ahead basis is addressed in [14] using OPF techniques, combined with probabilistic weather forecasts. The reactive potential for a LV distribution grid is estimated in two scenarios, considering the VDE requirements for connected DG (\(\cos \phi \leq 0.95\) inductive or capacitive) and inverter phase-shifting capabilities (where the \(Q_{\text{max}} = \tan \phi_{\text{max}} \cdot P_{\text{max}}\) is always available). It is shown how forecast errors have a larger impact in the former case, while lower in the latter case, when DG potential is not dependent on energy source availability, i.e., on active power output \(P_g\).

It can be concluded that most existing studies focus on a reduced part of the problem, adopting a passive approach to DSO participation in reactive power management, assuming fixed set points or targets which are computed without considering actual DSO flexibility potential, considering a stiff transmission system, and so on. Conversely, an active inclusion of distribution grids in the TSO voltage regulation mechanism implies that a flexibility statement is provided to the TSO in the proper time horizon in order to be used for the determination of setpoints through the TSO scheduling or real-time voltage...
regulation process. This requires a coordination between the two SOs. Only in this way, the distribution grids can be considered real competitors of conventional power plants in the reactive power provision to the TSO.

4.3 Regulatory Framework for TSO-DSO Coordination

The topic of TSO-DSO coordination at T-D interface is addressed at national level by national grid codes and at European level by the DCC (Demand and Connection Code) [8] and the System Operation Guidelines [15], whose updated version entered into force on September 14th 2017. Many other studies, position papers and informal guidelines have been published by expert associations such as ENTSO-E, European Distribution System Operators (EDSO), Eurelectric and others. The ensemble of these sources is a useful blueprint of current trends in Europe on the topic of TSO-DSO coordination, not only limited to the voltage control task. The huge amount of published material suggests how topical is this issue in the European electricity system. The reason is once again the development in distributed generation from renewable sources connected mainly at distribution level.

Starting from formal regulations, the DCC entails the following prescriptions in terms of reactive power management, written in article 15.1(b):

*For transmission-connected distribution systems, the actual reactive power range specified by the relevant TSO for importing and exporting reactive power shall not be wider than:

I 48 % (i.e. 0.9 power factor) of the larger of the maximum import capability or maximum export capability

II 48 % (i.e. 0.9 power factor) of the larger of the maximum import capability or maximum export capability during reactive power export (production)*

Points 15.3 and 15.4 also specify:

"3. Without prejudice to point (b) of paragraph 1, the relevant TSO may require the transmission-connected distribution system to actively control the exchange of reactive power at the connection point for the benefit of the entire system. The relevant TSO and the transmission-connected distribution system operator shall agree on a method to carry out this control, to ensure the justified level of security of supply for both parties. The justification shall include a road-map in which the steps and the time-line for fulfilling the requirement are specified.

4. In accordance with paragraph 3, the transmission-connected distribution system operator may require the relevant TSO to consider its transmission-connected distribution system for reactive power management."

It is thus envisioned a double mechanism: a passive one, where minimal reactive power limits are stated, and an active one which is not mandatory (by now) and involves a direct participation of the DSO in system voltage control. As for the System Operation Guidelines [15], article 29.5 on Obligations of all TSOs concerning voltage control and reactive power management in system operation states:
"Each TSO shall agree with each transmission-connected DSO on the reactive power setpoints, power factor ranges and voltage setpoints for voltage control at the connection point between the TSO and the DSO in accordance with Article 15 of Regulation (EU) 2016/1388. To ensure that those parameters are maintained, each transmission-connected DSO shall use its reactive power resources and have the right to give voltage control instructions to distribution-connected Smart Grid Users (SGUs)."

Article 29.8 stresses the importance of TSO-DSO coordination on this regard:

"Each TSO shall determine the voltage control actions in coordination with the transmission-connected SGUs and DSOs and with neighbouring TSOs."

Chapter 3 defines also relevant data to be exchanged between TSO and DSO, classifying them between structural and real-time data. It also defines an observability area of the transmission-connected distribution grid for the TSO. Article 109 rules reactive power ancillary services, defining relevant equipment the TSO can use for operational security and efficiency, distribution grids are included:

"In order to increase the efficiency of operation of its transmission system elements, each TSO shall monitor:

(a) The available reactive power capacities of power generating facilities
(b) The available reactive power capacities of transmission-connected demand facilities
(c) The available reactive power capacities of DSOs
(d) The available transmission-connected equipment dedicated to providing reactive power
(e) The ratios of active power and reactive power at the interface between the transmission system and transmission-connected distribution systems"

An informal guideline on Reactive power management at T–D interface was published by ENTSO-E in 2016 [16]. It states the importance of distribution system participation in voltage support affirming that "overall system performance is improved, either technically or economically, if appropriate measures are taken concerning reactive power management for transmission connected distribution networks"[16]. The trends mentioned in Chapter 2 concerning RES deployment and synchronous generators decreasing operating hours are described, leading to the conclusion that reactive power procurement is becoming more and more challenging for TSOs in order to cope with their own reactive power needs and those of connected distribution grids and demand facilities.

A general framework for coordinated reactive power management is here proposed based on the steps shown in Figure 4.2. This procedures is based on the the important principle of optimisation between highest overall efficiency and lowest total costs for all parties involved. The high level allocation is performed taking into account also the principle of proximity, since reactive power cannot be transported over long distance. The procedure proposed in this work is inspired to these guidelines and reflects their spirit.

In the position paper on General Guidelines for reinforcing the cooperation between TSOs and DSOs [17], the key enablers for TSO-DSO cooperation are grouped in three sectors:
4.4. Proposed Coordination Procedure between TSO and DSO

(a) **Coordinated access to resources**: SOs should exploit a common pool of demand and supply resources to meet their own needs. Since respective actions on these shared resources have mutual influence, these should be coordinated.

(b) **Regulatory stability**: clear, efficient and transparent regulatory guidelines should be in place to avoid inefficient investments.

(c) **Grid visibility and grid data**: data gathering and exchange should be improved so that TSOs and DSOs receive adequate data from each other.

Concerning the last point mentioned a lot of regulatory activity is underway. Coordination requires knowledge and knowledge is not possible without proper data. It is a very delicate topic, since a lot of parties are involved and privacy of customer data as well as secrecy of proprietary data of involved firms must be preserved. In a recently published report commissioned by ENTSO-E to the consulting firm Thema [18], a complete overview of European current trends on this topic is described. Useful data are classified between Meter, Grid and Market data and needs of concerned actors for each class are identified. The exchange can be performed through distributed interactions (via agreements between parties) or via a central Data Exchange Platform (DEP). The report suggest the preference of centralized platforms due to their efficiency. As shown in Figure 4.3, DEPs are still not widely diffused in Europe, concerning this aspect Italy is a pioneer along with Ireland, Denmark and the Netherlands. Other useful documents dealing with data exchange and coordination between TSO and DSO are the TSO–DSO data management report [19] and the position paper by EDSO *Coordination of transmission and distribution system operators: a key step for the Energy Union* [20].

4.4 Proposed Coordination Procedure between TSO and DSO

From the previous sections we should have gained a good overview of the coordination problem between TSO and DSO for reactive power management, both in terms of state-of-the-art solutions and existing grid codes and guidelines. The problem is indeed quite
complex and, before presenting the solution developed, we want to sum up and enumerate here some of the main issues to be addressed:

1. The optimization should involve different grid operators controlling each one a portion of the system and some control variables.

2. To reach global optimality the different actions should be coordinated since there is a strong mutual influence.

3. The potential contribution of the DSO (flexibility) should be computed somehow in real-time.

4. The TSO needs to know in the proper time horizon the flexibility potential of distribution grids to dispatch them efficiently together with other sources.

5. The interface between transmission and distribution is made of several CPs, coupled by the meshed networks at both voltage levels (see Figure 4.4).

6. When conflicting objectives are sought by TSO and DSO, fair and efficient use of control resources should be achieved.

7. Both operators do not want to disclose proprietary data, e.g. network data.

8. The unavoidable exchange of information should be kept to a minimum to improve robustness.
9. Mathematical techniques traditionally used for multi-area optimization often do not meet practical applications requirements (e.g., time of convergence).

All these issues and considerations were taken into account in the design of the present coordination scheme. In particular, the second point is paramount. Once established that both operators make use of an optimization tool, the necessity to coordinate these optimizations is evident: actions taken by the TSO affect the optimality of measures adopted by the DSO, and to a lesser extent, vice-versa. If we consider a mechanism similar to the Swiss system [5], where a reactive power capability is associated to each distribution transformer and then it is used by the TSO to find the optimal voltage setpoint, it is clear that this flexibility statement depends on the configuration of the transmission grid and the voltage at the interface points. At the same time, the results of the TSO OPF will take advantage of the flexibility offered by the DSO and will change slightly with different values of flexibility. Constraints and requirements of both systems should be taken into account. A simple solution to this problem could be to assume fixed flexibility ranges the DSO can provide, computed for instance using test cycles like proposed in [4]. Constant reactive power capabilities are also used in the Swiss system. However, this solution is quite inaccurate and could be too conservative or lead to infeasibilities. It is in general not very suitable to accommodate the variability and unpredictability of reactive power flows, especially when phase shifting capability of DG is not available and the reactive power limits of DG units change according to wind or solar intensity. Therefore, as already stated in the conclusion of Chapter 2, the problem demands for real-time solutions.

The scheme developed is targeting practical applications and should be able to get smoothly integrated in current or future system operation procedures. The need of data exchange, which arises from the nature of the physical problem, should be kept to a minimum for security concerns. Notwithstanding this, as prescribed by the DCC, a communication system must be in place between TSO and DSO to communicate reactive power flexibility and setpoints in real time. The proposed procedure is made of three sequential steps: reactive power flexibility assessment by DSO, TSO OPF and DSO OPF.
4.4.1 DSO Flexibility Assessment

Firstly, a reactive power flexibility assessment is performed every 15 minutes by the DSO using its own OPF tool. In presence of \( N \) connection points, the flexibility is computed maximizing and minimizing in sequence the overall reactive power exchange between the transmission and distribution grid, using the objective functions (4.1) and (4.2):

\[
Q_{\text{ext},t}^{\max} = \max_u \sum_{t=0}^{T} \sum_{i \in M} \sum_{j \in K} U_{i,t} U_{j,t} [G_{ij,t} \sin(\theta_{i,t} - \theta_{j,t}) - B_{ij,t} \cos(\theta_{i,t} - \theta_{j,t})] \tag{4.1}
\]

\[
Q_{\text{ext},t}^{\min} = \min_u \sum_{t=0}^{T} \sum_{i \in M} \sum_{j \in K} U_{i,t} U_{j,t} [G_{ij,t} \sin(\theta_{i,t} - \theta_{j,t}) - B_{ij,t} \cos(\theta_{i,t} - \theta_{j,t})] \tag{4.2}
\]

Control variables in this subproblem are controllable wind farms and OLTC transformers. After this first step, results are communicated to the TSO in the form of an overall range for the whole grid and corresponding specific ranges for single connection points to be used as capability limits in the TSO optimization, based on corresponding \( Q \) flows at each CP according to eq. (4.3) and (4.4):

\[
Q_{\text{ext},t}^{\max} = Q_{1,t}^{\max} + Q_{2,t}^{\max} + \cdots + Q_{N,t}^{\max} \tag{4.3}
\]

\[
Q_{\text{ext},t}^{\min} = Q_{1,t}^{\min} + Q_{2,t}^{\min} + \cdots + Q_{N,t}^{\min} \tag{4.4}
\]

The choice to consider the overall maximum and minimum lies in the fact that, in case of multiple CPs and meshed systems, which is the standard in 110 kV grids, these are interrelated and it is not possible to define the flexibility of a single CP unless the others are determined. This is a very important point to avoid infeasibilities during the optimization chain. The identified flexibility ranges are theoretically narrower than the correspondent ranges computed maximizing and minimizing the reactive power exchange over a single connection point per time. However, their sum respects the global reactive exchange limits identified in this step, and we are thus sure that the reactive dispatch request (in terms of total sum) from the TSO can be met in any circumstances.

In this step, as well as in the following DSO optimization, the overall regional grid model shown in Figure 4.4 is used, where only variables under DSO control are optimization variables: the set \( A \), defined in Chapter 3, includes only the distribution grid. This assumption is equivalent to the use of an accurate reduced model of the TSO network, which is updated at each time step based on measurements at the interface and data coming from the TSO itself. Such reduced models with real-time definition will be likely available to system operators in the near future, as envisioned in the new EU System Operation Guideline [15], as described in the previous Section.

A graphical representation of this step is shown in Figure 4.5: the DSO uses its own optimization tool having as input the state-estimation of the system based on measurement data, and computes the maximum and minimum reactive power exchange over the multiple CPs. The result is the flexibility statement, above described, which is sent to the TSO over the communication link between the two SOs. In this step the control actions are not actually performed, the OPF tool is used in simulation mode. Finally, it should be pointed out that the computed range is limited only by technical constraints, which can be voltage limits, tap operation limits, and, naturally, reactive power capabilities of WPPs. This point will be further discussed later on.
4.4. Proposed Coordination Procedure between TSO and DSO

4.4.2 TSO OPF

The TSO uses the reactive flexibility communicated for the whole grid and the values declared for each connection point to run its OPF. The distribution grid CPs are represented as virtual generators, as shown in Figure 4.6: each virtual generator has a fixed active power output and a reactive power output defined by an initial value (the one measured at the interface) and a range $[Q_{cp}^{min}, Q_{cp}^{max}]$, communicated by the DSO. This is similar to the solution adopted by SwissGrid, but the reactive power range is computed in real-time for each CP.

The TSO runs its OPF dispatching distribution virtual generators as well as other reactive power sources under its control. Generally, these can include SGs, FACTS, shunt compensators, OLTC transformers, and so on, as detailed in Chapter 2. In this application, however, the TSO controls only a certain amount of SGs. These are treated as PV generators, i.e., they follow a voltage setpoint which is defined by the TSO through its
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OPF at each time step. Non-regulating generators are treated as PQ generators with a null or predefined reactive power exchange. As for the determination of setpoints for the DSO, the additional constraint of eq. (4.5) is enforced:

\[ Q_{\text{ext},t}^{\text{min}} \leq Q_{\text{ext},t} \leq Q_{\text{ext},t}^{\text{max}} \]  \hspace{1cm} (4.5)

This is to ensure that the deriving reactive power flows between the transmission and the distribution grid fulfill the identified capability limits of the transmission connected distribution grid. Optimal setpoints are then found for both regulating SGs in the TSO grid and distribution grids. The optimization problem is configured as a NLP problem, since OLTC transformers are considered under DSO control and thus are not a control variable of this problem. This is an assumption of the author, since, in the current practice, they can be under the control of both operators depending on individual cases. Thus, all the constraints related to tap positions and operations are obviously not included, even though it would not be a problem to include them also in this case. In Figure 4.7 the present step of the optimization chain is represented, showing how the TSO dispatches SGs and distribution grid CPs in a coordinated way, based on its optimization results. In this figure, in particular, voltage setpoints are issued also for the DSO.

![Figure 4.7: Scheme of the second step: the ORPF computed by the TSO](image)

As for the TSO objective function, several objectives can be found in literature for ORPF problems [21], [22], among the most common we find: losses minimization, cost of reactive power procurement minimization, minimization of quadratic deviations from a voltage profile and maximization of loadability margins (refer also to Section 3.2). In the presented simulations, the OF of the TSO was built assuming a main interest in losses minimization and considering the cost of reactive power procurement, from both SGs and distribution grids, equal to zero. This reflects the current status in some countries, such as Italy, while in some countries, such as Switzerland and also Germany, reactive power
is remunerated through a regulated price. Market mechanisms for reactive power are also used in some countries (see Section 4.5).

4.4.3 DSO OPF

The final step of the coordination scheme is represented by the DSO OPF. In this step the DSO runs its optimization tool to find the optimal dispatch of its resources, namely controllable WPPs and OLTC transformers (which are under its control, as previously mentioned). The problem to be solved is thus a MINLP problem. The optimization is aimed at achieving a dual-goal: on the one hand fulfilling the targets received from the TSO to support transmission voltage, on the other hand fulfill the DSO own internal objectives related to reactive power management and voltage control.

Focusing on the first component, the TSO targets, can have three different forms:

- Reactive power sum (overall network)
- Voltage targets (for each CP)
- Reactive power targets (for each CP)

Voltage setpoints are, for instance, used in the Swiss system for active distribution grids [5]. Reactive power setpoints are instead proposed in [11] and [4]. They can be stated as a global sum over the whole network or as individual targets: in the first case, results in terms of Q flows at T-D interface would be less close to the optimal values requested by the TSO, but the DSO would enjoy more flexibility and possibly achieve a better result in terms of internal performance. In the second case, Q flows should be closer to TSO targets, but the limits imposed by the coupling electrical network could lead to infeasibilities. Actually, it is important to point out that the TSO has no clue about the coupling between virtual generators on the HV side, and the setpoints computed could be individually not achievable for the DSO.

This brings in another question: whether to translate the setpoints coming from the TSO as hard constraint of the DSO optimization problem or include them in the MO function. For individual targets (either based on voltage or reactive power) the choice is simple: hard constraints are simply not feasible and these setpoints have to be translated into the OFs (4.6) and (4.7) based on minimization of the sum of quadratic deviations from individual targets.

\[
\begin{align*}
    f_{V_{ext}} &= \sum_{t=0}^{T} \sum_{i \in K} \left[ U_{i,t} - U_{i,t}^{set} \right]^2 \\
    f_{\Delta Q_{cp}} &= \sum_{t=0}^{T} \sum_{cp} \left[ Q_{cp,t} - Q_{cp,t}^{set} \right]^2
\end{align*}
\]

As for a cumulative reactive exchange target, although generally feasible to fulfill it when set as a hard constraint, simulations show it is highly preferable to avoid that, in order to allow larger flexibility to the DSO and reduce tap operations. In case of model predictive control (MPC), it is also preferable for convergence reasons. Thus, the OF (4.8) is introduced, where \( Q_t^{set} \) is a global reactive power target:
\[ f_{\Delta Q} = \sum_{t=0}^{T} \left[ \sum_{cp} Q_{cp,t} - Q_{ct}^{ext} \right]^2 \]  

Function \( f_{\Delta Q}, f_{V_{ext}} \) and \( f_{\Delta Q_{cp}} \) are the same ones defined in the OPF mathematical model in Section 3.7. In the present study all the different types of setpoints were tested through simulations.

As for the second part of the MO function, related to the internal DSO objectives, also in this case many different OFs can be considered, similar to the ones of the TSO, except maybe the loadability margin maximization and OFs related to voltage stability. However, the choice of the MO function and weights corresponding to each OF, are paramount in determining the scheme performance and should be handled very carefully, as stated in Section 3.4. Therefore, in order to reduce complexity in defining OF weights, the main focus in setting the DSO internal objectives was put on indicators that determine an effective cost for the DSO itself: active losses \( (f_{\text{losses}}) \) and tap operations \( (f_{\text{Tap}}) \).

In Figure 4.8, the scheme of this last step is shown. Using field measurements and setpoints coming from the TSO, an ORPF for the transmission connected distribution grid is computed, in order to calculate optimal tap positions of OLTC transformers and setpoints for controllable wind farms in order to minimize the chosen OF. In this case the OPF is not in simulation mode: the control actions defined are actually sent to each unit and applied in real-time. Wind farms can be controlled either with Q setpoints or voltage setpoints for the \( Q = f(U) \) control law. In both cases the setpoint is processed by the wind park controller and individual setpoints for each WT and other installed equipment (STATCOM, OLTC transformers, capacitor/reactor banks) are issued in order to provide the required amount of reactive power at the PCC.
4.4. Proposed Coordination Procedure between TSO and DSO

4.4.4 Summary on the Coordination Procedure

In the previous subsections, the single steps of the coordination procedure were detailed. We would like here to explain some assumptions and concepts related to the implementation of the whole interaction chain. A scheme of the whole system can be appreciated in Figure 4.9, which was already shown in the introduction. Now the reader can have a better understanding of the details.

![Figure 4.9: Scheme of the proposed interaction between TSO and DSO for coordinated operation](image)

The proposed scheme allows to coordinate the reactive power and voltage control procedures of the TSO, in charge of the EHV system management, and the DSOs managing HV (110-kV) distribution grids. A flexibility potential is computed by the DSO and communicated to the TSO considering real-time network and weather conditions. The TSO, using ORPF techniques, finds the best dispatch of SGs, distribution grids and other possible resources considering its OF, e.g., minimizing real losses in the EHV system. Each distribution CP is treated independently as a virtual generator in the TSO OPF, without any direct knowledge of the network structure at HV level. Only eq. (4.5) introduces a global constraint on overall reactive exchange of the whole distribution grid. Several types of setpoints can be used for distribution CPs, based on voltage or reactive power values. The choice of a particular type depends on requirements and procedures peculiar of each power system. Finally, setpoints are sent to the DSO (as well as to SGs of course) and the DSO computes its OPF to find the best dispatch for WPPs and OLTC transformers.

Within the simulation environment, at the initial time step, these steps are preceded by a system initialization, which optimizes the whole medium-scale system controlling at the same time all control variables. This step is performed only at the beginning of the simulation and it is necessary in order to compute optimal initial tap positions. Then, only the three steps are repeated at each time interval of 15 minutes, as shown in Figure 4.10.

On the left side of the blocks diagram, the employed grid model in each optimization is displayed. The medium-scale model is used in the DSO optimizations, but such a model is not available to the DSO, since proprietary TSO data cannot be disclosed. However, the assumption made is equivalent to the use of an accurate reduced grid model (e.g. using an extended Ward equivalent, see Section 3.6) which is updated at each time interval based on measurements. An example of such a technique was presented in Section 3.6 based
on the work in [23]. On the right side instead, the information communicated between the TSO and DSO control centre is shown. A key point of the developed mechanism is that minimizes the data exchanged. The dashed feedback line indicates the possibility of running the present scheme in closed loop operation iterating the same procedure at each time step. However, provided the system is initialized and the optimization is performed often enough (e.g., each 15 minutes), variations in system variables between successive time steps are usually small and an open loop control can be employed effectively, as shown in Chapter 5.

![Scheme of the proposed interaction between TSO and DSO for coordinated operation](image)

**Figure 4.10: Scheme of the proposed interaction between TSO and DSO for coordinated operation**

### 4.5 Market Models for TSO-DSO Coordination

#### 4.5.1 Introduction

The reactive power provision by DSOs to the TSO leveraging the potential of distribution connected DG should be considered as an ancillary service (AS). The proposed mechanism allows the TSO to harness this resource in alternative or in competition with traditional providers of this service. The need of coordinating all the concerned parties (TSO, DSOs, DG) and regulate this service from an economic perspective is evident.

Today ancillary services are distinguished between technical requirements, which should be provided according to grid codes and are not remunerated, and remunerated services, which are paid with regulated tariffs or purchased through competitive mechanisms within an ancillary service market. As mentioned in the beginning of this chapter, the voltage control service can belong to any of these classes depending on national regulations: in Italy it is mandatory and not remunerated, in Switzerland and Germany is remunerated through regulated tariffs (an idea of reactive power prices in Switzerland is included in Section 2.4.2). Reactive power AS markets are instead used in UK, Australia and some portions of the US, to procure at least part of the reactive power required by the ISO [24].

However, in most systems, reactive power and voltage control AS providers, either remunerated or not, are still limited to synchronous generators. Very few systems conceive the possible provision of this AS by distribution systems and distribution-connected DG. Such an example is the Swiss system. The growing interest in involving DG in ancillary services provision has led to the definition of several market mechanisms to allow different
SOs, such as TSOs and DSOs, to utilize this potential in an efficient and coordinated way. The role of the DSO is becoming thus more and more important [25], from a grid operator with responsibilities in the reliability and secure operation of the distribution level alone, the DSO is gradually moving to new roles of system manager, data manager and technological enabler taking on new responsibilities traditionally belonging exclusively to the TSO. The DSO could also take part in establishing new local AS markets with the role of market officer, neutral market facilitator, or contributor to system security [25]. As market officer, the DSO can contract the provision of AS from DG for local purposes. As neutral market facilitator, the DSO supports the participation of resources connected to the distribution grid to AS markets. While, as contributor to system security, the DSO can use local resources to contribute in system-wide tasks (e.g., frequency stability). As well as for the TSO, rules concerning roles separation should apply also for the DSO, meaning he cannot be on both sides of the market acting at the same time as commercial provider and purchaser of AS [25].

4.5.2 Market Models Description

Within the European project SmartNet [25], five different market mechanisms were conceived for TSO-DSO coordination:

- Centralized AS market model
- Local AS market model
- Shared balancing responsibility model
- Common TSO-DSO AS market model
- Integrated flexibility

In the following, these market structures and their applicability to the voltage control AS are briefly described. Next, these strategy will be compared with the coordination mechanism employed in our scheme and some interesting considerations will emerge.

Centralized AS market model

The centralized AS market managed by the TSO is extended to distributed resources. The TSO has a direct access to DG owners and contracts with them AS provision. The DSO can also access these resources for local purposes but in a different time frame, not in real-time or close to real-time. The DSO is thus not involved but for a pre-qualification process to avoid that ancillary services, activated by the TSO from DG, cause some violation in the DSO grid.

Local AS market model

In this model the DSO creates a local AS market where DG and distributed resources connected to the distribution system can bid their offers. The DSO procures first flexibility for local AS, and offers the remaining flexibility to the TSO for system-wide services. He has thus a priority access to distributed resources, and acts as trader/aggregator for DG towards the TSO. This scheme gives more importance to the DSO and prioritizes its objectives: only residual flexibility is offered in the centralized market and DSO constraints are taken into account.
Shared balancing responsibility model

In this scheme the TSO transfers part of the "balancing responsibility" to the DSO for the distribution grid area. This means the DSO has to fulfill a pre-defined exchange profile agreed with the TSO, using DG flexibility acquired through a local market. The exchange schedule is defined in agreement between TSO and DSO or by the TSO only, for each CP or for the sum of them. It is based on energy market outcomes, historical data and forecasts of load and generation. In this scheme the TSO is responsible of balancing the transmission system only, and has no direct access to distribution connected resources.

Common TSO-DSO AS market model

This market model aims at building a common AS market for both SOs. This common market would be used by both TSO and DSO to procure the required flexibility. This model has the advantage of seeking the optimal allocation of flexibility from a global system perspective, without any SO interest prioritization (as requested also by ENTSO-E [16]). Two variants are envisioned in terms of market clearing process: either based on a single optimization encompassing all constraints of distribution and transmission level (centralized variant), or based on two separate optimizations, each one including resources and constraints of a particular system, and exchanging information to achieve the best overall outcome (decentralized variant). The centralized variant is an extension
4.5. Market Models for TSO-DSO Coordination

Figure 4.13: Scheme of the Shared balancing responsibility model, based on [25]

of the centralized AS market model, which includes distribution constraints. While the decentralized variant is a version of the local AS market model where the DSO has no access priority on DG flexibility.

Figure 4.14: Scheme of the Common TSO-DSO AS market model, based on [25]

Integrated flexibility

In the integrated flexibility model, an AS market managed by a third party market operator is established. TSO, DSOs and aggregators take part to this market without formal distinction between regulated and liberalized operators. All flexibility resources take part to the same market, and the resources are allocated to the highest bidder.

Not all these models are suitable for application to the voltage control service due to the peculiarity of this service, only three models are proposed in this case (see Table 4.1): the local AS market model, the shared balancing responsibility model, the common TSO-DSO AS market model. The reason behind this choice is that voltage control is a strongly location based AS, and therefore, models which do not conceive a direct DSO involvement, are not feasible.

Within the local AS market model, the DSO first procures the required services from DG for voltage control of its own system, later offers to the TSO the remaining reactive
power flexibility. In the shared responsibility model, a schedule of reactive power or voltages at the CPs is sent from the TSO to the DSO and the DSO has to fulfill it leveraging on DG services procured in the local market (or demanded as technical requirements). Finally, the common TSO-DSO market implies that there is no prioritization in the usage of DG resources, therefore the DSO is willing to offer an amount of reactive power also at the expenses of higher losses in its system (compared to the local AS market model).

A similar classification is provided in [26] (in Italian), where three models are proposed very similar to the centralized AS market model, the local AS market model, and the shared balancing responsibility model in the SmartNet denomination.

4.5.3 Market Models for the Developed Coordination Procedure

This part intends to answer the following question: which market structure could be adopted to regulate the AS provision within the coordination scheme developed in this thesis? The goal is achieving a fair coordination between TSO and DSO, ensuring the optimal use of flexibility resources from a system perspective. This aspect is paramount and it is pointed out also by ENTSO-E in [16], where it is stressed that “this aspect should be considered from the point of view of the global system benefits and not from individual owner/operator interest”.

Table 4.1: Summary of AS market models for TSO-DSO coordination

<table>
<thead>
<tr>
<th>Market Model</th>
<th>Voltage Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Centralized AS market model</td>
<td>–</td>
</tr>
<tr>
<td>Local AS market model</td>
<td>√</td>
</tr>
<tr>
<td>Shared balancing responsibility model</td>
<td>√</td>
</tr>
<tr>
<td>Common TSO-DSO AS market model</td>
<td>√</td>
</tr>
<tr>
<td>Integrated flexibility model</td>
<td>–</td>
</tr>
</tbody>
</table>

Figure 4.15: Scheme of the Integrated flexibility model, based on [25]
4.5. Market Models for TSO-DSO Coordination

In Section 4.4 it was not explicitly mentioned any bidding process or remuneration form to apply to the presented scheme. The problem was mainly discussed from a technical perspective. We can now compare the scheme with the AS market models identified in the previous subsection. The procedure developed, in the form so far presented, can resemble the structure of the shared responsibility model, since the OPF setpoints can be considered as the exchange profile schedule which should be fulfilled by the DSO. In our case this schedule is agreed on the basis of a coordinated optimization, thus reflecting limits and constraints of distribution systems (and not univocally determined by the TSO, as done by SwissGrid).

The coordination mechanism could also resemble the common TSO-DSO market model, in its decentralized variant, where the flexibility is allocated to each operator based on two coupled but separated optimizations. The similarity is underlined by the fact that also in our scheme the DSO is willing to offer flexibility also at the expenses of its own losses or additional tap operations. As a matter of fact, the flexibility computed in step 1, and offered to the TSO, is limited only by technical constraints, opportunity-cost considerations are not taken into account in the described version. This could be a limit of the presented scheme, implying an imbalance towards TSO interests. In terms of losses, for instance, the risk is that, in order to decrease slightly the losses in the transmission system, a significant increase of losses could be incurred in the distribution grid. This becomes more important when a large number of distribution grids are involved in the coordinated control scheme.

In the next chapter, two different DSO strategies will be simulated, adjusting the OF weights in the DSO OPF in step 3, to represent a more collaborative or greedier behaviour of the DSO towards the TSO. However, this method is not optimal since the DSO strategy is applied in the last step, after TSO actions have been determined, implying a deviation from the TSO dispatch orders and a possibly non-optimal coordination. This choice was motivated by the intention to show the whole flexibility potential the DSO can offer. However, the willingness of the DSO to provide flexibility should transparently emerge from the flexibility offer itself in step 1: this could be achieved in two ways:

- **Limiting the amount of flexibility** from the technical maximum to a value determined including losses and/or tap operations limits (this is already done to a certain extent setting the maximum of one tap operation per time step).

- **Setting a price for each offered Mvarh** reflecting the cost incurred by the DSO to provide it at the T-D interface (always taking into account losses and tap operations and other possible costs).

Both methods, or a combination of them, lead to a scenario quite similar to the local AS market model, where the DSO has a priority access to DG resources, and can offer the remaining flexibility to the TSO based on its interests. Therefore, it can be concluded that the technical coordination procedure developed in this chapter to achieve a joint voltage control actively including distribution connected wind farms is suitable to be used in all the three possible market mechanisms identified in [25], applying slight modifications.

In chapter 5 the simulation setup and the simulation results for the validation of this coordination scheme are presented.
Bibliography


Chapter 5

Simulations

“As engineers, we were going to be in a position to change the world - not just study it”
Henry Petroski, Engineer

This chapter is aimed at describing the simulation setup used for simulating and validating the proposed coordination procedure and the simulation results. Section 5.1 introduces the method and the software tools used for simulations, Section 5.2 presents the system studied and features of the grid model used, and Section 5.3 describes the time series data used in simulations. Section 5.4 describes the scenarios investigated and Section 5.5 some general settings and assumptions used. Finally, Sections 5.6.1, 5.6.2 and 5.6.3 provide the simulations results.

5.1 Introduction on Simulation Methods and Softwares

In this Section a general introduction on simulation methods is provided. In Chapter 3 it was already described the mathematical model of the OPF tool used. This tool was modelled in GAMS [1], a popular commercial software, and the solver used, for both MINLP and NLP problems was KNITRO [2]. As it is shown in Figure 5.1, two other softwares were needed: DIgSILENT PowerFactory [3] and Matlab® [4].

![Figure 5.1: Work-flow and tools used in the simulations](image)

First of all, the grid model was created in PowerFactory. As it will be explained in detail in the next Section, it is a medium-scale model including a 110-kV distribution grid
and a portion of the German transmission system. The two separate models, coming from different sources, were merged and combined together in PowerFactory. A different version was built, starting from the same medium-scale model, with a reduced equivalent of the distribution grid based on virtual generators (external grids) for each CP. This model is needed in the TSO OPF, as explained in Chapter 4. PowerFactory was fundamental to implement and verify the reduction and modification process comparing load flow results.

The different grid models were then exported from PowerFactory to Matlab using a specifically designed DigSilent Programming Language (DPL) filter realized at IWES. The format used is the \textit{mpc} format, compatible with the Matpower [5] tool in Matlab. Matpower is a tool for steady-state power system analysis and optimization, widely used in the Academia. The grid data are then loaded by other Matlab codes and combined with several other settings, options and time series data to build the \textit{.gms} input files for the optimization. In total around 2000 lines of Matlab code were needed just to handle this input data creation part. The GAMS input files are divided in two types: a unique file, \textit{gms\_GridDATA}, with general simulations settings and parameters declaration, and the files \textit{gms\_GridDATA\_t0}, \ldots, \textit{gms\_GridDATA\_tT}, which contain the grid data for each time step over the whole MPC time horizon $T$ (in our simulations equal to 0). Grid data include bus, branches, generators and load information. Matlab is in charge of creating these files at each time step in the GAMS project directory, opening it and launching the desired GAMS optimization.

After GAMS has solved the problem, a report file with results is created and exported back to Matlab, where it is stored and relevant information are possibly taken for the following optimization step (e.g., setpoints or flexibility values). When a time step is completed, the Matlab time variable is increased and a new time step is run in a fully automated way. When the desired hours of simulations have been completed, the results are combined and visualized in Matlab. Several optimization modes can also be simulated in cascade providing a comparison among them. This will be shown in the next part on simulation results. Each time step of the optimization is very fast, also when computing all three steps of the coordination procedure, the simulation time is generally equal to few dozens of seconds overall.

### 5.2 Grid Models

The medium-scale system used in this work is based on a portion of the German power system close to the North Sea. In this region a real 110-kV distribution grid with 1.6 GW of total wind generation is modelled together with the surrounding 220/380-kV transmission system (Figure 5.2).

#### 5.2.1 Transmission Grid Model

The transmission grid model is a regional model derived from the German grid model available at Fraunhofer IWES. It corresponds to the North Sea region across the control areas of TenneT and 50 Hertz. The remaining part of the German transmission system is modelled as a reduced network equivalent with a slack generator. Other distribution grids, except the one modelled in detail, are represented as equivalent loads. The transmission grid modelled includes 15 synchronous generators and 3 offshore wind farms (static generators). Generation connected to the distribution level is implicitly taken into account as a
5.2. Grid Models

Figure 5.2: PowerFactory model of the transmission system used for simulations

negative load. Details are included in Appendix A.

5.2.2 Distribution Grid Model

The distribution grid used in this work was provided by Avacon within the IMOWEN project. A snapshot of the PowerFactory model of this grid is shown in Figure A.1. It is one of the largest 110-kV meshed networks in Germany, located in the Nordring region in Lower Saxony. It is a region, facing the North Sea, with a very high wind energy potential and an historically high development of WPPs. About 1.6 GW of wind power are present in this area, with 55 wind farms (1029 MW) directly connected to the 110-kV network. 611 MW of aggregated generation are connected to lower voltage levels (mainly small wind farms or single WTs). The transmission and distribution grids are connected via 8 OLTC transformers, located in 5 connection points, one with primary voltage of 380 kV, the others 220 kV. CPs are shown in Figure 5.3, where the green color stands for the 220 kV level and the red color for the 380 kV level. Names and characteristics of each substation are shown in Table 5.1.

Existing WPPs in the Avacon grid belong to two classes: new wind farms (WEA_NEU) and old wind farms (WEA_ALT). New WPPs are the ones equipped with remote control systems, while old ones lack this functionality. The acronym WEA in the grid model comes from the German Wind Energie Anlagen (WEA). A further type of generator is present and called with the acronym Dezentralen Erzeugungs Anlagen (DEA), equivalent to DG, to account for MV and LV plants. Also an offshore wind farm is directly connected to the distribution system: is the Alpha Ventus WPP, the first German offshore wind farm, a 60
MW plant with 12 WTs connected to the shore with a 60 km sub-sea AC cable. Further data and details and a single-line diagram of the distribution grid model are included in Appendix A.

5.3 Time Series Data

In order to perform time-series simulations, the load and generation profile for the considered region have to be included. A weekly time-frame is considered for simulations. Figure 5.4 shows the load and generation profile in the whole system (transmission plus distribution) and in the DSO grid alone. Two different sources are basically used for this purpose:

- **Distribution system time-series**: yearly load and generation profiles were provided by Avacon for the grid under examination. The available data refer to measurements taken at HV-EHV transformers for each 15 minutes over one year (both P and Q). From these data, the nodal generation and load values are estimated. The
5.3. Time Series Data

Figure 5.4: Weekly load and generation profile of the overall system (top) and distribution system (bottom)

load time-series include also the contributions of loads corresponding to neighbouring 110-kV grids. The inclusion of these contributions is necessary to have realistic voltages (especially during high wind power in-feed). This explains why the internal load can exceed values as high as 1200 MW while in table A.1 the maximum load is defined at 430 MW: the former value includes of course also neighbouring grids.

- **Transmission system time-series**: in the transmission grid, data regarding individual power plants dispatch and aggregated residual load (load minus DG generation) are obtained from a Unit Commitment (UC) model of the German power system [6]. A weekly time series is extrapolated from the yearly data, corresponding to the first week of December in order to have a match with the DSO grid data. Load values are available only at an aggregated scale, for the sake of simplicity the overall residual load is therefore divided equally over nodal loads. The equivalent power factor used is 0.9 inductive. Since the region is not an island power system, power exchanges with the rest of Germany, represented in our model as a network equivalent, are usually substantial. The mismatch power is absorbed or provided by the slack generator. However, to limit power flows to or from the slack, time-series of generating plants are slightly modified from the UC results, in order to follow more closely the regional load profile and limit losses in the equivalent impedances of the reduced model. The power plants dispatch profiles used in simulations are shown in Figure 5.5. Details about these PPs, such as capacity and fuel, are included in Table A.3.
Chapter 5. Simulations

5.4 Description of Simulation Cases

Once built the grid model and procured the time-series data, some significant simulation cases need to be defined in order to evaluate different features of the proposed coordination scheme described in Chapter 4. Three main simulation cases have been carried out and are described in subsections 5.4.1 - 5.4.3.

5.4.1 Q-Q(U) Comparison

This simulation compares the results of the coordinated optimization, as described in Chapter 4, using voltage setpoints to modulate a Q(U) law or Q setpoints for optimal control of WPPs in the DSO OPF. These control modes were introduced in subsection 3.7.5. The goal is to validate the proposed Q(U) mathematical model and compare its performance with the one of Q setpoints. Results are shown in subsection 5.6.1.

5.4.2 Feasibility and Performance of Different Setpoints

This simulation is based on running the coordination scheme with the three different forms of setpoints at T-D interface (reactive power sum for the whole grid, voltage targets at each CP, reactive power targets at each CP), in order to assess their feasibility (particularly in case of individual targets for each CP) and evaluate differences in the performance. Results are shown in subsection 5.6.2.

5.4.3 Performance of the Coordinated Optimization

This simulation aims at evaluating the coordination scheme performance, to assess if advantages can be derived from its application. To do so, within the same simulation, the coordination scheme, with a chosen type of setpoints, is compared with other scenarios: a basecase and a benchmark case. The basecase should consist in a scenario without any coordination between TSO and DSO actions and be similar to the current system operation.
5.4. Description of Simulation Cases

procedures, while the benchmark case should represent the system global optimality conditions. In order to evaluate the performance of the coordinated optimization, the scenarios presented in Table 5.2 were thus ideated. Results are reported in subsection 5.6.3.

Table 5.2: Summary of scenarios for the performance of the coordinated optimization simulation

<table>
<thead>
<tr>
<th>Scenario name</th>
<th>DSO control variables</th>
<th>Coordination with TSO</th>
</tr>
</thead>
<tbody>
<tr>
<td>OLTC OPF - cosphi=1</td>
<td>OLTC</td>
<td>No</td>
</tr>
<tr>
<td>OLTC OPF - Static Q(U)</td>
<td>OLTC</td>
<td>No</td>
</tr>
<tr>
<td>Coordinated Optimization TSO-DSO</td>
<td>OLTC + WPPs</td>
<td>Yes</td>
</tr>
<tr>
<td>Overall System OPF</td>
<td>Omniscient SO optimization</td>
<td></td>
</tr>
</tbody>
</table>

The first two scenarios represent, with a small variant, the so called basecase. It is actually very difficult to define a relevant basecase which is close to current system operation, since the voltage regulation task is performed mainly through manual dispatch in the German system. For sure, two main points distinguish the current system operation from the vision proposed in this work: the lack of active involvement of DSOs in the transmission system voltage control and the lack of real-time optimization-based coordinated control of WPPs at 110-kV level. The two "basecase" scenarios were built having these considerations in mind.

In the OLTC OPF - cosphi=1 scenario, wind farms reactive behaviour is not optimized and they operate at fixed cosφ = 1 at the PCC, a practice still common for many system operators, not only in Germany. In this scenario, OLTC transformers represent the only regulating tool for the DSO. The OLTC operation is here also driven by an optimization, not only by a local control of the tap changer. Therefore an OPF is run to simulate also this (and the following) scenario. No coordination with the TSO voltage control system is adopted and only the distribution system is optimized in a single step. Concerning the transmission system, the same voltage setpoints for synchronous generators found in the coordinated optimization are used to simulate the results of a separate TSO OPF. The reason behind the choice to use the same setpoints is to have a fair performance comparison with the coordinated optimization. This makes this scenario very "optimized" and represents an optimistic approximation of the current operation methods.

The OLTC OPF - Static Q(U) represents a variant of the previous scenario. WPPs are controlled with a static $Q = f(U)$ control law, with a common fixed voltage setpoint. The control has thus a local aim and belongs to the uncoordinated class presented in Section 2.7. The voltage setpoint selected is crucial in determining the reactive power exchange of the distribution grid, as shown in Figure 5.6, where different values of $U_i^{opt}$ are applied to the Q(U) control.

In the Coordinated Optimization TSO-DSO, the here proposed optimization chain is applied comprising the three sequential steps. Different objective functions can be conceived for the TSO and the DSO. Reactive power (sum or individual targets) or voltage setpoints can be followed by the DSO at the interface. Different collaboration strategies are tested for the DSO: a greedier one, where its interests are given more importance, and
Chapter 5. Simulations

5.5 General Simulation Settings

As in any scientific work, the output achieved, i.e., in this case the simulation results, is highly dependent on the input data used. We have already described the grid model and the time series data used in this work, we would like to report here some further considerations on important simulations settings employed.

5.5.1 Reactive Power Settings of WPPs

The simulations results are highly influenced by the reactive power capability and controllability of WPPs. As shown in Section 2.6, the possibility of harnessing reactive power from wind farms depends mainly on two factors:

1. **Reactive power capability**: a wide reactive power capability should be available not only at WT but also at WPP level. Modern wind turbines of type C (DFIG) and D (full-converter) offer a large reactive margin down to low active power production ($\sim 20\% P_n$), and, when equipped with STATCOM functionality, also until zero active power (phase-shifting capability). Due to the presence of the electrical network

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Figure 5.6: Reactive power output of wind farms and exchange at T-D interface with different voltage setpoints for static $Q(U)$ control (same setpoint for all WPPs)

Finally, the **Overall System OPF** scenario represents the benchmark case corresponding to overall system optimality: the whole grid is assumed to belong to a unique system operator (comparable to an Independent System Operator (ISO) in the US), which optimizes both grid levels controlling wind farms, OLTC and synchronous generators at the same time and within the same optimization.
5.5. General Simulation Settings

and the step-up transformer, the reactive power capability of the WPP at the PCC is not equal to the sum of the capabilities of individual WTs, and it depends on the external voltage too. Additional equipment, such as STATCOM, OLTC or compensation banks, might be installed at the substation to achieve a desired reactive power capability.

2. **WPP controllability**: in order to remotely regulate the reactive power production of a WPP, a control system should be in place at wind farm level and a communication channel should be present between the wind farm and the SO control room. Old wind farms often lack these systems and, also when a reactive capability is present, it cannot be exploited. Repowering of these WPPs is a solution commonly adopted to overcome this problem.

| Table 5.3: Summary of WPPs reactive power harnessing potential in different scenarios |
|-----------------------------------|---------------------------------|--------------------------|
| cosφ<sub>max</sub>=0.95 | phase-shifting capability (STATCOM) |
| New wind farms (525 MW) | Scenario 1 | Scenario 2 |
| All wind farms (1029 MW) | Scenario 3 | Scenario 4 |

In the case under examination we have different possibilities to consider, represented in Table 5.3: the most conservative scenario (scenario 1) corresponds to minimum grid code requirements for WPP reactive capabilities (cosφ<sub>max</sub>=0.95) and controllability of new wind farms only (this is the scenario closest to the current situation faced by Avacon). Two
intermediate scenarios stem from considering either an extended reactive capability only for new wind farms (scenario 2), or grid code limits but with all wind farms under control (scenario 3). Finally, the most optimistic scenario implies that all wind farms connected to the 110-kV level are controllable and can provide phase shifting capabilities installing STATCOM devices at wind farm level (scenario 4). This is a likely future scenario after repowering operations.

In Figure 5.7, the global reactive power exchange limits of the distribution grid, as computed in the first step of the coordination chain by the DSO, are represented in scenarios 1 and 4. Negative Q values imply a flow from the TSO to the DSO and vice versa. The difference between scenario 1 and 4 is shown quite clearly. In the former case (red range), the flexibility is much lower and largely depends on the wind availability: the range is larger in the end of the first day when wind in-feed is very high (compare with Figure 5.4), but almost zero in times of low wind in-feed. Interestingly, during high wind in-feed the reactive power exchange at T-D interface reaches the highest negative values due to the high loading of the distribution system to export active power which increases reactive demand. The reactive power range in scenario 4 is instead larger and decoupled from active power availability, i.e., wind resource availability, using STATCOM and achieving a P-Q capability curve at the PCC such as the one of Figure 5.8 [7]. Since we are interested in reactive power potential at the PCC, phase shifting capability of individual WTs is not enough and additional STATCOM equipment must be installed at wind farm level to guarantee the P-Q curve of Figure 5.8. The final choice for the reactive power capability of WPPs to use in simulations is taken for the fourth and most optimistic scenario, since the larger reactive power range can lead to more significant simulation results in terms of validation and performance analysis of the coordinated scheme.

### 5.5.2 Voltage Setpoints

During the optimizations, optimal voltage setpoints for Q(U) wind farms and synchronous generators are determined. The feasible values for these setpoints are:

- **Q(U) wind farms**: 0.9 – 1.1 p.u.
- **Synchronous generators (PV mode)**: 0.95 – 1.05 p.u.

In the OLTC OPF Static Q(U) optimization mode (used in the performance of the
5.6. Simulation Results and Discussion

coordinated optimization simulation), the fixed voltage setpoint $V_i^{opt} = 1.02$ p.u. is used, corresponding to a realistic arbitrary value.

5.5.3 OLTC Tap Operations Cost

As mentioned in Section 4.4, the DSO OF is based on minimizing the costs incurred. Assuming no cost of reactive power provision from WPPs, cost entries include active power losses and OLTC tap operations. Both terms are considered in the MO function. But how is it possible to set the weights associated to the two functions $f_{losses}$ and $f_{Tap}$ in a reasonable way? A procedure was developed based on the estimation of costs associated to each tap operation and knowing the cost of active power (€/MWh). The data and the computations performed are explained in Appendix B. The final result is that a ratio of 0.001 should be used between the $w_{Tap}$ and $w_{losses}$ weights.

5.6 Simulation Results and Discussion

5.6.1 Q-Q(U) Comparison

In this section a simulation over a reduced time period of 24 hours is performed, comparing the same optimization mode, based on the coordinated optimization mechanism, employing reactive power sum setpoints ($f_{\Delta Q}$), with different wind farm controls: namely Q setpoints and voltage setpoints for Q(U) control (see subsection 3.7.5). Both controls are dynamic, i.e., the setpoints are defined at each time step by the DSO OPF and sent to WPPs. This means that a setpoint of reactive power sum is computed by the TSO through its OPF, based on the DSO flexibility declaration, and sent as setpoint to the DSO which tries to fulfill it using WPPs and OLTCs. Loss minimization is the primary objective for both operators, plus OLTC operations minimization for the DSO. OF weights are shown in Table 5.4.

<table>
<thead>
<tr>
<th>OPF</th>
<th>$w_{losses}$</th>
<th>$w_{profile}$</th>
<th>$w_{Tap}$</th>
<th>$w_{\Delta Q}$</th>
<th>$w_{V_{ext}}$</th>
<th>$w_{\Delta Q_{cp}}$</th>
</tr>
</thead>
<tbody>
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<td>TSO</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>DSO Q sum</td>
<td>1</td>
<td>0</td>
<td>0.001</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

In Figure 5.9 the global reactive power output of WPPs in the two cases is compared. We can see how results are generally close but present some differences. The difference is due to the Q(U) control law which links the nodal voltage and the WPP reactive power injection. In our case this function was approximated using a fifth order polynomial function, as detailed in subsection 3.7.5. In Figure 5.10 the reactive power exchange at T-D interface, as well as the feasible range, are shown. It can be noticed how the two WPPs control modes lead to similar results. This can be considered a validation evidence for the proposed $Q=\phi(U)$ mathematical model. Table 5.5 provides some performance indicators in the two cases. It is possible to notice that, with similar losses, the Q(U) control leads to a lower amount of OLTC tap operations, which is a positive feature. From now on, the developed dynamic Q(U) control is applied in the following simulations as WPPs control method (obviously, only in optimizations with WPPs under OPF control).
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Figure 5.9: Reactive power production of WPPs with Q and Q(U) control

Figure 5.10: Reactive power exchange and limits with Q and Q(U) control

Table 5.5: Overall performance indicators in the Q(U) validation simulation

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Q(U) control</th>
<th>Q control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reactive power exchange (Mvarh)</td>
<td>690.46</td>
<td>623.40</td>
</tr>
<tr>
<td>TSO active power losses (MWh)</td>
<td>852.91</td>
<td>851.92</td>
</tr>
<tr>
<td>DSO active power losses (MWh)</td>
<td>278.67</td>
<td>279.54</td>
</tr>
<tr>
<td>Total OLTC operations</td>
<td>9</td>
<td>19</td>
</tr>
</tbody>
</table>
5.6. Simulation Results and Discussion

5.6.2 Feasibility and Performance of Different Setpoints

In this section the three setpoints types (reactive power sum, voltage targets, reactive power targets) for the TSO-DSO coordination scheme are evaluated through a weekly simulation to test their feasibility and performance. In particular, for individual reactive power or voltage targets at each CP, feasibility should not be given for granted, due to the meshed coupling network. Preliminary simulations showed how stating these targets as hard constraints leads to infeasibility and convergence problems. Therefore the setpoints are added in the MO function of the DSO, as shown in Section 4.4, along with internal objectives such as loss and tap operations minimization. The TSO is instead minimizing only active power losses. The chosen weights in the MO functions are shown in Table 5.6. The ratio between losses and tap costs is derived from computations in Appendix B. The weights associated to external setpoints have been determined instead through a tuning process: the reactive power targets require the lowest weight, while voltage targets the highest, since quadratic voltage deviations are very small. Dynamic Q(U) control for WPPs is here applied.

Table 5.6: OF weights of eq.(3.28) chosen for the feasibility and performance of different setpoints simulation

<table>
<thead>
<tr>
<th>OPF</th>
<th>(w_{\text{losses}})</th>
<th>(w_{\text{profile}})</th>
<th>(w_{T_{\text{tap}}})</th>
<th>(w_{\Delta Q})</th>
<th>(w_{V_{\text{ext}}})</th>
<th>(w_{\Delta Q_{\text{cp}}})</th>
</tr>
</thead>
<tbody>
<tr>
<td>TSO</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>DSO Q sum</td>
<td>1</td>
<td>0</td>
<td>0.001</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>DSO V targets</td>
<td>1</td>
<td>0</td>
<td>0.001</td>
<td>0</td>
<td>100</td>
<td>0</td>
</tr>
<tr>
<td>DSO Q targets</td>
<td>1</td>
<td>0</td>
<td>0.001</td>
<td>0</td>
<td>0</td>
<td>0.1</td>
</tr>
</tbody>
</table>

In Figure 5.11 the different reactive power exchanges between the distribution and the transmission grid over the week are shown. Reactive power targets (either sum or individual) lead to a similar exchange profile while in case of voltage setpoints this is rather lower and closer to a neutral balance. The profile also follows quite clearly the daily load profile. The flexibility range is rather constant thanks to the use of STATCOM, which decouple reactive power from wind resource availability. The average value is about 350 Mvar.

In Figure 5.12 the first 24 hours are shown in detail. The red dashed line represents the cumulative reactive power sum request coming from the TSO OPF, and it is very close to the actual flow in case of \(Q_{\text{sum}}\) optimization.

During the first 24 hours we have the highest wind power in-feed (especially in the second half of the day) and relatively low load: the reactive power exchange range reaches the minimum lower point close to -400 Mvar (see Figure 5.11) since the grid is heavily loaded to export active power: in this scenario the reactive power support from WPPs is most needed to support both local and transmission voltage. It is possible to see that the outcome of the coordinated optimization in all three cases leads to operation points very close to the upper limit of reactive power exchange in the first 24 hours, with slightly lower values in case voltage setpoints are used.

The total reactive power provision of WPPs can also be appreciated from Figure 5.13. It is possible to notice very similar outputs in case of reactive power based coordination,
Chapter 5. Simulations

Figure 5.11: Reactive power exchange and limits with the different setpoints over one week

Figure 5.12: Reactive power exchange and limits with the different setpoints in the first 24 hours
5.6. Simulation Results and Discussion

Figure 5.13: Total reactive power support from WPPs over one week

while a generally lower output is requested to wind farms using voltage setpoints. The cycles due to load and wind profiles are clearly visible. This variability depending on external conditions is one of the main reasons backing the need of real-time coordinated solutions for wind farms reactive power control.

The Mean Absolute Errors (MAE) in p.u. between optimal, computed in the TSO OPF, and actual voltages, after the DSO OPF, at each CP, are computed with eq. (5.1), where $\tau$ is the total number of time steps in the simulation and $K_{cp}$ the EHV bus for each CP. MAE in the different optimizations are shown in Table 5.7.

$$MAE_{cp} = \frac{\sum_{\tau=0}^{\tau} |U_{i,\tau} - U_{set,\tau}|}{\tau} \quad i \in K_{cp}$$  (5.1)

Table 5.7: MAE of voltages at each CP [p.u.]

<table>
<thead>
<tr>
<th>OPF</th>
<th>Conneforde 220-kV</th>
<th>Conneforde 380-kV</th>
<th>Emden 220-kV</th>
<th>Emden-Borßum 220-kV</th>
<th>Voslapp 220-kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>DSO Q sum</td>
<td>0.0004</td>
<td>0.0003</td>
<td>0.0032</td>
<td>0.0031</td>
<td>0.0001</td>
</tr>
<tr>
<td>DSO V targets</td>
<td>0.0008</td>
<td>0.0008</td>
<td>0.0004</td>
<td>0.0004</td>
<td>0.0010</td>
</tr>
<tr>
<td>DSO Q targets</td>
<td>0.0004</td>
<td>0.0003</td>
<td>0.0007</td>
<td>0.0007</td>
<td>0.0001</td>
</tr>
</tbody>
</table>

Lowest errors are generally associated with individual targets for each CP (either voltage or reactive power), but this naturally depends also on the chosen weights in the OF. The $Q_{sum}$ and $Q_{targets}$, although very similar in the overall Q exchange, differ in the MAE of
the voltages in Emden and Emden-Borkum quite noticeably. It is actually quite intuitive that a global reactive target cannot provide such an accurate performance as individual targets. The Swiss regulation for active distribution grids [8] requires a maximum deviation of:

- $\pm 0.0079$ p.u. (3 kV) at 380-kV level
- $\pm 0.0091$ p.u. (2 kV) at 220-kV level

Compliance with these limits was achieved in all three scenarios and for each time step, also in case of $Q_{\text{sum}}$ coordination.

The other significant performance indicators (losses, Q exchange, OLTC operations) are presented in Table 5.8. The best overall performance was in this case achieved with the use of voltage targets, entailing the lowest losses for both the DSO and the TSO and no tap operations at all. Another difference is the much lower reactive power amount injected in the transmission grid, with a close to neutral balance over the week. This is probably due to the fact that the required reactive power injections from the DSO to support optimal interface voltages are overestimated in the TSO OPF, without knowledge of the HV grid and couplings between CPs. The performance of $Q_{\text{sum}}$ and $Q_{\text{targets}}$ are similar for many indicators, except for the number of tap operations which is significantly higher in the second case, since a more accurate performance is required.

However, the presented results depend highly on the chosen weights (especially for the external setpoints), the grid structure and the input data and, therefore, it is not possible to draw general conclusions on the preferability of the different setpoints. Different choices could be made in different contexts depending on specific needs of both operators and the regulatory framework. For instance, in Switzerland the focus is on voltage targets, while in Germany, the focus is usually on prescribed global reactive power ranges. The feasibility of all the three setpoints for the coordination scheme has been demonstrated. In the following simulation, voltage targets will be used as example, as suggested also in [9].

### Table 5.8: Overall performance indicators in the feasibility and performance of different setpoints (weekly)

<table>
<thead>
<tr>
<th>Indicator</th>
<th>DSO Q SUM</th>
<th>DSO V targets</th>
<th>DSO Q targets</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reactive power exchange (Mvarh)</td>
<td>9897.46</td>
<td>187.52</td>
<td>8721.36</td>
</tr>
<tr>
<td>TSO active power losses (MWh)</td>
<td>5051.60</td>
<td>5045.25</td>
<td>5052.07</td>
</tr>
<tr>
<td>DSO active power losses (MWh)</td>
<td>1350.32</td>
<td>1335.73</td>
<td>1352.66</td>
</tr>
<tr>
<td>Total OLTC operations</td>
<td>33</td>
<td>0</td>
<td>123</td>
</tr>
</tbody>
</table>

#### 5.6.3 Performance of the Coordinated Optimization

In the present section, the coordinated optimization scheme, based on the chosen voltage targets, is tested and compared to the other scenarios: the OLTC OPF, featuring unitary
5.6. Simulation Results and Discussion

Table 5.9: OF weights in the performance of coordinated optimization simulation

<table>
<thead>
<tr>
<th>OPF</th>
<th>$w_{\text{losses}}$</th>
<th>$w_{\text{profile}}$</th>
<th>$w_{\Delta Q}$</th>
<th>$w_{V_{\text{ext}}}$</th>
<th>$w_{\Delta Q_c}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>OLTC OPF-cosphi=1</td>
<td>1</td>
<td>0</td>
<td>0.001</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>OLTC OPF-Static Q(U)</td>
<td>1</td>
<td>0</td>
<td>0.001</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Overall System OPF</td>
<td>1</td>
<td>0</td>
<td>0.001</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Coordinated V targets</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TSO</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>DSO (Collaborative)</td>
<td>1</td>
<td>0</td>
<td>0.001</td>
<td>0</td>
<td>100</td>
</tr>
<tr>
<td>DSO (Greedy)</td>
<td>1.2</td>
<td>0</td>
<td>0.005</td>
<td>0</td>
<td>10</td>
</tr>
</tbody>
</table>

power factor or static Q(U) control of wind farms, and the Overall System OPF as benchmark case (refer to Section 5.4 for details). Two different coordinated optimizations are run with different weights for external setpoints, tap operations, and losses in the DSO OPF. This is to simulate different degrees of cooperation of the DSO: a collaborative strategy and a greedy strategy, in which the DSO prioritizes more its internal objectives:

- **Collaborative DSO**: the same weights used for the voltage targets scenario in the previous simulation are kept
- **Greedy DSO**: the weights associated to internal objectives (losses and tap operations) are increased and the weight associated to external voltage targets is lowered

![Figure 5.14: Reactive power exchange and limits in the different scenarios over one week](image)
The chosen OF weights are displayed in Table 5.9. The overall reactive power exchange in the different scenarios is presented in Figure 5.14. In the absence of WPPs control in the OPF, the reactive exchange at T-D interface goes strongly negative during high wind in-feed. The situation is only slightly improved controlling wind farms with a static Q(U) using a uniform 1.02 p.u. voltage setpoint, compared to $\cos \phi = 1$ operation. Conversely, during low wind in-feed and low load (always refer to Figure 5.4), positive reactive power flows take place at the interface also in OLTC OPF scenarios, due to the capacitive behaviour of the distribution grid. The overall exchange profile is very fluctuating and variable over the weekly time-frame. Instead, a close to neutral reactive power balance is achieved using the proposed coordinated optimization scheme employing voltage setpoints from the TSO. In case of a stronger coordination (blue line), the DSO tends to provide an higher reactive support especially during high wind in-feed, in sharp contrast with the OLTC OPF cases. If instead the internal objectives of the DSO are given higher priority (greedy strategy, orange line) a (generally) lower reactive injection takes place, achieving a result very close to the overall system OPF (yellow line). This is because the imbalance towards TSO interests is partially mitigated. A focus on the first 24 hours is shown in Figure 5.15, where the difference between the scenarios can be appreciated even more.

The reactive power output from WPPs in the different cases is shown in Figure 5.16. The horizontal green line represents of course the OLTC OPF-$\cos \phi = 1$ scenario, where WPPs provide only active power. In the static Q(U) case, the reactive power output is quite limited and fluctuates around the zero line depending on the network conditions: during high wind in-feed and high system loading, the reactive power provided is positive to support system voltages (in the distribution network) and achieve values close to the 1.02 target. During low loading conditions, the voltages tend to rise even above the setpoint and reactive power is absorbed by WPPs due to the (static) Q(U) law. The influence of network conditions (including the transmission system) on this process is paramount, but
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Figure 5.16: Total reactive power output of WPPs in the different scenarios (weekly)

In this scenario no optimization of setpoints and no coordination between the two operators is used. In the other scenarios instead, involving reactive power optimization of WPPs and coordination between the two systems, a much higher reactive support is obtained from WPPs, up to 150 Mvar overall. However, the reactive power requested is not always positive, during particularly low loading periods the DSO asks WPPs to absorb reactive power.

The reactive power output in the coordinated optimization scenarios and in the Overall System OPF is achieved modulating the Q(U) control law at wind farm level through the communication of a voltage setpoint set by the DSO OPF in the admissible range [0.9 - 1.1]. In Figure 5.17 the voltage setpoints and the corresponding reactive power outputs of the 55 controlled wind farms are shown over the entire week for the V targets optimization (collaborative DSO). The use of a Q(U) control has the theoretical benefit of working also as local control in case of a communication failure. The outlier curve with very high voltage targets indicated by the arrow in Figure 5.17, represents the offshore wind farm Alpha Ventus, connected via a 60 km long AC cable to the shore. The long cable capacitance leads to very high voltages at the PCC and thus, in order to get a positive reactive injection from this wind farm, it is necessary to set a high voltage setpoint for the Q(U) control. The limit is represented by the upper value of 1.1, which cannot be exceeded [10]; voltage limits are thus a constraint to WPPs reactive power capability exploitation and this case shows it quite well. Also the behaviour of other grid nodes and connected WPPs is very important: if the other wind farms inject a lot of reactive power the voltages will rise on average over the distribution grid; if the voltage on the CP onshore will be higher, this will entail also an higher voltage at the offshore node where the Alpha Ventus wind farm is connected and thus a lower reactive power that can be obtained from this WPP. This intuitive example shows why a coordinated control of the WPPs, based on optimization tools and knowledge of the overall network structure, is best suited for the task targeted in this work.
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Figure 5.17: Voltage targets and reactive power of WPPs in the collaborative DSO scenario

Figure 5.18: Voltage setpoints of transmission connected PPs in voltage regulation mode (collaborative DSO scenario)
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In Figure 5.18, the voltage setpoints of voltage regulating units connected to the TSO grid are shown (always for the collaborative DSO case). These setpoints are found by the TSO OPF along with voltage setpoints for distribution CPs in a coordinated way, within the defined range $[0.95-1.05]$. The behaviour of Brokdorf nuclear power plant stands out due to the very high constant voltage setpoint.

Table 5.10: Overall performance indicators in the performance of the coordinated optimization simulation (weekly)

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Coord. V targets</th>
<th>Coord. V (greedy)</th>
<th>Overall System OPF</th>
<th>OLTC OPF Static Q(U)</th>
<th>OLTC OPF cosphi=1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reactive power exchange (Mvarh)</td>
<td>187.5</td>
<td>-1569.5</td>
<td>-629.9</td>
<td>-10163.8</td>
<td>-9283.8</td>
</tr>
<tr>
<td>Reactive power output synchronous plants (Gvarh)</td>
<td>173.56</td>
<td>175.33</td>
<td>174.23</td>
<td>189.77</td>
<td>188.90</td>
</tr>
<tr>
<td>Net reactive power WPPs (Mvarh)</td>
<td>6239.12</td>
<td>4613.17</td>
<td>5432.88</td>
<td>-707.39</td>
<td>0</td>
</tr>
<tr>
<td>TSO active power losses (MWh)</td>
<td>5045.25</td>
<td>5048.17</td>
<td>5047.15</td>
<td>5082.65</td>
<td>5083.31</td>
</tr>
<tr>
<td>DSO active power losses (MWh)</td>
<td>1335.73</td>
<td>1331.56</td>
<td>1329.85</td>
<td>1374.50</td>
<td>1367.25</td>
</tr>
<tr>
<td>Average OLTC utilization (%)</td>
<td>0</td>
<td>0.15</td>
<td>0</td>
<td>0.30</td>
<td>1.2</td>
</tr>
<tr>
<td>Total OLTC operations</td>
<td>0</td>
<td>8</td>
<td>0</td>
<td>16</td>
<td>64</td>
</tr>
</tbody>
</table>

In Table 5.10 the weekly performance indicators (reactive power exchange, losses, OLTC operations, etc...) are collected. Controlling wind farms through the coordinated optimization allows to reduce losses not only in the transmission system but also in the distribution system, creating a win-win strategy for the two operators. Losses in the TSO and DSO systems under the different scenarios are represented in Figure 5.19.

Loss reduction for the TSO is not so huge, since it reaches up to 0.7% (-38 MWh over one week compared to the unitary power factor operation). A little higher value is achieved at DSO grid level where losses decrease up to 3% (-43 MWh compared to the static Q(U)). However, it should be pointed out that a very optimized basecase is used as term of comparison: it is also based on a OPF and the same setpoints of synchronous generators found in the coordinated optimization are used. Therefore the only difference is represented by the control of wind farms at 110-kV level. The impact of one single distribution grid is also evaluated on a rather big portion of the transmission system.

In any case, the proximity to results of the overall optimization, suggests the effectiveness of the method proposed. Moreover, loss reduction is not the only point of interest for the TSO in increasing the coordination with DSOs, and probably not even the main
one. The knowledge of the available flexibility at each connection point and the possibility to issue voltage and reactive power targets at T-D interface is a very important resource and could be used for several purposes (for instance in emergency situations or to avoid to perform voltage redispatch actions). It demonstrates how, with the correct tools, active distribution grids can be operated in a way very similar to power plants.

Comparing the two coordination strategies, it can be noticed how the greedy strategy leads to slightly higher losses for the TSO in favor of lower losses for the DSO, as expected. Interestingly, the tap operations are higher with the greedy strategy, even though a weight of 0.005 instead of 0.001 was used in this case: this is because the increase in $w_{\text{losses}}$ at the meantime triggers additional OLTC operations. This shows how delicate is the weights choice in the MO function, since even small variations can modify Pareto surfaces significantly, leading to undesired results.

In Table 5.11 and Figure 5.20 are reported mean voltage errors at each EHV busbar in p.u., under the two different DSO strategies. As expected, deviations from the targets are higher under the greedy strategy even though still widely within the Swiss regulation limits. This is because the weight associated to external setpoints is lower and the DSO gives more importance to its internal objectives defining the optimal dispatch of its control variables.

However, a recommendation is that the DSO strategy is transparently shown in the flexibility declaration, not to affect the optimality of TSO control actions. As already mentioned in Section 4.5, in the present simulations the DSO offers the whole flexibility
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In Figure 5.20, the MAE of voltages at each CP with different DSO strategies is shown. The mechanism is somewhat unbalanced towards the TSO interests. Two possible ways can be introduced to make it more balanced in a transparent way, as requested in [11]: either a price is attributed to each supplied Mvarh or the flexibility range is limited before technical constraints, considering losses and tap operations for instance, or even a combination of both methods. In the first case, the challenge is how to distinguish the reactive power adjustment to be paid from the natural reactive power flow, also considering that the former is influenced by internal DSO objectives (how is it possible to distinguish in the presented OPF results which Mvar or tap operation were triggered by the external set points and which by distribution losses minimization or other possible DSO objective functions?). In the second case, the flexibility computation could take into account that no tap operation should be incurred and losses should not increase over a defined threshold. This restricted range could be bid or made freely available under normal operation and transmitted along with the technical flexibility, available for emergency situations or under (higher) remuneration.

Another main point of interest is shown in Figure 5.21, where the reactive power exchange at T-D interface in all scenarios is shown. A remarkable decrease in Q absorption of the distribution grid is experienced using the coordinated scheme and controlling WPPs, compared to OLTC OPF scenarios: a close to neutral balance is achieved.

The impact on the other reactive power providers (i.e., SGs) is clearly shown in Figure 5.22, where the sum of the net reactive power output of wind farms (light blue) and synchronous generators (dark blue) is displayed. Thanks to the active involvement of wind farms, not only is the reactive power provision of transmission connected power plants decreased of about 8% on a weekly basis between the coordinated strategy and the OLTC OPF, but also the overall reactive power production is lowered (sum of reactive power from wind farms and synchronous generators).
In the OLTC OPF scenarios the total reactive production from SGs is almost 190 Gvarh, slightly higher in the Static Q(U) case due to the negative net output from WPPs. In all the scenarios where a coordinated optimization or an overall optimization is done, involving WPPs, the overall reactive production does not exceed 180 Gvarh (-5.2%), of which a part is provided by DSO-connected WPPs.

This suggests a leverage effect of each wind-produced Mvarh at distribution level and a net benefit of decentralized sourcing of reactive power from DG. A reason behind this could be the fact that producing locally reactive power to cover the load and network demand at distribution level, avoids to import this reactive power from the transmission grid, were it is produced mainly from power plants potentially located tens or hundreds of kilometers apart. In Chapter 2 the importance of local production of reactive power, due
to the additional active and reactive losses associated with long-range transfer of reactive power, was stated [12]. Another possible explanation is that the combined optimization of WPPs reactive power and OLTC tap positions, in coordination also with TSO-connected SGs, leads to an amplification effect of wind-produced reactive power. Most probably, this important result found can be put down to a combination of both factors.
Bibliography


Chapter 6

Conclusion and Future Research

“Are there any problems concerning balancing of large amounts of wind power? Yes, but: a good engineer can not stop solving problems”

Lennart Söder, Professor in Power Systems at KTH, Stockholm

This Master Thesis illustrates a procedure to achieve a coordinated reactive power management between TSO and DSO considering constraints and interests of both operators. The proposed procedure is based on the coordination of Optimal Power Flow (OPF) tools operating in real-time. It allows to actively involve distribution grids, and the connected DG, into transmission system voltage control, whilst fulfilling at the same time the voltage control requirements of the distribution level itself. The procedure is also able to handle complex meshed grid structures with several connection points between the transmission and distribution level and different DG control modes, such as dynamic Q(U) control. Thanks to the modular OPF tool developed, several setpoints can be applied in this scheme, based on voltage or reactive power values. The feasibility of fulfilling individual targets for each CP (both for voltage and reactive power), minimizing the sum of the quadratic deviations from the targets within the MO function was demonstrated. The whole coordination procedure is based only on three sequential steps: the flexibility computation by the DSO, the TSO OPF to dispatch reactive resources including distribution grids, and the DSO OPF to dispatch DG and OLTCs in the optimal way. The information exchange along the chain and the computation time are kept to a minimum.

The concept developed was evaluated through time-series simulations on a medium-scale system, based on a portion of the German transmission system and a large 110-kV grid with high wind power penetration. Simulation results demonstrated the feasibility of all the different setpoints types, and showed the benefits associated with the application of the proposed scheme, especially in the considered scenario with phase-shifting capability of WPPs using STATCOM. Loss reduction, compared to traditional operation, was experienced both at distribution and transmission level, implying a win-win strategy for both SOs. Also a considerable reduction of the reactive power output from transmission connected synchronous generators was registered, as well as a decrease in the overall reactive demand within the considered region. This suggests that distribution systems, exploiting the reactive capabilities of connected DG, can act as reactive power providers towards the TSO in a very similar way as synchronous power plants have traditionally been doing. Optimization tools and communication systems operating in real-time are here successfully proposed as the best method to achieve a coordinated control of DG resources at distribution level and, at an higher level, a coordinated control and optimal exploitation of DG
resources between the DSO and the TSO. The possibility to know the available reactive flexibility from distribution grids and the ability to dispatch it in the proper time horizon, are key resources for the TSO, not only to decrease losses in the current operation, but also to reduce voltage redispatch measures, cope with the decreasing availability of traditional var sources, and, ultimately, ensure a more secure system operation also in scenarios with very high RES penetration.

The present research work can be extended in many ways in the future, and this will hopefully happen through the continuation of the IMOWEN project or within other research initiatives. The coordination scheme should be tested in presence of several distribution grids taking part to it, and possibly in closed loop control. Also the utilization of reduced equivalents of the transmission system in DSO optimizations, and methods to simply and accurately update these models in real-time, should be developed and tested. Simulations using Model Predictive Control (MPC), which is already included in the tool, should be extensively run to evaluate whether the longer computation times are balanced by net benefits deriving from its application, especially in terms of tap operations reduction and possibly including also forecast errors. This activity was only started during my research work. Also some improvements to mathematical models of $Q=f(U)$ and complementarity constraints should be implemented to reduce further convergence times.

Moreover, the inclusion of other OFs could be considered, such as voltage stability related objectives, maybe in connection with a dynamic analysis tool. The market coordination aspect and the aspects related to a fair balance between TSO and DSO objectives, could be further investigated and expanded. A key upgrade could be the inclusion of further components within the OPF control variables, such as STATCOM, SVCs, shunt reactors or capacitors, and, above all, VSC-HVDC stations, which could play an important role in voltage control, especially in this northern German region.

Finally, the developed concept could be extended for active power control applications, such as redispatch, always targeting the interface and the coordination between TSO and DSO.
Appendix A

Grid Model Data

This Appendix includes additional data on the grid models described in Chapter 5.

*Table A.1: Distribution grid overview data*

<table>
<thead>
<tr>
<th>Data</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum load (MW)</td>
<td>430</td>
</tr>
<tr>
<td>Number of nodes</td>
<td>167</td>
</tr>
<tr>
<td>Maximum total generation (MW)</td>
<td>1640</td>
</tr>
<tr>
<td>Number of branches</td>
<td>189</td>
</tr>
<tr>
<td>Lower voltage level generation (MW)</td>
<td>611</td>
</tr>
<tr>
<td>Number of transmission transformers</td>
<td>8</td>
</tr>
<tr>
<td>Controllable wind generation (MW)</td>
<td>525</td>
</tr>
<tr>
<td>Remaining wind generation (MW)</td>
<td>505</td>
</tr>
</tbody>
</table>

*Figure A.1: Avacon 110-kV distribution grid PowerFactory model*
Appendix A. Grid Model Data

Table A.2: Transmission grid overview data

<table>
<thead>
<tr>
<th>Maximum residual load (MW)</th>
<th>4195</th>
<th>Number of nodes</th>
<th>68</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum total generation (MW)</td>
<td>4165</td>
<td>Number of branches</td>
<td>104</td>
</tr>
<tr>
<td>Number of synchronous generators</td>
<td>15</td>
<td>Number of off-shore wind farms</td>
<td>3</td>
</tr>
</tbody>
</table>

Table A.3: Power plant data (TSO grid)

<table>
<thead>
<tr>
<th>BNA code</th>
<th>Power Plant Name</th>
<th>$P_{max}$ (MW)</th>
<th>Fuel</th>
</tr>
</thead>
<tbody>
<tr>
<td>BNA0142</td>
<td>KW Mittelsbüren</td>
<td>150</td>
<td>Gas</td>
</tr>
<tr>
<td>BNA0140</td>
<td>KW Hastedt</td>
<td>155</td>
<td>Coal</td>
</tr>
<tr>
<td>BNA0146</td>
<td>KW Hafen</td>
<td>300</td>
<td>Coal</td>
</tr>
<tr>
<td>BNA0147</td>
<td>Farge</td>
<td>321</td>
<td>Coal</td>
</tr>
<tr>
<td>BNA0157</td>
<td>Brokdorf</td>
<td>1410</td>
<td>Nuclear</td>
</tr>
<tr>
<td>BNA0161</td>
<td>Brunsbüttel GTA-D</td>
<td>771</td>
<td>Nuclear</td>
</tr>
<tr>
<td>BNA0239</td>
<td>Huntorf</td>
<td>321</td>
<td>Gas</td>
</tr>
<tr>
<td>BNA0245a</td>
<td>Emden Gas</td>
<td>50</td>
<td>Gas</td>
</tr>
<tr>
<td>BNA0245b</td>
<td>Emden Gas</td>
<td>380</td>
<td>Gas</td>
</tr>
<tr>
<td>BNA0402</td>
<td>Tiefstack</td>
<td>194</td>
<td>Coal</td>
</tr>
<tr>
<td>BNA0418</td>
<td>GKL</td>
<td>250</td>
<td>Gas</td>
</tr>
<tr>
<td>BNA0526</td>
<td>Gemeinschaftskraftwerk Kiel</td>
<td>323</td>
<td>Coal</td>
</tr>
<tr>
<td>BNA0918b</td>
<td>Dow Stade</td>
<td>163</td>
<td>Coal</td>
</tr>
<tr>
<td>BNA1061</td>
<td>Wilhelmshaven</td>
<td>757</td>
<td>Coal</td>
</tr>
<tr>
<td>BNA1558</td>
<td>Moorburg B</td>
<td>766</td>
<td>Coal</td>
</tr>
<tr>
<td>BNA0039</td>
<td>BARD 1</td>
<td>412</td>
<td>Wind</td>
</tr>
<tr>
<td>BNA1560</td>
<td>DanTysk</td>
<td>296</td>
<td>Wind</td>
</tr>
<tr>
<td>BNA1561</td>
<td>Meerwind SüdIOst</td>
<td>296</td>
<td>Wind</td>
</tr>
</tbody>
</table>
Appendix B

OLTC Tap Operations Cost

In order to estimate the correct ratio between the cost of losses and tap operations for the DSO, the following procedure was used (B.1):

\[
cost_{\text{losses}} : cost_{\text{Tap}} = \mu_{\text{losses}} : \mu_{\text{Tap}}
\]  

(B.1)

To perform the computation, the data included in Table B.1 were used.

Table B.1: Tap operation cost estimation data

<table>
<thead>
<tr>
<th>OLTC capacity range</th>
<th>100-300 MVA</th>
<th>OLTC average estimated cost</th>
<th>800000 €</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum # of operations</td>
<td>600000</td>
<td># of operations per time step</td>
<td>1</td>
</tr>
<tr>
<td>Cost of losses</td>
<td>50 €/MWh</td>
<td>Base [MVA]</td>
<td>100</td>
</tr>
</tbody>
</table>

\[
cost_{\text{losses}} = \frac{100 \cdot 50 \cdot 15}{60}
\]  

(B.2)

\[
cost_{\text{Tap}} = \frac{800000}{600000}
\]  

(B.3)

\[
\frac{\mu_{\text{losses}}}{\mu_{\text{Tap}}} = \frac{cost_{\text{losses}}}{cost_{\text{Tap}}} = 1000
\]  

(B.4)