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# Provision of Ancillary Services by Distributed Generators

## Technological and Economic Perspective

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## Abstract (English)

The challenges of designing a sustainable future electrical power system with an improved integration of distributed energy units and renewable energy units are tackled in various research and development projects with different approaches. Due to the early but rapidly maturing stage of research on this complex topic many definitions of future concepts are not harmonised yet. The complete picture of the future power system is still under investigation with regard to technical as well as economic aspects.

This thesis provides four main contributions to this research process:

1. A set of adequate definitions for various concepts concerning the integration of distributed energy units (distributed generators, loads and storage) in the electrical power system is proposed. These definitions are required to reach a common understanding because many of them are still under discussion. An extensive review on definitions and concepts is the basis for the proposed structure of aggregation approaches. Also ancillary services are characterised that can be provided by distributed generators by extending the present focus from transmission networks to active distribution networks.
2. A comprehensive overview of the technological control capabilities of distributed generators and the resulting possibilities of providing ancillary services is provided. The technological potential is investigated by application of a new assessment approach that considers the grid-coupling converter separately with its particular capabilities. An enormous technological potential is identified.
3. The economic potential of a participation of distributed generators in frequency control and reactive power supply is investigated with cost-benefit-analyses that are based on newly developed assessment approaches. Especially reactive power supply by distributed generators looks very promising. Therefore, a modified droop concept is developed that can reduce the operational costs of reactive power supply in mini-grids considerably.
4. A control system for distributed energy units in ISET’s Design-Centre for Modular Supply Technology is developed. This control system allows demonstrating the technological and economic capabilities of distributed energy units with regard to the provision of ancillary services by hardware experiments. Optimised reactive power supply is demonstrated with centralised and decentralised control concepts.

## Abstract (Deutsch)

Es gibt viele Ansätze zur Gestaltung eines zukünftigen nachhaltigen Stromversorgungssystems mit einer verbesserten Einbindung dezentraler und erneuerbarer Energiequellen. In diesem komplexen Themenfeld werden zahlreiche Definitionen und Konzepte noch nicht einheitlich verwendet. Zudem werden viele technische und wirtschaftliche Eigenschaften noch intensiv untersucht.

Zu diesem Forschungsprozess liefert die vorliegende Arbeit vier wichtige Beiträge:

1. Eine Durchsicht vorhandener Definitionen und Konzepte für die Einbindung von dezentralen Energieeinheiten (dezentrale Erzeuger, Lasten und Speicher) in das Stromversorgungssystem offenbarte Uneinheitlichkeiten und Abgrenzungsschwierigkeiten. Für die verschiedenen Integrationsansätze werden deshalb Definitionen und eine Gesamtstruktur vorgeschlagen. Zudem werden Systemdienstleistungen beschrieben, welche durch dezentrale Erzeuger bereitgestellt werden können, wenn das derzeitige Blickfeld von Übertragungsnetzen auf aktive Verteilnetze erweitert wird.
2. Es wird ein umfassender Überblick über die technischen Regelungsfähigkeiten von dezentralen Erzeugern gegeben sowie über die sich daraus ergebenden technischen Möglichkeiten, Systemdienstleistungen bereitzustellen. Das technisch verfügbare Potenzial wird durch einen neu entwickelten Untersuchungsansatz ermittelt, welcher die netzgekoppelten Energiewandler mit ihren speziellen Eigenschaften getrennt von der gesamten Erzeugungseinheit betrachtet. Die ermittelten technischen Möglichkeiten sind enorm.
3. Auf Basis dieser technischen Möglichkeiten wird das wirtschaftliche Potenzial untersucht, Systemdienstleistungen durch dezentrale Erzeuger bereitzustellen. Dabei werden neu entwickelte Bewertungsansätze auf Basis von Kosten-Nutzen-Vergleichen eingesetzt, um die Wirtschaftlichkeit der Teilnahme an der Frequenzregelung und der Blindleistungsbereitstellung zu bewerten. Dabei ist das wirtschaftliche Potenzial der Blindleistungsbereitstellung durch dezentrale Erzeuger besonders viel versprechend. Deshalb wurde auch ein modifiziertes Konzept für die Anwendung von Statiken in Inselsystemen entwickelt, welches die Betriebskosten der Blindleistungsbereitstellung beträchtlich reduzieren kann.
4. Für die dezentralen Energieeinheiten im Design-Zentrum Modulare Versorgungstechnik (DeMoTec) des Instituts für Solare Energieversorgungstechnik (ISET) in Kassel wurde ein Steuerungssystem entwickelt. Dieses ermöglicht die Untersuchung und Vorführung der technischen und wirtschaftlichen Möglichkeiten verschiedener Regelungskonzepte in Laborumgebung. Eine wirtschaftlich optimierte Blindleistungsbereitstellung durch dezentrale und zentrale Regelungskonzepte wurde im Rahmen der Arbeit damit demonstriert.

# Executive Summary


Two main political aims in the European Union are the reduction of greenhouse gas emissions and the reduction of the dependency on fossil energy imports. The use of local Renewable Energy Sources (RES) and Distributed Energy Resources (DER) can contribute to reach these objectives.

In some countries incentive systems boost investments in DER and RES. The main objective in many of these countries is to feed-in maximum active power, but in future the need increases for an active participation of DER units in supporting network operation. With high shares of DER units in power generation they should cover also similar control tasks as conventional power plants in order to keep or even increase the efficiency, quality and security of the power supply system.

Distribution networks were formerly designed for a predominantly passive operation because their task was mainly to distribute electricity with unidirectional power flow from the transmission level down to the consumer. In future the distribution system should be controlled more actively in order to utilise both the network and the DER/RES units more efficiently because power flows can be reversed and power generation can be variable.

The challenges of designing a sustainable future electrical power system with an improved integration of DER and RES are tackled in various research and development projects with different approaches. Due to the early but rapidly maturing stage of research on this complex topic many definitions of future concepts are not harmonised yet. Many aspects of the future power system are still under investigation and need to be analysed.

This thesis has the following four main objectives:

1. The first objective is to propose appropriate definitions for future ancillary services and various aggregation approaches that integrate distributed energy units (distributed generators, loads and storage) in the electrical power system.
2. The second objective is to give a comprehensive overview of the technological control capabilities of distributed generators and the resulting possibilities of providing future ancillary services.
3. The third objective is to assess the economic potential of providing ancillary services by distributed generation with focus on frequency control services and reactive power supply.

4. The fourth objective is to demonstrate the technological and economic capabilities with software simulation as well as hardware laboratory experiments with focus on optimisation approaches for cost-efficient reactive power supply.

These objectives can also be understood as answers to the following questions:

1. How can future ancillary services, controllable distributed energy units and aggregation approaches be structured and defined?
2. What are the technological capabilities of providing future ancillary services by distributed generators?
3. What are the costs of active and reactive power control and is it profitable to provide frequency control services and reactive power by distributed generators?
4. How can these technological and economic capabilities be demonstrated?

The following four main contributions to the research process on future power systems result from the presented thesis. They provide answers to the above posted questions and indicate that the initial objectives of the work are accomplished.

**1) Definitions for future ancillary services and aggregation approaches for the improved integration of distributed energy units in future power systems**

The future power system may have a large number of distributed generators and variable power generation from renewable energy resources. Many approaches are investigated that may facilitate the system integration of controllable distributed energy units with the aim of improving the efficiency, quality and security of the system operation. A set of definitions and a structure for basic aggregation approaches is proposed in this thesis on the basis of a literature review.

Operators of controllable distributed energy units can provide services for the operation of the public network by autonomous operation or by letting them be aggregated technically and commercially. The following types of aggregation approaches are identified and definitions are proposed:

- Active Customer Network
    - connected to the public distribution network or
    - connected to the public transmission network,
- Active Distribution Network, and
- Commercial Aggregation such as

- Virtual Power Plant, and
- Pool-BEMI.

The proposed structure of basic aggregation approaches provides an adequate framework for further analyses on the integration of distributed energy units in future power systems.

Presently, ancillary services are mainly provided by large power plants to the transmission network operator. In future also ancillary services can be provided by controllable distributed energy units to active distribution network operators. These future ancillary services comprise:

- Power/Frequency control,
- Power/Voltage control,
- Congestion management,
- Improvement of power quality,
- Reduction of power losses,
- Black start, and
- Islanded operation.

The characterisation of these ancillary services in this thesis is considered as a reference for further analyses, esp. in the presented work, because the definitions and regulations are not harmonised yet.

**2) Comprehensive analysis of technological capabilities of distributed generators to provide future ancillary services**

The technological capabilities of distributed generators to provide ancillary services depend mainly on the type of unit and its grid-coupling converter. Many studies are available that investigate partly the capabilities but not comprehensively. An assessment approach is proposed here that considers the grid-coupling converter separately. Four types are distinguished:

- directly-coupled induction generator,
- directly-coupled synchronous generator,
- inverter, and
- doubly-fed induction generator.

The assessment approach allows providing a comprehensive overview on technological capabilities of distributed generators to providing ancillary services. Analysed distributed generators comprise:

- wind turbine generator systems,
- photovoltaic systems,
- hydroelectric power stations,
- combined cooling, heating and power systems, and
- storage systems.

The most important result of the performed assessment is that controlled distributed generators can provide all types of ancillary services. Constraints resulting from the availability of single units with variable power generation can be reduced by making use of aggregation approaches and inclusion of advanced forecast models. Further limitations exist for thermally-driven combined heat and power systems that cannot control active power without additional storage equipment independent from the thermal process. Moreover, distributed generators that are coupled with induction generators cannot control reactive power without additional equipment such as capacitor banks. All other distributed generators can provide the full range of ancillary services that is based on active and reactive power supply. Power quality, as an additional ancillary service, can only be improved by distributed generators that are coupled with inverters or doubly-fed induction generators.

This comprehensive assessment of technological control capabilities of distributed energy units shows the huge technical potential that is available to support network operation by provision of ancillary services. On this basis, the economic potential can be analysed in order to indicate those units that can provide ancillary services most economically.

**3) Economic potential of providing ancillary services by distributed generators**

An assessment approach is developed that allows performing a cost-benefit-analysis of the participation on frequency control services markets by distributed generators that use renewable energy sources and receive feed-in tariff reimbursements in Germany. The cost-benefit-analysis shows two main results. On the one hand, the participation in primary control, positive secondary control, and positive tertiary reserve is presently not attractive for the analysed units because the required reduced power generation causes high opportunity costs. Not considered in this assessment is a possible new design of hydroelectric power systems and bio-fuelled plants. On the other hand, the participation in negative secondary control and negative tertiary reserve can be attractive because the basic operation mode is not changed.

Another assessment approach is developed that allows determining the investment and operational costs of reactive power supply. Investment costs caused by additional capacity requirements and variable operational costs caused by additional losses are investigated in detail for distributed generators and their different types of grid-coupling converters. Compared to the costs of conventional reactive power sources, distributed generators are evaluated to be cost competitive in general, especially when they increase their reactive power capacity only modestly and share reactive power supply between each other so that reactive power supply causes only little additional loading of single units.

The cost analysis of reactive power supply shows a large range of variable operational costs depending on the amount of reactive power supply, the actual active power generation, the available reactive power capacity and the efficiency characteristic of the grid-coupling converter. In order to reduce the costs of reactive power supply, different approaches can be considered that distribute reactive power supply between participating units adequately. Two optimisation approaches are analysed. The lowest operational costs of reactive power supply can be obtained by centralised control approaches that are based on the full knowledge of network operators on the cost structure of all devices. However, also decentralised approaches result in significant reductions of the costs without the need of knowing exactly the cost structure and having a continuous communication between the controller and the component.

The droop mode that couples voltage and reactive power is further developed and modified droop functions are applied in order to integrate information on the cost structure of the different components. For instance, in hybrid systems and mini-grids reactive power supply can be extended from grid-forming units to grid-tied units by application of the modified droop concept. This extension reduces the costs but also increases the redundancy and by relieving the grid-forming unit also the reliability of the system. Calculations with the network simulation software PowerFactory from DIgSILENT and MATLAB® from The MathWorks show considerable cost reductions.

**4) Laboratory demonstration of providing optimised reactive power supply by distributed generators**

A control system is developed that allows demonstrating centralised and decentralised control approaches in ISET’s Design-Centre for Modular Supply Technology (DeMoTec). The centralised and decentralised optimised reactive power supply in mains-connected and islanded operation is demonstrated and first results are presented here. These experiments show the technical feasibility of controlling active and reactive power supply of distributed energy units in DeMoTec. The two scenarios are simulated with PowerFactory and the results are compared with measurements of the experimental demonstration in DeMoTec. Both study approaches (simulation and laboratory experiment) have similar results and complement each other.

**According to the investigations in the presented thesis, controllable distributed generators have the technological potential to provide ancillary services. They also have an attractive economic potential that can be used to full capacity by different types of technical and commercial aggregation approaches. Thereby, distributed generators can substitute conventional power plants, not only in terms of active power generation but also in terms of providing ancillary services.**

**Distributed energy units can be integrated in network operation contributing to cost-efficient and secure power system operation. A future power system based on a significant share of distributed generators and renewable energy sources seems to be feasible, not only technically but also economically.**

# Contents

# 1. Introduction

Presently, two main political aims in the European Union are the reduction of greenhouse gas emissions and the reduction of the dependency on fossil energy imports. The use of local Renewable Energy Sources (RES) and Distributed Energy Resources (DER) can contribute to reach these objectives.

According to related political aims, incentives are offered in some countries that boost DER and RES. In many countries the main objective is to feed-in maximum active power, but in future the need for active participation of DER units by supporting network operation increases. With high shares of DER units they principally should cover also similar control tasks as conventional power plants in order to keep or even increase the efficiency and the security of the power supply system.

Distribution networks were formerly designed for a predominantly passive operation because their task was mainly to distribute electricity with unidirectional power flow from the transmission level down to the consumer. In future the distribution system should be controllable more actively in order to utilise both the network and the DER/RES units more efficiently.

The challenges of designing a sustainable future electrical power system with an improved integration of DER and RES are tackled in various research and development projects with different approaches. Due to the early but rapidly maturing stage of research on this complex topic many definitions of future concepts are not harmonised yet and the complete picture is still under investigation.

This thesis has four main objectives of contributing to the described research process:

The first objective is to give appropriate definitions for ancillary services, DER units, and various concepts for their integration in the electrical power system. These definitions are required to reach a common understanding because many of them are not yet consolidated.

Chapter 2 looks at various concepts of integrating distributed energy units in network operation. Typical integration approaches are virtual power plants, Microgrids and active networks. A review shows that harmonised definitions are still missing. Therefore, an applicable structure of aggregation approaches is proposed that includes adequate definitions for such concepts.

Chapter 3 characterises ancillary services and provides the terms and the classifications which are used in this thesis. This characterisation is important because ancillary services are presently mainly used in the transmission system. In future also ancillary services for the distribution system are of interest which can be provided by distributed energy units.

The second objective is to give a comprehensive overview of the technological control capabilities of distributed generators and the resulting possibilities of providing ancillary services.

Chapter 4 analyses the technological control capabilities of providing ancillary services by distributed generators with a new approach that is proposed herein. By separately looking at the grid-coupling converter (directly-coupled induction generator, doubly-fed induction generator, directly-coupled synchronous generator or inverter) a more detailed and comprehensive assessment is achieved for wind turbines, photovoltaic systems, hydroelectric power stations, combined heat and power systems, and storage systems.

The third objective is to assess the economic potential of providing ancillary services by distributed generation with focus on frequency control services and reactive power supply.

Chapter 5 provides an assessment of the costs of active and reactive power control by distributed generators. These control functionalities are the basis for the provision of ancillary services such as frequency control, voltage control, congestion management and reduction of power losses. The economic potential of these types of services is estimated by comparing the benefits of these ancillary services with the costs of controlling active and reactive power.

Chapter 6 presents different approaches for centralised and decentralised reactive power dispatch aiming at reducing the overall costs of reactive power supply.

The fourth objective is to demonstrate the technological and economic capabilities with software simulation studies as well as hardware laboratory experiments. These demonstrations aim at showing some of the theoretically elaborated insights with real systems and real measurement data.

Chapter 7 provides software simulations and laboratory experiments in comparison. The developed control infrastructure for the laboratory is presented in the first section. Then, two approaches of minimising the costs of reactive power supply are demonstrated. On the one hand, central reactive power dispatch in grid-connected applications is demonstrated that uses the developed centrally-oriented control infrastructure. On the other hand, decentralised reactive power control in island grid applications is demonstrated that uses a modified droop concept for the minimisation of reactive power supply costs.

# 2. Review on Aggregation Approaches for Controllable Distributed Energy Units

The challenge of designing a sustainable future electrical power system is tackled with various concepts that allow an improved integration of DER and RES units. Different approaches for adequate aggregation approaches are under development, e.g. Active Distribution Networks, Cells, Microgrids, Virtual Utilities and Virtual Power Plants. They are key concepts for the so called "SmartGrids" approach ([Sanchez 2007] and [EC 2006]) with Information and Communication Technology (ICT) as their enabling technology.

This chapter aims at answering the following question:

> Which types of basic aggregation approaches for the integration of DER units in future power systems can be distinguished?

The definition of DER will be discussed in the first section. Then, different aggregation approaches will be analysed and structured in Section 3. And finally, the interoperability of these aggregation approaches will be discussed in Section 4 with the complete structure.

## 2.1. Fundamental Definitions

Several definitions are available for describing distributed energy resources. Here, the aim is to develop a new, more general term that embraces all controllable grid-connected devices that generate and consume electrical power in the distribution network.

### 2.1.1. Distributed Generation (DG)

Many definitions for 'distributed generation' (DG) exist, such as in [Sanchez 2007], [Driesen;Belmans 2006], [Jenkins et al 1999], [Ackermann et al 2001], [IEEE Std 1547.3], [IEC 60050-617] and [Pepermans et al 2005]. One conclusion from the review of these definitions and discussions is that the connection point of the generator seems to be the most relevant. It includes indirectly criteria for voltage levels and the unit's ratings which are used in many definitions. Here, the definition in [Ackermann et al 2001] is selected as an appropriate one:

*"Distributed generation is an electric power source connected directly to the distribution network or on the customer site of the meter".*

### 2.1.2. Distributed Energy Resources (DER)

The understanding of a resource may be different depending on the perspective of the observer. A network operator may consider all distributed energy units as resources which are able to influence actively the operation of the electrical power system (e.g. *“Distributed resources consist of two aspects: 1. distributed generation, […] and 2. demand-side resources, such as load management system”* [Ackermann et al 2001]).

But this understanding has not prevailed because the more common understanding of the term “resource” is that it delivers energy. Accordingly, ‘distributed energy resources’ or ‘distributed resources’ are defined in [IEEE Std 1547.3] as to *“include both generation and energy storage technologies”.* This general understanding leads to the distinction of

- distributed energy resources (DER) that are
  - distributed generators (that are able to deliver electrical power) or
  - distributed bidirectional storage units (that are able to deliver electrical power after storing it), and
- distributed electrical loads.

These two categories can be embraced with the term ‘Distributed Energy Units’ that allows subsuming all distributed sources and sinks of electrical (active) power. Distributed Energy Units can be further distinguished into controllable and non-controllable units.

### 2.1.3. Controllable Distributed Energy (CDE) Units

Controllable Distributed Energy (CDE) units are the basic elements of all further discussed aggregation approaches. CDE units are capable of controlling active and/or reactive power. These basic control capabilities enable extensive possibilities to provide energy and ancillary services (see Chapter 4).

Ancillary services (AS) are those services that are required for secure and cost-efficient network operation as characterised in Chapter 3, such as power/frequency control, voltage control, reduction of power losses, and improvement of power quality and reliability (see definitions in [IEC IEV 2008]). ‘(System) ancillary services’ are *“services necessary for the operation of an electric power system provided by the system operator and/or by power system users”* according to [IEC 60050-617].

CDE units can provide

- Ancillary Services to the private Customer Network (**AS-CN**),
- Ancillary Services to the public Distribution Network (**AS-DN**)
  at the Point of Common Coupling (PCC), and/or
- Ancillary Services to the public Transmission Network (**AS-TN**)
  at the Grid Supply Point (GSP) via a customer or distribution network.

Not only ancillary services can be provided but also Energy Services (ES) to other network customers either by contracting bilaterally or on the power exchange market. Energy services are understood here as the exchange of active power (energy/power exchange).

**Definition 1:**

**Controllable Distributed Energy units (CDE units) are sources or sinks of electric power that can be connected to the public distribution network (DN). CDE units are able to control active or reactive power.**

The CDE unit can either be connected directly to the public DN or indirectly at the DN customer's side of the meter. Important is the wording 'can be connected' in the definition. With this definition also a photovoltaic generator on the roof of a large industrial facility or a wind turbine within a wind farm are CDE units, even if the wind farm is directly connected to the transmission network. Bulk power plants or other large energy units are obviously excluded by the definition because they cannot be connected at distribution level.

The following section provides definitions of different aggregation approaches that use CDE units to optimise the integration of DER/RES units in the electrical power system.

## 2.2. Aggregation Approaches

A literature review on future electrical power systems showed non-consistent definitions of aggregation approaches for the integration of Controllable Distributed Energy (CDE) units. Here, the aim is to define a set of definitions for basic types of aggregation approaches giving references to reviewed definitions.

The following four main tasks have to be handled in order to organise the electrical power supply system:

- the production of electricity,
- the operation of the transmission network,
- the operation of the distribution network and
- the supply of electricity

These tasks are distinguished in accordance with the unbundling criteria of the EU Directive 2003/54/EC [EU 2003]. This provides a fundamental framework which is assumed to be valid for the aggregation approaches in the future power system as well.

The participants of the power system are differentiated by legal links and respective property rights. According to [IEC 60050-617] a point of connection is a *“reference point on the electric power system where the user’s electrical facility is connected”*. The Point of Common Coupling (**PCC**) is the *“point in the public system which is closest to the customer concerned and to which other customers are or may be connected”* [IEC 61000-3-12] in the distribution network. The Grid Supply Point (**GSP**) is *“a point of delivery from the GB Transmission System to a Distribution System or a Non-Embedded Customer”* that is *“a Customer except for a Public Distribution System Operator receiving electricity direct from the GB Transmission System”* [CUSC 2008].

Operators of private electrical networks and operators of public electrical networks can be distinguished. ‘Public’ and ‘private’ is understood here in relation with the use of the network and not its ownership. Operators of public distribution and transmission networks are obliged to guarantee non-discriminating network access to producers and consumers of electrical power as well as subordinated networks with transparent rules and costs comparable to other cost-efficient public network operators. In addition, they have to operate the network secure, reliable and efficient [EU 2003]. [IEC 61000-6-1] gives as definition of the ‘public mains network’: *“electricity lines to which all categories of consumers have access and which are operated by an electrical power supply and/or distribution organization for the purpose of supplying electrical energy”*. In contrast, system users (customers of the public network) can operate their own private network without any obligation to provide access to others at their premises. A ‘(power) system user’ or ‘(power) network user’ is defined in [IEC 60050-617] as a “*party supplying electric power and energy to, or being supplied with electric power and energy from, a transmission system or a distribution system”*.

The following five main participants can be classified in the power system:

- **Distribution Network Operator** (DNO) or Distribution System Operator (DSO) as the “*party operating a distribution system”* [IEC 60050-617],
- **Transmission Network Operator** (TNO) or Transmission System Operator (TSO) as the “*party operating a transmission system”* [IEC 60050-617],
- **(Electricity) supplier** as the “*party having a contract to supply electric power and energy to a customer”* [IEC 60050-617], and
- user of the public network (and operator of a private network),
    - **Distribution Network (DN) customer**, such as
        - DER unit operator (mainly generation), or
        - residential/commercial customer (mainly consumption)
    - **Transmission Network (TN) customer**, such as
        - operator of a bulk power plant (mainly generation), or
        - commercial customer (mainly consumption).

Five main system integration approaches are discussed in the following. The first approach is the presently dominating way of integrating single distributed energy units. The other four approaches are aggregation approaches. Five main approaches that provide a fundamental classification are considered in the following:

1. Autonomous Controllable Distributed Energy units:
   **Autonomous CDE units** (Section 2.2.1)
2. Active Customer Networks connected to the public Distribution Network: **ACN-DN** (Section 2.2.2/2.2.2.1)
3. Active Customer Networks connected to the public Transmission Network:
   **ACN-TN** (Section 2.2.2/2.2.2.2)
4. Active Distribution Networks:
   **ADN** (Section 2.2.3)
5. **Commercial Aggregation** (Section 2.2.4)

These approaches can easily coexist, merge in hybrid structures (e.g. with regard to distribution and transmission networks) and they can form different subcategories (e.g. based on voltage levels, network areas, and portfolios of CDE units). The paper does not discuss each possible subcategory and hybrid form in detail.

### 2.2.1. Autonomous Controllable Distributed Energy (CDE) Unit

The first approach is the presently pre-dominating way of integrating distributed energy units: each single unit is considered individually and operated autonomously. In addition to energy services, Controllable Distributed Energy (CDE) units can provide ancillary services to the distribution network (AS-DN) via their PCC with the distribution network (here: ADN) as depicted in Figure 2-1. They may also provide ancillary services to the transmission network (AS-TN) at the GSP of the ADN via the distribution network.

The equivalent to the controllable distributed energy (CDE) unit that is connected at the distribution network is a Controllable Energy Unit (CEU) that is connected at the transmission network and that provides energy and ancillary services directly at the GSP to the TN. Conventional Bulk Power Plants (BPPs) and large pumped storage power stations are examples of such controllable energy units.

The aggregation of CDE units increases availability and reliability of services and supports high efficiency in the management and trading of services. Different aggregation approaches are discussed in the following sections.

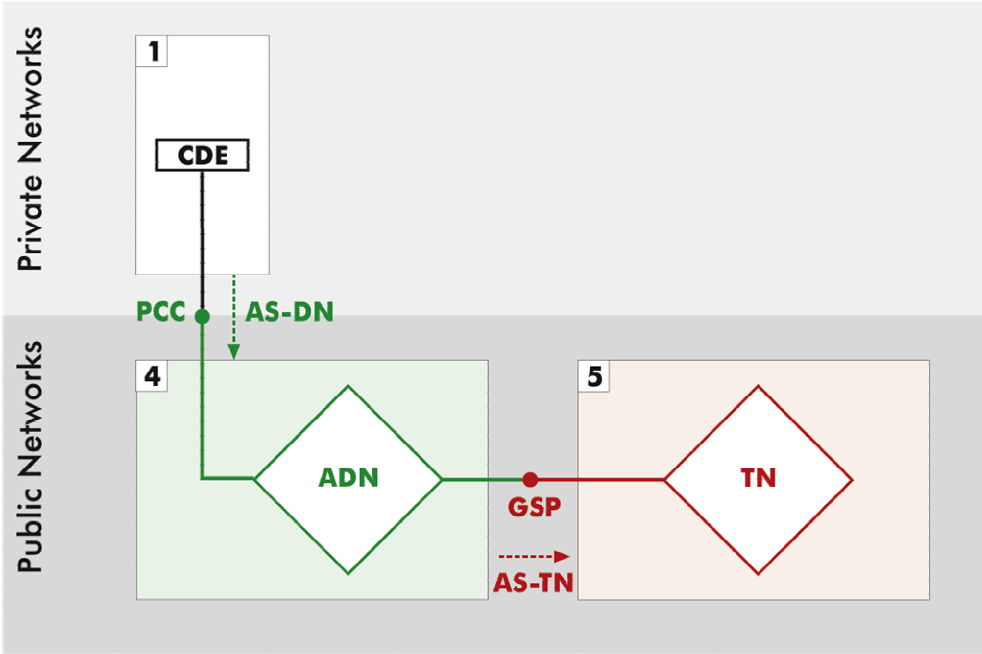


Figure 2-1: Autonomous Controlled Distributed Energy (CDE) unit

### 2.2.2. Active Customer Network (ACN)

The aggregation approach ‘Active Customer Network’ (ACN) considers private networks of public network customers in which CDE units are installed. Services provided by each CDE unit are aggregated by the ACN operator on his/her side of the meter. They can be summarised as ancillary services to this customer network (AS-CN). The ACN operator can provide energy and ancillary services to the public power system at the point of connection. An example of this approach is given in [Bendel;Nestle 2005]. Not only domestic or commercial customers can have active customer networks but also operators of clusters of generators such as wind farms.

Operators of ACNs can optimise the operation internally, e.g. to pay lower energy prices by energy and capacity management such as peak-shaving, whilst providing services at the point of connection to the public power system. This optimisation of the aggregated ensemble of CDE units in the private network can allow a more efficient provision of energy and ancillary services compared to operating each CDE unit individually. An ACN normally operates connected to the public network but may also be operated islanded in order to increase the security of supply and improve the power quality [Reekers et al 2006].

Two basic types of ACNs can be distinguished:

- **ACN-DN**: ACN connected to the public Distribution Network (DN) at the Point of Common Coupling (PCC) and

- **ACN-TN**: ACN connected to the public Transmission Network (TN) at the Grid Supply Point (GSP).

They can provide energy services on power exchange markets and ancillary services to network operators.

**Definition 2:**

**An <u>Active Customer Network (ACN)</u> is a private network whose integrated Controllable Distributed Energy (CDE) units are aggregated in order to control active or reactive power at the point of connection.**

*2.2.2.1. Active Customer Network Connected to the Public Distribution Network (ACN-DN)*

Figure 2-2 illustrates the Active Customer Network connected to the Distribution Network (ACN-DN). It can provide ancillary services to the DNO (AS-DN) at the PCC as well as to the TNO (AS-TN) at the GSP of the Active Distribution Network (ADN) via the distribution network. Domestic consumers often have limited capabilities. Smaller commercial or industrial facilities connected to the distribution network can have sufficient flexibility at their premises to provide all kind of ancillary services.

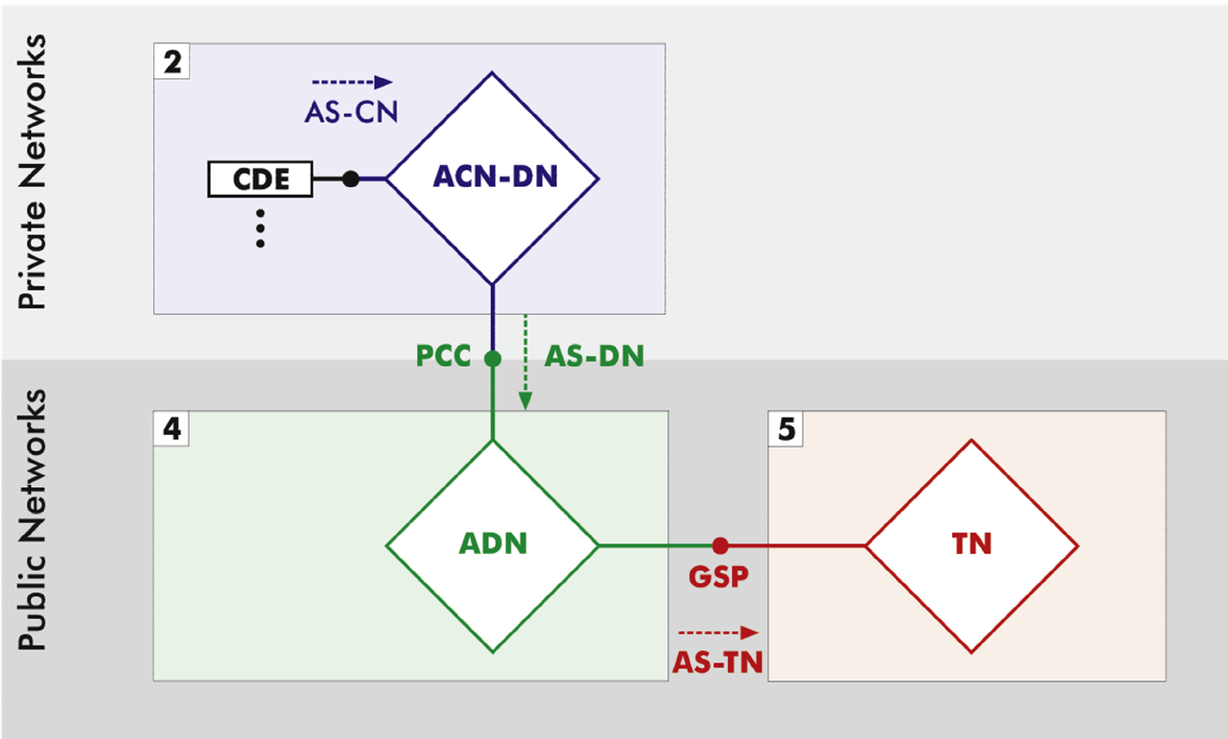

Figure 2-2: Active customer networks connected to the public distribution network at the point of common coupling (ACN-DN)

Different kinds of this aggregation approach have been investigated in a variety of projects, e.g. the German project DINAR [Bendel et al 2008] and the European project CRISP [Schaeffer;Akkermans 2006]. An advanced implementation has already been achieved with the Bidirectional Energy Management Interface (BEMI) as described in [ISET 2003] and [Bendel;Nestle 2005]. BEMI extends the standard PCC by locally aggregating CDE units and providing energy management within the customer's premises. The local decisions of control are based on local information within the premises (e.g. consumer behaviour) and central information (e.g. time-variable prices) which are provided from the energy supplier.

#### 2.2.2.2. *Active Customer Network Connected to the Public Transmission Network (ACN-TN)*

Figure 2-3 illustrates the Active Customer Network connected to the Transmission Network (ACN-TN). In contrast to the ACN-DN, it can only provide ancillary services to the TNO (AS-TN) at the GSP but not to the distribution network. However, it can offer AS-TN directly to the TNO without the need of considering the DNO as it may be the case for the ACN-DN or autonomously operated CDE units.

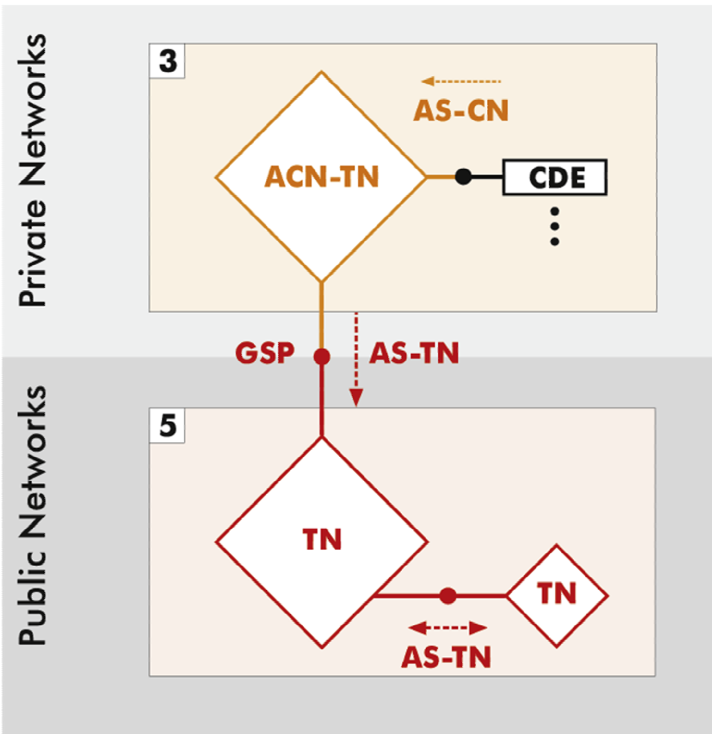

Figure 2-3: Active customer networks connected to the public transmission network at the grid supply point (ACN-TN)

The ACN-TN operator aggregates the connected Controllable Energy Units (CEUs) on his/her side of the meter. Some or all of these CEUs may be CDE units if they also can be connected directly to the distribution network or at the distribution network customer side of the meter.

Larger commercial and industrial facilities are examples of ACN-TNs as well as large wind farms representing a cluster of wind turbines. An internal operational management can guarantee certain characteristics at the GSP emulating a single conventional large power plant.

The aggregation of controllable energy units in a private customer network forms an ACN. In the following subsection, a more extended aggregation approach for the public distribution network is looked at: the Active Distribution Network.

### 2.2.3. Active Distribution Network (ADN)

The change from passive to active distribution network operation is based on taking advantage of local CDE units. This is illustrated in Figure 2-4. In addition to his/her own facilities, an Active Distribution Network (ADN) operator can use ancillary services offered by autonomous CDE units and ACN-DNs in his/her own network or ancillary services offered by neighbour ADNs to optimise his/her network operation. On the other hand, an ADN operator can also provide AS-DN at connection points to neighbour ADNs and AS-TN at the GSP to the Transmission Network (TN). A hierarchical or parallel structure of ADNs may exist, for instance according to different voltage levels or different network regions. Many examples for ADNs can be found in the Active Network Deployment Register [MacDonald et al. 2008].

Different kinds of this control concept have been investigated and defined, such as ‘Cells’, ‘Microgrids’, and ‘Virtual Utilities’. Their definitions will be looked at in more detail in the following review. The term ‘Technical Virtual Power Plants’ (TVPP) is discussed in Section 2.2.4 and can be subsumed with ADN as well.

The approach of so-called ***Cells*** defined in [van Overbeeke;Roberts 2002], [ten Donkelaar 2004] and [Lund et al 2003] aims at changing the presently mostly passive distribution networks by:

1) providing connectivity between points of generation and consumption allowing multiple links for bidirectional power flows and by

2) interacting with the customers in active distribution networks for optimising operation of both, generators and consumers, to provide customer-specific system services. This requires a

3) new control hierarchy by forming local control areas, so-called Cells, with its own power control system allowing islanded operation.

This concept is presently implemented in Denmark by Energinet.dk [Lund et al 2006] and has been investigated in the European projects DISPOWER [Degner et al 2006] and CRISP [Schaeffer;Akkermans 2006]. The voltage levels (LV, MV and HV cells) can be used as levels of hierarchy [van Overbeeke;Roberts 2002].

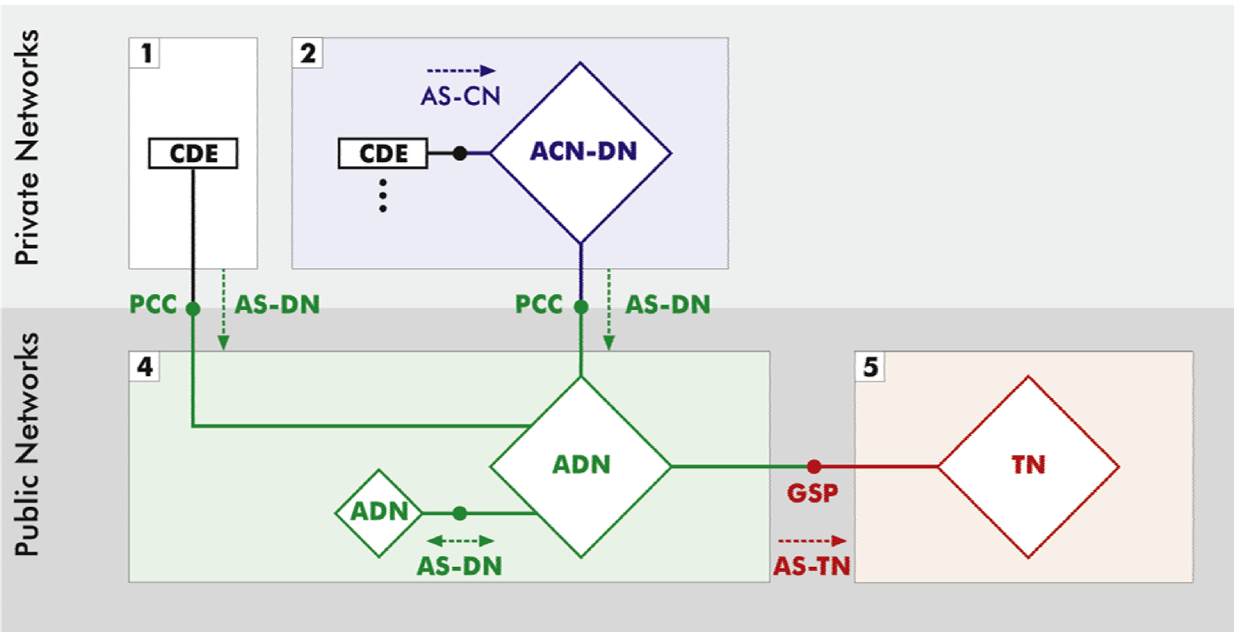


Figure 2-4: Active Distribution Network (ADN)

***Microgrids*** are small electrical distribution networks that can be operated in islanded operation mode or interconnected with the mains. This flexibility can increase the local security of supply.

'Decentralised Grid-Compatible PV Power Supply' as described in [Kleinkauf et al 1998] and [Kleinkauf;Raptis 1997], was a concept where the Microgrid concept evolved from. The transition from one term into the other occurred in the framework of the European projects MORE und PV-Mode [Strauss et al 2000] in the years 1998-2002 with field demonstrations on the Greek island Kythnos. Recent European projects analysing this aggregation approach are MICROGRIDS and More-MICROGRIDS. In parallel, the

CERTS Microgrid Concept has been developed in the USA. The conceptual results of these projects are discussed in the following paragraph. A general overview of related ongoing research, development and demonstration projects is given in [Hatziargyriou et al. 2007].

In European community research, the MICROGRIDS project resulted in a long definition that is given in [Hatziargyriou et al 2006] and in the following short definition for Microgrids: *"Interconnection of small, modular generation to low voltage distribution systems forms a new type of power system, the Microgrid. Microgrids can be connected to the main power network or be operated islanded, in a coordinated, controllable way"* [Hatziargyriou 2005].

The follow-up project More-MICROGRIDS extends the research work of the MICROGRIDS project. The hierarchical aggregation approach of this concept comprises three levels [Hatziargyriou et al 2006]:

1) Local controllers for microgenerators and loads,
2) MicroGrid System Central Controller (MGCC) that promotes technical and economical operation by interfacing with local controllers, and
3) Distribution Management System (DMS) that aggregates multiple MGCCs.

This aggregation approach allows a decision making process which is more or less decentralised depending on its application on the three levels. A fully decentralised control approach allocates the responsibility to the local controllers, for instance by using multi-agent systems. Contrarily, in a centralised control the local controllers follow the orders of the MGCC, when connected to the mains. The DMS enables the integration of several Microgrids into the distribution network's operation on the medium voltage level.

In the USA, the CERTS MicroGrid Concept was the starting point of defining microgrids [CEC 2003]. The following definition is often used for Microgrids: *A microgrid is an integrated energy system consisting of interconnected loads and distributed energy resources which as an integrated system can operate in parallel with the grid or in an intentional island mode"* [Agrawal et al 2006].

Some predominant aspects can be attributed to the **Virtual Utility** (VU) concept (early definitions in [Awerbuch;Preston 1997] and [Carayannis et al 1996]) even though the definitions in literature show a large variety of understanding:

1) aggregation of DER units (portfolio building), which can be considered as a single power plant, without necessarily owning them;

2) use of a web-based communication infrastructure (internet-like model) [EC 2006], [Jones;Petry 2000], [Bayegan 2001]; and
3) can either be connected to the main grid or operate as stand-alone [Jones;Petry 2000], [Coll-Major et al 2004].

Many of the definitions for VU also refer to definitions for Virtual Power Plant (VPP), e.g. [Castelaz 2000], which is discussed in Section 2.2.4. Some papers also distinguish VU from a Microgrid: *“The Virtual Utility approach is a more flexible option than the Microgrid as it can utilise both local and remote generation resources, and requires little immediate change in the way the power networks are operated”* [Ramsay;Leach 2005]. The term ‘Virtual Utility’ is a good example of present inconsistencies in definitions.

This review of conceptual approaches for aggregating CDE units in distribution networks shows that ‘Microgrids’, ‘Cells’ and ‘Technical Virtual Power Plants’ (see Section 2.2.4) have similar properties. Consequently, they can be subsumed with only one term instead of using several one. In the following the embracing term ‘Active Distribution Network’ with the following definition is used´.

**Definition 3:**

**An <u>Active Distribution Network (ADN)</u> is a distribution network in which CDE units provide ancillary services for network operation.**

The ADN operation can be optimised with regard to cost-efficiency but also with regard to security of supply, e.g. by being able to operate in intentional island mode as a Microgrid.

### 2.2.4. Commercial Aggregation

Either each operator of autonomous CDE units or ACNs manages his/her commercial activity (i.e. providing ancillary services to network operators) individually or he/she decides to give it into the hands of an agent who aggregates them commercially. The commercial aggregation can be efficient in many situations, because it can reduce transaction costs of small players significantly [Williamson 1975].

Commercial aggregation is based on contractual links between the aggregator and the energy unit’s operator as well as between the aggregator and the network operators and the power exchange market. Commercial aggregators are traders who contract services to provide them to other parties without using them themselves. They make profit from selling and buying services. In contrast, the technical aggregation that is described for ACNs and ADNs is based on physical links and power flows between the energy units and the aggregated network. Contractual links may exist as well but are not the constituting element for technical aggregation as it is for commercial aggregation.

From the perspective of the operators of public networks, in particular of transmission networks, it can become challenging and costly to negotiate with a large number of autonomous CDE units and ACNs individually. The use of an intermediate aggregation, e.g. by the energy supplier, is one approach to solve effectively restrictions that are caused by quantity and size. The aggregation approach for this approach is the so called ‘commercial aggregation’. Commercial aggregation of CDE units and ACNs via ICT, esp. the Internet, forms a multi-fuel, multi-location and multi-owned power plant which is constituted on a contractual basis.

Different control approaches can be distinguished in commercial aggregation. Five main types of relationships between distributed energy units, CDE units and ACNs on the one side and the commercial aggregator on the other side are listed in Table 2-1 and discussed in the following paragraphs.

The first type of relationship is named ‘**No Integration**’. Neither active communication nor control exists. However, there is a contract basis that forms the relationship.

The use of ‘**Smart Metering**’, as the second type of relationship, establishes an information flow for metering purposes only to the commercial aggregator. *“Smart metering is designed to provide utility customers information on a real time basis about their domestic energy consumption […]. The key distinction between smart-meter types is determined by their communication i.e. whether there is any with the energy supplier, whether this is one-way or two-way”* [Venables 2007]. Time series of measurement data which are available near to the time of measurement, allow analysing the behaviour of distributed energy units and their dependency on certain framework conditions such as time of day, season of the year, weather and events. The achieved knowledge on actual generation and consumption facilitates appropriate power system operation.

In the third type of relationship **‘Variable Pricing’**, information flows in opposite direction. Operators of CDE units and ACNs can consider the variable prices for energy consumption, energy feed in or for ancillary services as incentives to optimise their behaviour. No direct control from the side of the commercial aggregator can be stated in this relationship because the result of the incentives is assumed not to be measured accordingly and/or analysed in due time (i.e. ‘Smart Metering’ without communication back to the aggregator).

| Type of Relationship | Communication | Control Approach of the Aggregator |
|---|---|---|
| 'No Integration' | No<br>Distributed Energy Unit   Commercial Aggregator | No |
| 'Smart Metering' | Unidirectional<br>Distributed Energy Unit → Commercial Aggregator | No<br>But information |
| 'Variable Pricing' | Unidirectional<br>CDE unit ACN ← Commercial Aggregator | No<br>But incentives |
| 'Pool-BEMI' | Bidirectional<br>CDE unit ACN ↔ Commercial Aggregator | Incentive-based<br>Indirect control |
| Virtual Power Plant (VPP) | Bidirectional<br>CDE unit ACN ↔ Commercial Aggregator | Direct control |

Table 2-1: Types of relationships between CDE unit / ACN and the commercial aggregator

The **'Pool-BEMI'** approach (BEMI = bidirectional energy management interface) allows an incentive-based indirect control, meaning that the behaviour of contracted BEMI operators – the operators of CDE units and ACNs – cannot be defined by setting target values but a certain behaviour can be incentivised. This concept has been introduced in [Bendel et al 2006]. The fundamental characteristic of this aggregation approach is that BEMI operators receive central information (e.g. variable prices) in addition to having local information (e.g. amount of local energy demand). This information basis enables them to decide locally in order to maximise their benefit. Therewith, BEMI operators can stay autonomous whilst the aggregator can control the customers' behaviour on a statistical basis without requiring direct control in the customers' system.

**Definition 4:**

**A <u>Pool-BEMI</u> is an information and communication system that aggregates Controllable Distributed Energy (CDE) units or Active Customer Networks (ACNs) which are controlled by Bidirectional Energy Management Interfaces (BEMIs). The Pool-BEMI applies incentive based indirect control.**

The '**Virtual Power Plant' (VPP)** approach is an aggregation approach with direct centralised control of CDE units. The integration in the power system control can be intensified by setting target values in a direct closed-loop-control. This direct control allows optimising the market participation of those CDE units which can be controlled flexibly.

The VPP is under investigation in many projects such as FENIX [Pudijanto et al 2008] and the European Virtual Fuel Cell Power Plant [Dauensteiner 2007]. A literature review showed that numerous definitions of VPP have been created. The most important ones are cited here to give an overview and extract the fundamental characteristics of this aggregation approach.

A scientific-oriented short definition is provided in the European project CRISP [Andrieu et al 2005]: A *"Virtual Power Plant"* is an *"aggregation of DER units dispersed among the network, but controllable as a whole generating system"*. They also define a superordinated entity which aggregates VPPs as well: A *"Large-Scale Virtual Power Plant"* (LSVPP) is an *"aggregation of VPP or of DER units dispersed widely among the network, controllable as a whole generating system"*. Two aspects of a VPP can be derived from this definition. Firstly, different levels of aggregation are possible and, secondly, dispersed CDE units are controllable by the VPP.

The following definitions are provided by the European project FENIX [Pudijanto et al 2008] (previously [Pudjianto et al 2007]):

*"A Virtual Power Plant (VPP)* […] *is a flexible representation of a portfolio of DER that can be used to make contracts in the wholesale market and to offer services to the system operator. There are two types of VPP, the Commercial VPP (CVPP) and the Technical VPP (TVPP). DER can simultaneously be part of both a CVPP and a TVPP."*

*"A CVPP has an aggregated profile and output which represents the cost and operating characteristics for the DER portfolio. The impact of the distribution network is not considered in the aggregated CVPP profile. Services/functions from a CVPP include trading in the wholesale energy market, balancing of trading portfolios and provision of services* […] *to the system operator. The operator of a CVPP can be any third party aggregator or a Balancing Responsible Party (BRP) with market access; e.g. an energy supplier."*

*"The TVPP consists of DER from the same geographic location. The TVPP includes the real-time influence of the local network on DER aggregated profile as well as representing the cost and operating characteristics of the portfolio. Services and functions from a TVPP include local system management for DSO, as well as providing TSO system balancing and ancillary services. The operator of a TVPP requires detailed information on the local network; typically this will be the DSO."*

CVPPs perform commercial aggregation and do not take into consideration any network operation aspects that active distribution networks have to consider for a stable operation. TVPPs are designed to control the participating CDE units in ADNs.

An extended list of constituting aspects of a VPP is given in [Santjer et al 2002]:

1. Aggregation of a large amount of widely dispersed energy generators
2. Behaviour similar to a conventional power plant
3. A management system coordinates the aggregated generators
4. Bidirectional communication
5. Internet technology

Based on the literature review, the following definition of a Virtual Power Plant is proposed:

**Definition 5:**

**A <u>Virtual Power Plant (VPP)</u> is an information and communication system that aggregates Controllable Distributed Energy (CDE) units or Active Customer Networks (ACNs) by direct centralised control.**

Multi-Agent Systems (MAS) are one presently investigated approach of aggregating CDE units. MAS using electronic markets for coordination fit into a line of research that is called market-based control as described in [Bendel et al 2007], [Dimeas;Hatziargyriou 2005], [Oyarzabal et al 2005], [Kok et al 2005a], [Kok et al 2005b] and [Kamphuis et al 2007].. Each CDE unit can be controllable by its agent that participates on electronic markets where optimised control decisions can be found. The application is presently limited to control actions where the location is not important (e.g. power exchange and balancing services). Location-specific ancillary services for an Active Distribution Network are challenging to handle in such a concept. In future it may be applicable as well for ADNs.

The next section discusses the structure of power systems that consists of the described aggregation approaches and extends the scope by discussing the provision of energy services on the power exchange market.

## 2.3. Structure of a Power System with the Identified Aggregation Approaches

Figure 2-5 illustrates a power system with the discussed basic co-existent aggregation approaches. They enable reducing the complexity of its operation by technical and commercial aggregation. Different levels of aggregation and hybrid forms of the aggregation approaches may exist but are not further discussed here.

The fundamental element of all aggregation approaches is the Controllable Distributed Energy (CDE) unit. A CDE unit is connected either to the public distribution network and operated autonomously or connected to a private customer network that is connected to the distribution network. The basic characteristic of a CDE unit compared to DER units and loads in general is its capability to control active and/or reactive power. Each *autonomous CDE unit* (No. 1 in Figure 2-5) can control its active and/or reactive power in order to provide energy services on the power exchange market and ancillary services (AS-DN) to the active distribution network (ADN).

With the aggregation approach of an active customer network connected to the distribution network (ACN-DN), CDE units are integrated by using ancillary services to private customer networks (AS-CN) to optimise the operation of the ACN. An Active Customer Network connected to the Distribution Network (*ACN-DN*, No. 2 in Figure 2-5) represents one profile of all technically aggregated CDE units at the PCC and provides ancillary services (AS-DN) to the Active Distribution Network (ADN) operator. In contrast, an Active Customer Network connected to the Transmission Network (*ACN-TN,* No. 3 in Figure 2-5) represents one profile of all technically aggregated Controllable Energy Units (CEUs) at the GSP and provides Ancillary Services (AS-TN) to the Transmission Network (TN). An ACN-TN may also comprise CDE units.

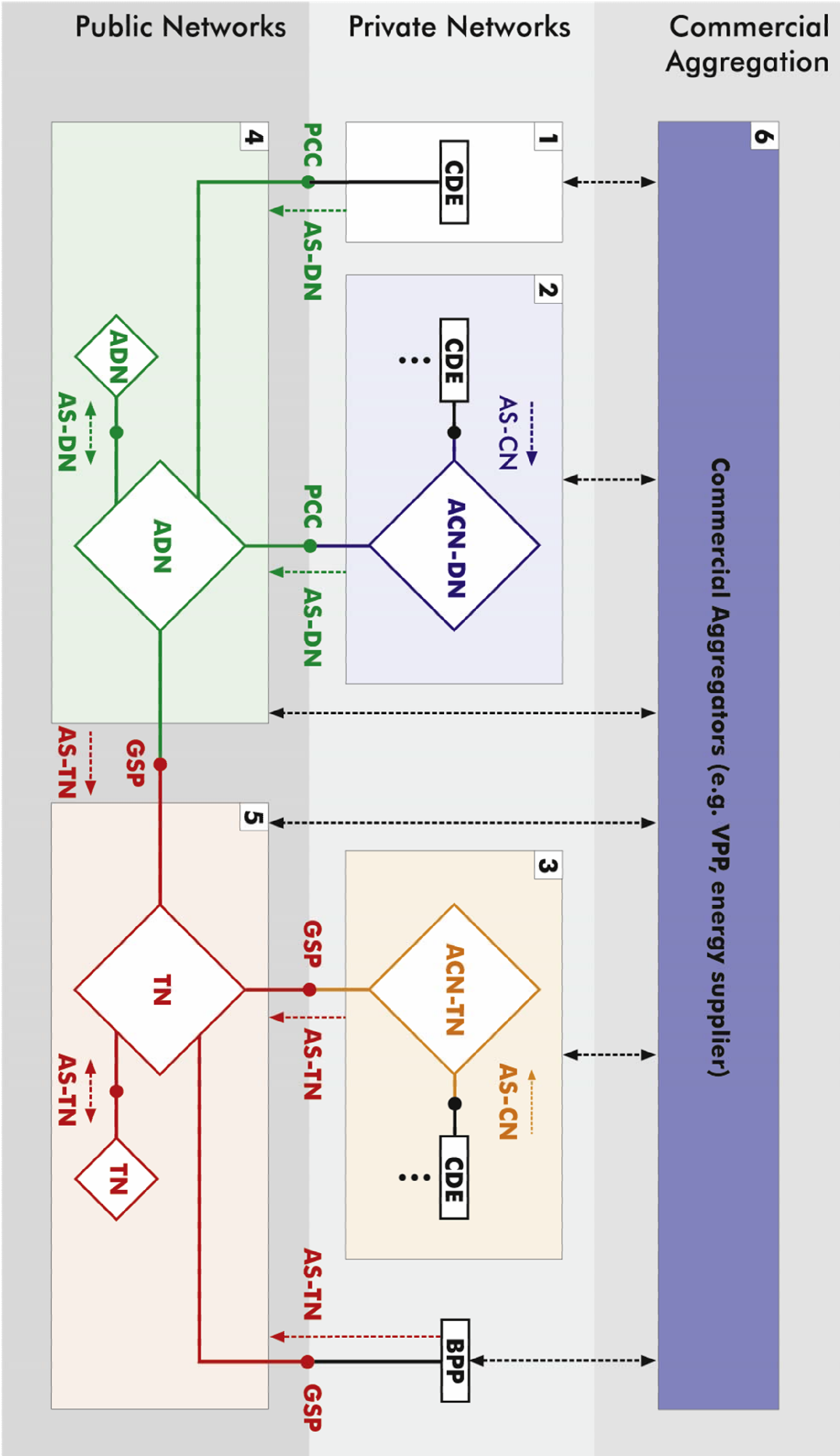


Figure 2-5: Basic aggregation approaches for the integration of controllable distributed energy units in the operation of the electrical power network

In addition to own network facilities, the Active Distribution Network (*ADN*, No. 4 in Figure 2-5) operator uses ancillary services (AS-DN) offered from autonomous CDE units, ACN-DNs and other connected ADNs in order to optimise the operation of his/her public distribution network. The operator can provide AS-DN to other connected ADNs as well as ancillary services (AS-TN) to the superior transmission network (TN).

The transmission network (*TN***,** No. 5 in Figure 2-5) operator uses ancillary services (AS-TN) offered from ADNs, ACN-TNs, bulk power plants (BPPs) and other connected TNs as well as own network facilities with the aim is to optimise the operation of his/her public transmission network.

Finally, next to the technically aggregation in public and private power networks, the *commercial aggregation* is given with No. 6 in Figure 2-5. This commercial aggregation can reduce transaction costs for service delivery compared to autonomous market participation of each single unit. A Virtual Power Plant (*VPP*) operator aggregates and controls CDE units and ACNs on a contractual basis and offers aggregated profiles of his portfolio in form of AS-DN to ADN operators, AS-TN to TN operators, and energy services to the power exchange market. Another way of commercial aggregation can be achieved by incentive-based control of CDE units and ACNs using the *Pool-BEMI* approach as the enabling technology for the energy supplier.

Energy units under consideration have the primary objective of providing or consuming active power contracted (directly or indirectly) on the power exchange markets. The same can be stated for private customer networks that technically aggregate the energy units. CDE units and ACNs consequently contract primarily energy services that can be aggregated commercially. In addition, they can provide services, ancillary services, to the public network operators in order to support secure and efficient network operation as discussed above.

## 2.4. Summary of Chapter 2

The future power system may have a large number of distributed generators and variable power generation from renewable energy resources. Many approaches are investigated that may facilitate the system integration of controllable distributed energy units with the aim of improving the efficiency and security of the system operation. This chapter analyses a set of basic aggregation approaches and definitions based on a literature review.

The proposed set of basic aggregation approaches provides a framework for further analyses on the integration of distributed energy resources and loads as well as renewable energy resources in future power systems. Operators of controllable distributed energy units can provide services for the operation of the public network by autonomous operation, by letting them be aggregated technically in private active customer networks or public active distribution networks. Finally, operators of controllable distributed energy units can also hand over the control of the unit to a commercial aggregator (e.g. a VPP operator) who is contracted to sell possible services to other parties of the power system.

The next chapter characterises the ancillary services which can be provided by controlled distributed energy units.

# 3. Characterisation of Ancillary Services

The previous chapter gives an overview of approaches that allow integrating controllable distributed energy (CDE) units in the operation of the power system. CDE units can provide different types of control services to the power system. The scope of this thesis is on ancillary services for network operation. '(System) ancillary services' are *"services necessary for the operation of an electric power system provided by the system operator and/or by power system users"* according to [IEC 60050-617].

Another definition is given by the Union of Electric Industry EURELETRIC: *"Ancillary Services are those services provided by generation, transmission and control equipment which are necessary to support the transmission of electric power from producer to purchaser. These services are required to ensure that the System Operator meets its responsibilities in relation to the safe, secure and reliable operation of the interconnected power system. The services include both mandatory services and services subject to competition"* [Eurelectric 2000].

## 3.1. Ancillary Services Provided by Controllable Energy Units

One basic distinction of these ancillary services is based on the way of the provision of the service:

- fast, local and generally automatic control within seconds
  (e.g. primary voltage or primary frequency control), or
- remote, centralised and coordinated control within minutes
  (e.g. secondary/tertiary voltage control or secondary/tertiary frequency control).

These two ways include different time horizons (speed of service provision) and different spatial perspectives (local or remote).

With an increasing number of controllable distributed energy units it becomes possible to operate active distribution networks (ADNs) more reliably and cost-efficiently by making use of ancillary services offered by CDE units. An ADN can be operated alternately grid-connected (connected to the transmission network) or islanded (disconnected from the transmission network)[1].

---

[1] An 'island' is the *"portion of a power system, that is disconnected from the remainder of the system, but remains energized"* [IEC 60050-617].

Ancillary services provided at ADN level can be categorised according to the operation modes ‘grid-connected operation’ and ‘islanded operation’:

- Ancillary Services in Islanded Operation:
  - **Black Start**
  - Grid-Forming Operation:
    - **Frequency Control**
    - **Voltage Control**
      = “the adjustment of the network voltages to values within a given range” [IEC 60050-617]
  - Grid-Tied Operation:
    - **Power/Frequency Control**
      or ‘power/frequency control’ = “*secondary control of the active power of generating sets in response to variations in system frequency*” [IEC 60050-617]
    - **Power/Voltage Control**
      or ‘reactive-power voltage control’ = “*voltage control by the adjustment of reactive power generation in a power system*” [IEC 60050-617]
    - **Improvement of Power Quality**
      ’power quality’ = “*characteristics of the electric current, voltage and frequencies at a given point in an electric power system, evaluated against a set of reference technical parameters*” [IEC 60050-617]
    - **Congestion Management**
    - **Reduction of Power Losses**
      ’power losses’ are *“the difference at a given moment in time between the total active input power and the total active output power in a network”* [IEC 60050-617]
- Ancillary Services in Grid-Connected Operation:
  - Power/Frequency Control (to TNO)
  - Power/Voltage Control
  - Improvement of Power Quality
  - Congestion Management
  - Reduction of Power Losses

These ancillary services are shortly characterised in Annex II.

## 3.2. Basic Control Capabilities for Ancillary Services

The *basic* control capabilities which are necessary for the provision of ancillary services (exclusively the improvement of power quality) are active power, reactive power, (direct) voltage and (direct) frequency control. Table 3-1 shows their allocation to the ancillary services they can be or have to be applied for.

| **Ancillary Services** | **Active Power Control** ***P*** | **Reactive Power Control** ***Q*** | **Direct Voltage Control** ***V*** | **Direct Frequency Control** ***f*** |
|---|---|---|---|---|
| Power/Frequency Control | X | | | |
| Power/Voltage Control, Congestion Management, Reduction of Power Losses | X | X | | |
| Grid-Forming / Black Start | X | X | X | X |

Table 3-1: Basic control capabilities (P,Q,V,f) for ancillary services provided by CDE units

Active power control is necessary for power/frequency control. Power/voltage control, congestion management and the optimisation of power losses depend on the active and reactive power control. Active power control may be the second-best option because of its normally bigger economic value compared to reactive power (cf. Section 5.2).

Active and reactive power control is necessary for grid-forming (islanded operation) and black start because the active and reactive power has to be balanced in a stable network operation. In addition, it is necessary to define directly the frequency and the voltage setpoints. Only with all four basic control capabilities it is possible to form a grid adequately. The interdependences between active and reactive power on the one hand and voltage and frequency on the other hand in case of islanded operation of distribution networks are discussed in [Engler 2005] and analysed in the following according to [Jahn 2007].

Figure 3-1 shows the analysed equivalent circuit with two voltage sources $\underline{u}$ and $\underline{u}_2$ which are connected via the network impedance $\underline{z}$ with its impedance angle $\varphi_N$ or the ratio of resistance and reactance $R/X = 1/atan(\varphi_N)$. The transfer capability of active power $P$ and reactive power $Q$ is analysed with regard to the voltage difference (corresponding to voltage control)

$$dU = U - U_2 \tag{3-1}$$

and the voltage angle $\delta$ (delta) resulting from the integral over the frequency deviation of the two voltage sources (corresponding to frequency control):

$$\delta = \int_t \Delta f \; dt \tag{3-2}$$

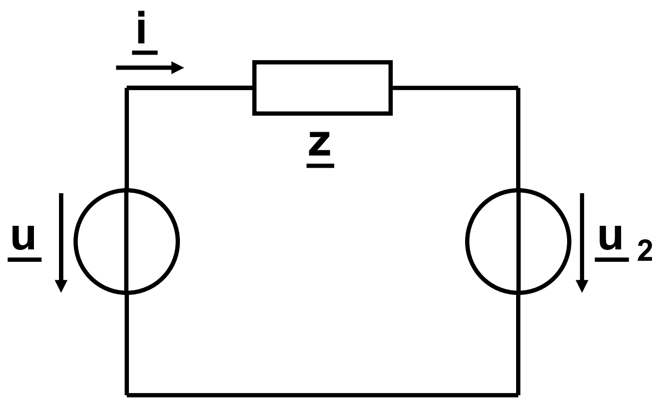


Figure 3-1: Equivalent circuit of two voltage sources connected via an impedance

With the following basic electrical equations the interdependencies are analysed:

$$\begin{aligned} \underline{u} &= U e^{j\omega_N t} \\ \underline{u}_2 &= U_2 e^{j\omega_N t} e^{-j\delta} \\ \underline{z} &= Z e^{j\varphi_N} = R + jX \\ \underline{i} &= \frac{\underline{u} - \underline{u}_2}{\underline{z}} \end{aligned} \tag{3-3}$$

$$\begin{aligned} \underline{S} &= \frac{1}{2} \underline{u} \cdot \underline{i}^* \\ P &= \Re(\underline{S}) \\ Q &= \Im(\underline{S}) \end{aligned} \tag{3-4}$$

The voltage magnitude of $\underline{u}$ is fixed to $U$ = 230 V and the absolute value of the network impedance is fixed to $Z$ = 0.5 Ω for all four graphs of Figure 3-2. As the steady-state is analysed, the time $t$ is set to zero.

On the left hand side of Figure 3-2 active and reactive power are presented in dependency on the voltage angle delta at fixed voltage difference *dU* = -3 V. It can be seen that at the impedance angle $\varphi_N$ = 0° (pure resistive coupling) the active power is nearly independent on the voltage angle delta but the reactive power shows a clear linear dependency. These relationships are reversed at an impedance angle $\varphi_N$ = 90° (pure reactive coupling) because only active power shows the linear dependency on delta.

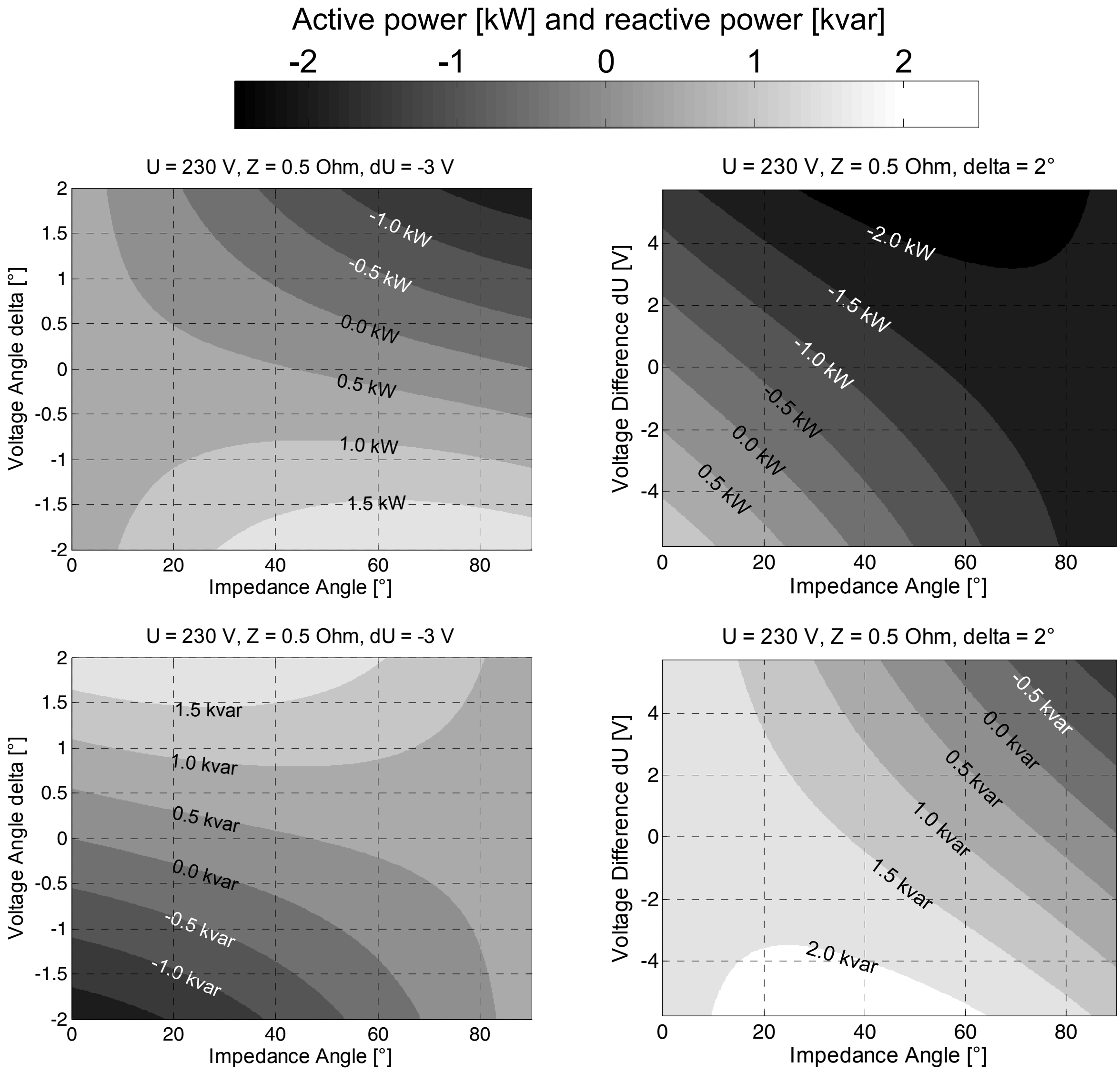


Figure 3-2: Interdependency of active power *P,* reactive power *Q,* voltage *U,* voltage angle *δ,* impedance angle $\varphi_N$ (MATLAB calculations)

On the right hand side of Figure 3-2 active and reactive power are presented in dependency on the voltage difference *dU* at fixed voltage angle *δ* = 2°. It can be seen that at an impedance angle $\varphi_N$ = 0° (pure resistive coupling) reactive power transfer is nearly independent on *dU* but active power transfer shows a linear dependency. This behaviour is reversed at an impedance angle $\varphi_N$ = 90° (pure reactive coupling) because the controllability is limited to reactive power. Compared to the two pictures on the left hand side, the dependencies are reversed.

Table 3-2 provides an overview of typical line data. These data allow categorising the interdependency on different voltage levels.

Overhead lines in HV (here: 110 kV) and EHV (here: 750 kV) have a ratio of $R/X$ << 1 and can therefore be considered as inductive. The clear functional dependency $P(\delta)$ and $Q(U)$ is applicable in transmission networks resulting in simple control functions for frequency and voltage.

At LV level (here: 1 kV) the cross section of cables is often below 150 mm² resulting in $R/X$ > 1 and at MV (here: 10 - 30 kV), the cross section is normally around 150 mm² resulting in $R/X \approx 1$. There is no simple control function with $P(U,\delta)$ and $Q(U,\delta)$ in distribution networks. These interdependencies result in more complex approaches for frequency and voltage control in distribution networks.

| **Voltage Level** | **Material** | **Cross Section [mm²]** | **R' [Ohm/km]** | **X' [Ohm/km]** | **X/R** | **R/X** | **$\varphi_N$ [°]** | **Type** |
|---|---|---|---|---|---|---|---|---|
| Overhead line conductors [Hosemann 1988]: | | | | | | | | |
| 750 kV | Al/St | 805/102 | 0.009 | 0.272 | 30.2 | 0.0 | 88.1 | |
| 110 kV | Al/St | 435/55 | 0.033 | 0.266 | 8.1 | 0.1 | 83.0 | |
| Cables [DIgSILENT 2007]: | | | | | | | | |
| | Al | 50 | 0.641 | 0.107 | 0.2 | 6.0 | 9.5 | NA2XSY 3x50sm 6/10kV |
| 10 - 30 kV | Cu | 150 | 0.124 | 0.104 | 0.8 | 1.2 | 39.9 | N2XSY 3x150rm 12/20kV |
| | Cu | 500 | 0.034 | 0.166 | 4.5 | 0.2 | 77.6 | N2XS2Y 1x500RM 18/30kV |
| | Al | 50 | 0.641 | 0.072 | 0.1 | 8.9 | 6.4 | NA2XY 3x50sm 0.6/1kV |
| 1 kV | Al | 150 | 0.206 | 0.069 | 0.3 | 3.0 | 18.6 | NA2XY 3x150sm 0.6/1kV |
| | Cu | 300 | 0.060 | 0.069 | 1.2 | 0.9 | 49.0 | N2XY 3x300sm 0.6/1kV |

Table 3-2: Typical line data

### 3.3. Power/Voltage Control

The power/voltage control capability based on active and reactive power control is analysed more deeply in the following. It is assumed that a generator (the current source) is feeding-in a current $\underline{i}_G$ with different generator phase angles $\varphi_G$ (see equivalent circuit in Figure 3-3).

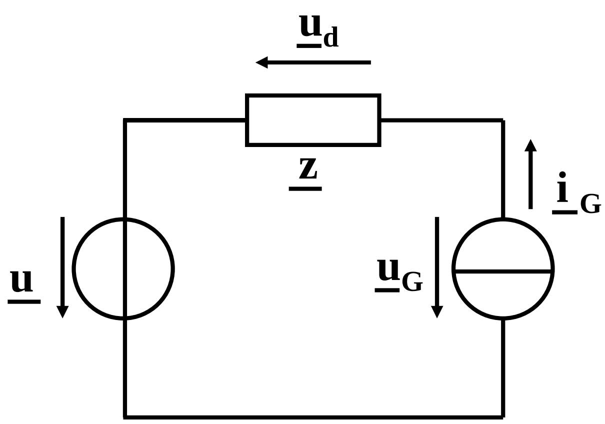


Figure 3-3: Equivalent circuit for voltage control

The result on the generator-side voltage $\underline{u}_G$ is calculated according to the following (steady-state) equations with the network impedence $\underline{z}$ and its network phase angle $\varphi_N$:

$$
\begin{aligned}
&\underline{u} = U \\
&\underline{i}_G = I_G e^{j\varphi_G} \\
&\underline{z} = Ze^{j\varphi_N} = R + jX \\
&\underline{u}_G = \underline{u} - \underline{u}_d \\
&\underline{u}_d = \underline{z} \cdot \underline{i}_G \\
&\frac{U_G}{U} = \frac{\left| U - Ze^{j\varphi_N} \cdot I_G e^{j\varphi_G} \right|}{U}
\end{aligned}
\tag{3-5}
$$

Figure 3-4 displays the voltage ratio $U_G/U$ where $U$ is the fixed network voltage and $U_G$ the terminal voltage of the generator. The dependency of the voltage ratio is given with regard to the generator's phase angle that specifies the reactive power supply and the network's phase angle that specifies the reactive or resistive behaviour of the network impedance.

Figure 3-4 shows that at a network phase angle of $\varphi_N$ = 0° (pure resistive coupling) the voltage is increased by feed-in of current (power generation). The maximum result on the voltage occurs at purely active power generation with $\varphi_G$ = 180°. At purely reactive power generation ($\varphi_G$ = 90° or $\varphi_G$ = 270°) no influence on the voltage exists. On the other hand, at a network phase angle of $\varphi_N$ = 90° (pure reactive coupling) the voltage is

- increased by capacitive reactive power supply ($\varphi_G$ = 90°),
- decreased by inductive reactive power supply ($\varphi_G$ = 270°), and
- not influenced by active power generation ($\varphi_G$ = 180°).

With the reference point of the generator phase angle at 180°, the voltage changes at a network phase angle of 0° in a cosine form and at a network phase angle of 90° in a sine form depending on the generator phase angle.

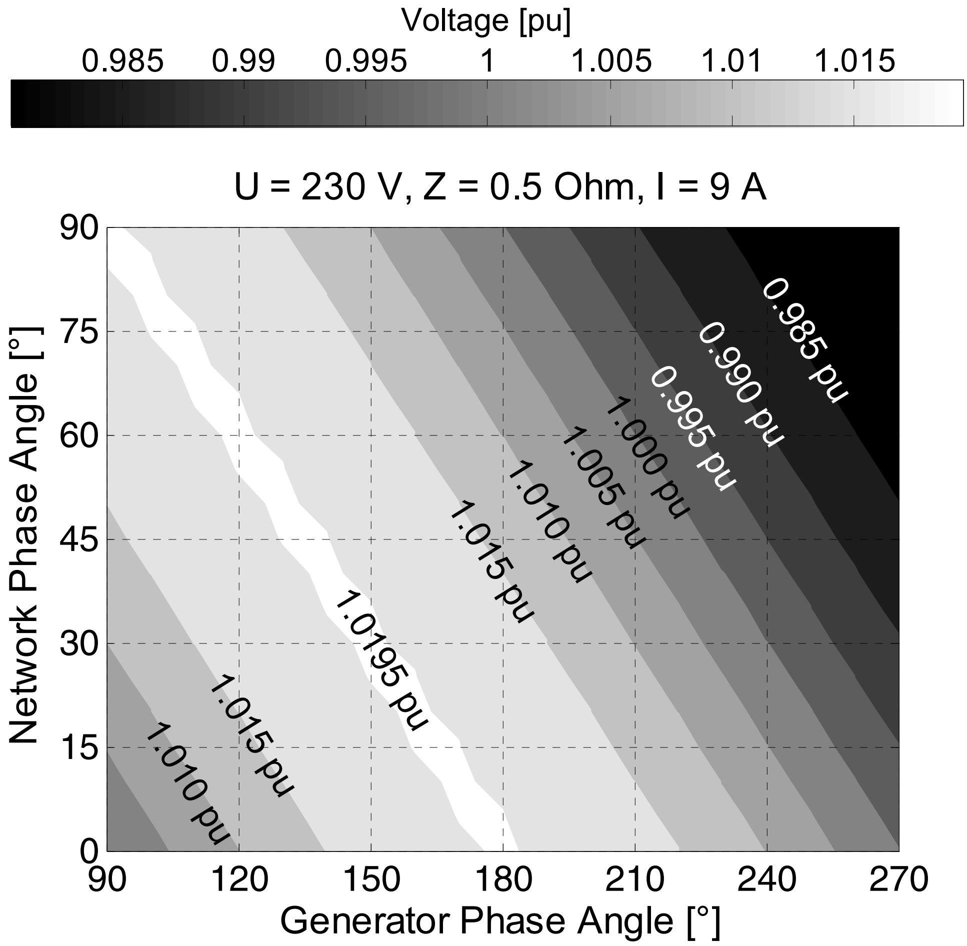


Figure 3-4: Voltage Control (Support) by generator phase angle $\varphi_G$ at different network phase angles $\varphi_N$ (MATLAB calculations)

Summarising these dependencies and referring to the discussion of Section 3.2, the following approximations can be stated:

- Transmission network:
  Power/Voltage control is mainly based on reactive power.
- Distribution network:
  Power/Voltage control is based on active and reactive power.

### 3.4. Summary of Chapter 3

This chapter together with Annex II provides a characterisation of ancillary services that can be supplied by controllable distributed generators. The characterisation here is considered as a reference for further analyses in this work because the definitions and regulations are not harmonised yet and are different from country to country and network to network.

The next chapter presents the results of a review on the control capabilities of distributed generators. Their capabilities of providing ancillary services are analysed in a comprehensive analysis that is described in the following.

# 4. Control Capabilities of Distributed Generators

Recently, several studies have analysed the capability of distributed generators to provide ancillary services: [Campbell et al 2005], [Degner et al 2006], [ILEX;UMIST 2004], [Jóos et al 2000], [Mutuale, Strbac 2005], [Robert et al 2005], [Robert;Belhomme 2005], and [Tolbert;Yu 2006]). These studies show different and partly contradicting results because of different assessment approaches. During the review of these previous studies three principal short-comings have been identified which directly lead to three requirements a comprehensive study should fulfil:

1) Economic and technological capabilities should be analysed separately. This separation is necessary because the economic framework is different in many countries and is expected to change in the future, e.g. by internalisation of external costs. The economic potential and therewith the economic capabilities are based on the respective economic framework and cannot be considered as constant or equal. In contrast, technological capabilities are expected to change only in the long-term technological progress and they are based on physical laws.
2) The technological capabilities should be analysed separately for the grid-coupling converter and the whole DER unit. This separation is necessary because the grid-coupling converter is the entity which connects the DER unit to the grid and defines many of the technological capabilities of the DER unit. This coupling device can be different for the same type of unit, e.g. a wind turbine can be connected to the network with an induction generator, a doubly-fed induction generator, an inverter or a synchronous generator.
3) A third short-coming arises from the number of ancillary services and DER units which is looked at. Many studies only analyse some ancillary services or some DER units without giving the full picture.

From these identified shortcomings a need was seen to analyse the technological capabilities systematically and comprehensively for a large range of DER units and a large range of ancillary services which are characterised in Chapter 3. The results of this analysis have already been published in [Braun et al. 2006] and [Braun 2007a].

The assessment follows the approach that is presented schematically in Figure 4-1. On the one hand, it separates technological capabilities based on physical laws from the economic attractiveness which depends on different economic frameworks. On the other hand, technological capabilities are analysed with an approach of looking firstly at the grid-coupling converter of the DER unit, and secondly looking at the complete DER unit.

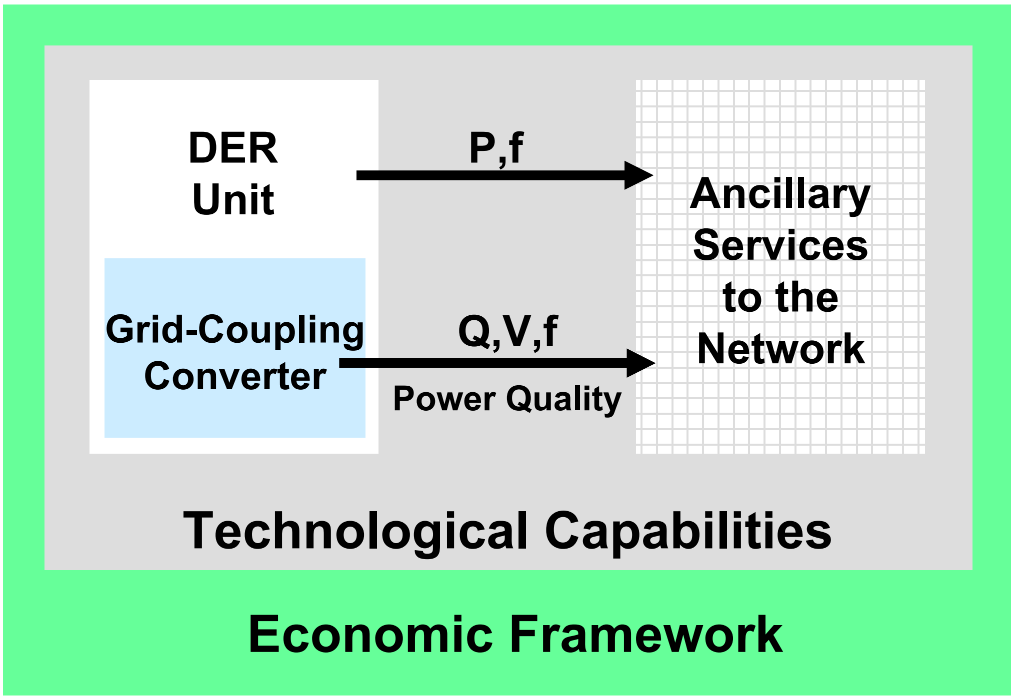


Figure 4-1: Approach for the assessment of control capabilities of distributed generators

The technological capability describes what the technology is capable to do. This does not mean that this "feature" is commercially available on the market. But it is at least demonstrated in non-commercial units. The economic potential of providing frequency and reactive power supply services is analysed in detail in Chapter 5.

Following the described approach, firstly, the technological capabilities of grid-coupling converters (i.e. induction generators, doubly-fed induction generators, synchronous generators, and inverters) are analysed in Section 4.1. Secondly, the technological capabilities of different types of DER units (i.e. wind turbine generator systems, photovoltaic systems, hydroelectric power stations, combined cooling heat and power systems, and storage systems) are investigated in Section 4.2.

## 4.1. Control Capabilities of Grid-Coupling Converters

In the first step of the assessment approach (see Figure 4-1), the control capabilities of four grid-coupling converters are analysed. Because these energy converters only transform the available power input into a power output of a different characteristic, active power control is provided by the unit's prime mover components which are analysed in more detail in the following Section 4.2. Consequently, only the capability of

- direct frequency control and direct voltage control,
- reactive power control, and
- improvement of power quality

is assessed with an isolated look at the grid-coupling converter in this section.

A generator system consists of a chain of energy converters. The last conversion element of this chain is the grid-coupling converter that feeds electrical energy into the grid. These grid-coupling technologies comprise:

- directly-coupled synchronous generators (SGs),
- inverters,
- directly-coupled induction generators (IGs), and
- doubly-fed induction generators (DFIGs).

The grid-side transformer of a DG that may exist as well is not considered here because it statically transforms voltage and current.

### 4.1.1. (Directly-coupled) Synchronous Generator (SG)

Two basic types of Synchronous Generators (SGs) exist. Either the excitation is achieved with a permanent magnet or with an excitation system.

Presently, most of the permanent magnet SGs are coupled with inverters to the grid (see Subsection 4.1.2). However, there are developments of grid-connected permanent magnet SGs in the area of hydro power plants. These generators use a damper cage to influence the magnetic field of the permanent magnets. This allows a direct grid-coupling with a behaviour which is quite similar to induction generators with a damper cage (see Subsection 4.1.3). The advantage of permanent magnet SGs lies in saving the excitation system with its excitation losses, its costs and its need for space. Its disadvantage lies in missing reactive power and voltage control capabilities as well as reactive power flows and oscillations between the damper cage and the grid.

Consequently, the use of the term SG is limited here to SGs with excitation system. Their control capabilities are described in the following. The rotor windings of a SG with excitation system are fed by DC excitation current to create a magnetic field in the air gap with a sinusoidal distribution in space. Rotating the rotor induces sinusoidal voltages in the stator windings [Kundur 1994].

#### *4.1.1.1. Direct Frequency and Direct Voltage Control*

The stator voltage can be controlled directly with the excitation system. By an increase of the DC excitation current the induced magnetic field in the air gap is increased. This higher magnetic field induces higher stator voltage. The voltage increase is limited by the iron's magnetic saturation.

Also the frequency can be controlled directly by rotation speed control due to the direct coupling of electrical frequency *f* [Hz] and rotor speed *n* [$\min^{-1}$] via the number of pole pairs *p*:

$$f = p \cdot n \cdot \frac{1\min}{60s} \tag{4-6}$$

The mechanical torque applied on the rotor not only influences the frequency but also the induced voltages on the stator windings. However, a decoupled control is possible.

#### *4.1.1.2. Reactive Power Control*

In grid-tied operation the voltage characteristic is given by the mains grid. The SG has to be synchronised to the grid's voltage with regard to its voltage magnitude, frequency, phase sequence, and phase shift by use of the above described control capabilities. The rotor is then forced by the stator field to rotate with the network frequency. If the mechanical power and therewith the torque is increased on the rotor the frequency stays constant but the angular displacement between rotor axis and the magnetic field increases. In this situation, active power is injected into the mains grid. The angular displacement (also called internal rotor angle) is limited so that the SG cannot fall out of step. Vice versa the synchronous machine can operate as a motor if the angular displacement is negative.

With the excitation system the reactive power output of a SG can be controlled. SGs have a capacitive characteristic ($Q > 0$; delivering inductive reactive power) when overexcited and they have an inductive characteristic when underexcited ($Q < 0$; delivering capacitive reactive power).

Figure 4-2 illustrates an exemplary loading capability chart of a SG with

- the stator limit $S_{max}$ (green)
  that results from the maximum stator current without overheating the stator coils,
- the rotor limit $Q_{max}$ (blue)
  that results from the maximum rotor current without overheating the rotor coils,
- the prime mover limit $P_{max}$ (red)
  that results from the maximum mechanical power applicable at the rotor shaft, and

- the prime mover limit $P_{min}$ (red)
  that results from the minimum mechanical power applicable at the rotor shaft, and
- the underexcitation limit $Q_{min}$ (blue)
  that allows a stable grid-tied operation.

At $P$ = 0, when the SG would be deactivated ($f$ = 0), it is also possible to provide Q if the prime mover can be disconnected with a clutch [Kueck et al 2006]. Then, the SG can operate as a synchronous condenser.

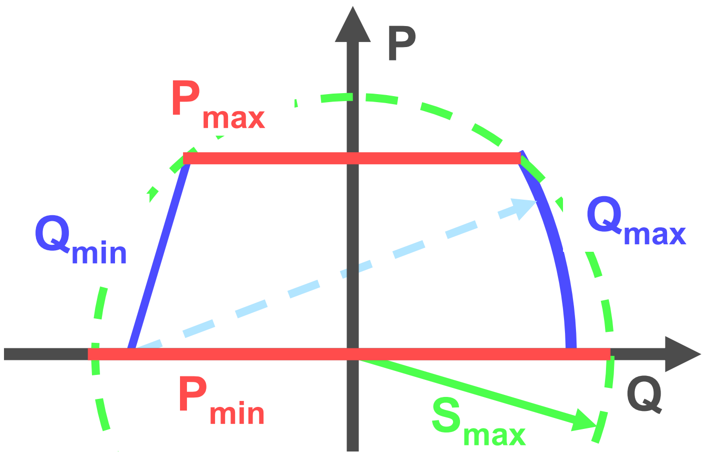


Figure 4-2: Exemplary loading capability chart of a SG
($Q > 0$: capacitive; $P > 0$: active power generation)

*4.1.1.3. Improvement of Power Quality*

An active improvement of power quality (= voltage quality) is not possible. However, three-phase SGs contribute a symmetric power flow to the grid with low harmonic distortion.

### 4.1.2. Inverters

Using power electronics increases the possibilities of power conversion significantly because the output voltage or current signal can be defined precisely with available control techniques. Not all inverter topologies allow all control functions that are described in the following but an inverter can be designed accordingly. For instance, only bipolar inverter topologies can control reactive power but not unipolar ones.

*4.1.2.1. Direct Frequency and Direct Voltage Control*

Inverters can be distinguished in line-commutating inverters and self-commutating inverters. Line-commutating inverters need the grid's voltage for operation but self-commutating inverters are able to operate without. Thus, self-commutating inverters in contrast to line-commutating inverters are capable of defining frequency and voltage themselves. Actual inverters in distributed generators are self-commutating using IGBTs as switching devices.

Depending on their DC-Link characteristics, inverters can also be classified as Current Source Inverters (CSI), Voltage Source Inverters (VSI) and Z-Source Inverters (ZSI). An overview of these classification and their characteristics provide [Bülo et al 2007]. The most common type of inverter is the VSI that has a voltage source characteristic, normally backed up with capacitors in parallel to the DC-Link.

When the inverter is operated in grid-forming mode (Vf-controlled), the inverter detects only the load impedance and thus only the voltage resulting from the voltage divider between the load and the coupling impedance. The inverter will then try to retrieve the nominal voltage set point by increasing the amplitude of its internal voltage and by changing its virtual impedance. With adequate switching also the frequency can be defined.

#### *4.1.2.2. Reactive Power Control*

When the inverter is operated in grid-tied mode (PQ-controlled), the inverter can adjust its internal voltage to be able to provide the set points of *P* and *Q*. In grid-tied operation a current is injected. If it is in phase with the grid's voltage only active power is provided. Switching adequately, a phase shift between the terminal voltage curve and injected current curve causes reactive power supply.

One fundamental limit is the maximum current transfer of the inverter. As long as the absolute value of the current does not exceed the limit the phase angle of the current vector can be arbitrarily controlled. It is possible to control active and reactive currents independently from each other with response times in the order of milliseconds.

Analogous to the current domain, also the power domains can be looked at assuming that the terminal voltage is constant. Instead of a maximum current $I_{max}$ we can then consider a maximum apparent power $S_{max}$ with the same flexibility of active and reactive power control as for the current. The actual active power transfer $P_{act}$ can be assumed to be most important (see Section 5.2) so that it limits the maximal possible reactive power supply $|Q|_{max}$ according to

$$\left|\mathrm{Q}\right|_{\max}(\mathrm{t}) = \sqrt{S_{\max}^2 - P_{act}^2(t)} \tag{4-7}$$

However, also the reactive current has further limits. Figure 4-3 presents an example of the loading capability chart (power domain) of an inverter with

- apparent power limit $S_{max}$ (green)
  that results from the maximum allowed current transfer, esp. over the IGBTs,

- the active power generation limits $P_{min}$ and $P_{max}$ (red)
  that result from the minimum and maximum power applicable at the DC-link,
- the inductive reactive power limit $Q_{min}$ (blue, left-hand side)
  that results from possible stability limits, and
- the capacitive reactive power limit $Q_{max}$ (blue, right-hand side)
  that results from the maximum DC voltage and possible stability limits.

Technologically, the solid blue line can be achieved as reactive power limits in Figure 4-3. But the costs of designing a stable inverter with reactive power supply at low active power (stability) or near the maximum reactive power (high DC-voltage) are often saved leading to reactive power limits as displayed by the dashed blue line for one example.

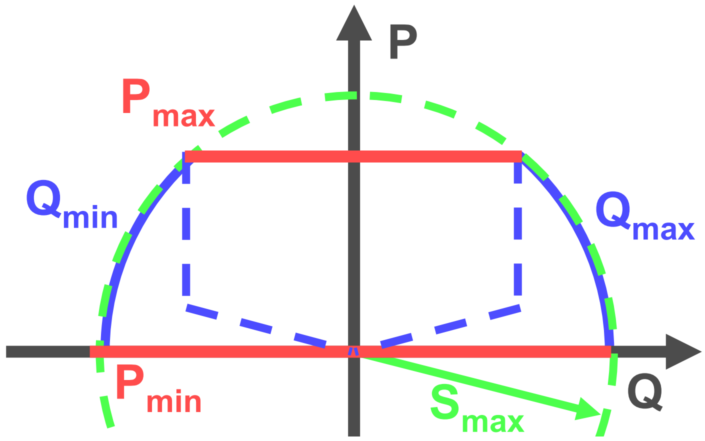


Figure 4-3: Exemplary loading capability chart of an inverter
(Q > 0: capacitive; P > 0: active power generation)

### *4.1.2.3. Improvement of Power Quality*

Inverters are able to improve the power quality actively by reducing/compensating harmonics and flicker. The inverter's capabilities are predominantly limited by the maximum current and the switching frequency of the IGBTs.

Generally the wording of reactive power *Q* refers to the reactive power of the fundamental component. Also DC and harmonic components have to be considered which can be referred to as distortion power *D* [Jahn 2007]. This additional power component adds geographically to *P* and *Q* and gives the total apparent power *S* in Figure 4-4 that is limited by the maximum current of the inverter.

As one example, several functions for improving the power quality have been developed and implemented in an inverter prototype in voltage control mode with subordinate power or current control and external current measurement [DGFACTS 2005] [Jahn 2007]:

- Reactive power compensation,
- Harmonic's compensation,
- Line current rate limitation for flicker reduction, and
- Current injection in case of voltage dips.

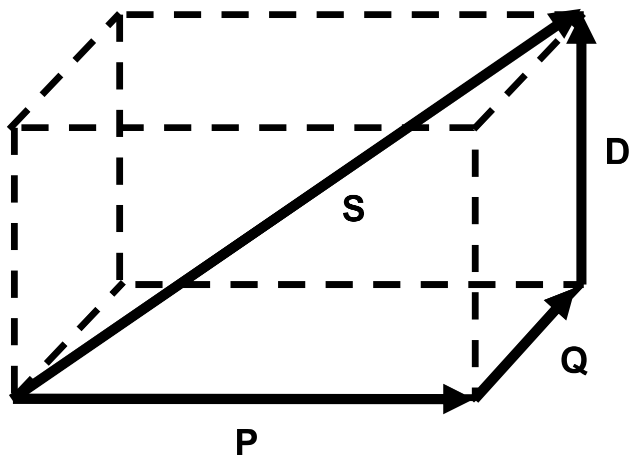


Figure 4-4: Apparent power components

### 4.1.3. (Directly-coupled) Induction Generator (IG)

An IG converts mechanical power to electrical power. Different to the directly-coupled SG, the rotor has no active control capability of the magnetic field. Grid-tied with the mains, the stator windings create a magnetic field in the air gap. Rotating the rotor windings of the IG in the magnetic field of the stator induces currents in the rotor that also produce a magnetic field. If the rotor field turns faster than the stator field the IG acts as a generator injecting active power into the mains grid. The creation of the magnetic field requires capacitive reactive power which is often supplied by capacitors installed at the grid connection point.

#### *4.1.3.1. Direct Frequency and Direct Voltage Control*

IGs need the grid voltage to induce the magnetic field and thus start operation. An IG itself is not capable of directly controlling voltage and frequency independently. Therefore, IGs operate grid-tied and normally not grid-forming.

However, IGs can be fitted with "soft starters" that limit inrush currents and external reactive power sources. Therewith, it becomes possible to start induction generators independently from the availability of a grid and operate them in a certain type of grid-forming mode. One example of this modification is the doubly-fed induction generator as discussed in the next section.

*4.1.3.2. Reactive Power Control*

An IG itself is not capable of controlling reactive power independently from the active power. It even needs capacitive reactive power to magnetise its inductances. External reactive power compensation devices, e.g. capacitor banks, are installed in order to reduce the reactive power demand from the mains. Reactive power control is possible with this additional equipment. However, the control results from the separate equipment and not from the IG itself.

*4.1.3.3. Improvement of Power Quality*

IGs have no capability to improve the voltage quality actively. However, three-phase IGs contribute symmetric power flows with low harmonic distortion to the grid.

### 4.1.4. Doubly-Fed Induction Generator (DFIG)

The DFIG comprises an IG and two power electronic converters. An exemplary structure gives Figure 4-5 with the IG, rotor-side inverter and grid-side inverter. DFIGs behave similar to a mix of SGs, IGs and inverters, because they have a rotor excitation like SGs and the IG can be magnetised with reactive power that is supplied by the rotor-side inverter.

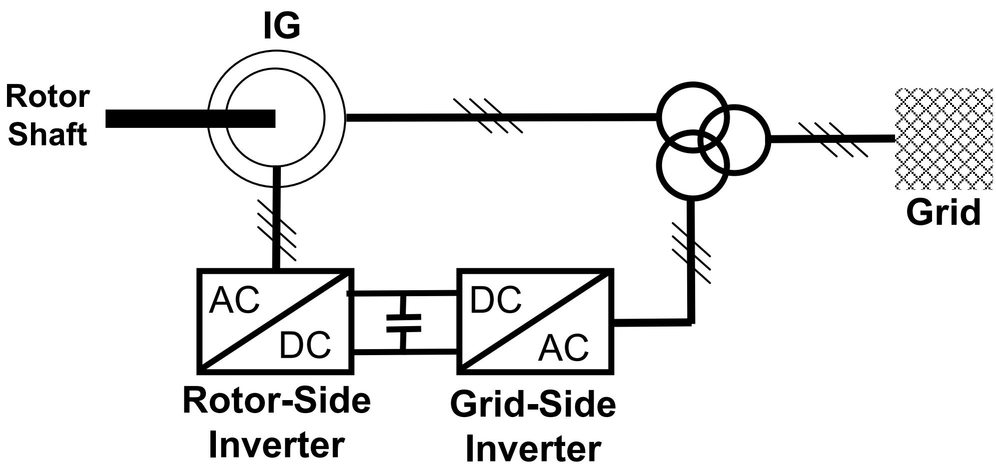


Figure 4-5: Exemplary structure of a DFIG

The AC/DC/AC converter is divided into two components: the rotor-side converter and the grid-side converter. Generally, both are of voltage source inverter type. A capacitor connected on the DC side acts as the DC voltage source. The three-phase rotor winding is connected to the rotor-side inverter, e.g. by slip rings and brushes. DFIGs are often used in wind turbines because of their capability to operate at variable speed on the rotor side. The rotor-side inverter can superpose an electrical field with a rotor frequency that adds to the mechanical rotor speed. The advantage compared to the full-inverter design is that only a fraction of the full rated power of the generator system is required for the power electronic converter.

#### *4.1.4.1. Direct Frequency and Direct Voltage Control*

[Aktarujjaman et al 2006] propose a control system for providing black start by DFIGs with battery storage at the inverter's DC link. The grid-side inverter can be Vf-controlled as long as the storage capacity is sufficient. Thereby, the DFIG controls directly frequency and voltage at the terminal by use of the grid-side inverter. The power electronic converter also supplies reactive power to magnetise the induction generator.

#### *4.1.4.2. Reactive Power Control*

The DFIG design allows an excitation in the rotor coils for speed regulation and reactive power control of the IG by the rotor-side inverter as well as reactive power supply by the grid-side inverter. Four limits define the reactive power capacity of DFIGs as illustrated in Figure 4-6:

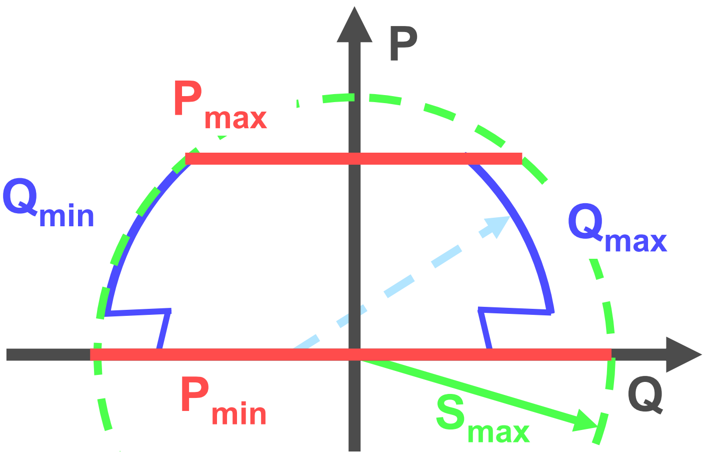


Figure 4-6: Exemplary loading capability chart of a DFIG
(Q > 0: capacitive; P > 0: active power generation)

- apparent power limit $S_{max}$ (green)
  that results from the maximum stator current without overheating the stator coils,
- the active power generation limits $P_{min}$ and $P_{max}$ (red)
  that result from the minimum and maximum power applicable at the rotor shaft,
- the inductive reactive power limit $Q_{min}$ (blue, left-hand side)
  that results from apparent power limit, and

- the capacitive reactive power limit $Q_{max}$ (blue, right-hand side) that results from the maximum rotor current without overheating the rotor coils (bright blue circle) and the maximum rotor voltage at low active power.

A detailed discussion on the functional dependencies can be found in [Lund et al 2007] and [Soens et al 2006] as well as Section 5.2.1.4.

#### *4.1.4.3. Improvement of Power Quality*

Due to the grid-side inverter it is possible to improve the power quality as described in Section 4.1.2.3. But as it is not a full-size inverter, the impact is smaller.

### 4.1.5. Control Capabilities of Grid-Coupling Converters

The control capabilities of the four grid-coupling converters are summarised in Table 4-1 with regard to direct frequency and direct voltage control as well as reactive power control and the improvement of power quality. Induction generators (IG) are not able to provide any of these control capabilities without additional external equipment. The synchronous generator (SG) cannot improve the power quality actively but is able to compensate reactive power and operate as a grid-former with direct frequency and voltage control. Only the inverter and the doubly-fed induction generator (DFIG) are able to provide all control capabilities. From a technical point of view, they are generally of higher quality in case of (full) inverters because the power electronic converters in a DFIG are smaller and partly restricted by other duties such as the reactive power demand of the induction generator.

The control capabilities of the whole DER units are analysed in the following section building on the control capabilities of their grid-coupling converters as given in Table 4-1.

| Basic Control Capabilities | IG | DFIG | SG | Inverter |
|---|---|---|---|---|
| Direct Frequency and Direct Voltage Control | No | + | ++ | ++ |
| Reactive Power Control | No | + | ++ | ++ |
| Improvement of Power Quality | No | + | No | ++ |

Legend:

++ indicates very good capabilities

+ indicates good capabilities

No indicates that this is not possible without additional external equipment

Table 4-1: Control Capabilities of Grid-Coupling Converters

## 4.2. Control Capabilities of Distributed Energy Resource Units

The previous section analyses the technological capabilities of the grid-coupling converters to provide reactive power control, direct frequency control, direct voltage control and improvement of power quality. Here, the complete DER unit that may use one of these grid-coupling converters is investigated with regard to the technological control capabilities, esp. active power control.

The capability of active power control is dependent on the energy availability and transformation before the final conversion by the grid-coupling converter. Mainly, the power gradient, the part-loaded operation capability and the active power limitations (maximum and minimum) in the framework of availability and reliability play key roles in the assessment of the system's capabilities to provide active power control of various time scales.

Renewable energy resources (wind, sun, water, etc.) often provide variable primary energy for power generation and limited storage capacity. However, it is assumed that with an aggregation of DER units it becomes possible to aggregate all individual availabilities into one generally better one (cf. Chapter 2). The analysis considers

- wind turbine generator (WTG) systems,
- photovoltaic (PV) systems,
- hydroelectric power (Hydro) stations,
- combined cooling, heating and power (CCHP) systems, and
- storage systems.

Annex III reviews the capabilities of these DER units with focus on their

- active power control capability considering
    - active power availability,
    - active power predictability,
    - system reliability, and
    - capability to control active power,
- reactive power control capability, and
- capability to provide ancillary services.

The summary of this review is given in Table 4-2 and considers

- wind turbine generator (WTG) systems,
- photovoltaic (PV) systems,
- hydroelectric power (Hydro) stations,
- combined cooling, heating and power (CCHP) systems, and
- storage systems

with regard to their capability to participate in

- power/frequency control (frequency control),
- power/voltage control (voltage control),
- congestion management,
- reduction of power losses (optimisation of grid losses),
- improvement of power quality (voltage quality),
- black start, and
- islanded operation.

The review provides a comprehensive overview of the technological control capabilities of DER units. Basically, all types of ancillary services can be provided by controllable distributed energy units. Limitations such as availability of those units with variable power generation can be reduced or even compensated by technical and commercial aggregation as described in Chapter 2 using forecasting and risk measures.

Some limitations exist for thermally-driven CCHP systems which, by definition, do not have active power control capability to provide power/frequency control and grid-forming services. Induction generator coupled systems cannot control reactive power. This limitation leads to restrictions with regard to power/voltage control, congestion management, optimisation of power losses and grid forming. All other systems can provide the full range of ancillary services with the exception of power quality that can only be improved by power electronic inverters.

Some enhancements of DER units have to be implemented to allow providing ancillary services optimally. The provision of ancillary services normally requires an upgrade of the DER unit's control if these functionalities are not implemented yet. Thermally-driven CCHP systems may need storage devices to decouple the active power generation from the heat generation profile in order to enable a certain degree of electricity-driven operation. All CCHP systems with fuel generation processes (e.g. biogas plants) may need to be enhanced by fuel storage in order to achieve the desired flexibility. In general terms, a re-design of DER units can be necessary if they are aimed to control active power more flexibly than they are designed for presently.

| Ancillary Services / DER Unit | WTG | | PV | Hydro | | CCHP thermal-driven | | CCHP electricity-driven | | Storage | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Frequency Control** | | + | + | | + | | no | | ++ | | ++ |
| **Voltage Control, Congestion Management, Optimisation of Grid Losses** | Inv | ++ | ++ | Inv | ++ | Inv | + | Inv | ++ | Inv | ++ |
| | SG | ++ | | SG | ++ | SG | + | SG | ++ | SG | ++ |
| | DFIG | + | | | | | | | | | |
| | IG | - | | IG | - | IG | no | IG | - | IG | - |
| **Improvement of Voltage Quality** | Inv | ++ | ++ | Inv | ++ | Inv | ++ | Inv | ++ | Inv | ++ |
| | SG | no | | SG | no | SG | no | SG | no | SG | no |
| | DFIG | + | | | | | | | | | |
| | IG | no | | IG | no | IG | no | IG | no | IG | no |
| **Black Start** | Inv | + | + | Inv | + | Inv | no | Inv | ++ | Inv | ++ |
| | SG | + | | SG | + | SG | | SG | + | SG | + |
| | DFIG | - | | | | | | | | | |
| | IG | no | | IG | no | IG | | IG | no | IG | no |
| **Islanded Operation** | Inv | + | + | Inv | + | Inv | no | Inv | ++ | Inv | ++ |
| | SG | + | | SG | + | SG | | SG | ++ | SG | ++ |
| | DFIG | - | | | | | | | | | |
| | IG | no | | IG | no | IG | | IG | no | IG | no |

Legend

Grid Coupling Technology
- IG directly-coupled induction generators
- SG directly-coupled synchronous generators
- DFIG doubly-fed induction generators
- Inv inverters (including inverter-coupled IG and SG)

- ++ indicates very good capabilities
- + indicates good capabilities
- - indicates little capabilities
- -- indicates very little capabilities
- no indicates that this is not possible without additional external equipment

Table 4-2: Technological Capabilities of DER units

Enhancements may be required for black start capabilities because distributed generators need activation energy without grid connection. Some systems can get part of their activation energy by ambient energy flows (e.g. sun for PV systems, wind for WTG systems and water for hydroelectric power stations). Part of the activation energy may also need to be provided by local storage devices in order to energise the control system, magnetise the circuits, ignite the fuel, or warm up the system.

Inverters are the grid-coupling converters that can provide all services with the highest degree of quality, esp. services for power quality improvements. They are only restricted by external constraints such as the limited active power control capability of thermally-driven CCHP systems.

## 4.3. Summary of Chapter 4

This comprehensive assessment of technological control capabilities of distributed energy units shows the large technical potential that is available to support network operation by provision of ancillary services. Individually looked at, single units can have various constraints but aggregated with control structures such as discussed in Chapter 2 the portfolio of different units reduces or even compensates these disadvantages. Consequently, it can be stated that all ancillary services (that are required for secure and efficient network operation) can be provided by controlled distributed energy units. Consumer loads are not in the scope of this thesis but they need to be included as one important complementing source of ancillary services.

With this result from a technological perspective a transition to the economic perspective is possible here. The next chapter analyses the economic potential that is based on the assessed technological potential (see Figure 4-1). An answer is aimed to be given to the question:

Which type of DER unit should provide which type of ancillary service
in order to achieve an economic optimal provision?

# 5. Economic Potential of Providing Ancillary Services by Distributed Generators

The previous chapters analyse the technological capabilities of providing ancillary services by controllable distributed energy (CDE) units integrated in adequate control structures. A large technical potential can be seen in these analyses. Building on this potential, this chapter complements the technological perspective by the economic perspective. It is not only necessary to know if it is technologically possible to provide ancillary services by distributed energy units but also if it is attractive from an economic point of view.

One challenge in assessing the economic potential is that the legal situation (the economic framework as given in Figure 4-1) is still under discussion and continuously changing. For instance, in Germany the feed-in-tariff until 2008 does not allow to be active on more than one market (§18 EEG :"Doppelvermarktungsverbot") [EEG 2004]. Operators of distributed energy units get the feed-in-tariff but they are not allowed to sell energy differently. This is a considerable barrier which would prevent the participation of distributed energy units on ancillary services markets. Within such regulatory framework the economic potential would be zero.

However, if the economic potential is interesting for improving the overall economics of energy supply it is expected that an appropriate legal and regulatory framework will evolve. Consequently, the following analyses on the economic potential base on the assumption that it is possible to be active on several markets. Feed-in-tariffs are understood to be a substitution of the normal power exchange market participation to facilitate power generation by renewable energies. In parallel to active power selling, also ancillary services can be provided.

Looking at costs and benefits always depends on the local situation with its particularities. The costs of power generation from distributed energy units based on renewable energies are strongly dependent on the weather conditions of the considered site. Also the benefits can only be assessed by looking at a specific economic framework. Here, the focus is on the German situation. Also references are given to other countries but they are not in the main focus.

The investigations in this chapter aim at providing an assessment technique which can be applied with little modifications to the situations of other countries. Therewith, analyses of improved framework conditions can be performed aiming at setting appropriate rules for the network integration of distributed generators.

In general, it can be assumed that ancillary services which are required to guarantee the security of supply always have priority. If the fundamental electrical parameters frequency or voltage are jeopardised it becomes of highest priority to solve these situations which are critical for secure network operation. Reactive power can be used for voltage control and active power control is required for frequency control.

Two main cost-benefit-analyses are performed in this chapter. The first one is a cost-benefits-analysis on frequency control services which can be provided by active power control. In this analysis, the costs of active power control are compared with the benefits which arise from participation on frequency control services markets in Germany.

The second cost-benefit-analysis concerns services that are based on reactive power control. An assessment approach is developed which allows calculating costs of reactive power control for different grid-coupling converters and distributed generators. They are compared to the benefits that arise from substituting conventional reactive power supply technologies.

Additional cost aspects that are difficult to handle are discussed in section three of this chapter. These cost aspects concern cost for information and communication technology, transaction costs and external costs. They are not included in the cost-benefit-analyses of the first two sections. The aim is to give a more complete picture with this additional discussion.

## 5.1. Cost-Benefit-Analysis of Frequency Control Services

The cost-benefit-analysis of frequency control services starts with an analysis of the costs of active power control by controlled distributed energy units. Then, these costs of active power control are compared with the market prices on the frequency services markets in Germany that can be claimed as the benefits.

### 5.1.1. Costs of Active Power Control by Distributed Generators

The DG operator sells active power to the power exchange market or gets a feed-in tariff for active power generation. If the network operator demands for active power control leading to physical changes of active power output this does not have any influence from an economic point of view on the formerly contracted power exchange. This is an important basic assumption.

The question of optimal generator sizing is not considered in the analyses here but it should be considered in a next step. Here, the costs are assessed under consideration of the present generator sizing that is optimised for maximum power generation.

The starting point for an assessment of the costs of active power control by DGs is the analysis of the costs of active power generation. They show a large range depending on the site's specific situation, e.g. given by the climatic conditions, economic framework conditions and the technology applied. In Germany, the feed-in-tariff is a good reference for the costs because the tariff is regularly adjusted to a level that is expected to compensate the costs.

The range of the feed-in tariff for the years 2005-2015 is given in Table 5-1 for PV, wind, hydro and biomass plants according to [BMU 2004]. This range represents the total costs *TC* of active power generation and their compensation. In addition, the table provides the assumptions for typical full load hours *FLH* and the ratio of variable operational costs *vOC*, e.g. fuel costs, over total costs *TC*. Also conventional coal- and gas-fired bulk power plants (Conventional BPP) are given in Table 5-1 with typical values according to [ISET;ISE 2008].

Average costs of active power generation by renewable energy sources using the feed-in tariff in Germany in 2006 are approx. 53 c€/kWh for PV, 8.9 c€/kWh for wind, 7.5 c€/kWh for hydro and 12.3 c€/kWh for biomass [VDN 2006/2007]. The share of the variable operational costs is very low in case of PV, wind and hydro plants because the primary energy is cheap. Biomass plants use secondary energy sources that cause variable operational costs.

| Generator Type | *TC* [c€/kWh] | *FLH* [h/a] | *vOC/TC* [%] |
|---|---|---|---|
| PV | 22-60 | 800-1400 | 0-0.5 |
| Wind | 4-9 | 2000 -4000 | 0-5 |
| Hydro | 7-10 | 4000-6000 | 0-5 |
| Biomass | 7-21 | 6500-8500 | 20-70 |
| Conventional BPP | 3-6 | 3000-7000 | 70-90 |

Table 5-1: Range for total costs *TC*, full load hours *FLH* and ratio of variable operational costs *vOC* over total costs *TC* for PV, wind, hydro and biomass plants

Four cost components are considered for the operational costs of active power control:

- **Annual capacity costs for reducing active power [€/kWa]:**

$$C_{C,P-} = 0\,\frac{€}{kWa} \tag{5-1}$$

No additional capacity costs have to be considered if the plant provides the possibility of reducing active power. The plant can be operated without changes until the command for power reduction is received.

- **Annual capacity costs for increasing active power [€/kWa]:**

$$C_{C,P+} = FLH \cdot (TC - vOC) \cdot 0.01\frac{€}{c€} = FLH \cdot TC \cdot \left(1 - \frac{vOC}{TC}\right) \cdot 0.01\frac{€}{c€} \tag{5-2}$$

Enabling an increase of active power generation requires operating the plant part-loaded below the actual maximum output. On the one hand, this causes a loss of revenues (opportunity costs) in the order of the *TC*. On the other hand, variable operational costs *vOC* can be avoided. The active power availability in the order of the full load hours *FLH* is included as well because only those opportunity costs arise from a loss of power production which would have been produced without interference.

One important finding here is that the capacity costs decrease with higher variable operational costs because the opportunity costs (resulting from the difference of feed-in tariff and variable operational costs) are lower.

- **Utilisation costs for reducing active power [c€/kWh]:**

$$C_{U,P-} = -TC \cdot \left( \frac{vOC}{TC} \right) \tag{5-3}$$

The market transaction on the power exchange or the payment of the feed-in tariff does not change. However, the ancillary service requires a reduction of active power. This saves *vOC* because physically less power is injected than sold. With higher *vOC* (e.g. fuel consuming DGs such as biomass plants), the cost savings are increasing.

- **Utilisation costs for increasing active power [c€/kWh]:**

$$C_{U,P+} = +TC \cdot \left( \frac{vOC}{TC} \right) \tag{5-4}$$

An increase of active power from part-loaded operation does not change the market transaction on the power exchange or the payment of the feed-in tariff. Physically producing more demands for additional fuel and therewith causes higher costs.

According to Table 5-1 the costs of active power control by the considered DGs for ancillary services applied after gate closure can be calculated with the equations given directly above. The result is listed in Table 5-2. Negative active power control does not have any capacity costs and the utilisation costs are negative because variable operational costs can be saved, esp. those of biomass plants. In contrast, positive active power control causes capacity costs in the range of 76-1428 €/kWa as well as utilisation costs esp. in case of biomass plants.

| Generator Type | $C_{C,P-}$ [€/kWa] | $C_{C,P+}$ [€/kWa] | $C_{U,P-}$ [c€/kWh] | $C_{U,P+}$ [c€/kWh] |
|---|---|---|---|---|
| PV | 0 | 167-836 | -(0.3-0) | 0-0.3 |
| Wind | 0 | 80-342 | -(0.5-0) | 0-0.5 |
| Hydro | 0 | 280-570 | -(0.5-0) | 0-0.5 |
| Biomass | 0 | 364-536 | -(14.7-1.4) | 1.4-14.7 |
| Conventional BPP | 0 | 27-42 | -(5.4-2.1) | 2.1-5.4 |

Table 5-2: Range for capacity and utilisation costs for active power control by PV, wind, hydro, biomass and conventional power plants

Conventional coal and gas-fired power plants are also given in the table in order to compare the values of RES-based DGs. It can be seen that conventional power plants have much lower capacity costs for positive active power control.

### 5.1.2. Benefits of Participating on German Frequency Control Services Markets

As benefits of frequency control the market prices of frequency control services in Germany are analysed.

- primary control,
- secondary control (positive and negative), and
- tertiary reserve (positive and negative)

are five types of frequency control services that are used in Germany [VDN 2007] according to [UCTE 2004] in order to stabilise the grid's frequency. Their main difference is the activation speed and control structure.

Present requirements for market participation (criteria for prequalification) cannot be fulfilled by many distributed energy units because of their availability and size if individually looked at [Gläser 2007]. Beside of the legal question [BMU 2004], which is discussed at the beginning of Chapter 5, also the grid code [VDN 2007] requirements prevent a participation of single DGs in Germany. The participation via pools comprising many DGs is considered. An aggregation enables to fulfil the participation requirements. Pools are already allowed for secondary and tertiary control but not yet for primary control.

The availability of DGs providing active power control is restricted by primary energy flows. It is assumed that a large number of units are aggregated and each one contributes according to its individual characteristics. This aggregation approach can reduce forecast errors, prequalification costs and transaction costs compared to the situation where each single unit is considered individually.

Present market prices are analysed using data from [www.regelleistung.net], [Oudalov et al 2007], [BNetzA 2006] and [Gläser 2007]. Four main revenue factors are distinguished, analogously to the four cost components of active power control:

- Annual capacity revenue for reducing active power [€/kWa]: $R_{C,P-}$
- Annual capacity revenue for increasing active power [€/kWa]: $R_{C,P+}$
- Utilisation revenue for reducing active power [c€/kWh]: $R_{U,P-}$
- Utilisation revenue for increasing active power [c€/kWh]: $R_{U,P+}$

Also the probability of utilisation is analysed within the interval [0;1] with 0 meaning no utilisation per year and 1 meaning always utilised over the whole year. The two probabilities are:

- probability of utilisation of reduced active power: $p_{U,P-}$
- probability of utilisation of increased active power: $p_{U,P+}$

The values of these fundamental factors are given in Table 5-3 for frequency control in Germany. Market prices have been analysed of the period 1 January 2004 – 30 November 2006 for primary and secondary control and of the period 1 January 2004 – 20 April 2006 for tertiary reserve.

| **Type of Frequency Control** | **Capacity Revenue $R_C$ for** | | **Utilisation Revenue $R_U$ for** | | **Probability of utilisation $p_U$ for** | |
|---|---|---|---|---|---|---|
| | **Negative Control** $R_{C,P-}$ **[€/kWa]** | **Positive Control** $R_{C,P+}$ **[€/kWa]** | **Negative Control** $R_{U,P-}$ **[c€/kWh]** | **Positive Control** $R_{U,P+}$ **[c€/kWh]** | **Negative Control** $p_{U,P-}$ **[c€/kWh]** | **Positive Control** $p_{U,P+}$ **[c€/kWh]** |
| Primary Control | 120-150 | | 0 | | 0.1-0.2 | |
| Secondary Control | 15-60 | 75-100 | (-1.5)-0 | 4-14 | 0-1 | |
| Tertiary Reserve | 10-50 | 10-180 | (-1.4)-0 | 9-280 | 0-0.04 | 0-0.066 |

Table 5-3: Revenue components and probabilities of utilisation for frequency control services in Germany

Positive tertiary reserve shows considerable fluctuations. For the period analysed, the following statistics are derived that result in the range of the prices in Table 5-3 comprising approx. a 90% percentile:

- Capacity price for positive tertiary reserve:
  - Maximum: 1322 €/kWa
  - Minimum: 7 €/kWa
  - Average: 65 €/kWa
  - < 10 €/kWa: 2% of all prices
  - > 180 €/kWa: 5% of all prices
- Capacity price for negative tertiary reserve:
  - Maximum: 200 €/kWa

  - Minimum: 6 €/kWa
  - Average: 25 €/kWa
  - < 10 €/kWa: 6% of all prices
  - > 50 €/kWa: 5% of all prices
- Utilisation price for positive tertiary reserve:
  - the maximum value of the bandwidth:
    - Maximum: 1200 c€/kWh
    - Minimum: 0 c€/kWh
    - < 40 c€/kWh: 5% of all prices
    - > 280 c€/kWh: 5% of all prices
  - the minimum value of the bandwidth:
    - Maximum: 25 c€/kWh
    - Minimum: -0.2 c€/kWh
    - < 9 c€/kWh: 1% of all prices
    - > 14 c€/kWh: 4% of all prices

The average utilisation of primary control is approx. 0.15 [Oudalov et al 2007] meaning that in 15% of the time the frequency exceeds the limits of 49.98 – 50.02 Hz and in 85% of the time it stays within. As soon as the frequency is out of limits primary control is activated automatically by all primary control plants. Due to the droop characteristics the utilisation of the capacity available is increasing with larger deviations. Statistically it can be assumed that the frequency exceeds the lower limit as often as the upper limit.

Different to primary control, the secondary control is always active because its objective is to bring the fluctuating frequency back to 50 Hz. When the utilisation price is very small the probability of utilisation is then nearly 100%. On the other hand, the probability of utilisation can also reach 0% for other plants whose absolute value of utilisation price is very high. In the latter case plants are only activated if the frequency deviates critically. The German regulator [BNetzA 2006] gives average probabilities of utilisation for the years 2004 and 2005 in the range of 0.07-0.09 for positive control and 0.19-0.22 for negative control.

The positive tertiary control has an average probability of utilisation of 0.001 in 2004 and 2005 [BNetzA 2006]. At maximum utilisation price this is 0 and at minimum utilisation price the probability is 0.001-0.04 in 2005 (dependent on the control area).

The average probability of utilisation for negative tertiary control was 0.009 in 2004 and 0.004 in 2005. A maximum utilisation price leads to 0 and a minimum utilisation price to 0-0.066 in 2005 (dependent on the control area).

### 5.1.3. Cost-Benefit-Analysis

With the costs of active power control and the market prices for frequency control services in Germany, the cost-benefit-analysis is performed by calculating the possible profit for participating DGs. The annual profit (gain) *G* is calculated by

$$G = G_C + G_U = \left[ \frac{FLH}{8760 \frac{h}{a}} \cdot R_C - C_C \right] + \left[ 0.01 \frac{€}{c€} \cdot FLH \cdot p_U \cdot \left( R_U - C_U \right) \right] \quad \text{(5-5)}$$

The profit has two components: gain $G_C$ from capacity revenues and gain $G_U$ from utilisation revenues. $G_C$ is calculated with the capacity costs $C_C$ and the capacity revenues $R_C$ that are weighted with the availability represented by the full load hours *FLH*. The profit from utilisation $G_U$ is calculated with the difference of utilisation revenues $R_U$ and utilisation costs $C_U$ weighted with the availability represented by the full load hours and the probability of utilisation $p_U$. This equation allows deriving conditions of profitability for primary control, secondary control and tertiary reserve. Participation is profitable if $G > 0$.

#### 5.1.3.1. *Cost-Benefit-Analysis of Primary Frequency Control Service*

In the present market design for primary control there exist no revenues for the utilisation and it is assumed that the frequency of utilising positive and negative control is similar. Different to secondary control and tertiary reserve, positive as well as negative control reserve have to be available for utilisation so that the capacity costs of positive as well as negative active power control have to be taken into account. With the profit from the participation in primary control

$$\begin{aligned} G_{pc} &= \left[ \frac{FLH}{8760 \frac{h}{a}} \cdot R_C - C_C \right] \\ &= FLH \cdot \left[ \frac{R_C}{8760 \frac{h}{a}} - TC \cdot \left( 1 - \frac{vOC}{TC} \right) \cdot 0.01 \frac{€}{c€} \right] \end{aligned} \quad \text{(5-6)}$$

the condition for profitability can be derived for the total costs:

$$TC \overset{!}{<} \frac{R_C \cdot 0.01 \frac{€}{c€}}{\left(1 - \frac{vOC}{TC}\right) \cdot 8760 \frac{h}{a}}. \tag{5-7}$$

With the different values for the capacity revenues according to Table 5-3 the boundary curves in Figure 5-1 separate the area of profitability (below the curves) from the area of non-profitability (above the curves). With the high total costs and feed-in tariffs of DGs, they are located in the area of non-profitability. Only conventional coal and gas-fired plants can make profit as they are the present market participants.

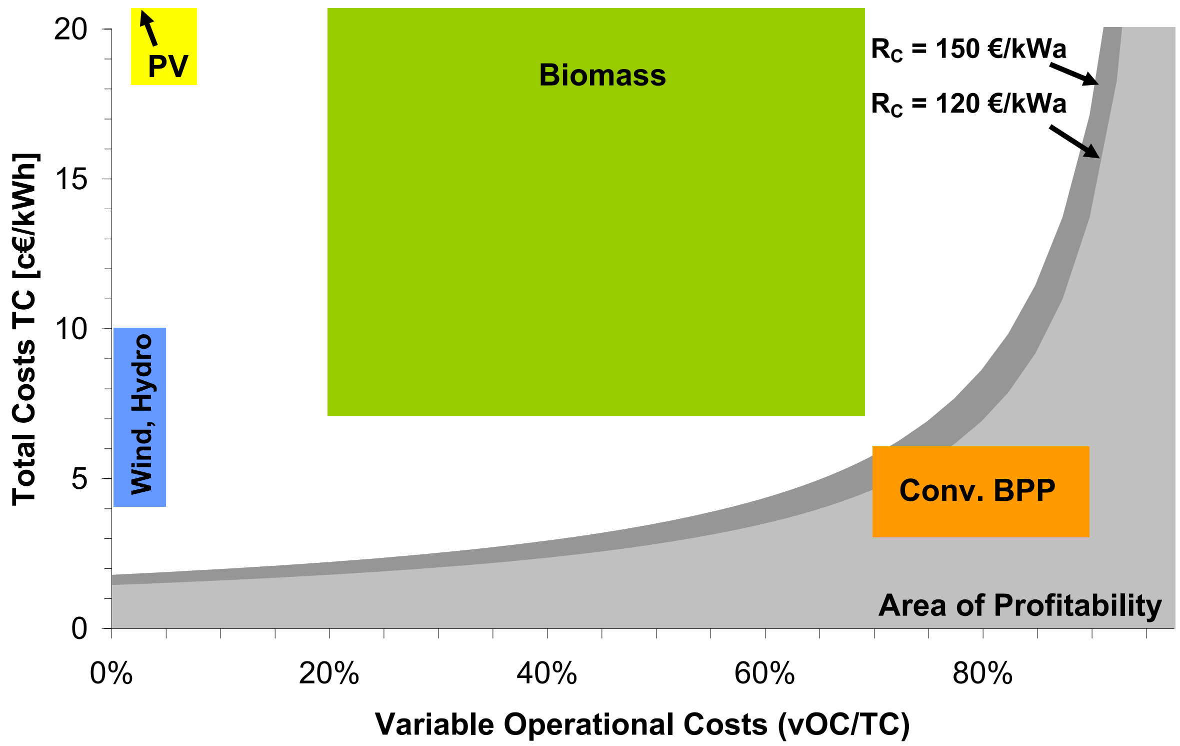


Figure 5-1: Profitability (below the curves) of participating in primary control

#### 5.1.3.2. Cost-Benefit-Analysis of Positive Secondary and Tertiary Frequency Control Service

The participation in positive secondary control or positive tertiary reserve gives a profit from positive control

$$\begin{aligned} G_{P+} &= \left[\frac{FLH}{8760\frac{h}{a}} \cdot R_{C,P+} - C_{C,P+}\right] + \left[0.01\frac{€}{c€} \cdot FLH \cdot p_{U,P+} \cdot \left(R_{U,P+} - C_{U,P+}\right)\right] = \\ & FLH \cdot \left\{\left[\frac{R_{C,P+}}{8760\frac{h}{a}} - TC \cdot \left(1 - \frac{vOC}{TC}\right) \cdot 0.01\frac{€}{c€}\right] + \left[0.01\frac{€}{c€} \cdot p_{U,P+} \cdot \left(R_{U,P+} - vOC\right)\right]\right\} = \\ & FLH \cdot \left[\frac{R_{C,P+}}{8760\frac{h}{a}} + 0.01\frac{€}{c€} \cdot p_{U,P+} \cdot R_{U,P+} - 0.01\frac{€}{c€} \cdot TC \cdot \left(1 - \left(1 - p_{U,P+}\right) \cdot \frac{vOC}{TC}\right)\right] \overset{!}{>} 0 \end{aligned} \quad (5\text{-}8)$$

from which the condition for profitability can be derived for the total costs

$$TC \overset{!}{<} \frac{\left(\dfrac{R_{C,P+}}{0.01\frac{€}{c€} \cdot 8760\frac{h}{a}}\right) + p_{U,P+} \cdot R_{U,P+}}{1 - \left(1 - p_{U,P+}\right) \cdot \dfrac{vOC}{TC}} \,. \quad (5\text{-}9)$$

With the different values for the capacity revenues, utilisation revenues and probabilities of utilisation according to Table 5-3 the boundary curves in Figure 5-2 separate the area of profitability (below the curves) from the area of non-profitability (above the curves) for positive secondary control and in Figure 5-3 for positive tertiary reserve. With the high total costs and feed-in tariffs of DGs, they are normally located in the area of non-profitability. Only wind turbines may generate profit on the positive secondary control market if their total costs are below 6 c€/kWh that is in most situations not reached presently in Germany with average feed-in tariff reimbursements of 9 c€/kWh. As for primary control also for positive secondary control and positive tertiary reserve, the conventional coal- and gas-fired bulk power plants are located in the area of profitability.

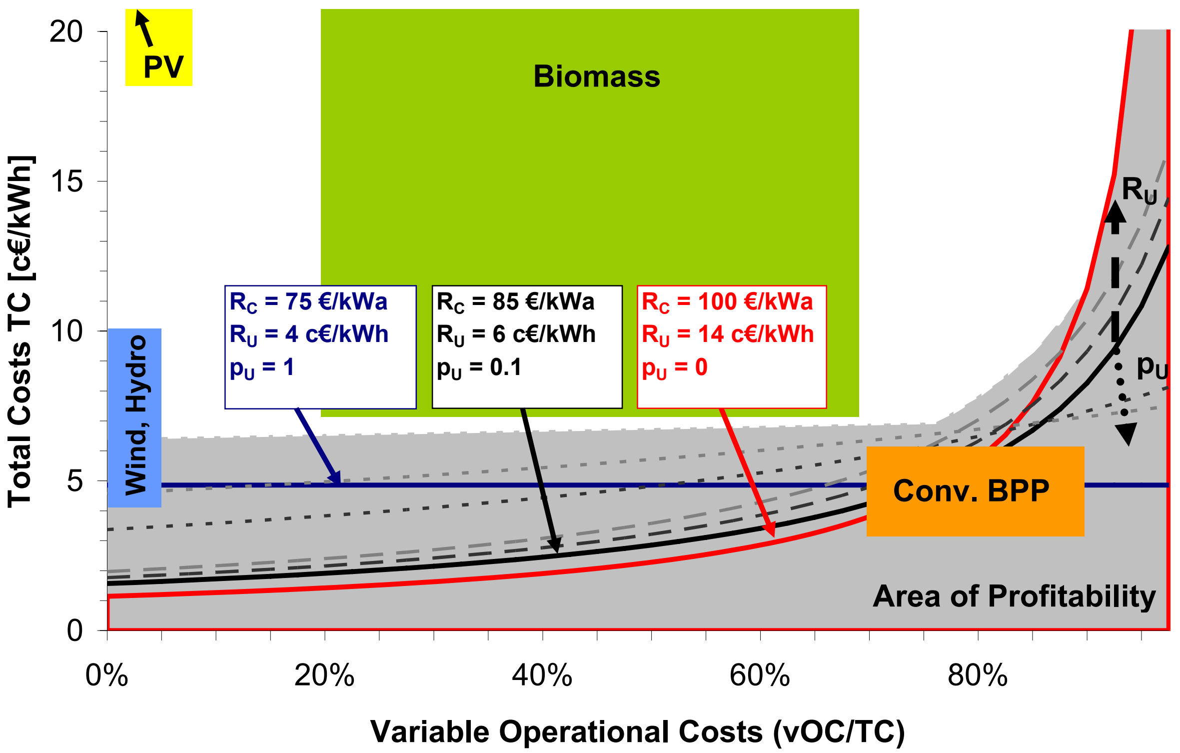


Figure 5-2: Profitability (below the curves) of participating in positive secondary control

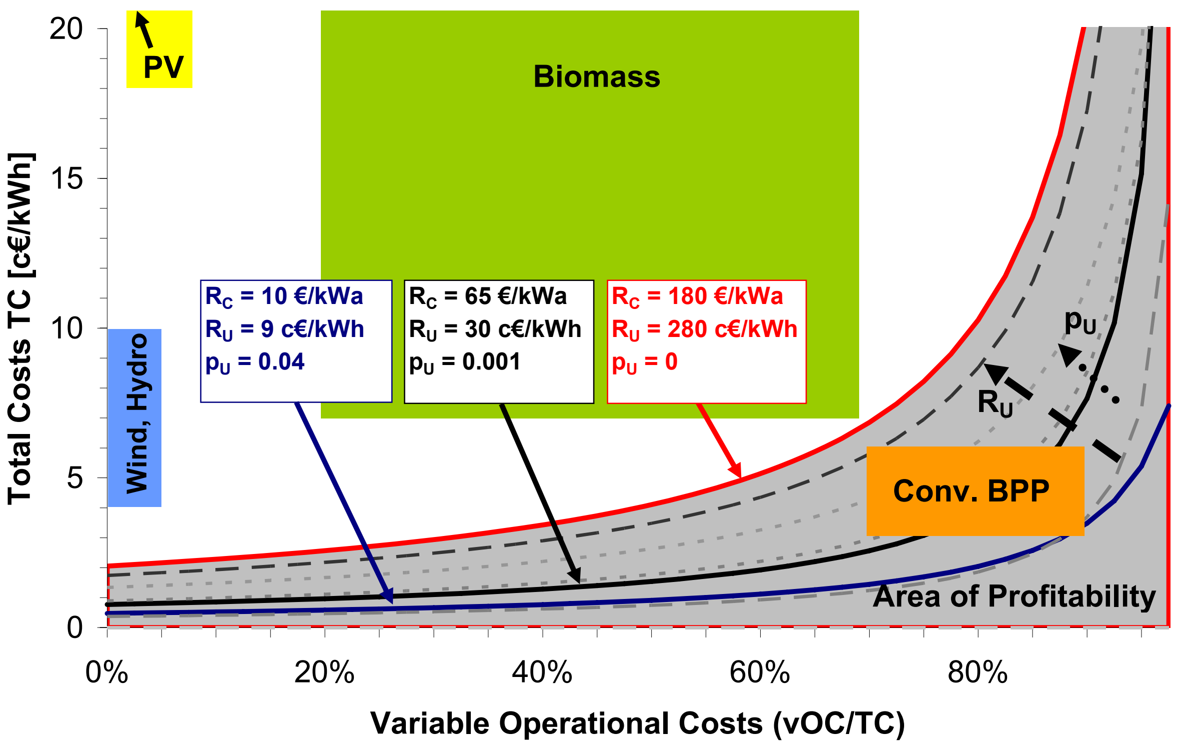


Figure 5-3: Profitability (below the curves) of participating in positive tertiary reserve

### *5.1.3.3. Cost-Benefit-Analysis of Negative Secondary and Tertiary Frequency Control Service*

A participation in negative secondary control or negative tertiary reserve does not cause capacity costs. The gain can be calculated by:

$$G_{P-} = \frac{FLH}{8760\frac{h}{a}} \cdot R_{C,P-} + \left[0.01\frac{€}{c€} \cdot FLH \cdot p_{U,P-} \cdot \left(R_{U,P-} - C_{U,P-}\right)\right] =$$
$$FLH \cdot \left\{\frac{R_{C,P-}}{8760\frac{h}{a}} + \left[0.01\frac{€}{c€} \cdot p_{U,P-} \cdot \left(R_{U,P-} + vOC\right)\right]\right\} \overset{!}{>} 0 \tag{5-10}$$

While the equations for primary control, positive secondary control and positive tertiary reserve give maximum total costs representing the feed-in tariff or market prices on the power exchange, the equation for negative secondary control and negative tertiary reserve is not dependent on the total costs. So the utilisation revenue $R_{U,P-}$ is looked at because it can be defined by the plant operator who can therewith control the probability of utilisation. The revenue from utilisation of negative control is never positive, so that the variable can also be written with its negative absolute value

$$R_{U,P-} = -\left|R_{U,P-}\right|. \tag{5-11}$$

With these assumptions it is possible to define the maximum absolute value of the utilisation revenues:

$$\left|R_{U,P-}\right| \overset{!}{<} \frac{R_{C,P-}}{p_{U,P-} \cdot 0.01\frac{€}{c€} \cdot 8760\frac{h}{a}} + vOC \tag{5-12}$$

Because the left term on the right-hand side of the equation is always positive the condition can definitely be fulfilled if the absolute value of the utilisation revenue is not bigger than the variable operational costs. The utilisation revenue can be defined by the generator operator. Large absolute values lead to large utilisation probabilities and vice versa. Within these dependencies the operator can optimise his/her market position. Based on the discussed assumptions it is possible to participate with DGs in negative secondary control and negative tertiary reserve with economic attractive prospects.

#### 5.1.4. Results from the Cost-Benefit-Analysis of Frequency Control Services

The cost-benefit-analysis shows that the participation in primary and positive secondary/tertiary frequency control services is not profitable with present distributed generators based on renewable energies. This mainly results from feed-in tariffs that are higher than present prices on power exchange markets. Prices on frequency services markets are defined by conventional gas- and coal-fired power plants whose costs mainly result from operational expenditures and whose costs correspond to prices on the power exchange markets. Presently, they have lower generation costs than renewable energies but they may cause higher external costs. The internalisation of these external costs may lead in future to a reduction of the gap and even to a competition with controlled distributed energy units that are presently already supported by feed-in tariffs as one means of internalisation with regard to the power exchange market.

Distributed storage and loads are not analysed in detail. In case of loads, there exists a considerable potential of active power control at low costs [Stadler 2005]. Utilisation of these resources for frequency control services may be profitable and attractive. Also storage systems may be used for frequency control services as analysed in [Oudalov et al. 2007] and [Braun;Stetz 2008] for instance.

It is recommendable to reconsider the sizing of the controlled distributed energy unit when active power control is provided. As an example, biogas plants can use larger storage for biogas to decouple the biogas conversion process from the electrical conversion. Also hydro power can increase the water storage capacity to enhance its flexibility of active power control. A re-dimensioning of the generator itself can be considered as well. In case of PV and wind power plants a re-dimensioning is not expected to be necessary because the maximum active power generation depends on the primary conversion and the primary energy flow conditions. In the case of loads, an enhancement of their active power control capabilities is possible by extending the storage capacity in case of heat processes for instance.

A re-dimensioning of biomass and hydro power plants can reduce capacity costs for active power increase partly. Storage of biomass/biogas and water allows decoupling the active power generation from the primary energy source. The increased generation is limited in time due to the storage capacity. With these assumptions, it is possible to substitute the given equation by an equation with additional investment costs for the storage, combustion and electricity conversion process. The annual capacity costs may then be lower dependent on the storage capacity.

## 5.2. Costs-Benefit-Analysis of Reactive Power Supply

The cost-benefit-analysis of reactive power supply is structured as follows: Firstly, the costs of reactive power control by distributed energy units are analysed. Then, the network components are taken into account as well. Finally, the costs of reactive power control are compared with the costs of conventional reactive power supply technologies and benefits for network operation.

### 5.2.1. Costs of Reactive Power Control

The costs supplying reactive power can be divided into two main categories: additional investment costs and additional operational costs. The operational costs can further be divided into fixed operational costs per year and variable operational costs. Often the investment costs can be converted into annual costs which allow adding them to the fixed operational costs per year. If nothing else is given as assumption in the economic calculation it is assumed that considered components have a lifetime of 20 years and the capital costs are covered with a discount rate of 5%. Then, only two types of costs have to be considered: fixed annual costs (including investment costs) and variable operational costs.

It has already been discussed by [Turner 1996] that in large generation plants the costs of reactive power consist of

- investment costs due to oversizing,
- operational costs due to energy losses, and
- additional minor cost factors.

The latter cost factors tend to be dependent on the higher currents (often dependent on $I^2$) causing electromagnetic forces (mechanical stress) and higher temperatures (thermal stress). These effects result in higher maintenance costs and equipment aging as well as higher costs of unavailability.

Costs of reactive power supply can be separated into investment costs [€/kvar/a] and operational costs [c€/kvarh]. The purpose here is to give an order of magnitude and an understanding of the various dependencies. Hence, the mentioned additional minor cost factors are not discussed in detail.

Another cost component is the opportunity costs that can occur if more reactive power is required than available. Then, the active power generation can be reduced to increase the reactive power capacity. The opportunity costs are operational costs as the additional capacity is only released for periods of time. If released all the time the available capacity would have been increased and constitute investment costs of reactive power supply.

As analysed in Chapter 4.1 the capability of reactive power supply mainly depends on the grid-coupling converter (IG, DFIG, SG or inverter). IGs are excluded because they need additional equipment for reactive power supply.

This section is structured in four subsections. Firstly, the investment costs are analysed. Secondly, the operational costs of inverter-coupled, SG-coupled and DFIG-coupled distributed generators are investigated. Finally, the opportunity costs as an additional component of the operational costs are discussed.

#### *5.2.1.1. Investment Costs for Reactive Power Capacity*

In principle, inverters, DFIGs and SGs can control reactive power without the need of additional investments due to the capabilities of these types of grid-coupling technologies as described in Chapter 4.1. Additional investment costs have to be considered if the converter's rated capacity is extended to guarantee a certain reactive power supply capacity $Q_g$. Then, the converter is not designed according to the maximum active power transfer $P_{max}$ but in addition to the desired guaranteed reactive power supply. The apparent power capacity $S$ is then extended to the new capacity $S'$ leading to an additional capacity of

$$\Delta S = S' - S = \sqrt{{Q_g}^2 + {P_{\max}}^2} - P_{\max} \, . \tag{5-13}$$

The additional capacity $\Delta S$ can be related to the guaranteed reactive power capacity $Q_g$ which leads to specific additional capacity increase in kVA/kvar of

$$\frac{\Delta S}{Q_g} = \frac{\sqrt{{Q_g}^2 + {P_{\max}}^2} - P_{\max}}{Q_g} \, . \tag{5-14}$$

Having the investment costs of apparent power capacity in €/kVA allows then calculating the investment costs for reactive power capacity in €/kvar. Generally, annual values are of interest so that the investment costs are transformed to their annuity having units of €/kVA/a resulting in units of €/kvar/a.

Table 5-4 gives the assumptions for the specific investment costs for capacity of inverters, DFIGs and SGs in the power range of tenths/hundreds to thousands of kilowatts connected to the low or medium voltage network. The given range should provide an order of magnitude and depends from generator to generator. Smaller generators of some kilowatt tend to have higher specific investment costs. These costs are transferred into specific investment costs of guaranteed reactive power capacity as given in Figure 5-4. If 48.4% of the maximum active power should be securely available as reactive power capacity (corresponding to a power factor of 0.9 at rated active power) the grid-coupling converter has to be oversized by 11.1%. This oversizing generates specific investment costs of 0.4-0.9 €/kvar/a for SGs, 1.0-1.6 €/kvar/a for DFIGs, and 2.8-5.5 €/kvar/a for inverters.

A general finding is that the additional investment costs are low at small guaranteed reactive power capacities. Synchronous generators tend to have the lowest costs and inverters the highest. DFIGs are in between because they not only have to increase the induction generator but also the rotor-side inverter that only has 10-25% of the size of a full inverter.

Not only the converter itself but also the wiring and protection system have to be extended. An important role also plays the network connection to the PCC which comprises transformers, cables, protection systems and other network equipment. The costs for one transformer connecting to low or medium voltage networks are already included in the given cost range of the converters. SGs can be connected directly to medium voltage networks without the need for transformers which inverters and DFIGs have. Also the converter's internal wiring and protection systems are assumed to be included. But the network connection between the generator's terminal and the PCC has to be taken into account separately. The increase of the transformer capacity has specific additional investment costs of 10-30 €/kVA and conductors also add some Euros per kVA and km.

A generator-specific calculation should be performed which may result in the order of magnitude as given here. Also the cost allocation may be under discussion. Possibly, the capacity increase is not only necessary for direct reactive power supply but also for other features such as fault-ride-through or compensation of harmonics. Then, the question arises if all additional investment costs should be attributed to reactive power supply or only a certain fraction of them. This question should not be answered in this work. Here, the focus is on stressing the need to consider investment costs for reactive power capacity in cost calculations. Other ways of assessing capacity costs are discussed in [Hao;Papalexopoulos 1997], [Lamont;Fu 1999] and [FERC 2005].

| Grid-Coupling Converter | Investment Costs [€/kVA] |
|---|---|
| Inverter | 150-300 |
| DFIG | 55-85 |
| SG | 20-50 |

Table 5-4: Investment costs of grid-coupling converters

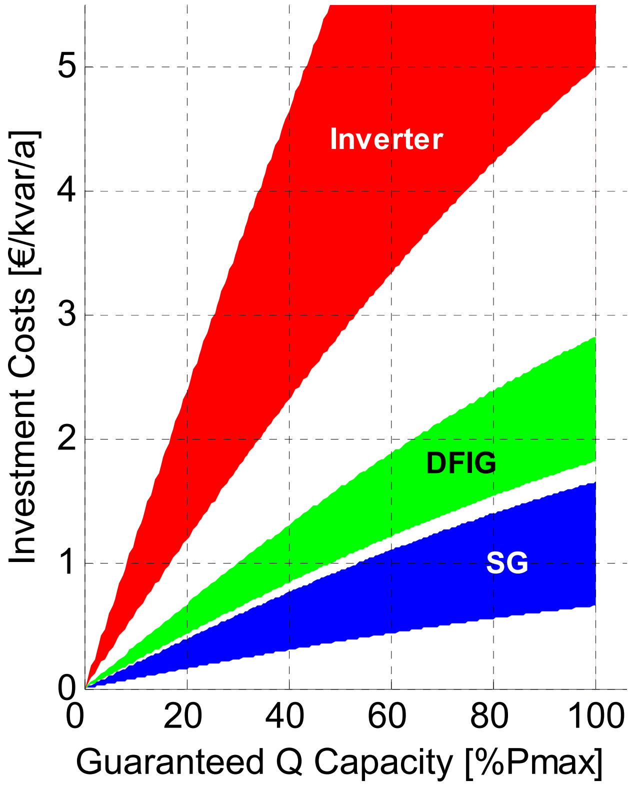


Figure 5-4: Additional investment costs for guaranteed reactive power supply capacity of inverters, DFIGs and SGs

In case of DGs which are not operating at full load all the time, reactive power capacity is available with a certain probability without the need for additional investments to increase the capacity. This is a valid assumption for PV systems (see section III.2.2) and WTGs (see section III.1.2). Hydro units with a higher capacity utilisation (more full load hours) can be considered similarly but the higher the full load hours the lower the availability of reactive power.

In many countries grid codes require a certain reactive power capacity which is not allowed to be based on probabilistic availabilities but has to be guaranteed. In these cases, additional investments have to be performed as discussed in this section.

#### *5.2.1.2. Operational Costs of Reactive Power Supply from Inverter-Coupled Distributed Generators*

Distributed generators have a certain self consumption similar to all other power plants. The additional self consumption due to reactive power supply is equivalent to additional losses in the converter which are compensated by active power. This additionally required active power determines a big part of the operational costs of reactive power supply.

The following operational cost estimation approach has been introduced in [Braun 2007b] for PV inverters. Moreover, the generalised method and the technical implementation are under examination to grant patent rights [Braun 2007patent]. The approach can be divided into two main steps:

1. Reactive power supply in addition to active power supply increases the losses of the grid-coupling converter.
2. These additional losses need to be compensated by active power
   - reducing the amount of active power generation, or
   - increasing the consumption if no or few active power is fed into the mains.

A description of the power flows of grid-coupling converters is provided with Figure 5-5. The apparent power with its two components: the active power $P_{AC}$ and the reactive power $Q$ flows over the Point of Common Coupling (PCC) and the primary active power $P$ (mechanical, AC or DC) is provided at the point on the generator side. An additional active power flow $P_L$ is considered representing losses of the energy conversion process:

$$P_L = P - P_{AC} \qquad (5\text{-}15)$$

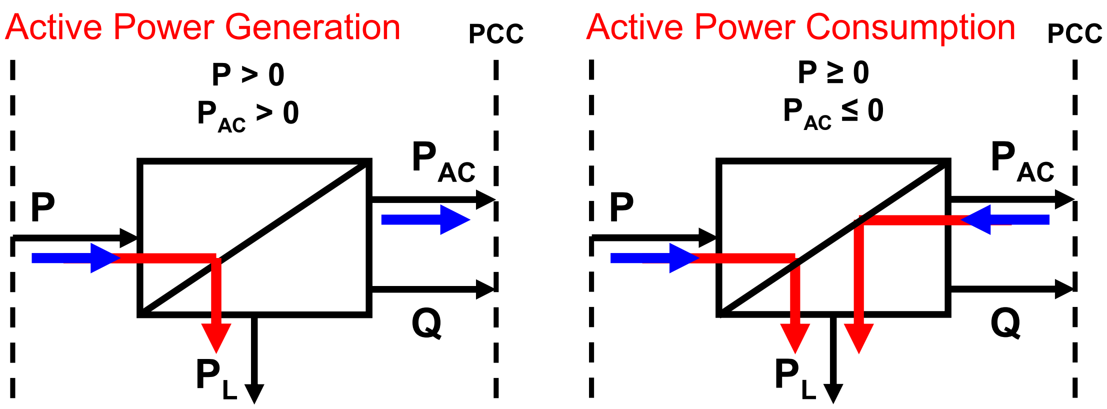


Figure 5-5: Power flows in grid-coupling converters [Braun 2008c]

These considerations directly lead to the definition of the converter's efficiency (if only active power generation is considered which is represented on the left-hand side of Figure 5-5):

$$\eta = \frac{P_{AC}}{P} = \frac{P_{AC}}{P_{AC} + P_L} \qquad (5\text{-}16)$$

Figure 5-5 shows one more important interrelationship based on the algebraic signs of the power flows which are defined by the black arrows. As long as the generator's active power $P$ is larger than the self consumption (feeding $P_{AC} > 0$ into the grid) all losses are compensated by active power from the DG unit. If $P$ is smaller than the losses $P_L$ additional active power has to be absorbed from the grid which causes $P_{AC} < 0$ (see right-hand side of Figure 5-5). Finally, in case of $P = 0$, all these standby losses have to be compensated by active power from the grid $P_L = - P_{AC}$. This has to be taken into account because the costs of energy losses compensated by the grid may be different to those compensated by the DG's prime mover active power.

At one point in time only the total losses resulting from active and reactive power supply can be determined. The allocation to $P_{AC}$ and $Q$ is not possible. It is necessary to compare these total losses with the total losses at another point of time where $P$ has been identical and $Q = 0$. We can determine the additional losses $\Delta P_L$ by comparing the difference of the inverter's losses with reactive power supply $Q(t) \neq 0$ and without $Q(t^*) = 0$ for the same generator side power $P$ (mechanical, AC or DC) at time $t$ and at reference time $t^*$ respectively:

$$\begin{aligned}&\Delta P_L(t) = \\ &P_L\big(P(t), Q(t) \neq 0\big) \\ &- P_L\big(P(t^*) = P(t), Q(t^*) = 0\big)\end{aligned} \tag{5-17}$$

The second term can be close to zero if no power would be supplied at reference time $t^*$ and the converter changes to power saving mode. These additional losses can be attributed to the reactive power supply to get the specific value in W/var (or kWh/kvarh in energy units):

$$\overline{P}_{loss}(t) = \frac{\Delta P_{loss}(t)}{Q(t)} \tag{5-18}$$

It is also possible that $\Delta P_L$ is negative if the lowest losses are not at $Q = 0$ but at some offset due to additional reactive elements between the source of $Q$ and the measurement point (PCC), such as in output filters, decoupling inductors, cables or transformers (see Section 5.2.2). Then, this reactive power offset $Q_{offset}$ can be used as the reference instead of reactive power equal to zero leading to the equations:

$$\begin{aligned}&\Delta P_L(t) = \\ &P_L\big(P(t), Q(t) \neq Q_{offset}\big) \\ &- P_L\big(P(t^*) = P(t), Q(t^*) = Q_{offset}\big)\end{aligned} \tag{5-19}$$

and

$$\overline{P}_{loss}(t) = \frac{\Delta P_{loss}(t)}{\left|Q(t) - Q_{offset}\right|} \; . \tag{5-20}$$

This approach of determining the additional losses is appropriate for measured exact data. For theoretical studies an approach for the approximation of these losses is proposed in the following. The focus here is on inverters but is transferred to synchronous generators further below.

The losses of an inverter can be approximated by a second order polynomial function [Schmidt;Sauer 1996]:

$$P'_{loss}\left(P_{AC}\right) = c_{self} + c_{Vloss} \cdot P_{AC} + \; c_{Rloss} \cdot \left(P_{AC}\right)^2 \tag{5-21}$$

with self losses (no-load losses) $c_{self}$, terminal voltage dependent losses over the power electronic components $c_{Vloss}$ (proportional to current $I$), and current dependent losses over the impedances $c_{Rloss}$ (proportional to squared current $I^2$).

Looking at present standard inverter designs, this approximation can be derived from the average total power dissipation. This derivation is given explicitly in Annex IV. The average dissipation can be written in a second order polynomial function

$$P_{av}(t) = c'_{self} + c'_{Vloss} \cdot i(t) + \; c'_{Rloss} \cdot i(t)^2 \tag{5-22}$$

dependent on the current $i(t)$. Consequently, the approximation equation 5-21 is given in dependency of the root-mean square (RMS) current $I$ instead of the RMS active power $P_{AC}$. With the assumption of constant terminal voltage $V_{AC}$ the current $I$ can also be substituted by the apparent power $S$. This enhancement of equation 5-21 with apparent power $S$ instead of active power $P$ is derived in the following.

The measured power flows of a PV inverter with 208 kVA maximum apparent power at 400 V and 50 Hz are analysed[2]. Figure 5-6 shows a contour graph with the active power losses of the inverter at active power output $P$ and reactive power output $Q$. The small white dots in the figure give the respective measurement points [source: SMA SOLAR Technology AG] that are the basis for the graph's cubic interpolation. It can be seen that

[2] The device under test was the PV inverter SC250U for 60 Hz/480 V from SMA SOLAR Technology AG that is measured at 50 Hz/400 V.

there is an area (framed by the lily rectangle) of distorted interpolation due to stability problems of the inverter's control system that has not yet been optimised for this operation area because it is not required in the present connection conditions. The behaviour in this distortion area can be improved and may then show a similar behaviour as on the negative side. Consequently, this area is excluded from the approximation of the loss curve in Figure 5-7.

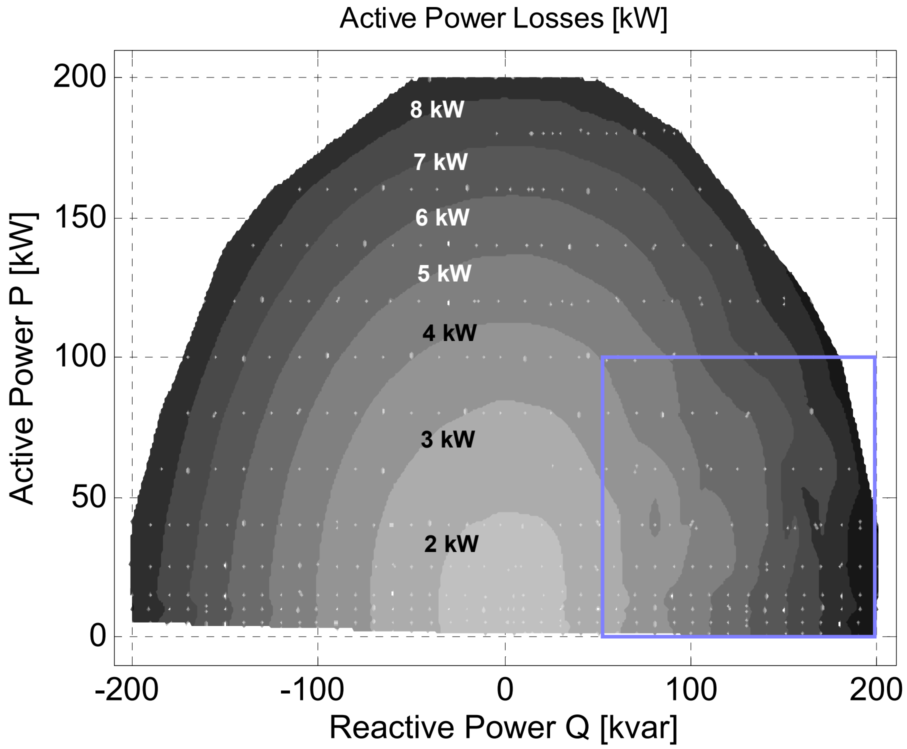


Figure 5-6: Isolines of interpolated losses of a 208 kVA PV inverter in the power output domain of P and Q (measured values at white dots) [measurement data: SMA]

Figure 5-8 illustrates the efficiency in the power domain of this 208 kVA inverter. The black dot in the middle gives the maximum efficiency of 96.6%[3] and the white dots state the respective measurement value as a basis for the cubic interpolated contour graph. It can be seen that the efficiency decreases as soon as reactive power is supplied in addition to active power. This results from the increases of the losses as illustrated in Figure 5-6.

Figure 5-7 depicts the measurement points of losses (in blue) and the interpolated values (in green) according Figure 5-6 over the apparent power output. The interpolated values can be found in the same band as the measured values. This scatter band

[3] The inadequate grid situation (50 Hz/400 V instead of 60 Hz/480 V) leads to efficiency results in this laboratory test that are below of the real efficiency of the inverter in adequate grid situations.

results mainly from the measurement preciseness. An approximation of the measured values with a second order polynomial function leads to the red curve that lies in the scatter band supporting the approach of the approximation.

Based on these results the inverter losses can be assumed to be dependent on the apparent power $S$ with only small errors when the terminal voltage is constant. The terminal voltage can be assumed to be constant in grid-connected applications. This leads to the polynomial approximation of the losses proposed in [Braun 2007b]:

$$P_L(S) = c_{self} + c_V \cdot S + c_R \cdot (S)^2 \tag{5-23}$$

with self losses (no-load losses) $c_{self}$, voltage dependent losses $c_V$ (proportional to $I$), and current dependent losses $c_R$ (proportional to $I^2$). This approximation function can be directly derived from the efficiency curve at $S = P_{AC}$ which is available from many manufacturers of DGs:

$$P_L(P_{AC}, Q=0) = \frac{1-\eta(P_{AC}, Q=0)}{\eta(P_{AC}, Q=0)} P_{AC} \,. \tag{5-24}$$

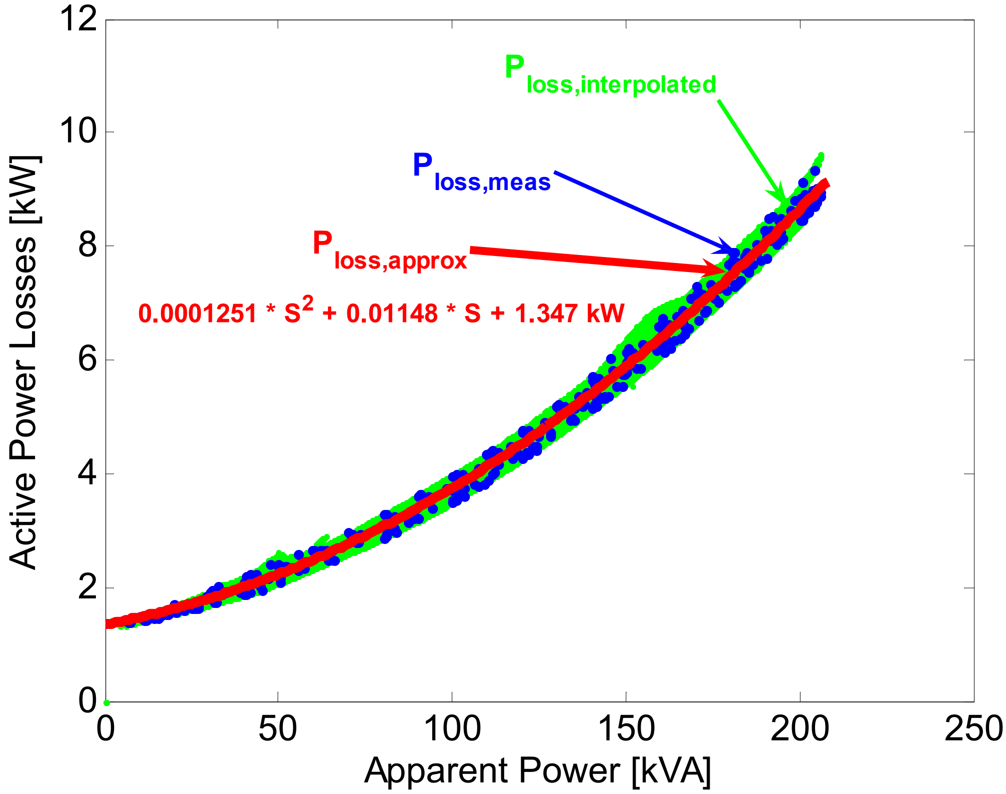


Figure 5-7: Losses of a 208 kVA PV inverter over the apparent power output (measured: blue, interpolated: green, approximated red) [measurement data: SMA]

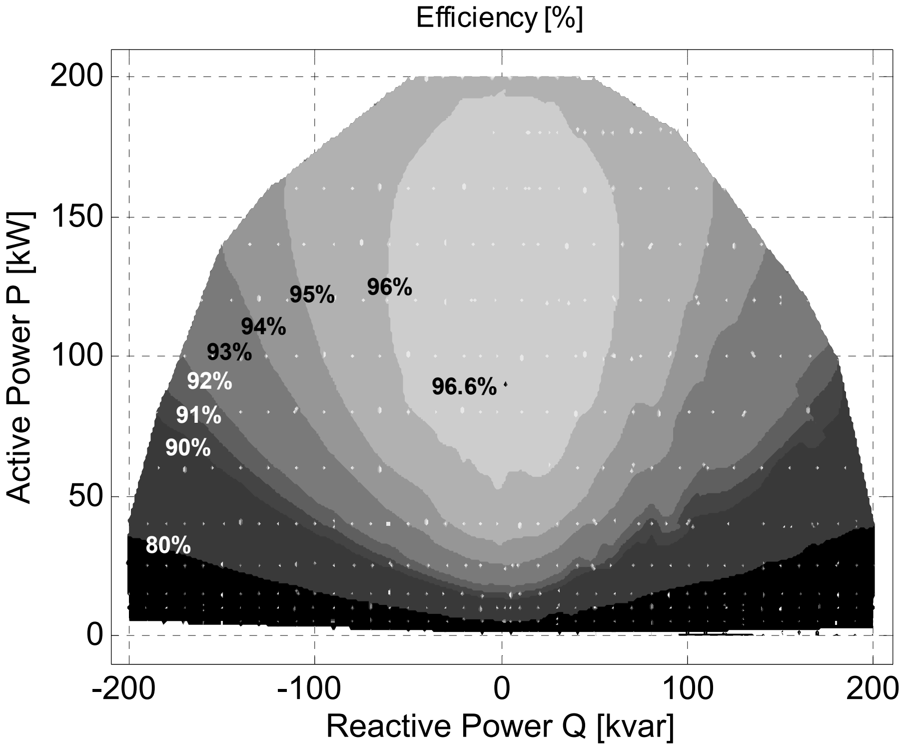


Figure 5-8: Isolines of interpolated efficiency of a 208 kVA PV inverter in the power output domain of P and Q (measured values at white dots) [measurement data: SMA]

The interrelationship is displayed in Figure 5-9 for an exemplary DG grid-coupling converter with 95% maximum efficiency. Figure 5-9 already shows a possible generalisation of the losses and the efficiency as they are not given dependent on the active power but dependent on the apparent power.

The generalised efficiency of the analysed 208 kVA PV inverter can be derived from Figure 5-7 and is depicted in Figure 5-10 over the apparent power:

$$\eta_S = \frac{S}{S + P_L} \,. \tag{5-25}$$

This generalised efficiency $\eta_S$ has to be treated carefully because it does not give the ratio between output and input active power but a figure to derive the losses that are not only dependent on active power but also on reactive power. The losses can be calculated by:

$$P_L(S) = \frac{1 - \eta_S(S)}{\eta_S(S)} S \,. \tag{5-26}$$

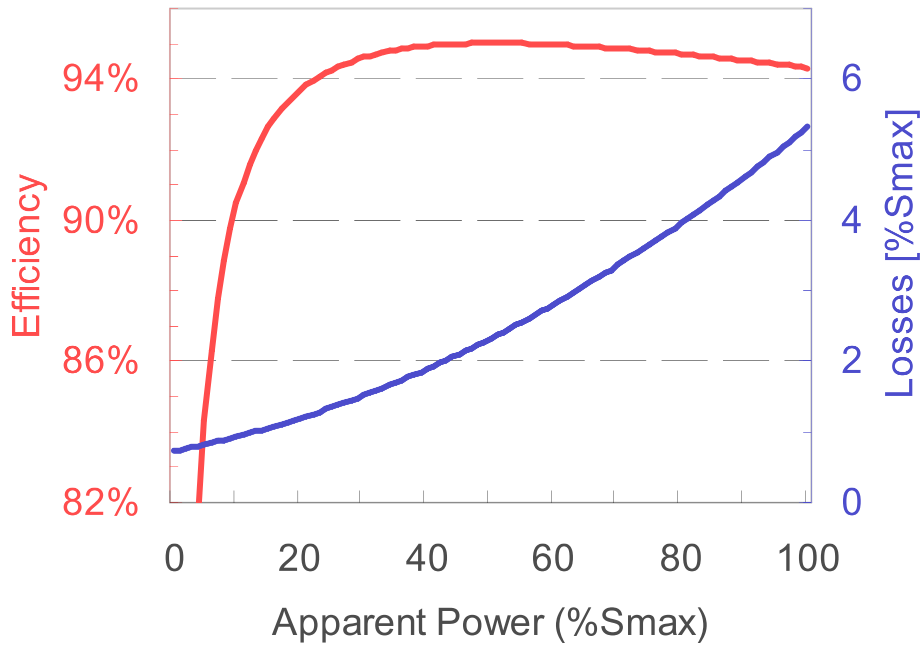


Figure 5-9: Efficiency (red) and losses (blue) of an exemplary PV inverter

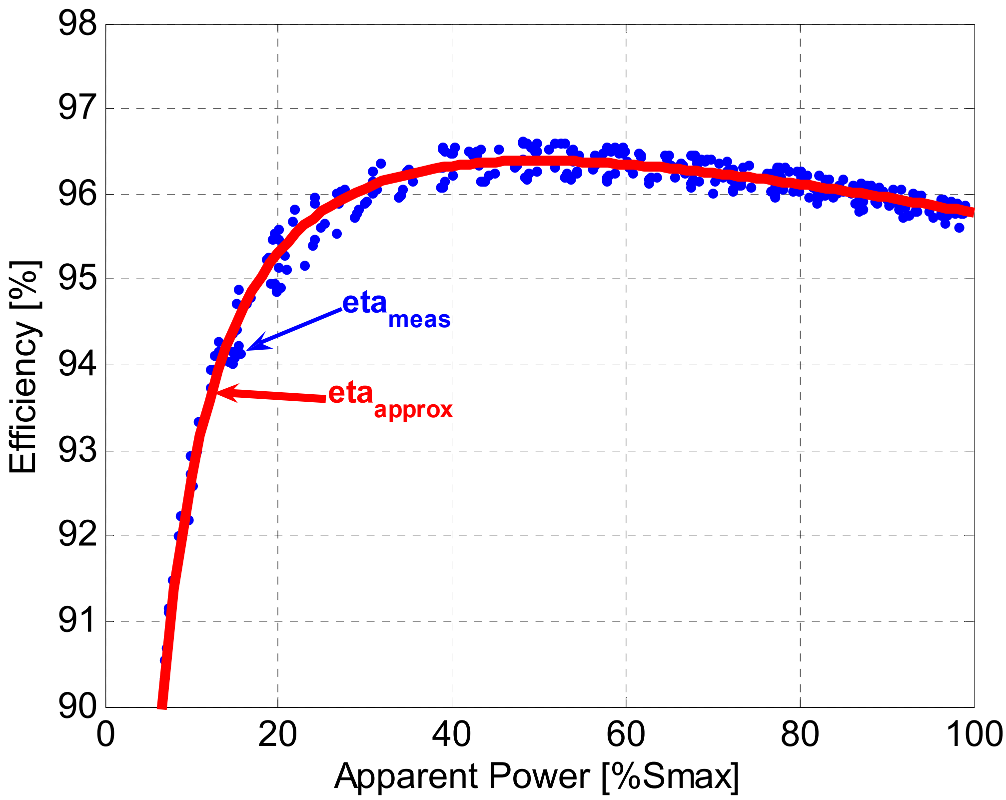


Figure 5-10: Approximated efficiency (red) and measured efficiency (blue dots) of a 208 kVA PV inverter over the apparent power output [measurement data: SMA]

Equation 5-23 can be used in equation 5-17 for approximation of the additional losses by reactive power supply:

$$\begin{aligned}&\Delta P_L(t)=\\&c_{self}+c_V\cdot\sqrt{P_{AC}{}^2(t)+Q^2(t)}+c_R\cdot\left(P_{AC}{}^2(t)+Q^2(t)\right)\\&-\left[c_{self}+c_V\cdot P_{AC}(t^*)+c_R\cdot P_{AC}{}^2(t^*)\right]\end{aligned} \tag{5-27}$$

However, the condition of equation 5-17 is $P(t^*) = P(t)$ and not $P_{AC}(t^*) = P_{AC}(t)$. The losses influence the result according to equation 5-15 because the change of $P_{AC}$ defines the additional losses caused by $Q$ if $P(t) = P(t^*)$:

$$\begin{aligned}&\Delta P_L(t)=P_{AC}(t^*)-P_{AC}(t)\\&\Rightarrow P_{AC}(t^*)=P_{AC}(t)+\Delta P_L(t)\end{aligned} \tag{5-28}$$

This leads to a recursive function which can be stopped after the first (or second) recursion due to sufficient preciseness:

$$\begin{aligned}&\Delta P_{L,0}(t)=\\&c_{self}+c_V\cdot\sqrt{P_{AC}{}^2(t)+Q^2(t)}+c_R\cdot\left(P_{AC}{}^2(t)+Q^2(t)\right)\\&-\left[c_{self}+c_V\cdot P_{AC}(t)+c_R\cdot P_{AC}{}^2(t)\right]\\[1em]&\Delta P_{L,1}(t)=\\&c_{self}+c_V\cdot\sqrt{P_{AC}{}^2(t)+Q^2(t)}+c_R\cdot\left(P_{AC}{}^2(t)+Q^2(t)\right)\\&-\left[c_{self}+c_V\cdot\left(P_{AC}(t)+\Delta P_{L,0}(t)\right)+c_R\cdot\left(P_{AC}(t)+\Delta P_{L,0}(t)\right)^2\right]\\&\ldots\\&\Delta P_{L,k}(t)=\\&c_{self}+c_V\cdot\sqrt{P_{AC}{}^2(t)+Q^2(t)}+c_R\cdot\left(P_{AC}{}^2(t)+Q^2(t)\right)\\&-\left[c_{self}+c_V\cdot\left(P_{AC}(t)+\Delta P_{L,k-1}(t)\right)+c_R\cdot\left(P_{AC}(t)+\Delta P_{L,k-1}(t)\right)^2\right]\end{aligned} \tag{5-29}$$

With the loss curve of Figure 5-9 the equation gives the additional losses caused by reactive power supply as displayed in Figure 5-11. The graph is limited by the semicircle $S_{max} = P_{max}$. It shows the symmetry of negative and positive reactive power supply. In reality there will be a certain asymmetry because the measurement point of the reactive power at the PCC has a phase shift compared to the converter's internal power generation (see Section 5.2.2).

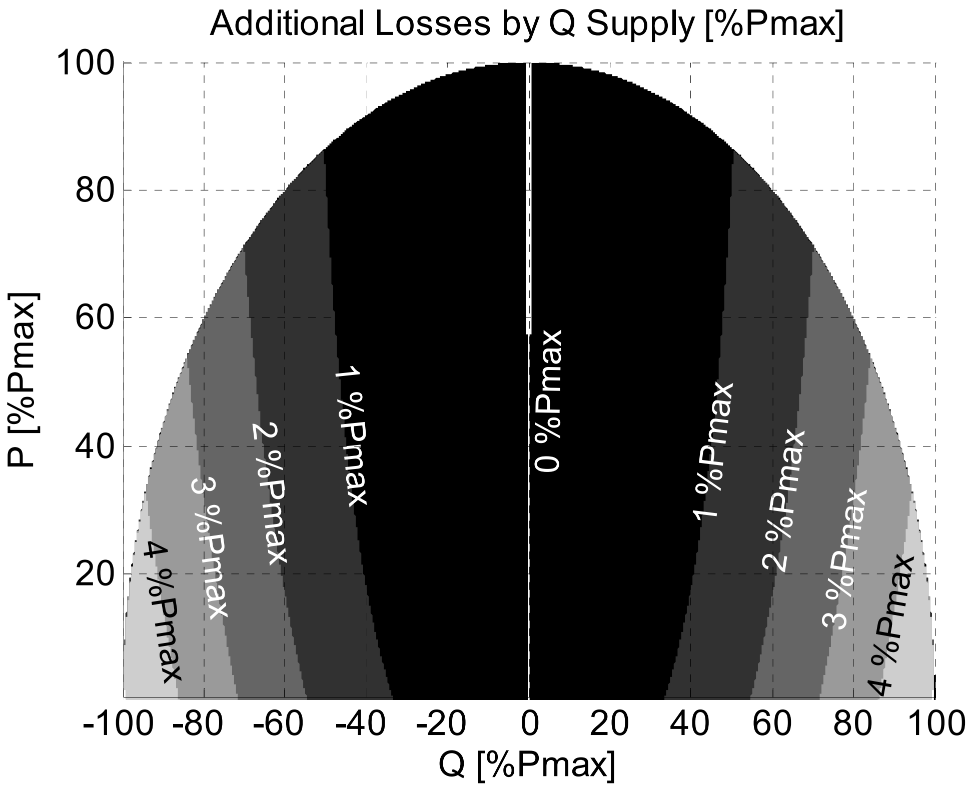


Figure 5-11: Isolines of additional losses caused by reactive power supply Q of an exemplary grid-coupling converter with 95% maximal efficiency (contour plot)

The specific additional losses by reactive power according to equation 5-18 are depicted in Figure 5-12. They have a similar characteristic as the additional losses in Figure 5-11:

- they increase with increasing reactive power supply; and
- they decline with increasing active power supply.

Consequently, it is more efficient to supply a certain reactive power with many DGs than with only few ones. The absolute level and form of the loss curve is different from DG to DG and the operating point defining the losses is variable in case of intermittent active and reactive power supply.

Figure 5-13 illustrates Figure 5-12 in another perspective. The red area gives the specific additional losses by reactive power supply which are represented in Figure 5-12 with isolines. The upper limit (green edge) gives the values near 0% active power and the lower limit (black edge) at 100%.

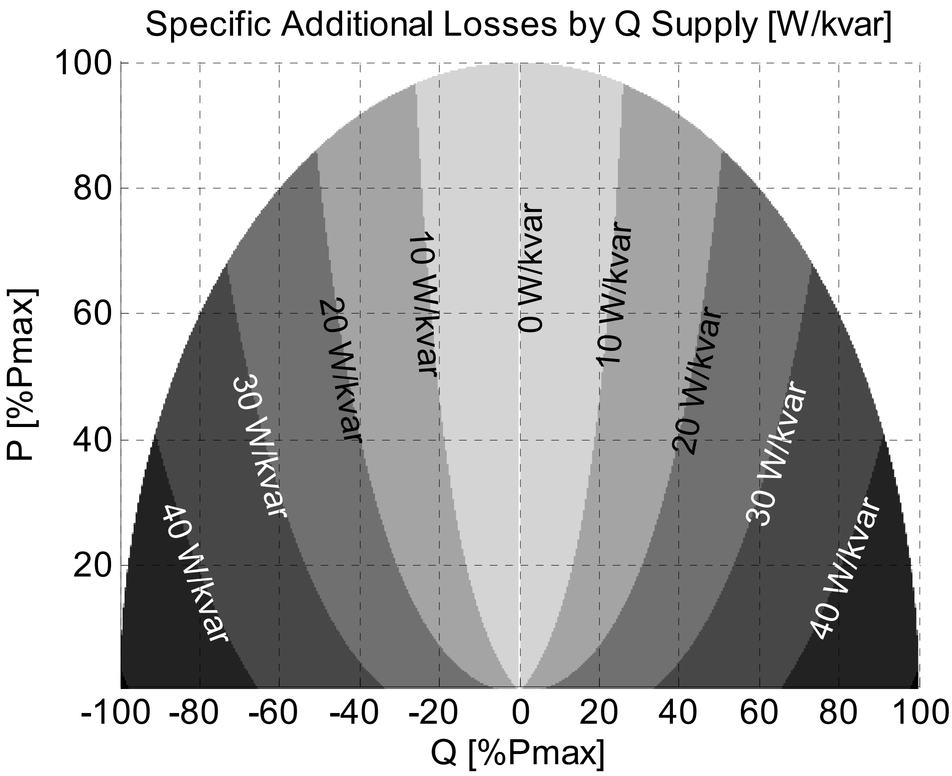


Figure 5-12: Isolines of specific additional losses caused by reactive power supply Q of an exemplary grid-coupling converter with 95% maximal efficiency (contour plot)

In the situation of 0% active and 0% reactive power supply, the converter can be in standby mode (with deactivated stack control). An activation of the converter is necessary to provide reactive power at 0% active power supply. The blue line in Figure 5-13 gives the values at 0% active power supply where only reactive power is supplied and all losses (also no-load losses less standby losses) are attributed to reactive power supply. At small reactive power supply values the specific additional losses are increasing steeply because the constant no-load losses are attributed to very small values of Q. However, this additional consideration (blue line) is a specific case for PV at night [Braun 2007b]. In most other applications, this discontinuity does not exist because the generator would be active all the time to allow active power flow.

Finally, the operational costs of reactive power supply can be calculated based on the active power losses as discussed above and the value of active power. One example is given here with the already discussed PV inverter with a maximum efficiency of 95% (see Figure 5-11). For the German situation it is assumed that the active power is worth 40 c€/kWh when generating active power (cp. feed-in tariff in Germany) and 20 c€/kWh when consuming active power (average end consumer electricity price in Germany).

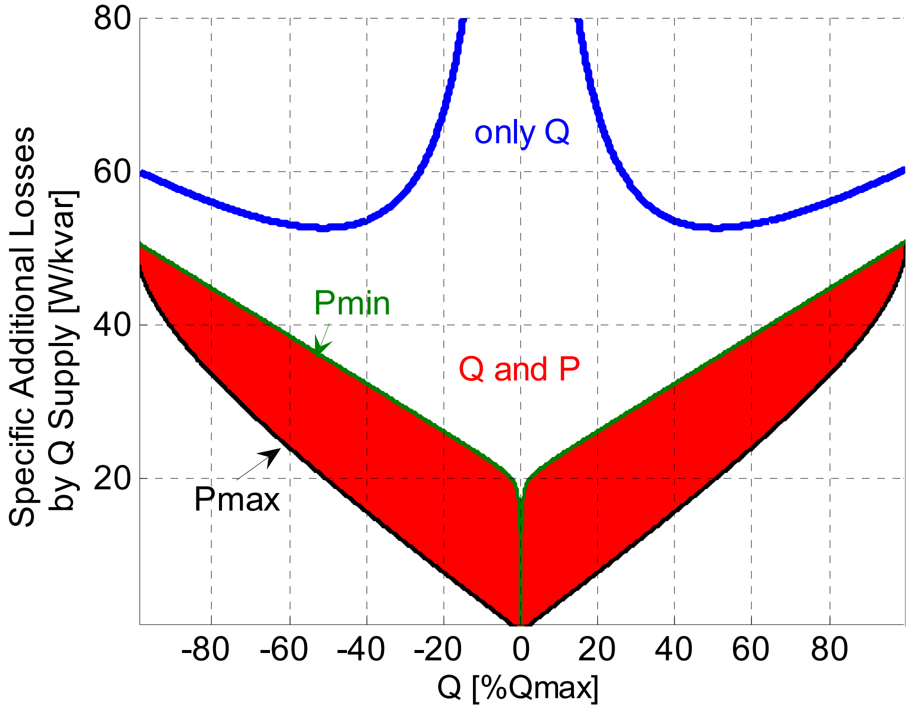


Figure 5-13: Specific additional losses caused by reactive power supply Q of an exemplary grid-coupling converter with 95% maximal efficiency
(blue curve: all losses are attributed to Q because no P is supplied
red area: only additional losses are attributed to Q (the rest is attributed to P),
the area gives all values between Pmin and Pmax at a specific Q)

Figure 5-14 illustrates the operational costs according to the specific additional losses as given in Figure 5-13 and weighted with the respective costs of active power. The red area gives the operational cost range of reactive power supply when active power is supplied in addition to reactive power (P and Q). In this range, the upper limit is for minimum and the lower limit for maximum active power generation. Moreover, the blue curve gives the operational costs of reactive power supply if the inverter only supplies reactive power (only Q) and generates no active power. Then, all losses (less the standby losses) can be attributed to reactive power supply. This results in very high costs at low reactive power supply (around 0%Qmax).

Next to this approximated calculation of the additional losses, they can also be calculated from the measurement values. This is done for the 208 kVA PV inverter with the measured and interpolated losses according to Figure 5-6. The calculation of the additional losses by reactive power supply leads to the contour graph of Figure 5-15. It has unsteady contour lines because the calculation has been done in discrete steps of 1 kVA. Also the specific additional losses of this inverter are given in Figure 5-16 that has also unsteady contour lines, especially in the distorted area, due to the same reason of discrete calculation.

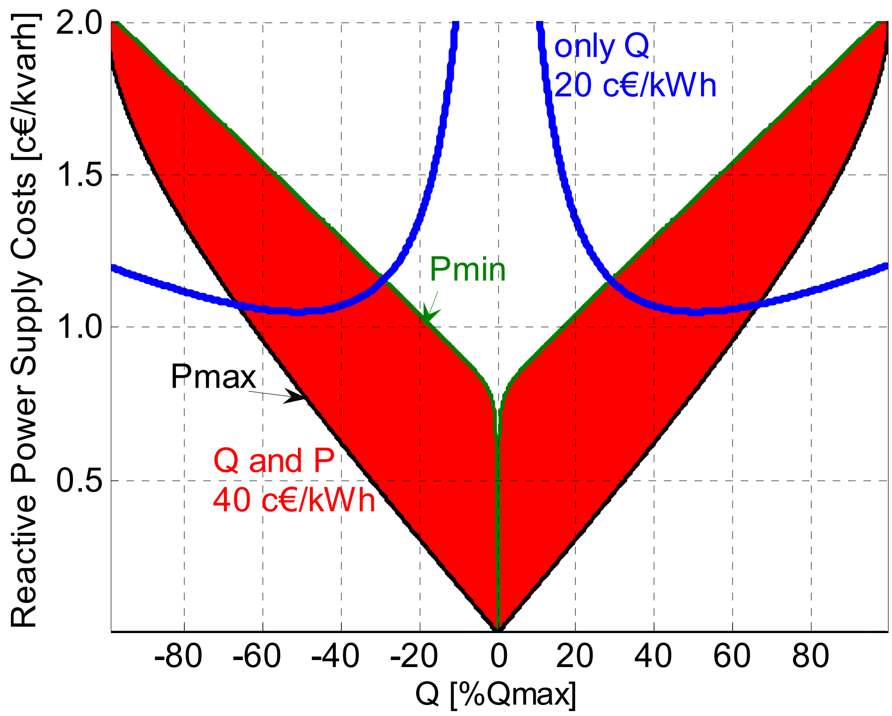


Figure 5-14: Operational costs of reactive power supply of a PV system in Germany with a maximum inverter efficiency of 95%
(blue curve: all losses are attributed to Q because no P is supplied
→ the losses are compensated by energy from the public network with 20 c€/kWh
red area: only additional losses are attributed to Q (the rest is attributed to P),
the area gives all values between Pmin and Pmax at a specific Q
→ the losses are compensated by PV energy with a value of 40 c€/kWh)

#### *5.2.1.3. Operational Costs of Reactive Power Supply from SG-Coupled Distributed Generators*

Synchronous generators have a loss characteristic similar to inverters. Their losses can be approximated with the same approach of a second order polynomial function dependent on the apparent power. Four main types of losses can be found [Chapman 2004]:

- Copper losses,
- Core losses,
- Mechanical losses, and
- Stray load losses.

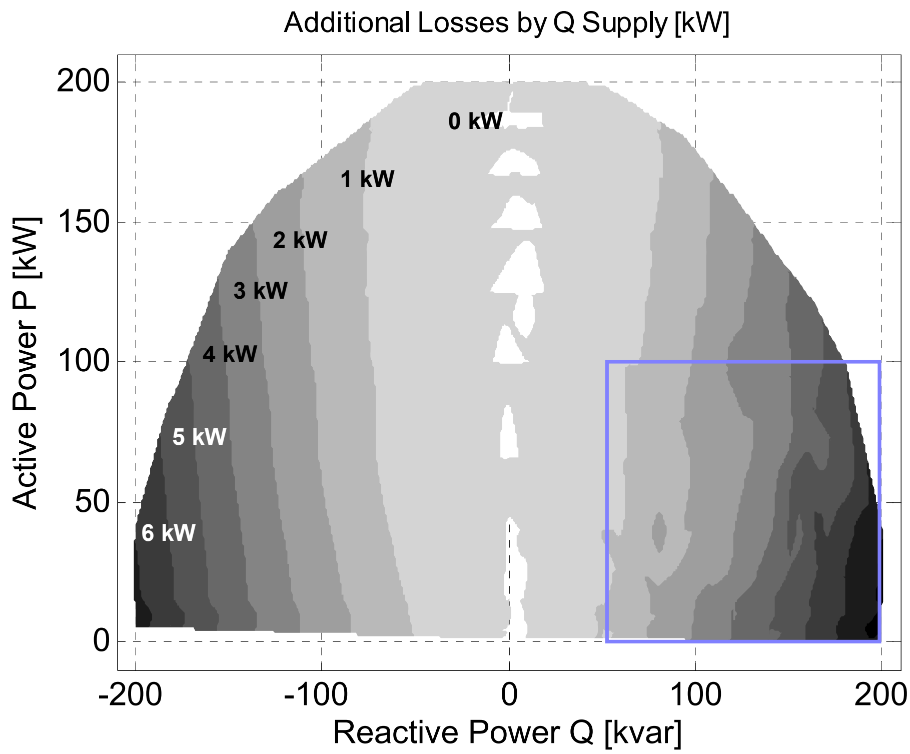


Figure 5-15: Isolines of additional losses caused by reactive power supply of the 208 kVA PV inverter [measurement data: SMA]

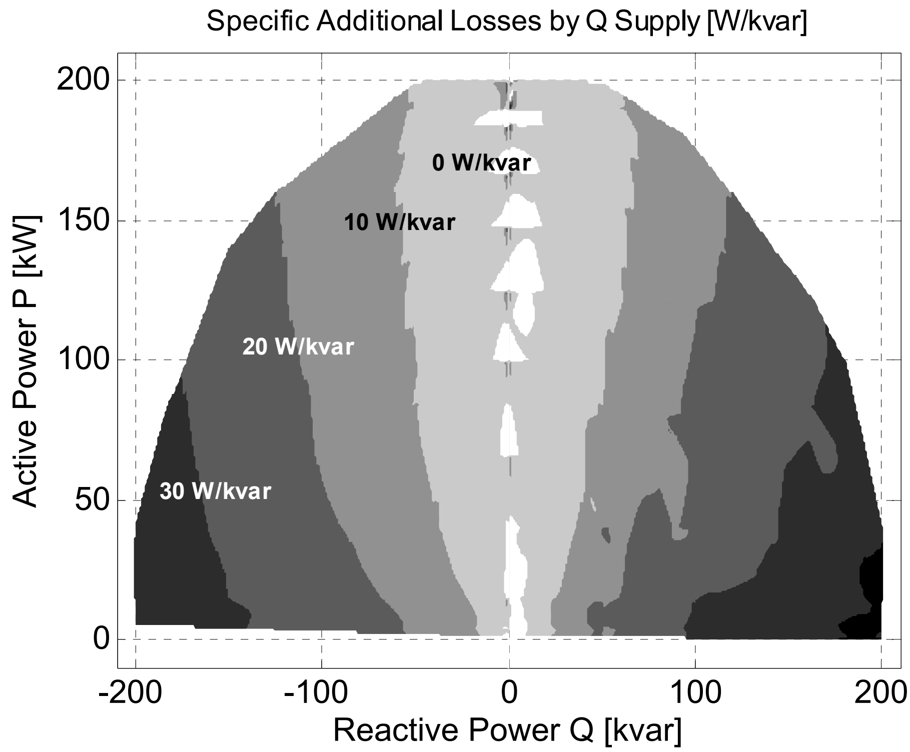


Figure 5-16: Isolines of specific additional losses caused by reactive power supply of the 208 kVA PV inverter [measurement data: SMA]

The copper losses occur in the stator and rotor windings of the synchronous generator as resistive heating. They are calculated by

$$P_{L,Cu,SG} = 3 \cdot R_a \cdot \left|\underline{I}_a\right|^2 + R_f \cdot \left|\underline{I}_f\right|^2 \qquad (5\text{-}30)$$

with the resistance $R_a$ and the current $I_a$ in each stator (armature) phase as well as the resistance $R_f$ and the current $I_f$ in the field winding. The copper losses in the field winding can be considered as constant. On the other hand, the copper losses in the stator windings are dependent on the apparent power with the power of two if the terminal voltage is assumed to be constant.

The core losses occur in the metal of the generator and consist of hysteresis losses and eddy current losses. They vary with the rotational speed and the voltage that both are assumed to be constant. Also the mechanical losses (comprising friction and windage losses, are dependent on the rotational speed and therewith assumed to be constant. The core losses and the mechanical losses are also named as no-load rotational losses. Finally, the stray losses are the category for miscellaneous losses that cannot be placed in one of the other three categories.

Based on these theoretical losses and verified by measurement data given in [Henry et al 2005] and data sheets of SG manufacturers, also the losses of SGs can be approximated by equation 5-23 similar to the situation of inverters. Also here, the approximation is valid in grid-connected applications where the terminal voltage can be assumed to be constant.

#### *5.2.1.4. Operational Costs of Reactive Power Supply from DFIG-coupled Distributed Generators*

The assessment of operational costs of reactive power from DFIG-coupled distributed generators demands for additional considerations. Because the majority of DFIG-coupled DGs are wind turbines the following descriptions concentrate on such units. Figure 5-17 illustrates the power flow in a DFIG that consists of an induction generator that is driven by the turbine with the mechanical power $P_{mech}$ and that generates the stator power $P_s$. Between the stator side and the rotor side of the induction generator a power electronic converter adds an additional power flow $P_r$ that is referenced to the rotor side. This additional power flow allows changing the power balance between stator and rotor side. Therewith, a slip-independent synchronous power generation to the electrical power network is achieved whilst having a mechanical rotation speed that is optimised according to the wind conditions in order to find the maximum power point.

The operation can be subsynchronous, meaning that the rotor-side inverter injects active power in the rotor (the grid-side inverter extracts active power from the stator side) and the rotor rotates below rated speed (positive slip $s$). Normally, this situation occurs in low wind conditions. In high wind situations active power is taken from the rotor and transferred to the stator side (negative slip). This operation mode constitutes the supersynchronous operation. The slip is defined by

$$s = \frac{f_s - f_r}{f_s} \tag{5-31}$$

with stator frequency $f_s$ and rotor frequency $f_r$.

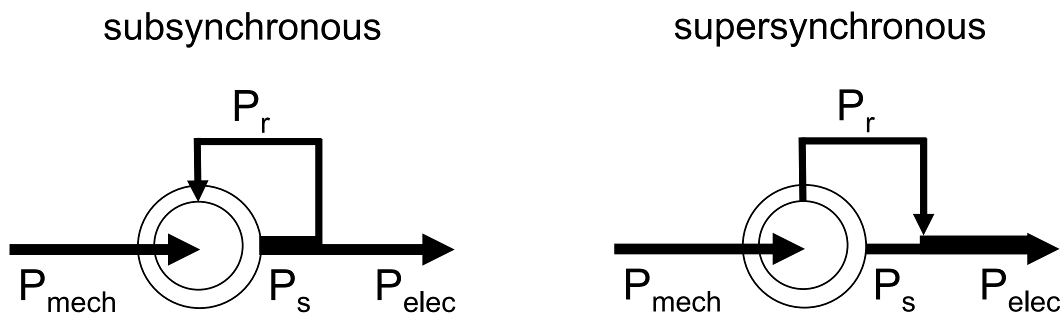


Figure 5-17: Power flow in a DFIG

Generally, it is assumed that the active power flow over the power electronics converter in direction to the rotor $P_r$ is in the order of

$$P_r \approx s \cdot P_s \tag{5-32}$$

depending on the active power flow through the stator $P_s$ [Akhmatov 2003] [Petersson 2005]. The active power $P_{elec}$ which is fed into the mains is the difference of $P_s$ and $P_r$:

$$P_{elec} = P_s - P_r \approx (1 - s) \cdot P_s \,. \tag{5-33}$$

In subsynchronous situation $P_{elec}$ is reduced compared to $P_s$ and in supersynchronous situation $P_{elec}$ is increased compared to $P_s$. This approximation can also be rewritten for the active power flow over the power electronic converter

$$P_r \approx \frac{s}{(1-s)} \cdot P_{elec} \tag{5-34}$$

and the active power of the stator

$$P_s \approx \frac{1}{(1-s)} \cdot P_{elec} \,. \tag{5-35}$$

The slip that optimises the wind turbine's efficiency can be approximated as a function of $P_{elec}$. A typical function $s(P_{elec})$ (similar to the one given in [Lund et al 2007]) is chosen here in order to illustrate the characteristic:

$$\begin{aligned} P_{elec} &= [0;0.1]pu: & s &= 0.3 \\ P_{elec} &= [0.1;0.4]pu: & s &= \frac{13}{30} - \frac{4}{3} \cdot P_{elec} \\ P_{elec} &= [0.4;1]pu: & s &= -0.1 \end{aligned} \tag{5-36}$$

The approximation function of $P_r$ is given in Figure 5-18. The subsynchronous mode can be seen in the interval of $P_{elec}$ = [0;0.25] when the active power $P_r$ is positive (extracting active power from the stator side) and the supersynchronous mode can be seen in the interval of $P_{elec}$ = [0.25;1] when the active power $P_r$ is negative (injecting active power from the stator side). The maximum rotor-side active power $P_r$ is about 0.1 pu of the active power $P_{elec}$ which is in accordance to typical layouts where the power electronic converter's capacity is about 10% of the DFIG total rating.

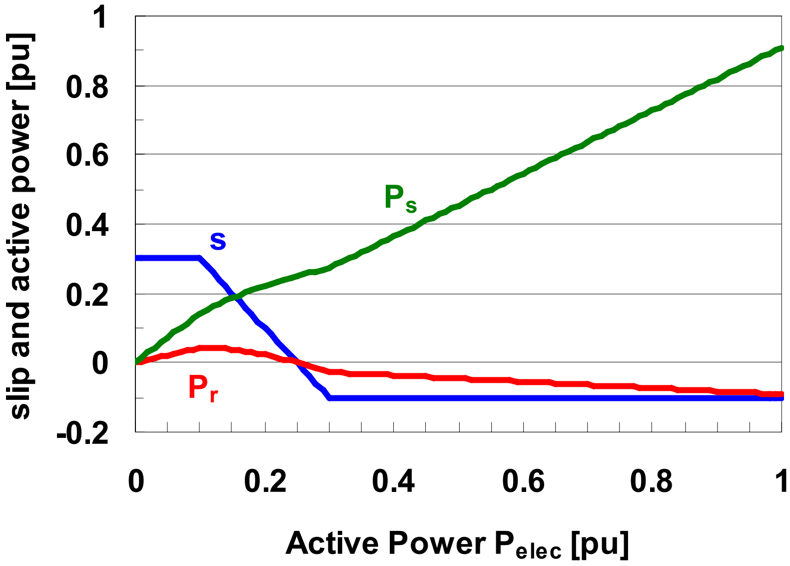


Figure 5-18: Slip $s$, active power $P_r$ and $P_s$ as functions of active power $P_{elec}$ (all in pu)

Figure 5-19 depicts the single-phase equivalent circuit diagram of the induction generator. The values on the rotor side (index $r$) are referred to the stator side (index $s$). In this diagram the rotor-side frequency $f_r$ is lower than the stator-side frequency $f_s$:

$$f_r = s \cdot f_s \tag{5-37}$$

The circuit of the rotor-side represents the rotor and how it can be influenced by the rotor-side inverter that adds a certain voltage $U_r$ and the current $I_r$ in the normally shortcircuited rotor. The electrical frequency of this electrical field from the rotor-side inverter is superposed to the rotating field of the mechanically driven rotor with the speed *n* and the pole pairs *p*. In order to balance the torque on both sides of the induction generator these two fields superpose and are synchronous with the electrical frequency on the stator side:

$$f_s = n \cdot p + f_r \tag{5-38}$$

The equation system for this equivalent circuit is given by:

$$\begin{aligned} \underline{U}_s &= \left(R_s + jX_s\right) \cdot \underline{I}_s + \left(R_{fe} + jX_m\right) \cdot \underline{I}_m \\ \underline{U}'_r &= \left(R'_r + jsX'_r\right) \cdot \underline{I}'_r + \left(R_{fe} + jsX_m\right) \cdot \underline{I}_m \\ \underline{I}_m &= \underline{I}_s + \underline{I}'_r \end{aligned} \tag{5-39}$$

with

- Stator resistance $R_s$ (here: 0.0013 Ω)
- Stator leakage reactance $X_s$ (here: 0.0238 Ω)
- Rotor resistance $R'_r$ referred to stator side (here: 0.0014 Ω)
- Stator leakage reactance $X'_r$ referred to stator side (here: 0.0257 Ω)
- Magnetizing reactance $X_m$ (here: 1.02 Ω) and
- Iron loss resistance $R_{fe}$ (here: 0.02 Ω).

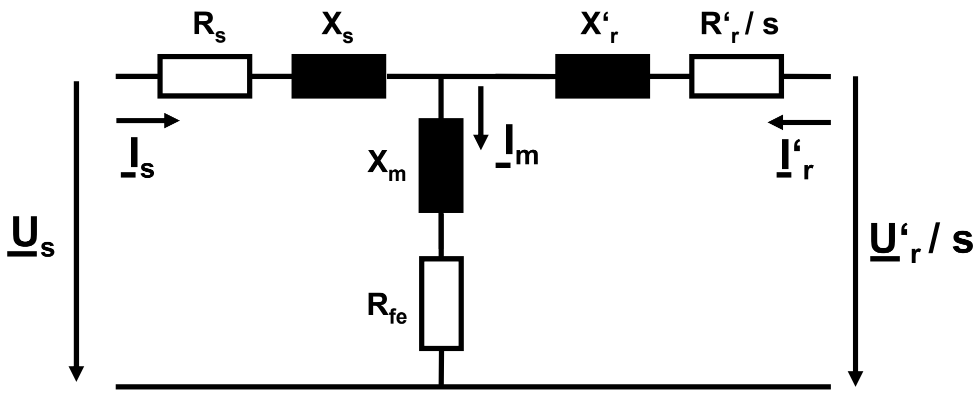


Figure 5-19: Single-phase equivalent circuit of the induction generator of a DFIG

This equation system is transformed in order to have the rotor-side current and voltage with a function of the stator-side current and voltage:

$$\begin{aligned}\underline{U}'_r &= \frac{\left(R'_r + jsX'_r + R_{fe} + jsX_m\right)}{R_{fe} + jX_m} \cdot \underline{U}_s \\ &+ \left[\frac{\left(R_{fe} + jsX_m\right)\cdot\left(R_{fe} + jX_m\right)}{R_{fe} + jX_m} - \frac{\left(R_s + jX_s + R_{fe} + jX_m\right)\cdot\left(R'_r + jsX'_r + R_{fe} + jsX_m\right)}{R_{fe} + jX_m}\right]\cdot \underline{I}_s \\ \underline{I}'_r &= \frac{1}{R_{fe} + jX_m}\cdot \underline{U}_s \\ &- \frac{R_s + jX_s + R_{fe} + jX_m}{R_{fe} + jX_m}\cdot \underline{I}_s\end{aligned} \tag{5-40}$$

The stator active power $P_s$ is given as a function of the total electrical active power output $P_{elec}$ at the grid connection point (Figure 5-18). Assuming that the grid-side converter does not participate in reactive power supply, the reactive power supply $Q_s$ at the stator is approximately the same as at the grid-connection point $Q_{elec}$:

$$Q_s \approx Q_{elec}\ . \tag{5-41}$$

Assuming a constant stator voltage $U_s$ (here: 398 V), the stator current $\underline{I}_s$ can be calculated by

$$\begin{aligned}\underline{U}_s &= U_s \\ \underline{I}_s &= -\frac{\underline{S}_s^*}{3\cdot\underline{U}_s} = -\frac{P_s - jQ_s}{3\cdot U_s} \approx -\frac{\frac{1}{\left(1-s\left(P_{elec}\right)\right)}\cdot P_{elec} - jQ_{elec}}{3\cdot U_s}\end{aligned} \tag{5-42}$$

with the slip $s$ as a function of he total electrical active power output $P_{elec}$ at the grid connection point (Figure 5-18). The resulting stator voltage and stator current are the input data to calculate the rotor voltage and rotor current with the above given equation system.

Several restrictions have to be taken into account to calculate the loading capability chart as already discussed in section 4.1.4.2:

- maximum active power generation (here: 2 MW) at maximum mechanical power,

- maximum stator current (here: 1800 A) that limits the inductive reactive power behaviour,
- maximum rotor current (here: 460 A) that limits the capacitive reactive power behaviour, and
- rotor voltage (here 2760 V with blocked rotor) that limits the reactive power capacity at high slips (low active power generation).

These restrictions lead to the loading capability chart that limits the operation area as can be seen in the following figures. As the induction generator has an inductive behaviour, the consumption of reactive power (inductive behaviour) has a larger capacity than the generation of reactive power (capacitive behaviour) where the inductances of the induction generator have to be compensated.

The copper losses $P_{L,Cu}$ in the windings and the iron losses $P_{L,Fe}$ in the analysed induction generator are calculated by

$$\begin{aligned} P_{L,Cu} &= 3 \cdot R_s \cdot \left|\underline{I}_s\right|^2 + 3 \cdot R'_r \cdot \left|\underline{I}'_r\right|^2 \\ P_{L,Fe} &= 3 \cdot R_{fe} \cdot \left|\underline{I}_s + \underline{I}'_r\right|^2 \end{aligned} \tag{5-43}$$

and given in Figure 5-20. It can be seen that the lowest losses occur at an inductive operation point according to the inductive characteristics of the induction generator.

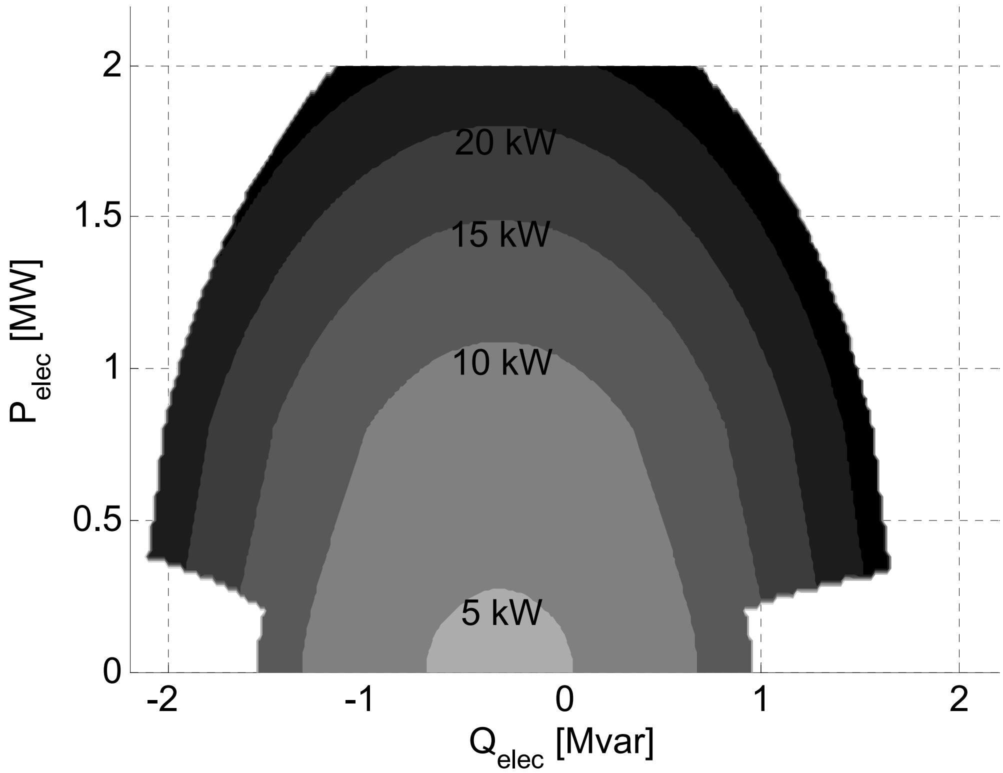


Figure 5-20: Isolines of copper and ion Losses in the induction generator of a typical DFIG

Also, the losses of the power electronic converter have to be taken into account (here: rated power of 400 kW). The grid-side and rotor-side converter have to be looked at individually because it is assumed that the grid-side converter only transfers the active power to the rotor while the rotor-side converter also supplies reactive power.

The grid-side converter is assumed to operate at constant network voltage $U_s$ and the maximum efficiency is assumed to be 98.5% (with approximation parameters $a_{1,g}$, $a_{2,g}$ and $a_{3,g}$ according to section 5.2.1.2). With the active power flow $P_r$ similar to the one in Figure 5-18, this leads to losses as given in Figure 5-21. They are calculated by

$$P_{L,Inv,grid} = a_{1,g} + a_{2,g} \cdot P_r + a_{3,g} \cdot (P_r)^2 . \tag{5-44}$$

It can be seen that these losses are much smaller than those in the induction generator. There is a first peak of converter losses in the area of $P_{elec}$ = 0.2-0.4 MW and $Q_{elec}$ = 0-1.5 Mvar that corresponds to the maximum positive $P_r$ transfer. With the increase of active power $P_{elec}$ there is a minimum of losses in the area of $P_{elec}$ = 0.5-0.7 MW that corresponds to the situation when the slip and therewith $P_r$ is near 0 in synchronism. Further increasing active power generation $P_{elec}$ increases the negative $P_r$ transfer that causes increasing converter losses.

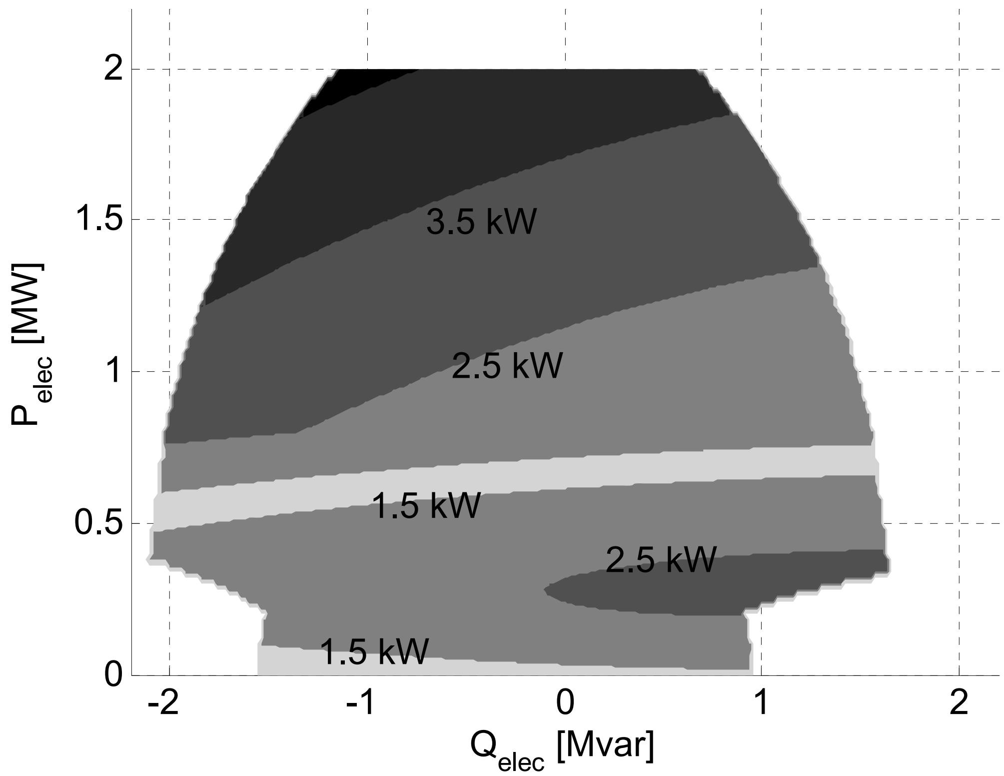


Figure 5-21: Isolines of losses in the grid-side inverter of a typical DFIG

The rotor-side converter is assumed to operate at constant network voltage $U_s$ and the maximum efficiency is assumed to be 99% (with approximation parameters $a_{1,r}$, $a_{2,r}$ and $a_{3,r}$ according to section 5.2.1.2). With an active power flow $P_r$ similar to Figure 5-18 and the reactive power supply to achieve $Q_{elec}$, this leads to losses as given in Figure 5-22 that are calculated by

$$P_{L,Inv,rotor} = a_{1,r} + a_{2,r} \cdot \left|\underline{S}_r\right| + a_{3,r} \cdot \left|\underline{S}_r\right|^2 . \tag{5-45}$$

It can be seen that these losses are much smaller than those in the induction generator and even smaller than in the grid-side inverter because of the higher efficiency due to the filter that is installed on the grid-side but not at the rotor-side. A similar behaviour as for the grid-side inverter can be seen with regard to a first maximum of losses at low $P_{elec}$, followed by a minimum in the area of $P_{elec}$ = 0.6, and an increase afterwards. As the rotor-side inverter provides the reactive power (different to the grid-side inverter), the dependency of the losses on the reactive power supply $Q_{elec}$ is significant, particularly in the area of small active power generation $P_{elec}$.

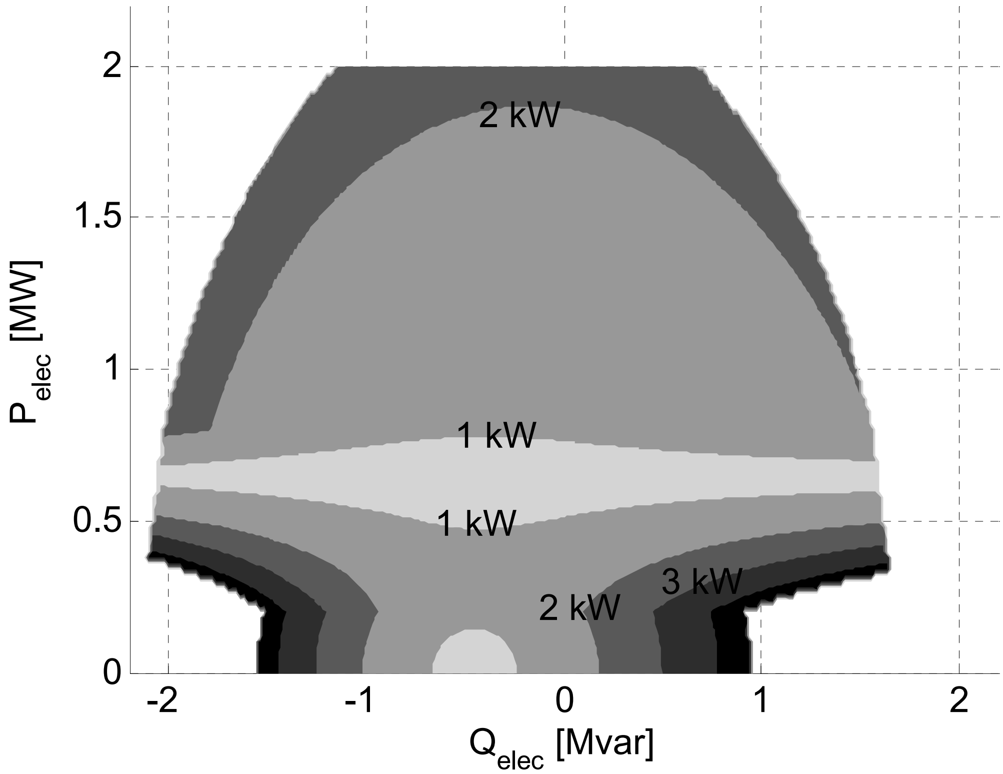


Figure 5-22: Isolines of losses in the rotor-side inverter of a typical DFIG

Finally, the total losses $P_L$ are calculated by

$$P_L = P_{L,Cu} + P_{L,Fe} + P_{L,Inv,rotor} + P_{L,Inv,grid} . \tag{5-46}$$

in the operation domain of the analysed DFIG. The result is given in Figure 5-23. It can be seen that the lowest losses occur in the area of $Q_{elec}$ = -(0.2-0.4) Mvar (inductive behaviour) and $P_{elec}$ = 0-0.5 MW.

In order to calculate the operational costs of reactive power supply by DFIGs only the additional losses due to reactive power supply are of interest. Specific additional losses are determined by dividing these additional losses with the reactive power supply (cf. section 5.2.1.2). As DFIGs are mainly used in WTs, active power generation and consumption costs of 10 c€/kWh are considered to calculated the operational costs of reactive power supply.

Figure 5-24 shows the operational costs of reactive power supply by a DFIG-coupled wind turbine. The figure depicts that the costs are nearly independent from the active power generation. In the operation area of $Q_{elec}$ = -(0-0.6) Mvar the costs are negative and the reactive power supply is cheaper than operating at $Q_{elec}$ = 0 Mvar. Operating more inductive or capacitive results in costs of about 0-0.15 c€/kvarh.

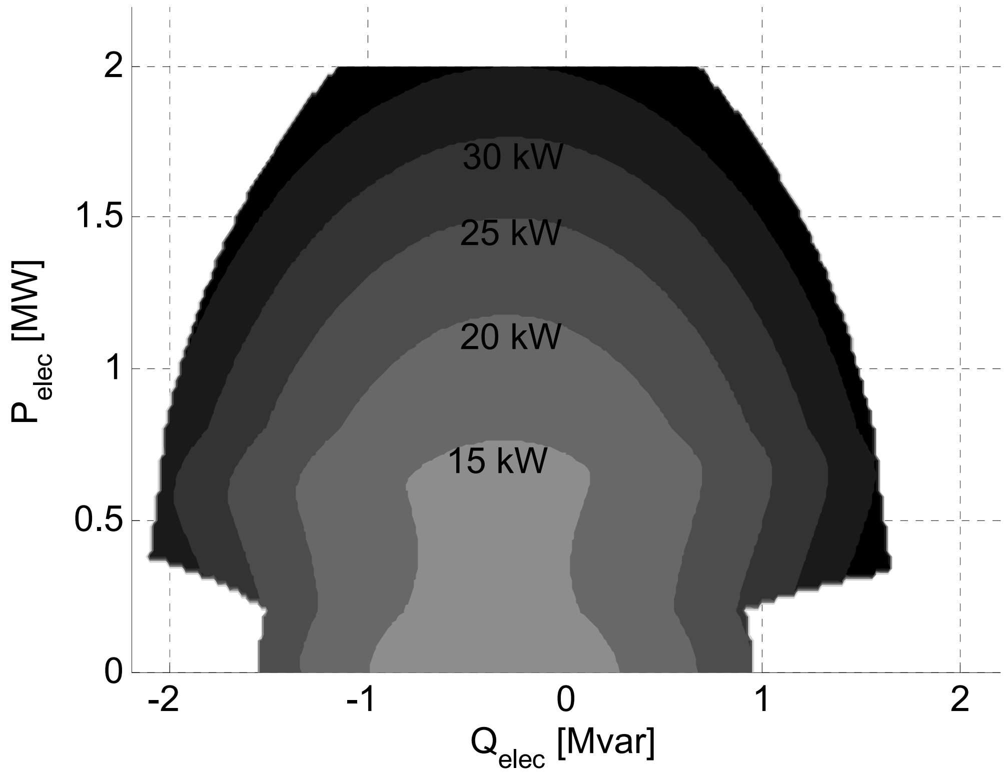


Figure 5-23: Isolines of total losses in a typical DFIG

Comparing these operational costs with the operational costs of inverter-coupled wind turbines shows a similar cost range for capacitive reactive power supply and less costs, even cost reductions, for inductive reactive power supply. However, several aspects have not been looked at in this analysis: delta-star-switching and the inclusion of the gird-side inverter for reactive power supply. These approaches can increase the reactive power capacity and reduce the costs of reactive power supply, both the investment costs by reducing the size of the power electronic converter and the operational costs by reducing the losses.

Delta-star-switching is often applied to reduce the stator voltage at low operation ranges and to reduce therewith the magnetizing losses that are dependent on the stator voltage with the power of two. This increases the reactive power capacity at low active power generation where less magnetizing losses have to be compensated. It also allows reducing the size of the power electronic inverter. More details on the delta-star-switching is given in [Lund et al 2007]

The inclusion of the grid-side inverter for reactive power supply also increases the reactive power capacity. However, the additional capacity is limited to the rated capacity of the inverter that is small compared to the rated power of the DFIG. But it also allows reducing the operational costs because a cost-minimal reactive power supply by both inverters can be found. [Sinelnikova 2005] shows that an optimal share factor alpha can be found where the efficiency of the whole system is maximal (lowest losses in converter and IG together). The results show that a capacitive power factor should be provided by rotor magnetisation. An inductive power factor at subsynchronous operation should be provided by stator magnetisation and a mixed rotor/stator magnetisation at supersynchronous operation.

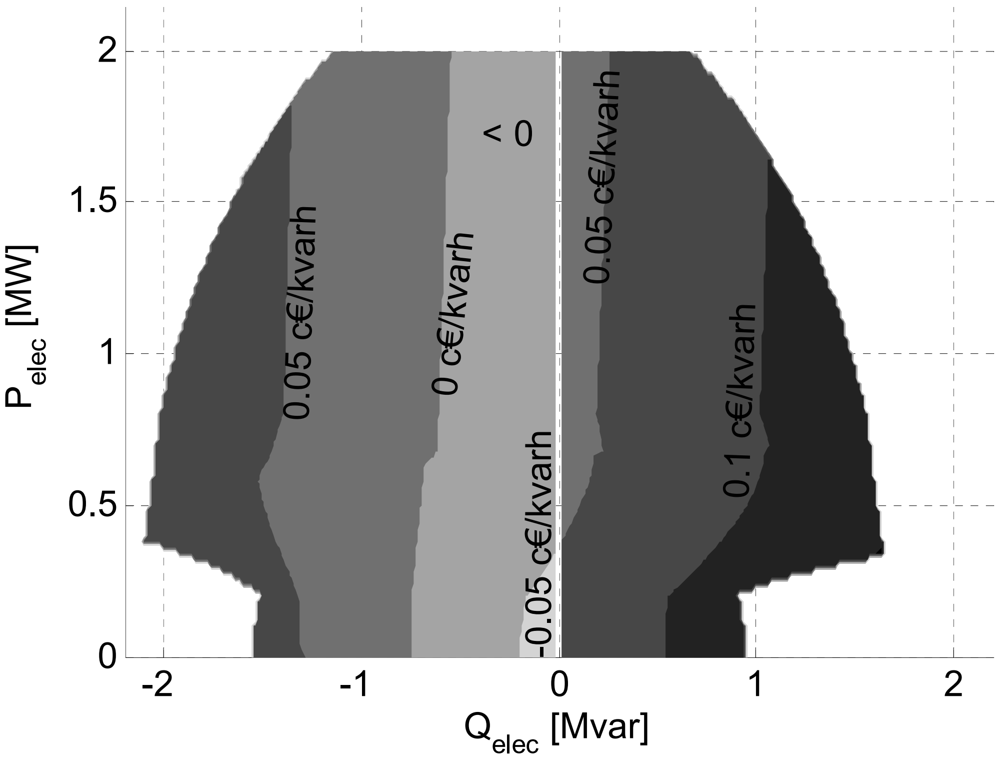


Figure 5-24: Isolines of Operational costs of reactive power supply [c€/kvarh] by a typical DFIG-coupled wind turbine

### *5.2.1.5. Opportunity Costs of Reactive Power Supply*

Another cost component is the opportunity costs that can occur if more reactive power is required than available. Then, the active power generation may be reduced to increase the reactive power capacity. This cost component is discussed in [Lamont;Fu 1999] and [Zhong et al 1999]. The opportunity costs can be attributed to the operational costs because the additional capacity is only released for periods of time.

The determination of the opportunity costs is based on the loading capability chart. An example is given in Figure 5-25 with the maximum apparent power $S_{max}$ and the change of the operation point from $S_1(P_1,Q_1)$ to $S_2(P_2,Q_2)$ that releases additional reactive power capacity:

$$S_1 = \sqrt{P_1^{\ 2} + Q_1^{\ 2}} = S_{\max} = \sqrt{P_2^{\ 2} + Q_2^{\ 2}} = S_2 \,. \tag{5-47}$$

The additional reactive power capacity

$$dQ = Q_2 - Q_1 \tag{5-48}$$

by reduction of the active power generation by

$$dP = P_1 - P_2 \tag{5-49}$$

is calculated by

$$dQ = \frac{1}{2}\left(-2Q_1 + \sqrt{4Q_1^{\ 2} - 4 \cdot dP^2 + 8 \cdot dP \cdot P_1}\right). \tag{5-50}$$

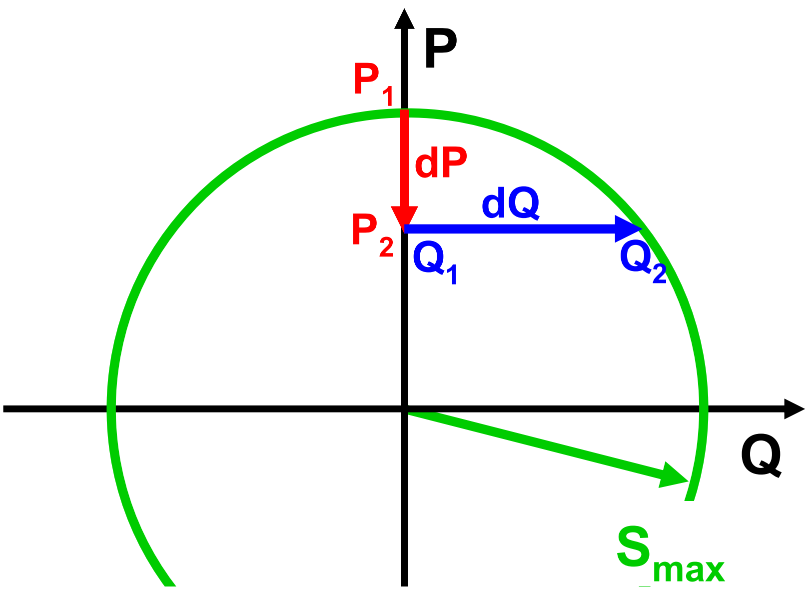


Figure 5-25: Schematic release of additional reactive power capacity *dQ* by reduction of active power *dP*

Figure 5-26 gives an example where $Q_1$ = 0%$S_{max}$ and either $P_1$ = 100%$S_{max}$ (blue curve) or $P_1$ = 80%$S_{max}$ (red curve). The reduction of the active power to $P_2$ results in additional reactive power capacity of $dQ$. With a reduction of only $dP$ = 5%$S_{max}$ from $P_1$ = 100%$S_{max}$ to $P_2$ = 95%$S_{max}$ an additional reactive power capacity of $dQ$ = 31%$S_{max}$ can be released. This means that the ratio $dP/dQ$ is 16%, i.e. each additional kvar reactive power requires a reduction of active power by 0.16 kW. A reduction of $dP$ = 5%$S_{max}$ from $P_1$ = 80%$S_{max}$ to $P_2$ = 75%$S_{max}$ releases an additional reactive power capacity of $dQ$ = 6%$S_{max}$. This means that the ratio $dP/dQ$ is 81%, i.e. each additional kvar reactive power requires a reduction of active power by 0.81 kW.

This example clearly shows that the lowest reduction of active power is required when $P_1$ is at 100%$S_{max}$ and a small amount of additional reactive power capacity is required. Assuming a reduction of only 1%$S_{max}$ releases 14%$S_{max}$ additional reactive power capacity that is 0.07 kW for each kvar additional capacity.

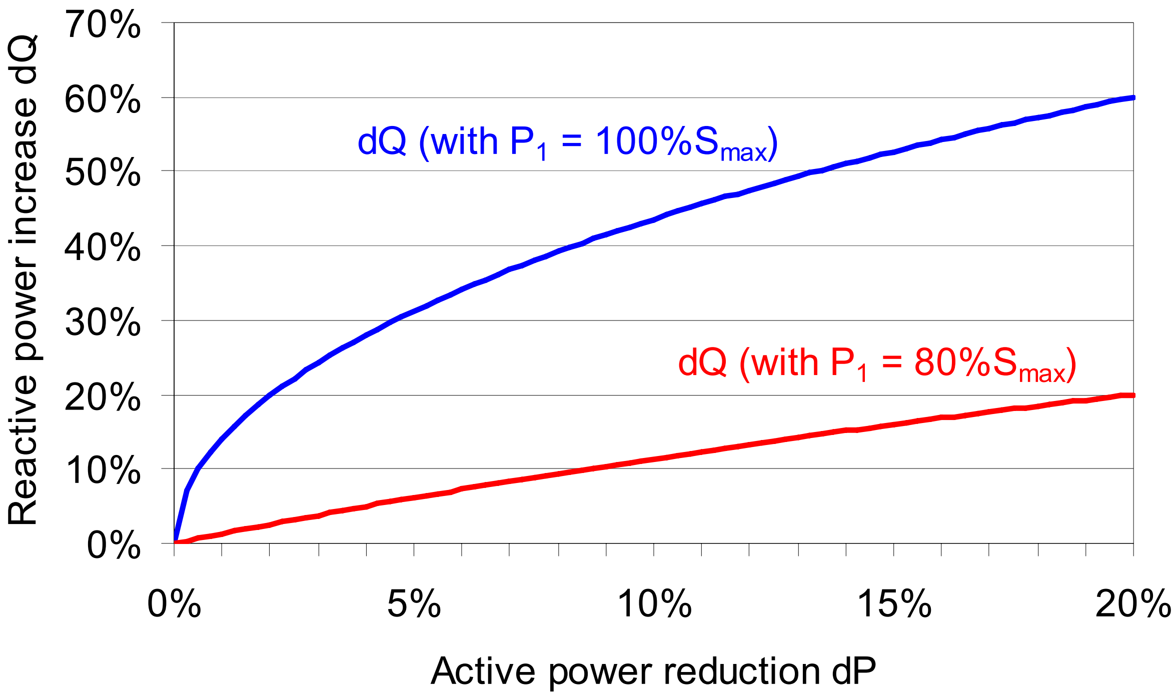


Figure 5-26: Additional reactive power capacity $dQ$ if active power $P$ is reduced by $dP$ starting from either $P_1$ = 100%$S_{max}$ (blue curve) or $P_1$ = 80%$S_{max}$ (red curve)

In other words: if each kW is worth 10 c€/kWh than the additional operational costs are 0.7 c€/kvarh. In the example with $dP$ = 5%$S_{max}$ this results in costs of 1.6 c€/kvarh with $P_1$ = 100%$S_{max}$ and in the second example with $P_1$ = 80%$S_{max}$ even 8.1 c€/kvarh. These additional operational costs resulting from the opportunity costs are significantly higher than the operational costs from additional losses.

### *5.2.1.6. Discussion on Operational Costs of Reactive Power Supply from Distributed Energy Units*

Three main factors define the characteristic of the additional losses caused by reactive power supply:

1. the converter type and its maximal efficiency,
2. the sizing compared to the primary converter, and
3. the active power characteristic of the DG.

These three factors are discussed in more detail in the following paragraphs.

Inverters are built with maximum efficiencies of up to 98% in the power range form kW to MW. Different to inverters, SGs show a larger range of efficiency as estimated in Table 5-5 according to [ESHA 2004] and [PACER 1995]. DFIGs are discussed in more detail in the next section 5.2.1.4. They have a total efficiency of approx. 98% similar to inverters.

| **Rated Power [kVA]** | **1** | **10** | **100** | **1000** |
|---|---|---|---|---|
| Maximal Efficiency | 80% | 90% | 95% | 97% |

Table 5-5: Efficiency of SGs

The sizing of the grid-coupling converter compared to the primary active power generator defines the used area on the efficiency curve. Oversizing extends securely available reactive power limits (see section 5.2.1.1). Furthermore it reduces the additional losses of $Q$ because larger converters with higher efficiencies can be used and they can be operated at lower loadings.

The efficiency curve is normally formed by converter design in a way to provide the best efficiency at the part load condition which is used most often in order to optimise the maximum power output. Hence, the active power characteristic defines optimised efficiency curve designs.

Different influences on the costs of reactive power control are discussed in the previous sections. However, the desired comparison with the benefits requires certain cost ranges. This is difficult because the operational costs have a large range and are variable. Different optimisation approaches dealing with different operational costs characteristics of diverse generators are discussed in Chapter 6.

The energy losses are compensated either by the generator reducing the power injection and/or by power supply from the network. This distinction is necessary because the feed-in tariff or the market price may be different to the power supply tariffs as long as the meter is not bidirectional (running forward and reverse with the same tariff). In Germany, feed-in tariffs are available as given in Table 5-1 with the total costs which are higher than the market prices. Energy supply tariffs are very different from customer to customer and vary with regard to voltage level, energy supplier and consumption profile. The following tariffs are assumed here:

- residential LV customers in Germany: approx. 20 c€/kWh [VDN 2007b]
- commercial MV customers in Germany: approx. 10 c€/kWh [Richmann 2007]

The operational costs are near to zero if only little reactive power is supplied. The maximum value of the upper range is at rated apparent power with the highest tariff compensating the losses. The assumptions in Table 5-6 are taken into account to calculate the upper value of the range. This upper limit does not show the absolute maximum which may be much higher for less efficient and more expensive units but it provides a reasonable range for grid-connected distributed generators in Germany.

| **Type of DG** | **Grid-coupling Converter** | **Maximum power converter efficiency** | **Maximum Costs for loss compensation [c€/kWh]** | **Actual active power generation [%Pmax]** | **Oversizing $S_{max}$ / $P_{max}$** | **Additional Losses by Reactive power [kW/kvar]** |
|---|---|---|---|---|---|---|
| PV | Inverter | 95% | 60 | 0% | 1 | 0.05 |
| Wind | Inverter/DFIG | 98% | 10 | 0% | 1.1 | 0.02 |
| Hydro | SG | 96% | 10 | 80% | 1.25 | 0.025 |
| Biomass | SG | 96% | 21 | 100% | 1.25 | 0.019 |

Table 5-6: Assumptions for calculating the upper limit of operational costs for reactive power supply of typical PV, wind, hydro and biomass plants at typical operational points

These considerations can be summarised in Table 5-7 with the ranges of operational costs of reactive power control from different types of controlled distributed energy units. For all types the range starts with zero costs because the costs of reactive power are very low as long as reactive power is supplied near the operational point of lowest losses.

The opportunity costs, as discussed in section 5.2.1.5, are not taken into account here. They are considerably higher than the upper limit of the given range of operational costs in Table 5-7. Here, the focus is on the available reactive power capacity.

| Type of DG | Operational costs of reactive power control [c€/kvarh] |
|---|---|
| PV | 0 - 3.04 |
| Wind | 0 - 0.21 |
| Hydro | 0 - 0.25 |
| CHP | 0 - 0.40 |

Table 5-7: Operational costs of reactive power control from different distributed generators (in Germany)

Another aspect has not been discussed yet: network components and the additional losses by reactive power supply. It is possible that a certain distance has to be covered between the generator and the reference point of reactive power supply. Then, additional losses can occur by transmitting the reactive power in the lines. Also transformers may be necessary to transform the voltage levels. The connection of distributed generators to the medium voltage often requires step-up transformers, especially for inverter- and DFIG-coupled generators. In these situations, the additional losses that are analysed in the next section have to be added.

### 5.2.2. Losses in Network Components

Normally active and reactive power is not needed directly at the point of generation. They have to be transmitted to other points in the network causing additional losses and phase shifts of the current. Two basic network elements have to be taken into account: lines and transformers.

Network losses play an important role in electricity network costs. According to [Targosz et al 2005], the world-wide average is estimated at 9% of electricity use. The range in Europe already spreads between 4% and 10% which is generally below world's average. Another extreme can be found in India with an average of 32.5% in 2004-2005 [Nouni et al 2008]. [Targosz et al 2005] point out that approx. one third of the losses occur in transformers and approx. 70% occur in the distribution system.

Different types of losses can be distinguished [Chapman 2004]:

- Load-dependent losses that occur by current flow in the network elements. They cause heat losses and increase with the square of the current (or the square of the apparent power flow when the voltage is constant).
- Load-independent (no load) losses that occur in overhead lines (e.g. corona losses), cables (e.g. dielectric losses, dissipation losses, and insulation losses),

and transformers (e.g. hysteresis losses). They are mainly dependent on the voltage and independent from the loading.

- Other losses such as measurement errors, theft and other defects are not considered further on.

In the distribution network the majority of the losses of the lines are load-dependent. Load-independent losses can be neglected in the analysis here. In contrast to lines, no-load losses of transformers have to be taken into account because they play an important role at low loading levels.

### 5.2.2.1. Lines

Typical line characteristics are already listed in Table 3-2. As an example the NA2XY 3x150sm 0.6/1kV cable is considered here with a resistance of *R'* = 0.206 Ohm/km, an reactance of *X'* = 0.069 Ohm/km, and a susceptance of *B'* = 191.6 µS/km. Figure 5-27 gives a one-phase equivalent circuit diagram in T form with the resistance *R*, the inductance *L*, and the capacitance *C*.

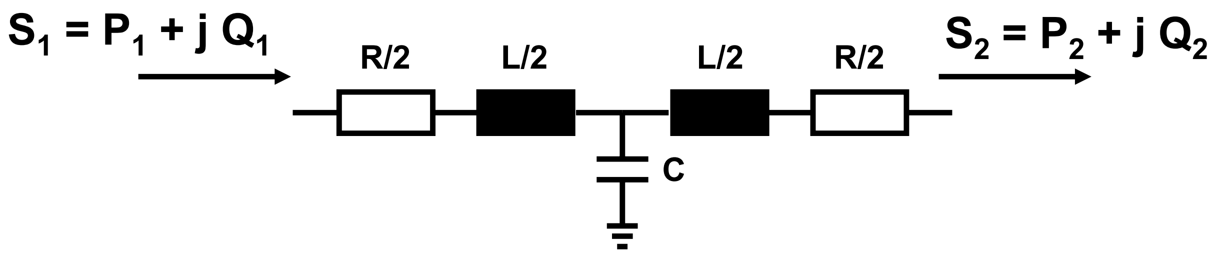


Figure 5-27: Simplified equivalent circuit diagram of a line element (one-phase)

The active power losses $P_{L,L}$ of a line with the length $l$ can be calculated with the injected active power flow $P_1$, the reactive power flow $Q_1$, and the voltage $U$ giving the difference to the active power flow at the end of the line $P_2$:

$$\mathrm{P_{L,L}} = P_2 - P_1 = \frac{\mathrm{R'} \cdot \mathrm{l} \cdot (\mathrm{P_1}^2 + \mathrm{Q_1}^2)}{\mathrm{U}^2} . \tag{5-51}$$

This is an approximation which is sufficient for the purposes here where the influence of the line on the reactive power supply of distributed generators is analysed (see also section II.5). Alongside the line the power flow and the voltage changes but this is not taken into account here because it is a minor effect.

These active power losses $P_{L,L}$ of the lines may also be approximated by a second order polynomial function (cf. section 5.2.1.2), where the fixed losses and the voltage fall can be neglected leading to a simplified approximation function:

$$P_{L,L} = a_{fix} + a_V \cdot S_1 + a_R \cdot (S_1)^2 = \frac{R}{U^2} \cdot (S_1)^2 \tag{5-52}$$

with fitting parameters $a_{fix}$, $a_V$ and $a_R$. The simplified function is a quadratic function of the apparent power flow $S_1$ with the resistance of the line $R$ and the voltage level $U$.

Also a phase shift results from the reactive behaviour of the line. The reactive power $Q_1$ which is injected at one side of the line is different to the reactive power $Q_2$ on the other side (positive = inductive). Inductive as well as capacitive behaviour of the line changes the reactive power flow. This reactive power change can be approximated by the reactive power of the line consisting of the inductive component $Q_L$ and the capacitive component $Q_C$. The inductive reactive power can be approximated by

$$Q_L = \frac{\mathrm{X'} \cdot \mathrm{l} \cdot (\mathrm{P_1}^2 + \mathrm{Q_1}^2)}{\mathrm{U}^2} \tag{5-53}$$

and the capacitive reactive power by

$$Q_C = -\mathrm{U}^2 \cdot B' \cdot l\,. \tag{5-54}$$

These two equations can be derived from the fundamental electrical complex power equation

$$\underline{S} = P + jQ = \sqrt{3} \cdot \underline{U} \cdot \underline{I}^* = 3 \cdot \underline{Z} \cdot I^2 = \frac{U^2}{\underline{Z}^*} = \underline{Y}^* \cdot U^2$$

$$\text{with } \underline{Z} = \mathrm{R} + \mathrm{jX} \tag{5-55}$$

$$\text{and } \underline{Y} = \mathrm{G} + \mathrm{jB}\,.$$

The impedance $Z$ comprises the resistance $R$ and the reactance $X$, and the admittance $Y$ comprises the conductance $G = 1/R$ and the susceptance $B = 1/X$.

The change of the reactive power flow with its inductive and capacitive component is:

$$\Delta Q = Q_2 - Q_1 = Q_L + Q_C = \frac{\mathrm{X'} \cdot \mathrm{l} \cdot (\mathrm{S_1}^2)}{\mathrm{U}^2} - \mathrm{U}^2 \cdot B' \cdot l\,. \tag{5-56}$$

This behaviour is depicted in Figure 5-28 for a cable and its loading in percentage of the capacity which also depends on the voltage level. In low voltage networks with 0.4 kV and a line length of 100 m, the capacitive influence is negligible and the inductive behaviour increases from zero to 0.9% of the rated cable capacity of 208 kVA which corresponds to 1.9 kvar. With increasing voltage level the influence of the susceptance becomes stronger leading to capacitive behaviour in low load situations. At 10 kV and a line length of 2.5 km, for instance, the capacitive behaviour is 0.9% of the rated cable capacity of 5190 kVA which corresponds to 47.9 kvar. With increasing loading of the cable the inductive behaviour gains influence compensating the capacitive behaviour leading to nearly zero reactive power. In between, at 6 kV and a line length of 1.5 km, the cable has capacitive behaviour at low load and inductive behaviour at high load.

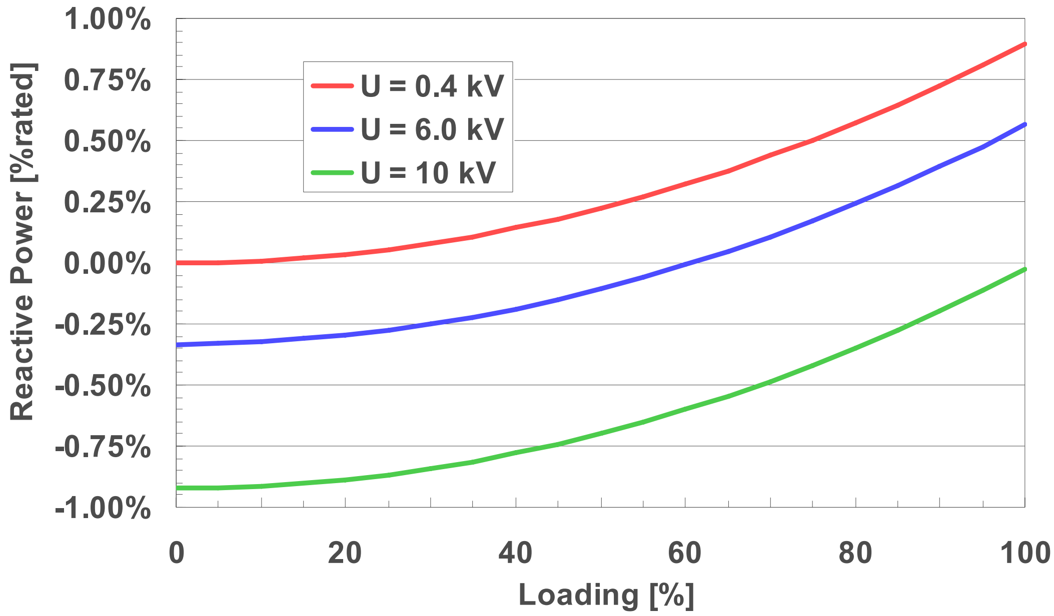


Figure 5-28: Reactive power characteristic (in percent of the cable's capacity) of a NA2XY 3x150sm cable at different voltages and different loadings

The active power losses $P_L$ of this cable are three times higher than the inductive reactive power losses $Q_L$ because of the $R/X$ ratio of 3. The losses of the studied cable are starting from zero (at no load) to 2.7% (full load) of the cables capacity and the given lengths. The 1% losses are exceeded at 61% load.

Costs from these losses and changes of reactive power supply have to be taken into account by the generator's operator if the line is on his side of the PCC. If not, the operator of the public distribution network has to consider these losses and reactive power changes if the control service is required at another network node.

### *5.2.2.2. Transformers*

Transformers may also be connected between the distributed energy unit and the connection point. The one-phase equivalent circuit diagram in T form is depicted in Figure 5-29 with resistances $R_{Cu}$ of the windings representing copper losses and a resistance $R_{Fe}$ representing the iron losses. Moreover, it comprises leakage reactances $X_l$ and the magnetizing reactance $X_m$.

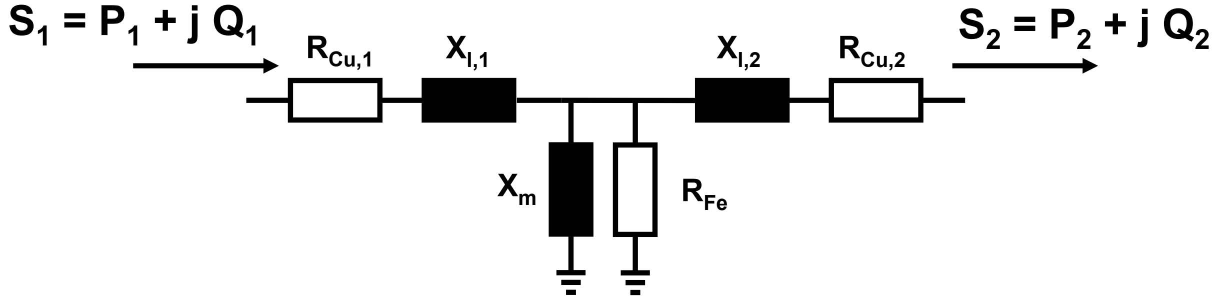


Figure 5-29: Simplified equivalent circuit diagram of a transformer (one-phase)

Two basic types of losses can be distinguished: no-load losses and load losses. No-load losses (or iron losses) are represented by the resistance $R_{Fe}$ and are caused by the hysteresis and eddy currents in the core which depend on the applied voltage (and not the current). Load losses (or copper losses), on the other hand, are represented by the resistance $R_{Cu}$ of the windings and vary with the square of the load current. According to [Targosz et al 2005], international standard efficiencies at 50% load are within 99-99.5% for transformers in the capacity range of some hundreds kVA to some MVA. In contrast to losses in lines which can be approximated only by load-dependent losses, active power losses in transformers need to be separated in fixed and variable losses. Similar to the approximation of the losses in inverters and synchronous generators with a second order polynomial function in section 5.2.1, also the losses of a transformer $P_{L,T}$ can be approximated thereby:

$$P_{L,T} = P_{Fe} + b_V \cdot S_1 + b_{Cu} \cdot (S_1)^2 \tag{5-57}$$

The fixed losses (iron losses) $P_{Fe}$ are assumed to be constant for one transformer. With an increase of the current (here: apparent power flow) from zero, the variable part of the losses becomes important. The copper losses $P_{Cu}$ which are defined by the parameter $b_{Cu}$ increase with the square of the apparent power flow. Also the voltage fall over these resistances is considered with the parameter $b_V$ but in this approximation it may also be neglected leading to a more simplified approximation including the rated apparent power of the transformer $S_n$:

$$P_{L,T} = P_{Fe} + \frac{P_{Cu}}{S_n^2} \cdot (S_1)^2 \tag{5-58}$$

As an example a 400 kVA 0.4/10kV transformer is looked at which has iron losses $P_{Fe}$ = 0.88 kW, copper losses $P_{Cu}$ = 4.3 kW, and a short circuit voltage of 4%. The $X/R$-ratio of the short-circuit impedance is 3.58. This transformer has the efficiency as depicted in Figure 5-30 which peaks at 99% in the range of 150 to 200 kVA and exceeds 98.8% in the range of 100 to 350 kVA.

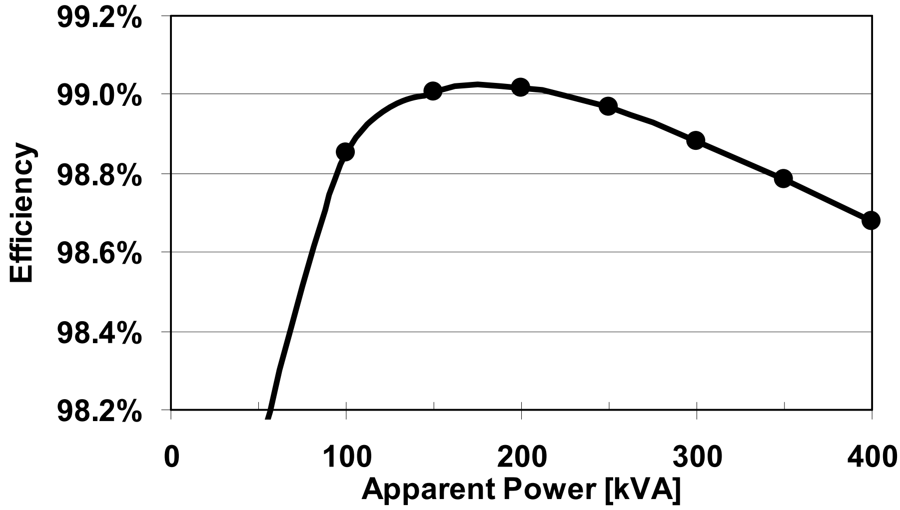


Figure 5-30: Efficiency of a typical 0.4/10 kV transformer

Apparent power flow over the transformer faces a phase shift due to its inductances. Reactive power transfer of the transformer is modified to be more inductive. This reactive power change *ΔQ* can be approximated by

$$\Delta Q = Q_2 - Q_1 = Q_m + b_{q,V} \cdot S_1 + b_l \cdot (S_1)^2 = X_\mathrm{T} \cdot (S_1)^2 \qquad (5\text{-}59)$$

with the fitting parameters $Q_m$, $b_{q,V}$, $b_l$ and $X_T$.

The transformer of the example above has a inductive reactive power characteristic of 0 kvar at zero load and 16 kvar at full load which results in a fitting parameter $X_T$ = 0.0001 kvar/(kVA)$^2$.

### 5.2.2.3. *Summarised Influence of Network Elements*

The approximation function for single network elements as given above can be used if only a small number of them are to be considered, for instance, a step-up transformer of the distributed generator or a single feeder to the PCC. However, more complex network configurations demand for the application of network calculation programs. As an example, PowerFactory from DIgSILENT is used to give an impression of the network influence if an inverter-coupled distributed generator is connected to the PCC via a 0.4/10 kV step-up transformer and a 10 kV cable of 2.5 km length. These two network elements are already introduced in the two sections above as examples. Figure 5-31 shows the network as represented in PowerFactory. Load flow analyses are performed with different active and reactive power settings of the generator. In 1% resolution, the active and reactive power domain of the 400 kVA generator is analysed resulting in the two given contour graphs of Figure 5-31 which illustrate the active power losses in the network connection in the power domain of the generator (figure above) and the capacitive reactive power shift caused by the network connection in the same generator power domain. Both domains have the PCC as reference. The active power losses are the lowest with 0.22 %Smax (0.88 kW) when capacitive reactive power of 11%Smax is supplied to the external grid (marked with a black dot in the figure). They increase up to 1.6 %Smax (6.4 kW) at the highest power flow values.

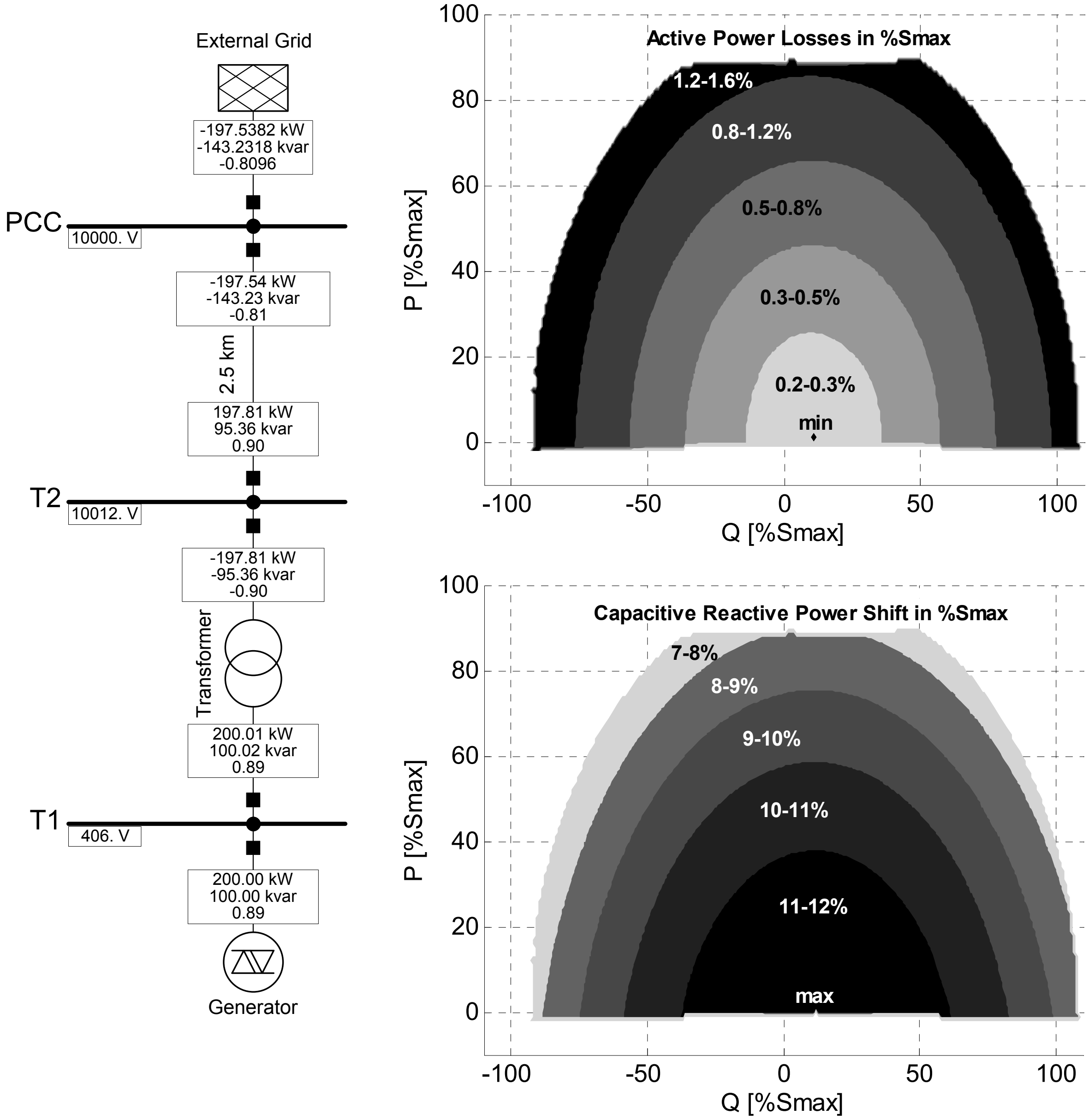


Figure 5-31: Network Connection of Generator to PCC (left) and the resulting active power losses (right above) and capacitive reactive power shift (right below)

The transformer causes an inductive reactive power shift but this is overcompensated by the capacitive behaviour of the cable which leads to a capacitive reactive power shift up to 12 %Smax (48 kvar) at lowest power flows with reactive power at the PCC of 12 %Smax. With increasing power flows the inductive behaviour of the cable gains influence (see also Figure 5-28) reducing the capacitive reactive power shift of the network connection to 7.1 %Smax (28.4 kvar).

Having analysed the network influence, the total losses caused by reactive power flows can be looked at. If the DG operator has to operate this part of the network connection to the PCC he has to take into account all losses. Figure 5-32 shows the related active power losses of the exemplary generator with an inverter efficiency of 96%. If the network as given in Figure 5-31 is also taken into calculation the total losses are higher and the minimum losses are at 12 %Smax capacitive reactive power (see Figure 5-33). The maximum related losses increase from 35 W/kvar without the network to 52 W/kvar with the network at high reactive power and low active power output.

One important conclusion can be derived from these illustrations. The network topology plays an important role. For instance, a wind farm with several similar generators connected together to the PCC may be operated as follows. Those generators which are nearest to the PCC can provide reactive power at lower costs than those at the farthest end of the feeder (assuming similar active power generation). Due to the increase of the costs with more reactive power supply there will still be a common sharing of reactive power supply but the weights of each one depend on their point of network connection.

#### *5.2.2.4. Influence of Network Elements on Active/Reactive Power Control Costs*

The losses in the network caused by active power control may often be neglected because they are a minor cost factor constituting only some percent of the total operational costs of active power control. This may be valid in Germany and also in Europe with low losses but in countries such as India and Brazil with average losses of around 20% they play an important role.

The operational costs of reactive power control are mainly defined by increased active power losses and their compensating costs. In the previous analysis, only the losses in the grid-coupling converter are considered. If reactive power is supplied by converters with an efficiency of around 95%, transformers with 98-99% already add 20-40% of the losses if they are required for network connection. Also the feeders of distributed generators may cause losses of one or more percent which cause additional 20% for each percentage point. Summarised, losses in network elements can play an important role in the assessment of operational reactive power control costs and need to be taken into account for proper analysis.

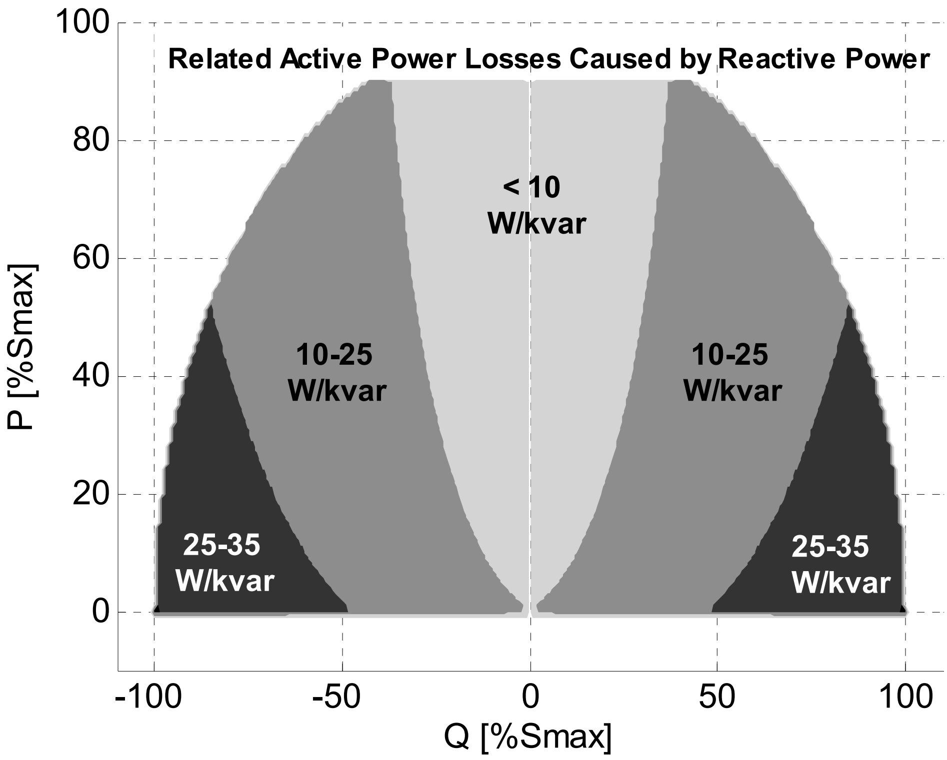


Figure 5-32: Active power losses caused by reactive power supply from an inverter with 96% efficiency

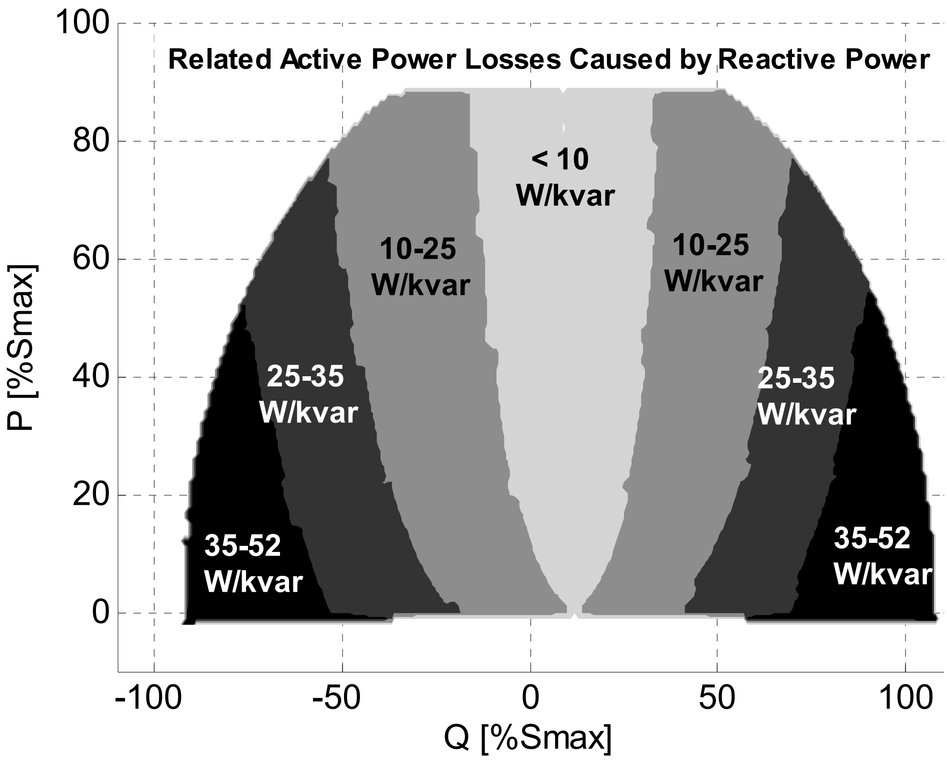


Figure 5-33: Active power losses caused by reactive power supply from an inverter with 96% efficiency connected over a transformer and 2.5 km cable

### 5.2.3. Cost-Benefit-Analysis

After analysing the costs of providing reactive power control by controlled distributed energy units the cost-benefit-analysis compares these costs with the benefits which arise from providing these services. The benefits of reactive power supply can be assessed by looking at alternative sources of reactive power which are presently used. Another approach is the analysis of the network effects by studying the benefits for network operation. This section provides

- a cost analysis of conventional reactive power supply technologies,
- a cost analysis of network purchase of reactive power, and
- an analysis of the benefits of reactive power based ancillary services for network operation:
    - voltage control
    - reduction of network losses
    - congestion management

#### *5.2.3.1. Costs of Conventional Reactive Power Supply Technologies*

Reactive power supply is provided by many different devices. The following conventional devices for reactive power supply are looked at:

1. static capacitors and reactors,
2. static compensators with power electronics,
3. synchronous condensers, and
4. synchronous generators of conventional power plants.

##### 5.2.3.1.1. Static Capacitors and Reactors

A standard network component for reactive power compensation is a capacitor bank. The cost estimation is based on the following assumptions:

- Investment costs [Braun 2007c] of
    - 150 €/kvar (or 12.0 €/kvar/a) for 10 kvar installed capacity
    - 31 €/kvar (or 2.5 €/kvar/a) for 100 kvar installed capacity
    - 14 €/kvar (or 1.1 €/kvar/a) for 200 Mvar installed capacity
- Operational costs of 0.015 c€/kvarh calculated with

- losses of 1.5 W/kvar [ZVEI 2006] or 0.0015 kWh/kvarh and
- power purchase costs of 10 c€/kWh [Richmann 2007].

Similar costs can be assumed for static reactors with investment costs that tend to be some tens of percent higher (20% in further calculations) than capacitors. If reactors as well as capacitors are installed at one node the investment costs of both have to be added resulting in 120% higher investment costs than given for static capacitors alone.

#### 5.2.3.1.2. Static Compensators with Power Electronics

Different types of static compensators with power electronics are available. Static VAR Compensators (SVCs) are capacitors and/or reactors grid-connected by thyristors (grid-commuting). Static Compensators (STATCOMs) are power electronics-based (self-commuting) with gate turn-off thyristors (GTOs) or insulated gate bipolar transistors (IGBTs) comparable to those of inverter-coupled distributed generators. Dynamic VAR (D-VAR) systems are advanced STATCOM systems that have a high overload capability allowing them to respond to voltage dips accordingly. [Kueck et al. 2006] estimate the investment costs in the range of 40-100 US$/kvar which is assumed to be in the range of 30-75 €/kvar for Mvar systems.

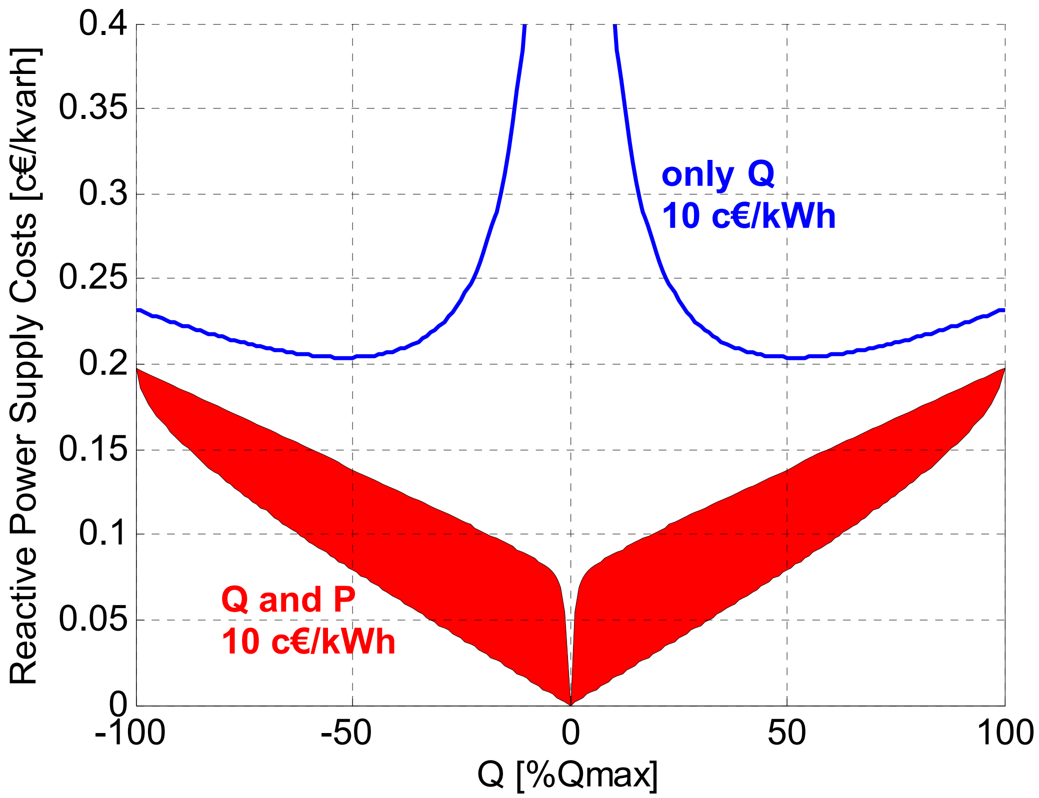


Figure 5-34: Operational cost (in c€/kvarh) of Q supply by inverters with a maximum efficiency of 98%

The energy losses depending on the efficiency of STATCOMs and grid-side inverters of distributed generators are similar due to comparable power electronic designs. Figure 5-34 shows that STATCOMs tend to have higher operational costs because all losses are attributed to Q (blue line: ‘only Q’) and only the additional losses are attributed to Q in case of inverter-coupled distributed generators (red area: ‘Q and P”) because P is transferred as well. The figure compares the operational costs of reactive power supply for inverters with 98% efficiency and assumes costs for active power compensation of 10 c€/kWh.

#### 5.2.3.1.3. Synchronous Generators of Conventional Power Plants

Conventionally also larger power plants are used for reactive power supply. The efficiency of their synchronous generators can be assumed to be near to 98% or even higher for very large plants. One important difference to DGs is that they generally sell their power generation on the power exchange with average prices, for instance, of 2.9 c€/kWh (2004), 4.6 c€/kWh (2005) and 5.1 c€/kWh (2006) on the European Energy Exchange (EEX). They are with 4.2 c€/kWh (average 2004-2006) considerably lower than the feed-in tariff prices in Germany (see Table 5-1). Taken these two influence parameters together (efficiency and active power generation for the power exchange) results in smaller operational costs of reactive power supply compared to DER units. Different to synchronous condensers which only supply reactive power, the combined supply of active and reactive power results in lower operational costs (see Figure 5-34), also because conventional power plants normally operate at rated power (lower value of the cost range).

The main objective of conventional power plants is the active power generation. If reactive power is supplied in addition the fixed operational costs can be assumed to be the same with regular maintenance cycles in low price periods. No additional fixed operational costs are considered here.

Investment costs for reactive power supply from conventional power plants result from the required oversizing which is necessary if reactive power should be supplied in addition to rated active power. The dependency of additional investment costs on the converter’s oversizing is discussed in Chapter 5.2.1.1 and depicted in Figure 5-4.

#### 5.2.3.1.4. Cost Comparison

The comparison of the investment costs leads to the result as given in Figure 5-35. The conventional reactive power supply technologies are assumed to have the following range of investment costs:

- Static capacitors:
  15-25 €/kvar
- Static capacitors and static reactors:
  33-55 €/kvar
- SVCs, STATCOMs and D-VARs:
  30-75 €/kvar (for Mvar systems)
- Synchronous condensers:
  10-50 €/kvar
- Grid-coupling converters (inverter, DFIG, SG) of distributed energy units:
  according to Figure 5-4 dependent on the guaranteed reactive power capacity

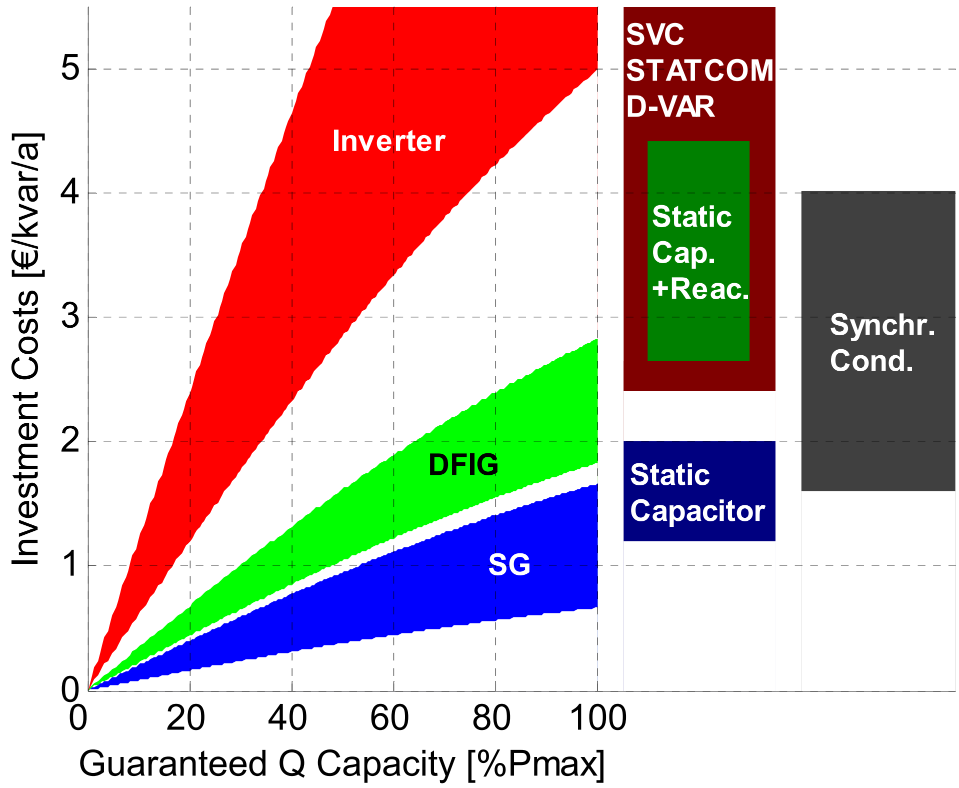


Figure 5-35: Additional investment costs for guaranteed reactive power supply capacity

The comparison of the investment costs in Figure 5-35 directly shows that grid-coupling converters can generally be cheaper at low guaranteed reactive power capacities. Network connections may add additional costs.

In comparison to static capacitors that have the lowest investment costs distributed generators are competitive with small guaranteed reactive power capacity. Comparing the operational costs in addition shows that DGs may mostly be more expensive because of higher operational costs. There exists only a small area in the power domain of DGs where they are more cost-efficient than static capacitors. The competitiveness with regard to investment costs increases significantly if not only static capacitors but also static reactors have to be taken into account.

However, the comparison of distributed energy units with static capacitors and static reactors may not be justified in all cases. An important feature of reactive power supply by DGs is their possibility to follow smoothly the demand. This is an important advantage compared to capacitor banks that switch discretely resulting in suboptimal compensation and transient voltage disturbances. In many cases a comparison to synchronous condensers or static compensators with power electronics of similar functionalities should be preferred. But, generally, STATCOMs as well as D-VARs and synchronous condensers are devices for transmission networks.

A comparison with these dynamic reactive power supply devices shows that DGs can guarantee a significant capacity whilst staying below the investment costs of the compared conventional devices (see Figure 5-35). As illustrated in Figure 5-34 operational costs of reactive power supply by DGs tend to stay below operational costs of conventional devices which only supply reactive power. This conclusion is only valid as long as efficiencies and loss compensation costs are similar. A shared reactive power supply by many DGs operating at lower capacity results in far lower operational costs per kvarh.

Different grid-coupling converters are used in DGs. From an investment cost perspective, the cheapest reactive power capacity can be provided by SGs. More expensive are DFIGs. The share of power electronics converter capacity is only in the order of 10-20% of the total generator's capacity which keeps the costs far lower than those of inverter-coupled generators that have to oversize the full converter.

More aspects need to be considered in a more comprehensive comparison. This includes the compensation of harmonics and the behaviour in fault-conditions.

IGTB-based inverters are capable to compensate harmonics while synchronous generators/condensors have no influence and SVCs even generate harmonics. Only STATCOMs and D-VARs may have similar capabilities as inverter-and DFIG-coupled DGs. Generally, inverter-coupled generators have the best capabilities of compensating harmonics.

In fault-conditions, the short-circuit behaviour and overload capability are important because these capabilities define the support of the network's stability in stressed situations. Synchronous generators add with their inertia to system stability and they have an inherent transient overload rating.

The reactive power capacity depends on the bus voltage V [Teshmont Consultants

2005]. Synchronous generators/condensers do not show this dependency which is advantageous. Inverters, on the other hand, have a linear dependency with Q ~ (1/V) and SVC, capacitors and reactors even have a squared dependency with Q ~ (1/V²). In case of voltage dips the behaviour of synchronous generators but also inverters is beneficiary to the other conventional reactive power suppliers.

A general statement cannot be given concerning the competitiveness of reactive power supply by distributed generators compared to conventional reactive power sources. But it is shown that DGs have comparable, often lower, costs, esp. if reactive power supply is shared between many of them.

##### *5.2.3.2. Network Purchase Costs of Reactive Power*

Reactive power supply costs or tariffs of network operators subsume all their sources of reactive power. Not single technologies are analysed but the average over all technologies. The results show the benefit (in saved costs) if reactive power is supplied by the distributed generator instead of purchased from the network operator.

A data analysis of [ENE'T 2007] of more than 800 network operators shows that German distribution network operators charge on average 1.1 c€/kvarh (within the range of 0.0 - 2.7 c€/kvarh) if the power factor is lower than $0.9_{ind}$ (in average). In the high voltage network the average charge is 1 c€/kvarh (0.0 – 1.5 c€/kvarh) and in the extreme high voltage one network operator has a charge of 0.3 c€/kvarh.

National Grid in the United Kingdom spends approx. 0.2 c€/kvarh on the reactive power market of the transmission network [National Grid Transco 2005]. ESB National Grid in Ireland has the following payment rates [ESBNG 2005]:

- Reactive Power Availability Payment:
    - 2005 (actual): 2.16 €/kvar/a
    - 2006 (planned): 1.29 €/kvar/a
- Reactive Power Utilisation Payment
    - 2005 (actual): 0.121 c€/kvarh
    - 2006 (planned): 0.124 c€/kvarh

The three transmission network organisations PJM, NYISO ad ISO-NE in the United States provide an annual payment in the range of 1005-5907 US$/Mvar [Kueck et al 2005] assumed to be 0.75-4.4 €/kvar/a. In addition, the three US network organisations also provide a compensation for lost profits on real energy sales (opportunity costs). ERCOT, for instance, pays not for capacity but for the utilisation 2.65 US$/Mvarh (assumed to be 0.2 c€/kvarh) at power factors smaller than 0.95 [Kueck et al 2005].

In Spain, a royal decree [Ministerio de Industria 2007] defines three load situations (peak, plateau, and off-peak). If generating units provide the correct power factors they receive an incentive if they counteract they have to pay a penalty. But it cannot be contrasted reasonably here because the incentive is paid per kWh instead of per kvarh.

These costs of network purchase of reactive power can be considered as benefits because they can be prevented if reactive power is supplied by DGs. It can be seen that different frames of benefits exist. Some network operators only charge/compensate operational costs, others only capacity costs, others operational and capacity costs, and others (e.g. in Spain) have a regulation that cannot be compared directly.

Comparing these benefits with the costs of reactive power supply by DGs shows that the costs in the smaller guaranteed capacity domain are in many cases lower than the benefits. This leads to the conclusion that reactive power supply by DGs can be attractive for network operation from an economic point of view. If only operational costs or only investment costs are compensated the compensation payment (benefit) also has to compensate the other cost category. For instance, assuming operational costs of 0.1 c€/kvarh in average and 1 €/kvar/a for guaranteed reactive power supply from DGs may be compensated only by operational benefits of 0.2 c€/kvarh. Then, each kvarh has to compensate the investment costs with 0.1 c€/kvarh. This overcompensation requires a minimum of 1000 full load hours of reactive power supply.

### *5.2.3.3. Comparison with Benefits for Network Operation*

The network operator uses reactive power four mainly four reasons:

- balance of reactive power demand
- voltage control,
- reduction of congestions, and
- reduction of power losses.

The value of these services is analysed in the following sub-sections individually. It is difficult to analyse all four of them combined because reactive power control may have opposed effects on these ancillary services depending on the system’s state. For instance, an increase of reactive power supply improves the voltage profile but increases the power losses as well as the probability of congestions. However, the network operator can take into account all these effects within his individual optimisation of the network’s operation.

The balance of reactive power demand has already been analysed by comparing different sources of reactive power in the previous section. In the following paragraphs the other three services are looked at.

**Benefits from Voltage Control with Reactive Power Control**

Voltage control is a basic need for network operation because the voltage has to stay within certain limits throughout the whole network (cf. EN 50160). Capacitive reactive power increases the voltage level while inductive reactive power decreases the voltage level [Kundur 1994] as discussed in Chapter 3.2. However, the voltage needs to stay within certain limits demanding for distributed reactive power compensation. Different reaction times are used to optimise the voltage in the network: primary, secondary and tertiary voltage control during normal operation, as well as grid design in the installation phase (especially of distribution networks), and transient voltage control during faults.

DGs can be integrated in primary, secondary and tertiary voltage control during normal network operation. Here they have to be compared to standard network components providing this service: tap-changing transformers and conventional reactive power sources. Reactive power supply by DGs can be competitive to conventional reactive power sources as analysed in section 5.2.3.1

Another benefit can arise at the installation phase. The grid design may have caused a restriction of larger DG installations due to voltage limits as given by [VDEW 1998] and [VDN 2004], for instance. Such connection conditions may be complied by using reactive power control of the respective distributed generator.

Transient voltage control happens in milliseconds up to few seconds. This is a service already required from wind turbines. Due to very fast reaction times and their spatial distribution throughout the network the voltage is supported effectively during faults by providing reactive power and staying connected to the grid (cf. fault-ride-through requirements e.g. in [VDN 2004] and [Ministerio de Industria 2006]). This transient behaviour is already planned to be applied in the medium voltage level in Germany [BDEW 2008]. The general benefit is difficult to quantify but avoiding blackouts by transient voltage support is expected to be highly valuable.

Reactive power supply for voltage control is very important from an economic perspective. As stated in [FERC 2005]: *"Inadequate reactive power leading to voltage collapse has been a causal factor in major power outages worldwide. Voltage collapse occurred in the United States in the blackouts of July 2, 1996, and August 10, 1996, on the West Coast. Voltage collapse also factored in the blackouts of December 19, 1978, in France; July 23, 1987, in Tokyo; March 13, 1989, in Québec; August 28, 2003, in London; September 23, 2003, in Sweden and Denmark; and September 28, 2003, in Italy"*. With the aim of improving security of supply of the power system in the future, the need for reactive power supply to support the voltage profile in normal and fault conditions is evident. Distributed generators that are spatially dispersed in the electrical power system are possible suppliers of reactive power for voltage control and they can be cost-efficient from an economic point of view.

**Benefits from Congestion Management with Reactive Power Control**

By compensation of reactive power it is possible to reduce the reactive power flows in the network. Particularly at peak load situations this can reduce the loading of the network helping to avoid congestions. In addition, also network losses are reduced but not considered in the following illustrative calculation but in the next paragraph.

Figure 5-36 displays the relative reduction of the loading of a considered network element (e.g. line or transformer) by reactive power compensation. The network element is assumed to operate at 100% rated capacity *Sg* considering different load power factors *cos(φ)*. The reactive power flow is compensated by distributed generators with 50% of their rated capacity. Their installed capacity *Pw* is assumed to be 5%, 20% and 50% of the network capacity *Sg*. The reduction of apparent power *ΔS* (in % meaning [kVA/kvar]) relative to reactive power compensation with the reactive power supply *Qw* by the DGs can be calculated by:

$$\Delta S = \frac{S_g - \sqrt{P^2 + (Q - Q_w)^2}}{Q_w} = \frac{S_g - \sqrt{(S_g \cdot \cos(\varphi))^2 + (S_g \cdot \sin(\varphi) - Q_w)^2}}{Q_w} \qquad \text{(4-60)}$$

Figure 5-36 shows that the loading can be reduced by 15% (*cos(φ)* = 0.98), 30% (*cos(φ)* = 0.94) or 45% (*cos(φ)* = 0.87) of the DG's reactive power supply at a penetration level of 20%. In other words: if the considered feeder is 100% loaded by a power flow with the power factor 0.94 a compensation of the reactive power flow (i.e. 0.34 kvar/kVA) by 20% DGs (i.e. 0.2 kW/kVA) with 50% of their capacity (i.e. 0.1 kvar/kVA) leads to a reduction of apparent power by 3% (i.e. 0.03 kVA/kVA). By that, a reduction of apparent power of 0.03 kVA/kVA caused by reactive power compensation of 0.1 kvar/kVA leads to a specific reduction of 0.3 kVA/kvar, i.e. 30%.

With the range of ΔS = 15-45% and network costs of 30-60 €/kVA/a (according to [ENE'T 2007] and [VDN 2007b]) the benefit can be calculated as 4.5-27 €/kvar/a which is by far greater than the investment costs in Figure 5-35. The operational costs can be neglected because congestions normally occur only for few hours per year. The peak load normally occurs on winter evenings in Europe [REE 2006] or under emergency network situations.

The calculated benefit is by far higher than the costs of reactive power compensation by DGs. However, most networks presently operate below 100% capacity.

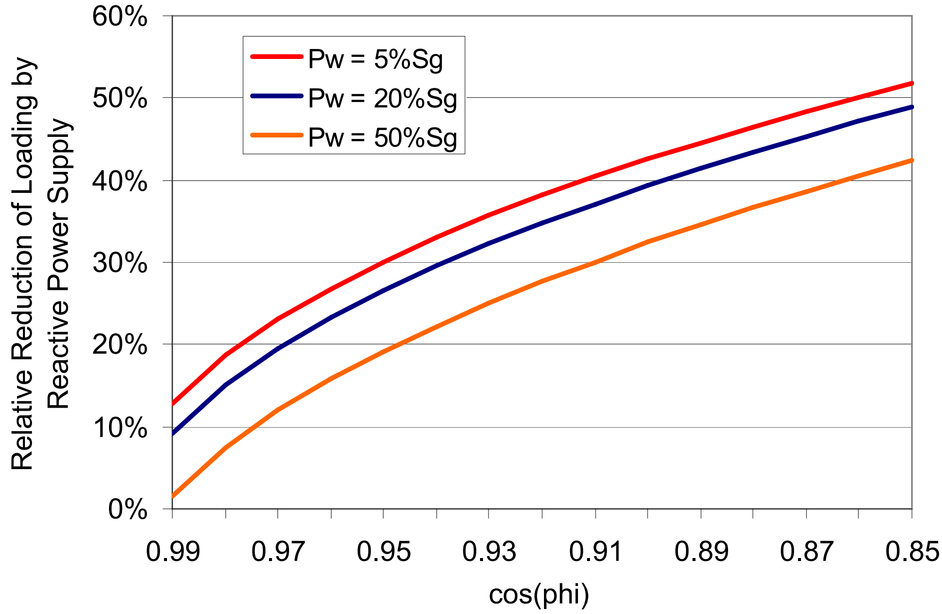


Figure 5-36: Relative reduction of network loading due to reactive power compensation by DGs considering different SG penetration levels *Pw/Sg* and different load power factors *cos(φ)*

### Benefits from a Reduction of Power Losses with Reactive Power Control

The transfer of reactive power causes active power losses in the network as analysed in section 5.2.2. Reactive power compensation reduces these active power losses. In addition, more network capacity can be used for active power transfer. This additional benefit is not included in the following calculation of an illustrative example but discussed in the previous paragraph.

Different load power factors *cos(φ)* and different average network losses $dP_L$ (in %) are looked at with constant active power flow *P*. A quadratic correlation (at constant voltage: $\sim I^2$) is assumed between losses $P_L$ and the apparent power flow *S* (cf. section 5.2.2.1):

$$P_L = dP_L \cdot S^2 = dP_L \cdot \left(P^2 + Q^2\right) \qquad (5\text{-}61)$$

with

$$Q = \sqrt{S^2 - P^2} = P \cdot \sqrt{\left(\frac{S^2}{P^2}\right)^2 - 1}$$
$$Q = P \cdot \sqrt{\left(\frac{1}{\cos(\varphi)}\right)^2 - 1} \quad > 0. \qquad (5\text{-}62)$$

The reduction of active power losses by full compensation of reactive power $Q$ relative to $Q$ [kW/kvar] is then defined by:

$$\begin{aligned}\Delta P_L &= \frac{dP_L \cdot \left(P^2 + Q^2\right) - dP_L \cdot P^2}{Q} \\ &= \frac{dP_L \cdot \left[\left(P^2 + Q^2\right) - P^2\right]}{Q} = dP_L \cdot Q \\ &= dP_L \cdot P \cdot \sqrt{\left(\frac{1}{\cos(\varphi)}\right)^2 - 1}\end{aligned} \tag{5-63}$$

With costs for the compensation of active power losses of 5 c€/kWh [Braun 2008a], the benefit of the loss reduction is given in Table 5-8. A comparison with the operational costs of reactive power supply shows that it can be economically attractive to use distributed generators for reactive power compensation in network situations with high network losses and low load power factors (high reactive power flow) as long as only a small reactive power capacity is used by the distributed generators.

| | **Average Network Losses $dP_L$** | | | |
|---|---|---|---|---|
| ***cos(φ)*** | **1%** | **2%** | **3%** | **4%** |
| 0.95 | 0.016 | 0.033 | 0.049 | 0.066 |
| 0.9 | 0.024 | 0.048 | 0.073 | 0.097 |
| 0.85 | 0.031 | 0.062 | 0.093 | 0.124 |

Table 5-8: Savings in c€/kvarh due to reduction of active power losses due to reactive power compensation with different load power factors cos(φ), average

## 5.3. Additional Cost Categories

The two previous sections 5.1 and 5.2 describe two cost-benefit analyses for the assessment of the economic attractiveness of providing ancillary services by controlled distributed energy units. These analyses do not include three cost categories as they are not in the scope of this thesis. The following subsections discuss these three cost categories suggesting enhancements for improved cost-benefit analyses of the given ones.

### 5.3.1. Costs of Information, Communication and Control Technology

The integration of distributed energy units in network operation demands for Information, Communication and Control Technology (ICCT). These costs normally do not have operational cost components which are variable with regard to the generated power. They may be variable with regard to information units but not directly with the power. Consequently all costs of ICCT can be considered as fixed operational costs and investment costs. The whole ICCT infrastructure can be divided into three main areas which are discussed separately in the following paragraphs:

- Communication Infrastructure
- Private network
- Public network

#### *5.3.1.1. Costs for Communication Infrastructure*

One major challenge is the allocation of the costs of the communication infrastructure. Presently, many DGs already have communication technologies available and in operation. For instance, the generator's data is measured and sent to databases in order to monitor proper operation. The communication is often internet-based so that the infrastructure can also be used for other functionalities with negligible additional costs.

Giving this example, the internet is one enabling technology for an improved integration of distributed energy units [Sanchez 2007] because it is normally accessible where interconnected electrical networks are available as well. In addition, it is one of the major means of communication for people providing a cost-efficient way of connecting all elements of the electrical infrastructure on a parallel communication layer. In other words, it is assumed that the communicative interconnection has a general benefit which often exceeds the fast decreasing costs for the infrastructure and no additional costs may need to be considered for additional use for communication in electrical power systems.

It may be necessary to setup a parallel fast interconnection infrastructure if time-critical actions are required but this is out of the scope of the investigations here. Also smaller DGs and loads often do not have any communication infrastructure. The cost from their integration in power control by adding communicative means may exceed the benefits and need to be investigated.

#### *5.3.1.2. Costs at the Private Network's Site*

On the private network's site it is necessary to distinguish between distributed generators and storage on the one hand, and loads on the other hand.

Controlled DGs and storage systems often have the full active and reactive power control architecture implemented. Even if certain functions are not activated presently they can often be activated, adjusted or implemented from the manufacturer with negligible additional effort for one unit with regard to the quantity of manufactured units.

Large consumer loads are sometimes controllable if integrated in energy management systems of network customers. However, most large loads and generally all smaller loads are not controllable yet. The installation of energy (here: power) management systems at the network customer site is a significant effort causing considerable costs for the automation and control architecture (the smaller the installed power the higher the costs in €/kW). But with its installation the network customer can improve his own network operation and can evolve to an active participant in the power system (active customer network (ACN), see Section 2.2.2). Many features can be attributed to an ACN. It can support actively the power supply system by all types of energy services as well as ancillary services to the public and the private network. Specific additional costs on the private network's site should be attributed to all additionally achieved functionalities. For instance, active customer networks may also be equipped with communication and control interfaces as well as with local communication and control infrastructure.

With different perspectives and different sites, the range of additional cost of enabling a provision of ancillary services to the public network is very large starting from zero costs for already controlled distributed energy units. Distributed energy units that are analysed to be equipped with control systems may have a large range of additional costs. They may exceed the benefits, in particular concerning units with little control impact.

#### *5.3.1.3. Costs at the Public Network's Site*

Transmission network operators do not face considerable investments of ICCT infrastructure because their energy management systems only have to include some additional providers of active and reactive power at the respective grid supply points (GSPs). Related to all Controllable Distributed Energy (CDE) units that are aggregated in Active Distribution Networks (ADNs) or Virtual Power Plants (VPPs) as discussed in Chapter 2 the costs of integration are assumed to be negligible. However, the communication with each single CDE unit may also cause additional efforts for ICCT infrastructure.

In contrast to the TNO, the DNO may face considerable investments because the low and medium voltage level is often not operated actively. With an increase of distributed generation Active Distribution Network (ADN) operation that integrates the local distributed energy units can be beneficial.

As the first fundamental requirement measurement data needs to be available for assessing the network's state. These measurement data may be provided by distributed energy units and ACNs which can measure electrical data such as frequency, voltage, current, and impedance. These communication flows require standards for cost-efficient integration to distribution management systems. The standard IEC 61850, for instance, gives rules defining the information exchange uniformly so that new installed components can be connected easily (Plug&Play) providing site-specific data. This provision of measurement data may be one service to the DNO which is not yet included in the given framework of ancillary services and which extends the available measurement data of the network operator's measurement devices that also may need to be extended for an active network operation.

Based on the gained knowledge of the network's state, the operator of the ADN can calculate with distribution management systems an improved (more cost-efficient and higher security of supply) network operation taking into account possible control actions of CDE units, ACNs and own control equipment. The most cost-intensive part may be the change from passive to active network operation. This requires having a complete network model taking into account controlled distributed energy units and active customer networks that deliver information on the network and can be contracted for control actions. Also calculation tools for distribution management systems may need certain enhancements. The resulting costs can have a large range.

#### *5.3.1.4. Summarising Remarks to Costs of Information, Communication and Control Technology*

Costs of ICCT may have an important impact on the utilisation of potential control functionalities from distributed energy units (cf. Chapter 4). In many cases, the additional ICCT costs for enabling active and reactive power control by CDE units to public networks may be small because the communication infrastructure already exists as well as the control functionalities. In other cases, the additional costs may be high and not compensated by generated benefits. The cost structure is not assessed in this work. Consequently, a reverse approach is preferred here assuming zero costs in the cost-benefit-analyses. With positive results of the cost-benefit-analysis an estimation of the maximum allowable additional costs for ICCT can be given.

Also another perspective may be taken. An increase of renewable energies that often have variable primary energy resources and highly-efficient distributed energy resources that provide power near to consumption and in combination with heat supply is a political objective in many countries. These changes require more active network operation dealing with multidirectional and variable power flows in distribution networks. Network customers with their CDE units can be important elements in active distribution network operation. The additional costs of active network operation including the integration of CDE units may be compensated by benefits that result from power generation with renewable energies and a more sustainable power supply system in general.

### 5.3.2. Transaction Costs

One additional cost category that is often not considered in detail is the category of transaction costs. These transaction costs [Williamson 1975] are studied in new institutional economics which include the principal-agent problem as well as the transaction cost theory.

The principal-agent problem refers to the difficulties of the relationship between a principal and an agent. For example, the CDE unit or ACN operator (as the principal) negotiates a contract with a VPP operator (as the agent) to optimise the service provision to the network operator and the participation on the energy market. This relationship is shaped by incomplete and asymmetric information with both sides aiming at optimizing their benefit (self-interest). Asymmetric information arises from the fact that the VPP operator, in the given example, has by far more knowledge of the markets and his own portfolio than the single CDE/ACN operator. The CDE/ACN operator, on the other hand, has a benefit from the contract with the VPP operator because his small portfolio may otherwise not get access to the markets or has to pay extremely high transaction costs. Generally, the most important incentive for the VPP operator is the benefit he has from the contracted principal. Also the CDE/ACN operator aims at receiving the highest benefit from the VPP operator and chooses with that objective the best VPP operator. It can be seen that the power of this relationship is more on the side of the VPP operator but the power imbalance can be reduced by having many VPP operators without market power which can be chosen by the CDE/ACN operator as well as transparent market activities of VPP operators.

The transaction cost theory [Williamson 1975] looks at contracts as forms of organisations and aims at explaining how contracts can be designed efficiently in certain institutional frameworks. Each contract (transaction) causes costs in a market economy. Transactions can be summarised as all transfers of property rights in form of products or services in interrelationship of at least two contract partners. [Williamson 1975] distinguishes between ex-ante transactions costs (i.e. costs before signing the contract such as costs for information searching and negotiations) and ex-post transaction costs (i.e. costs after signing the contract such as costs for control and modifications). These transaction costs have to be included in the total cost assessment because they are an important cost factor. The frequency of similar transactions reduces the specific transaction costs because of economies of scale and synergy effects. This is the main reason for the commercial aggregation by VPP operators because they can build a portfolio of CDE units and ACNs. This is an advantageous situation compared to individual market activities of each single CDE unit and ACN.

### 5.3.3. External Costs

Most economic analyses have one fundamental assumption: perfect competition (on an ideal market). This assumption is handy because it simplifies the economic assessment considerably but it is also a limitation to answer real-world questions because it neglects many important aspects. External costs are defined by representing these costs which are not included in existing market prices.

The main assumption of the neo-classical paradigm is perfect competition on all markets. This means, on the one hand, that all economic subjects act in the rational way of a homo oeconomicus, who maximises his utility with universal knowledge to his own interest without accounting for the interests of other people. On the other hand, perfect competition means that all economic subjects do not have a significant market share to influence the market in any noticeable way. With neo-classical assumptions there is a pareto-optimal market equilibrium on all markets so that supply and demand are equal and no economic subject is able to improve its own situation without deteriorating the situation of another one.

Usually, these pareto-optimal results are not achieved in real market conditions which are characterised by market imperfections, e.g. transaction costs, significant market powers, incomplete information, public goods and externalities. Public goods, e.g. clean air, differ from private goods, e.g. a car, in two ways. On the one hand, consumers of private goods are excluded from consuming the good if they do not pay the claimed price. In contrast, consumers of public goods can not be excluded because they do not need to pay for the use of the good. On the other hand, there exists no rivalry in consumption of public goods compared to private goods because the good can be used by all consumers at the same time, generally, without interference. With this definition of public goods, there will be no market for them since they can be used by everyone without the need to pay for them. In many situations public goods are used in a careless way because no compensation has to be paid for damages and nothing has to be paid for their use.

Externalities exist in the form of external costs and external benefits (see also [Pearce;Turner 1994], [Endres;Holm-Müller 1998], [Braun 2004] and [Clarkson;Deyes 2002]). External costs occur when an economic subject causes a loss of welfare to another one and does not compensate the change of welfare. In contrast, external benefits occur when an economic subject causes an increase of welfare to another one and is not compensated for this change of welfare. On perfect markets, the utility of a good would be compensated by the utility of the money paid for this good. A compensation for this change of welfare due to external costs of benefits would eliminate the market imperfection caused by externalities. This procedure is called internalisation of externalities because external costs and benefits are considered in market prices. In situation where all externalities are internalised, the compensation corresponds to the same utility as the change of welfare so that there is no externality anymore.

[Krewitt;Schlomann 2006] show that the largest share of external costs of conventional power generation is caused by $CO_2$ emissions. Consequently, only $CO_2$ emissions are looked at here. [Krewitt;Schlomann 2006] recommend to use a bandwidth of 15-280 €/t$CO_2$ with a best estimate of 70 €/t$CO_2$ as external costs caused by $CO_2$ emissions. Assuming $CO_2$ emissions of 350-1000 g$CO_2$/kWh (compare to [Braun 2004]) for conventional power generation by fossil fuels such as natural gas, coal and lignite leads to external costs of these technology in the order of 0.5-28 c€/kWh with a best estimate (according to [Krewitt;Schlomann 2006]) in the order of 2.5-7 c€/kWh.

In comparison, life-cycle $CO_2$ emissions of power generation that is based on renewable energies generally causes less than 100 g$CO_2$/kWh. Consequently, the use of renewable energy avoids the majority of $CO_2$ emissions from conventional fossil-fuelled power plants and the resulting external costs of several c€/kWh. These avoided external costs are not taken into account fully in the cost-benefit-analyses of the previous two sections. In general, the internalisation of external costs leads to an improvement of the economic potential of using distributed generators that are based on renewable energies for the provision of ancillary services. The results may be different with regard to the costs of loss compensation in case of operational costs of reactive power supply and the reduction of power losses. Also an important change of the utilisation prices and costs for frequency control may have a beneficiary influence on using controllable distributed renewable energy units.

## 5.4. Summary of Chapter 5

Based on the technological potential of the provision of ancillary services by distributed generators in Chapter 4, this chapter analyses the economic potential of distributed generators. Two main aspects are looked at in detail. Firstly, the potential to participate on frequency control services markets by active power control, and secondly, the potential to supply reactive power for ancillary services, esp. voltage control.

The cost-benefit-analysis of the participation on frequency control services markets shows two main results for distributed generators that receive feed-in tariff reimbursements in Germany. On the one hand, the participation in primary control and positive secondary control / tertiary reserve is not attractive for distributed generators because they have to reduce active power generation in general in order to be able to increase active power for frequency control for only certain periods of time. This operation mode has high opportunity costs due to relatively high feed-in tariffs compared to present market prices of conventional power plants.

On the other hand, the participation in negative secondary control / tertiary reserve can be attractive because the basic operation mode is not changed. Only in case of high frequency, the active power generation is reduced for the required period of time. The reduction of operational costs is comparably low for distributed generators compared to conventional power plants. Consequently, their frequency control capacity is used in second priority.

Not analyzed here is the potential of re-dimensioning distributed generators in order to optimise their participation on frequency control markets. Especially, biomass plants and hydro power plants have potentials to reduce their capacity costs for low frequency services by decoupling power generation from pre-processes. This should be analysed in further studies to re-estimate the potential.

Also the internalisation of external costs, esp. of $CO_2$-emissions, can change the situation significantly. If conventional power plants need to pay for the external costs of their $CO_2$-emissions the market prices may increase. Then, also distributed generators may get competitive.

The cost-benefit-analysis of reactive power supply provides an assessment of the costs of reactive power supply in general. Investment costs caused by increased capacity requirements and variable operational costs caused by additional losses are looked at in detail for distributed generators and their different types of grid-coupling converters. In particular, the variable operational costs are analysed for inverter-, synchronous generator- and doubly-fed induction generator-coupled distributed generators. Compared to the costs of conventional reactive power sources, distributed generators are evaluated to be cost competitive in general, especially when they increase their reactive power capacity modestly and share reactive power supply between each other so that reactive power supply generally happens at small additional loading levels.

Including the capabilities of reactive power supply and their costs in network calculations allows assessing the optimal placement of reactive power capacity and the cost-efficient supply of reactive power. Further investigations should evaluate the real potential of distributed generators in network studies that consider the full relevant power system.

Additional cost categories are discussed: ICCT infrastructure, transaction costs and external costs. These costs are difficult to estimate in general. They need to be taken into account in further investigations in order to complete the picture of the economic potential of distributed generators to provide ancillary services.

Also the consideration of all types of controllable distributed energy units is required in further investigations. Loads and storage system have an interesting economic potential as well that should be analysed.

Loads can be activated, deactivated, or operated with variable active power consumption. Apart from the control and automation infrastructure which would be necessary, active power control with loads does not necessarily have costs. Many loads have some kind of storage which enables flexible power consumption, e.g. refrigerators, ventilation and air-conditioning systems. Others are not required to be active all the time, e.g. washing machines and dryers. They have a certain variable time span where they can be operated flexibly. Generally speaking, a certain amount of the loads can be used for active power control without restriction to their application purpose [Stadler 2005]. Consequently, active power control costs are low.

Storage systems, different to generators and loads, are auxiliary devices that optimise the power balance. They can be considered as devices that can operate periodically as generators or as loads within their storage capacity. A storage system may have different purposes which can be fulfilled in parallel. In grid-connected operation, they may also be employed to provide ancillary services based on active and reactive power control. One multi-objective application of battery systems is analysed in [Braun;Stetz 2008] for industrial applications with emergency power requirements. There are attractive opportunities for the provision of various energy and ancillary services by storage systems if they are adjusted optimally for their application purposes [Sauer;Kowal 2007].

The cost-benefit-analysis of reactive power supply shows the large range of variable operational costs depending on the amount of reactive power supply, the actual active power generation, the available reactive power capacity and the type of distributed generators and their grid-coupling converters. In order to reduce the costs of reactive power supply, different approaches can be considered that distribute reactive power supply between participating units adequately. Some of these approaches are discussed in the next chapter.

# 6. Approaches for an Economic Optimisation of Reactive Power Supply

The previous chapter provides in section 5.2 an assessment for operational costs of reactive power supply from distributed generators. Depending on the operational point of the considered units the operational costs of reactive power supply are variable over a large range. In particular, distributed generators that are based on renewable energies, such as solar and wind, provide active power according to the primary energy situation according to the local weather situation. This variable behaviour directly influences the operational point and the operational costs of reactive power supply.

Three different examples are given in this chapter in order to illustrate approaches of an economic optimisation of reactive power supply from different sources.

- The first example shows a centralised optimisation of reactive power supply at one network node.
- Then, a decentralised optimisation of voltage control in grid-connection is proposed based on the definition of appropriate droop functions.
- Finally, a decentralised optimisation of reactive power supply in hybrid-systems is proposed by application of a modified droop concept.

## 6.1. Centralised Optimisation of Reactive Power Supply at one Network Node

Network operators have knowledge on their network topology and their network's state (power flows, voltages etc.). This is the basis for calculating an optimal reactive power dispatch. In a centralised approach the operators of DGs offer their possible reactive power capacity with the corresponding costs and receive set points from the network operator. The network operator may have different objectives: supporting voltage control (keeping the voltage limits), congestions management and minimisation of power losses.

A fictional scenario of one day (24 hours) is considered as follows: The network operator needs reactive power $Q_{sum}$ (1 Mvar before 12h and 2 Mvar afterwards) for optimised network operation at one node where three DGs (PV, Wind and Biogas) are connected to. This network configuration is depicted in Figure 6-1 where the three DGs are connected at the Point of Common Coupling (PCC) to the network operator. These three types of DGs with a rated active power of 1 MW each are characterised in Table 6-1 with their loss domains in Figure 6-2 and their active power generation curves of one day in Figure 6-3. The reactive power supply of these three DGs is optimised with the objective of minimum additional losses it is calculated with Matlab®. The oversizing of two converters (Wind and Biogas) provides a guaranteed reactive power capacity of 1.2 Mvar of the DG pool.

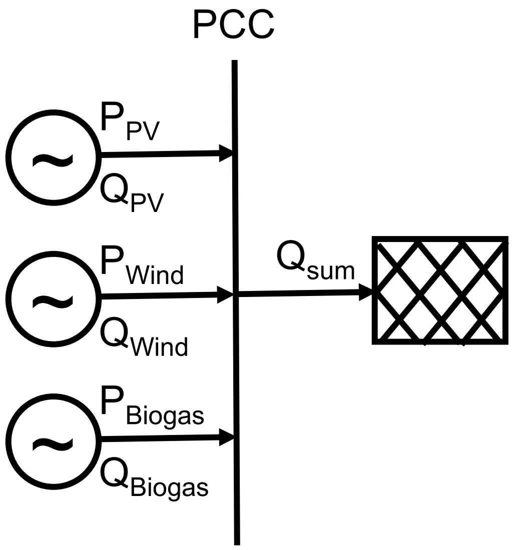


Figure 6-1: Analysed network for centrally optimised reactive power supply at the PCC

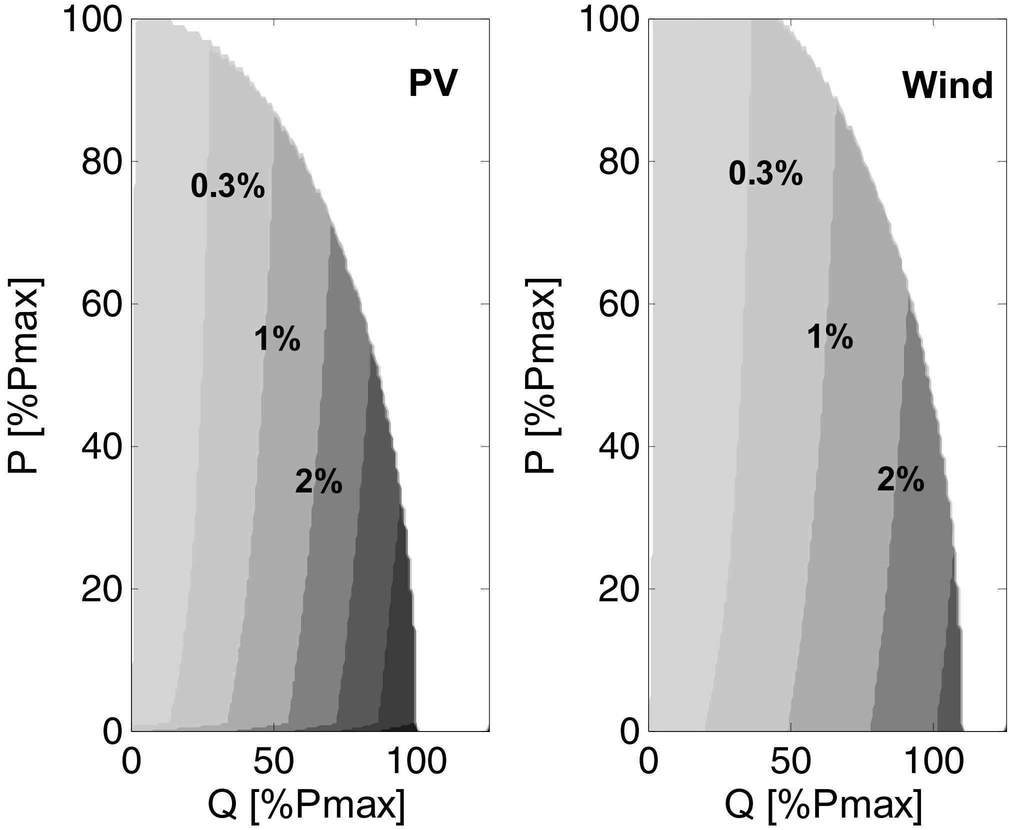


Figure 6-2: Isolines of additional losses [%Pmax] caused by reactive power supply of PV (left) and Wind (right) in the operational power domain (P,Q)

| | PV | Wind | Biogas |
|---|---|---|---|
| Converter efficiency $\eta_{max}$ | 95% | 97% | 96% |
| Sizing ($S_{max}/P_{max}$) | 1 | 1.1 | 1.25 |
| Secured $Q_{max}$ [Mvar] | 0 | 0.46 | 0.75 |
| Type of grid-coupling converter | Inverter | Inverter | SG |
| Deactivation | At night | No | No |

Table 6-1: DG characteristics

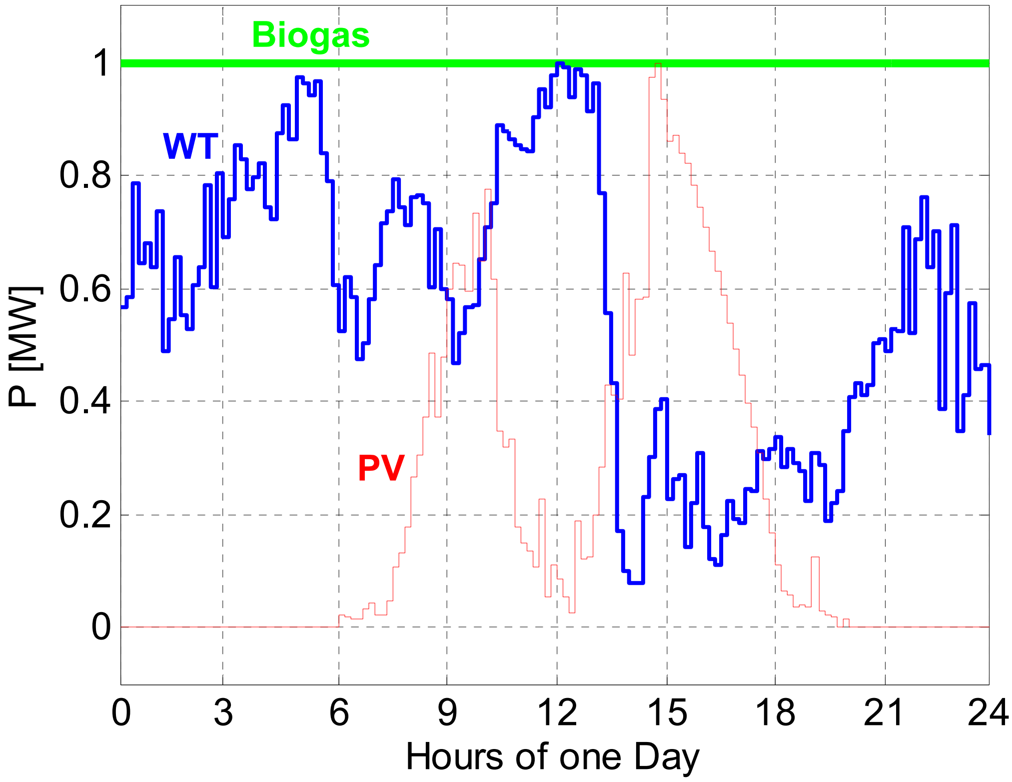


Figure 6-3: Active power generation from a PV (red), Wind (blue) and Biogas (green) over one exemplary day (10 min mean values)

The minimisation of the additional losses of reactive power supply from each of the three DGs gives an optimal distribution of reactive power supply. Figure 6-4 shows the result of this optimisation which allows describing different already theoretically explained characteristics:

- Hour 1-6:
  Wind and Biogas share the supply of $Q_{sum}$ because the losses are similar (Biogas at $P$ = 100%$P_{max}$ compared to Wind operating part-loaded with higher

efficiency). The PV inverter is deactivated due to high losses by Q at night that cause higher costs than those of Wind and Biogas (see Figure 5-11).

- Hour 6-12:
  The PV inverter gets active (lower losses) and shares the supply but at lower level than the other two due to lower efficiency. In the time of high $P_{PV}$ (hour 9-10) $Q_{PV}$ is increased because of lower losses.
- Hour 12-13:
  The required $Q_{sum}$ is increased to 2 Mvar. At $P_{Wind}$ = 100%$P_{max}$, $Q_{Wind}$ is limited to 0.46 Mvar so that PV has to supply more because also Biogas reaches its limits.
- Hour 14-15:
  $Q_{PV}$ is reduced while $P_{PV}$ is near at rated output. As Biogas operates already at maximum $Q_{Biogas}$ only Wind has capacity to increase $Q_{Wind}$ because $P_{Wind}$ is relatively small. However, it also reaches its limit so that the required $Q_{sum}$ = 2 Mvar cannot by fully supplied.
- Hour 21-24:
  Biogas and Wind operate at maximum but they cannot supply the full demand $Q_{sum}$. Therefore, the gap is supplied by PV (even with increased losses at night).

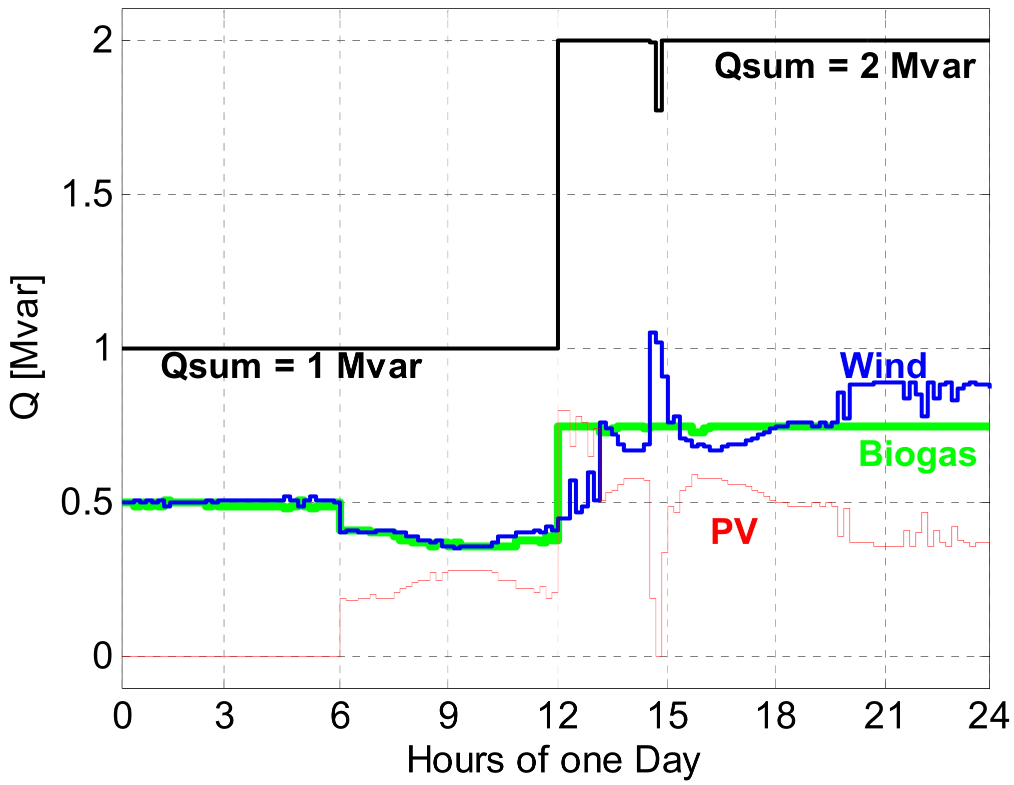


Figure 6-4: Cost-optimal reactive power supply from PV (red), Wind (blue) and Biogas (green) over the exemplary day (10 min mean values)

This example shows how the variable operational costs of reactive power supply can be shared between three distributed generators aiming at minimizing the total losses in the generators. The main objective of this example is to illustrate the characteristics of losses in different types of distributed generators.

## 6.2. Approach of Decentralised Optimisation of Voltage Control

Different to the centralised approach the pure decentralised approach has no link to a central coordinator. Each single DG must operate according to local information aiming at supporting the network's operation. Consequently, this approach focuses rather on voltage control support than on a minimisation of network losses or congestion management. Voltage can be measured locally and be kept in its limits locally as long as sufficient reactive power (and active power) capacity is available. A common control concept is the droop control [Engler 2005].

Generally, a linear droop function is utilised where the reactive power generation (capacitive behaviour) $Q$ (q in p.u. values) is increased with a decrease of the actual voltage $U$ (u in p.u. values) from its nominal value $U_{nom}$ (u = 1). Here, a modified droop function 'Droop 3' is proposed which includes the above described information on the operational costs (here: energy losses). Three types of droop functions are implemented describing the dependency of the reactive power on the voltage (see Figure 6-5) that should be kept in the limits of +/- 5% from its nominal value:

- Droop 1 (grey) is a linear droop function with maximum reactive power supply $Q_{max}$ at a voltage deviation of 5%:

$$Q(t) = \frac{U(t) - U_{nom}}{0.05 \cdot U_{nom}} \cdot Q_{\max} = \frac{dU(t)}{0.05 \cdot U_{nom}} \cdot Q_{\max}$$

$$q(t) = \frac{u(t) - 1}{0.05} = \frac{du(t)}{0.05} \tag{6-1}$$

- Droop 2 (black) limits the linear progressing activation of $Q$ within a window $du$ = [3.94%;4.7%] chosen to have the same voltage control behaviour as in case of Droop 3. The aim is to supply reactive power only when the voltage limits are in danger to be reached.

$$
\begin{aligned}
u &= [1.0394;1.0470]: \quad q(t) = \frac{u(t) - 1.0394}{1.047 - 1.0394} \\
u &= [1.0000;1.0394]: \quad q(t) = 0
\end{aligned}
\tag{6-2}
$$

- Droop 3 (PV: red; Wind: blue; Biogas: green) uses loss dependent functions for each individual unit. For simplicity they are based on approximations of the reactive power losses at $P$ = 1%$S_{max}$ that is derived from Figure 6-2 for PV and Wind. The approximation is a second order polynomial function and the three loss functions have the following order at a specific reactive power $Q$:

  $$P_{L,PV}(Q) > P_{L,Bio}(Q) > P_{L,Wind}(Q) \tag{6-3}$$

  With these functions, the droop functions *q(t) = f(du)* are calculated. At a specific voltage deviation *du*, more reactive power *q* is supplied by Wind than by Biogas and by Biogas more than by PV:

$$
\begin{aligned}
u = [1.04;1.05]: \quad & q_{Wind}(t) = f_{Wind}(du(t)) \\
& > q_{Bio}(t) = f_{Bio}(du(t)) \\
& > q_{PV}(t) = f_{PV}(du(t)) \\
u = [1.00;1.04]: \quad & q_{Wind,Bio,PV}(t) = 0
\end{aligned}
\tag{6-4}
$$

A simulation is performed with the network analysis tool *PowerFactory* from DIgSILENT with the models as described in Annex I with a time step of 0.01 s. The three above described DGs (Table 6-1) form an energy farm at the Point of Common Coupling (PCC) which is connected via a 9 km overhead line at 20 kV to a substation of the distribution network operator. The voltage u at the PCC is looked at because other customers may be connected there. Figure 6-6 shows the analysed network.

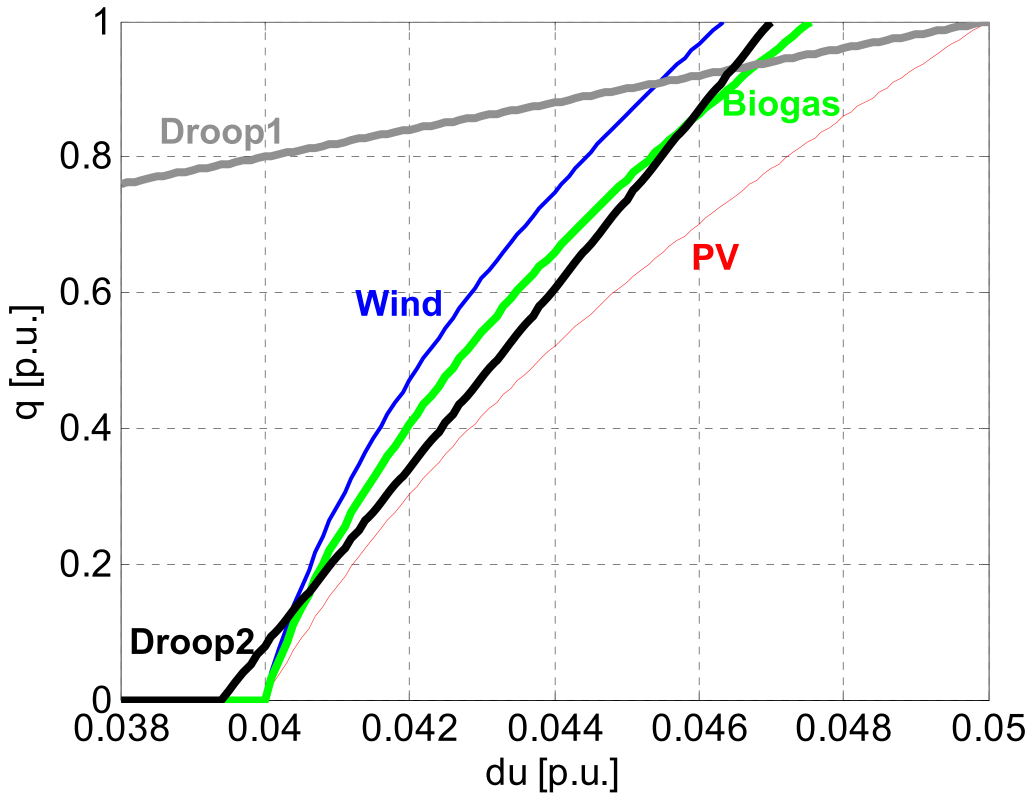


Figure 6-5: Droop functions: reactive power *Q* over voltage deviation *du*

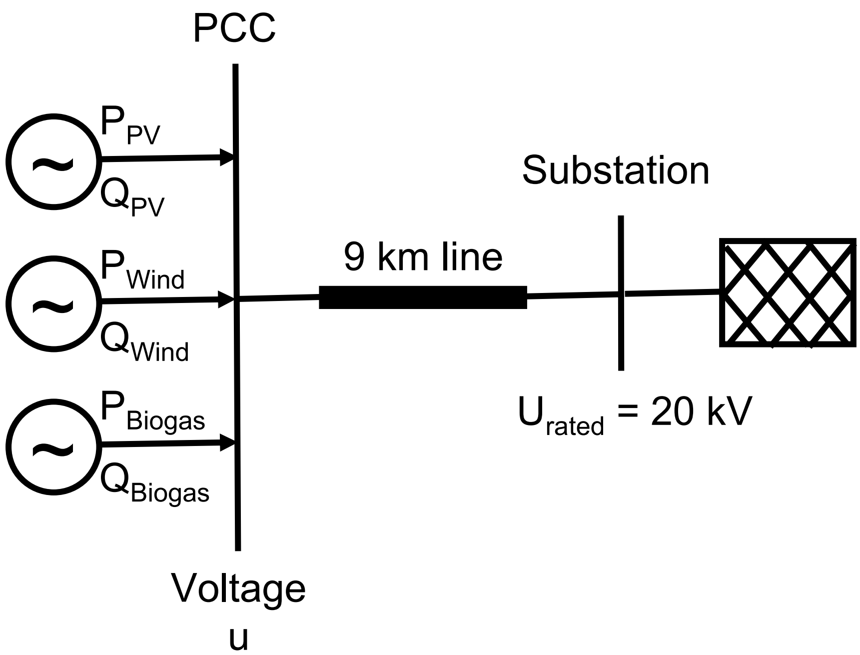


Figure 6-6: Analysed network for voltage-dependent reactive power supply at the PCC

Different to Table 6-1 the deactivation at night of the PV plant is not considered anymore to keep simple droop functions. The voltage control support of the DGs is depicted in Figure 6-7 with regard to the different droops (Figure 6-5) and the active power generation according to Figure 6-3. Without droop function (brown: ‘no Droop’) the voltage exceeds the maximum deviation limit of 5%. This should be prevented by voltage control. With Droop 1 (grey) the voltage keeps the limit, even more than necessary. Droop 2 (black) or Droop 3 (orange) smoothen the voltage at a secure distance from the limit. Using the ‘window’ reduces the need for reactive power from 1.85 Mvar (Droop 1) in average to 0.47 Mvar (Droop 2 and Droop 3). With regard to the losses (or costs of reactive power supply) Droop 2 reduces average losses by 83% from 4.38%$P_{max}$ for Droop 1 to 0.75%$P_{max}$. The application of the herein proposed Droop 3 leads to a further reduction by 6% to average losses of 0.71%$P_{max}$.

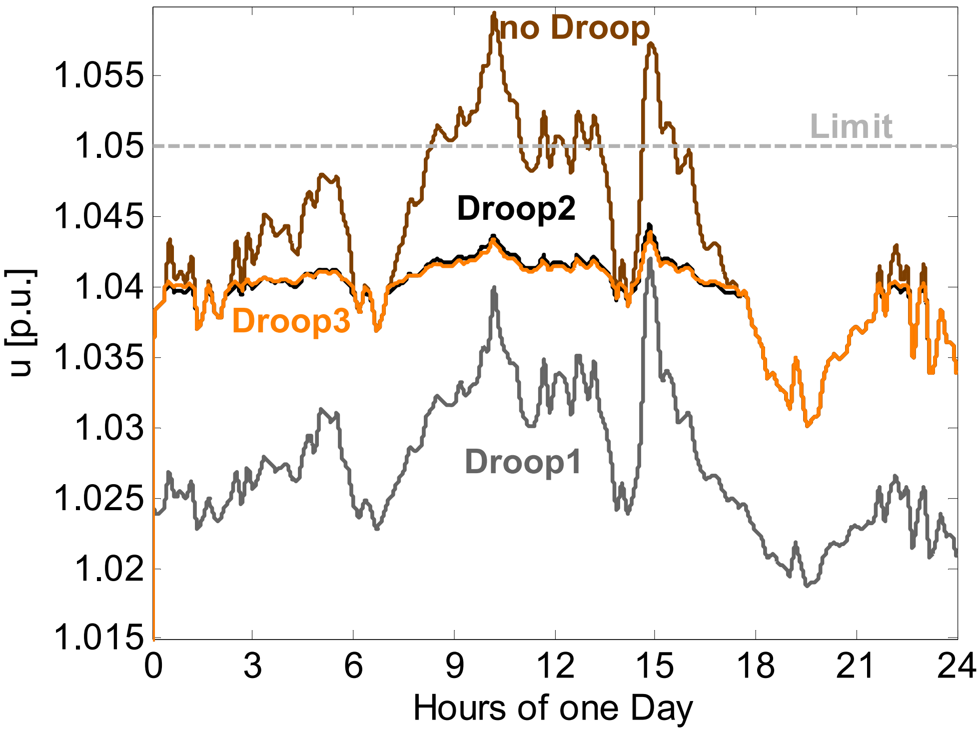


Figure 6-7: Voltage behaviour with different droop functions (simulation data)

Figure 6-8 describes the reactive power supply from PV, Wind and Biogas for the different droop functions. The order of $Q$ for Droop 2 results from the different sizing $S_{max}$ (see Table 6-1), with Biogas supplying more $Q$ than Wind and both more than PV as long as the capacity is sufficient. According to the loss dependent function of Droop 3 this order changes with more Wind than Biogas and both more than PV. This change goes alongside with the reduction of overall losses.

The simulation gives an example that loss dependent droop functions can reduce the overall losses in case of decentralised voltage control by DGs. The losses can be minimised by optimised droop curves and larger differences in the loss characteristic (efficiencies) of the considered group of DGs.

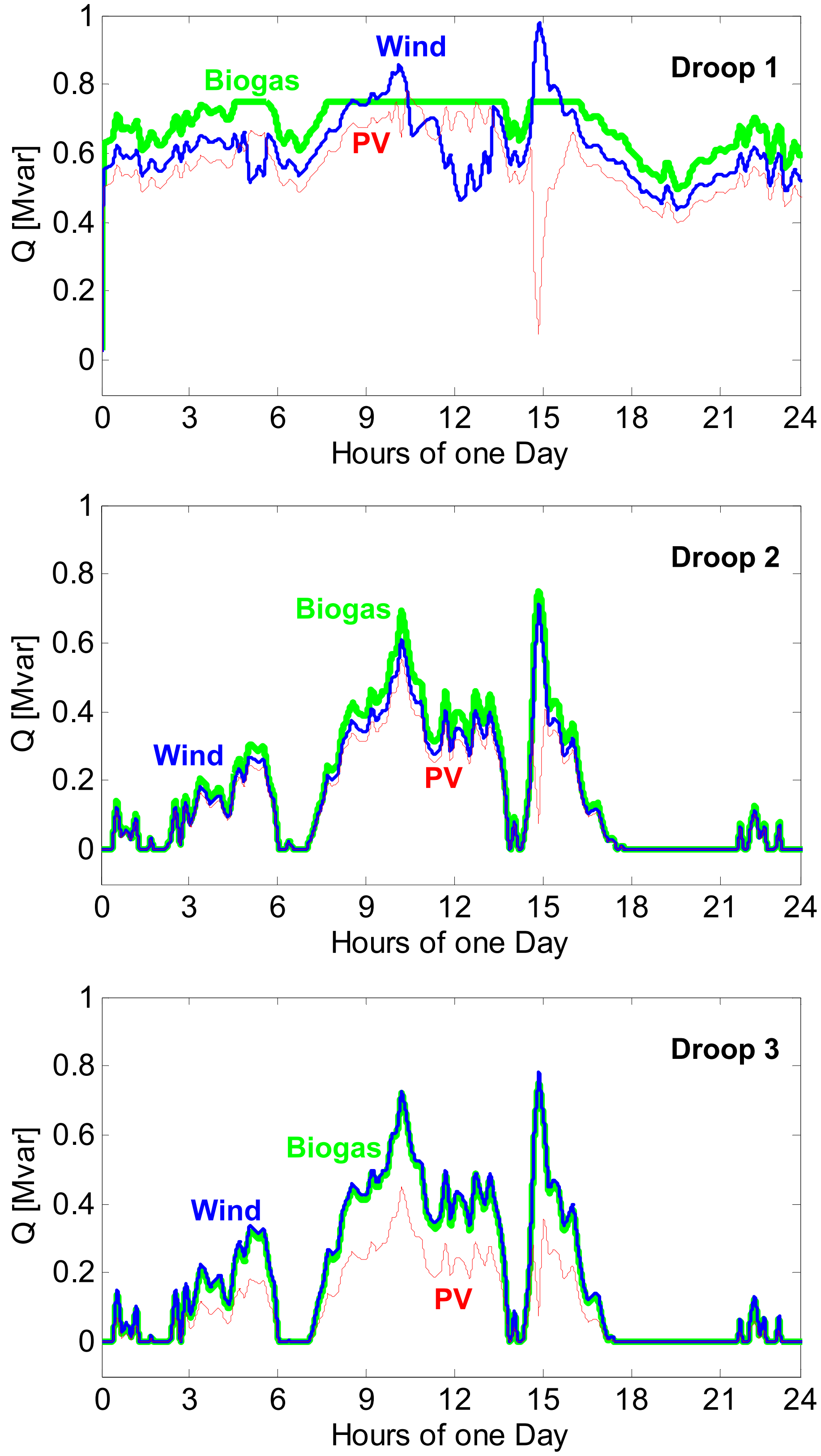


Figure 6-8: Distribution of reactive power supply with Droop 1, Droop 2 and Droop 3 (simulation data)

## 6.3. Approach for Decentralised Optimisation of Reactive Power Supply in Hybrid Systems and Mini-Grids

This section describes an approach for reactive power supply in hybrid systems / mini-grids. It takes into account all installed controllable distributed energy units with their reactive power supply capacities. The approach enhances the droop control that uses the voltage as an indicator for the reactive power demand in mini-grids. A mini-grid is understood here as a small islanded grid with a low voltage power system.

Most mini-grids and hybrid systems are formed by inverter-coupled battery units or by synchronous generator-coupled diesel units. An applicable solution for the operation is the use of the droop mode which couples the frequency with active power and the voltage with reactive power [Engler 2005]. Grid-tied DGs are technologically capable to take over some of the duties of the grid-forming units as discussed in Chapter 4. This can be beneficial for the grid's operation. From a technological perspective, an extension of reactive power sources in a grid increases the quality of supply due to diversification and redundancy. And from an economic point of view, the costs of grid operation can be reduced by substituting part of the capacity of conventional grid-forming components by the control capacity of DGs at lower costs. The focus here is on the dynamically changing operational costs of reactive power supply by DGs.

Reactive power supply causes active power losses. These losses have to be compensated by active power generation. The costs of active power generation for loss compensation depend on different operational situations in hybrid systems. As a case study an assumed hybrid system comprises the components listed in Table 6-2 with their respective characteristics concerning the type of grid-coupling converter, its maximum efficiency and the variable operational costs of active power generation.

The operational costs of a battery unit depend on the battery's efficiency $\eta_B$ and its charging history with operational costs $C_i$ [c€/kWh] from different energy sources $i$ [PV;WT;D] and the respective energy $E_i$ [kWh]. In a first approximation, the operational costs can be calculated by:

$$C_B = \frac{C_{PV} \cdot E_{PV} + C_W \cdot E_W + C_D \cdot E_D}{\left(E_{PV} + E_W + E_D\right) \cdot \eta_B}. \qquad (6\text{-}5)$$

With an assumed total efficiency $\eta_B$ of 1/1.4 (≈ 71.4%), the variable operational costs $C_B$ are 0 c€/kWh when the battery has been fully charged by PV and WT. They are 35 c€/kWh when the battery has been fully charged by the diesel generator. Generally, the operational costs are in between.

| Generating components i | Grid-coupling converter | Max. Efficiency of the grid-coupling converter | Variable operational costs [c€/kWh] |
|---|---|---|---|
| 3 kWp Photovoltaic plant (PV) | Inverter | 97% | $C_{PV} = 0$ |
| 5 kW Wind turbine (WT) | Inverter | 96% | $C_W = 0$ |
| 7 kW Diesel generator (D) | SG | 90% | $C_D = 25$ |
| 4 kW Battery unit (B), 8 kWh | Inverter | 95% | $0 < C_B < 35$ |

Table 6-2: Components of the hybrid system and their characteristics

In addition to the described generating components in Table 6-2, the load of the hybrid system is considered with a given active and reactive power demand. The active power load curve is depicted in Figure 6-10 and the inductive reactive power load curve in Figure 6-12 with the upper envelope curve.

Three main active power flow situations (S1-3) can be distinguished in the considered hybrid system that allow the determination of the actual costs of active power flows as given in Table 6-3. Figure 6-9 (together with the explanations in Section 5.2.1.2) is used in the following description of the three situations:

**Situation S1 (PV,WT)**

when $P_{PV,AC} + P_{WT,AC} > P_{Load,AC}$ and $P_B \leq 0$ (charged):

PV and WT supply the load (Figure 6-9 left) and charge B that behaves similar to a load (Figure 6-9 right). The losses in the grid-coupling converters by reactive power supply with PV, WT and B are compensated by active power generation from PV and WT. If $P_{i,AC} \leq 0$ (with $i = PV$ or $WT$) the losses are compensated by the other generator and the insufficient primary energy of the unit $i$ itself (Figure 6-9 centre).

**Situation S2 (PV,WT,B)**

when $P_{PV,AC} + P_{WT,AC} + P_{B,AC} = P_{Load,AC}$ and $P_B > 0$ (discharged):

PV, WT and B that behaves similar to a generator supply the load. The losses induced by reactive power supply of each unit are compensated by active power generation of the respective unit if $P_{i,AC} > 0$ (Figure 6-9 left). If $P_{i,AC} \leq 0$ the losses are compensated by the other two generators and the insufficient primary energy of the unit $i$ itself (Figure 6-9 centre).

**Situation S3 (PV,WT,D)**

when $P_{PV,AC} + P_{WT,AC} + P_{D,AC} + P_{B,AC} = P_{Load,AC}$ and $P_B \leq 0$ (charged):

PV, WT and D supply the load (Figure 6-9 left) and charge B (Figure 6-9 right). The losses induced by reactive power supply are compensated by active power generation of the respective unit if $P_{i,AC} \geq 0$ (Figure 6-9 left). If $P_{i,AC} < 0$ the losses are compensated by the other two generators and the insufficient primary energy of the unit *i* itself (Figure 6-9 centre).

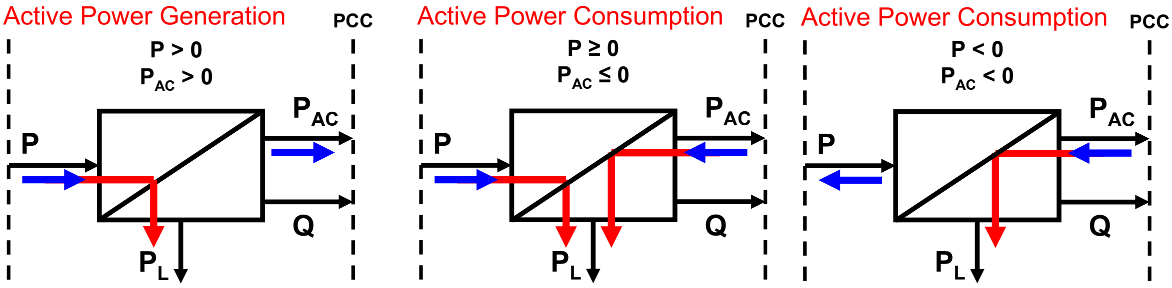


Figure 6-9: Power flows in the grid-coupling converters (partly [Braun 2008c])
left: DG generating $P_{AC}$ → losses $P_L$ reduce $P_{AC}$
centre: DG active but not generating $P_{AC}$ → $P_L$ also compensated from the grid
right: Storage is charged → $P_L$ compensated from the grid

| Generating unit i | Costs of losses $C_{i,Q}$ [c€/kWh] caused by reactive power supply with component i in different operational situations S1 (PV,WT) | S2 (PV,WT,B) | S3 (PV,WT,D) |
|---|---|---|---|
| Photovoltaic plant (PV) | $C_{PV,Q} = 0$ | $P_{PV,AC} > 0$: $C_{PV,Q} = 0$<br>$P_{PV,AC} \leq 0$: $C_{PV,Q} = 0\text{-}35$ | $P_{PV,AC} > 0$: $C_{PV,Q} = 0$<br>$P_{PV,AC} \leq 0$: $C_{PV,Q} = 0\text{-}25$ |
| Wind turbine (WT) | $C_{WT,Q} = 0$ | $P_{WT,AC} > 0$: $C_{WT,Q} = 0$<br>$P_{WT,AC} \leq 0$: $C_{WT,Q} = 0\text{-}35$ | $P_{WT,AC} > 0$: $C_{WT,Q} = 0$<br>$P_{WT,AC} \leq 0$: $C_{WT,Q} = 0\text{-}25$ |
| Diesel generator (D) | - | - | $P_{D,AC} > 0$: $C_{D,Q} = 25$<br>$P_{D,AC} \leq 0$: - |
| Battery unit (B) | $C_{B,Q} = 0$ | $C_{B,Q} = 0\text{-}35$ | $C_{B,Q} = 0\text{-}25$ |

Table 6-3: Costs of losses caused by reactive power supply for each generating component depending on the operational situation S1, S2 and S3

In all three considered situations the lowest costs of reactive power occur if reactive power is supplied by active power generating ($P_{i,AC} \geq 0$) PV plants and WTs. Higher costs occur if reactive power is supplied by the battery unit. The diesel generator has the highest costs in S3 and also the lowest efficiency. It may be taken into account in emergency situations but not in normal operation. Presently, mainly grid-forming batteries and diesel generators have been used for reactive power supply which seems not to be the most cost-efficient solution.

The exemplary hybrid system is analysed over one day. Figure 6-10 shows the active power supply of the battery, PV, WT and the Diesel. The upper envelope curve is the active power demand of the loads in the hybrid system and the lower envelope curve is the active power for charging the battery.

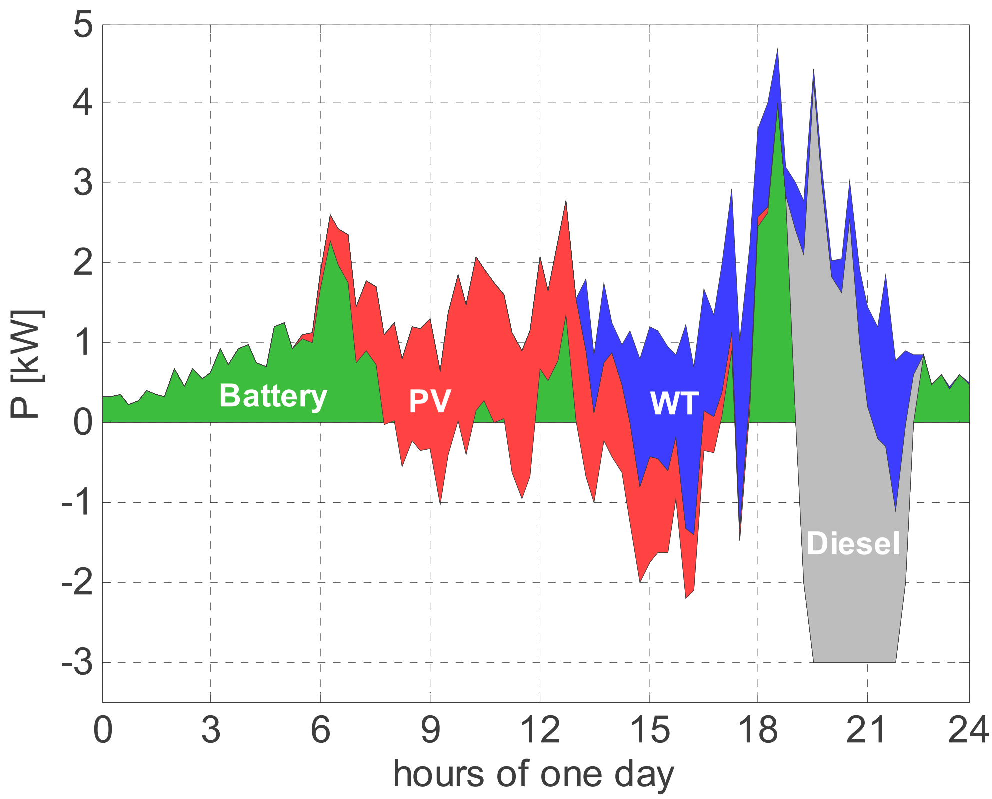


Figure 6-10: Active power supply of Battery, PV, WT and the Diesel generator.

Figure 6-11 shows that the costs for active power loss compensation by PV and WT are often cheaper than by the battery. The cost curves are based on the assumption that the battery has been 50% charged by the diesel generator and 50% by PV and WT at the beginning of the day. From 0-5 hours, situation S2 can be seen where the battery takes over all losses at costs of 17.5 c€/kWh. Then, PV becomes active reducing its costs of losses to 0 and providing part of the losses to the WT in combination with the battery. At 8-10 hours and 13-17 hours, situation S1 can be seen, where all costs are zero because they are compensated by PV and WT. In the evening, at 19 hours, the diesel generator is activated to charge the battery. This leads to situation S3 where losses in the PV and the battery would be compensated by the diesel generator and the WT.

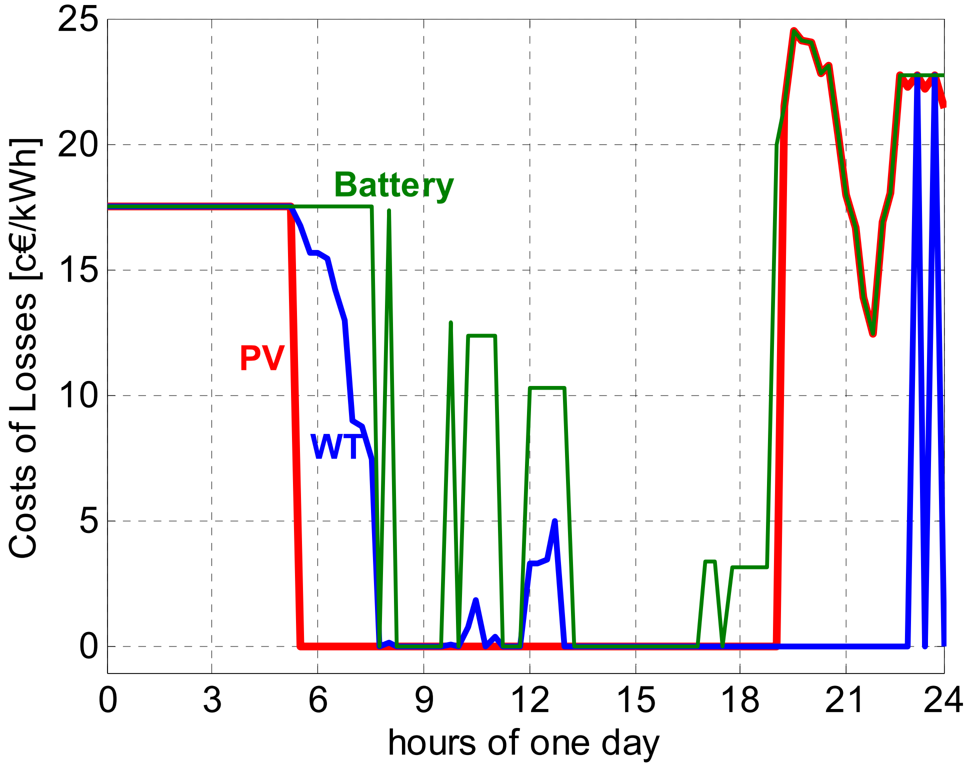


Figure 6-11: Costs of reactive power loss compensation of the Battery, PV and WT

Figure 6-12 depicts the optimal reactive power supply distribution under consideration of the efficiency curves in Figure 6-13 as calculated with MATLAB®. The upper envelope curve of the reactive power curves is the inductive reactive power demand of the loads. If the reactive power is supplied only by the battery operational costs of 1.62 €/d arise. An optimal distribution of reactive power supply causes only costs of 0.22 €/d. This is a reduction of 86%. The annual savings are 511 €/a assuming that this is an average day of the whole year. This optimal reactive power supply may have been achieved by a central controller which knows the cost data of all components exactly and gives reactive power set points.

Another approach of reactive power control in hybrid systems is the use of droop functions which relate a decrease of the voltage with an increase of reactive power generation (capacitive). This droop concept has the big advantage compared to central reactive power dispatch concepts that each DG only considers its own local information including the terminal voltage. The reactive power control of the whole grid is optimised without need of additional communication between the components or a central dispatch centre.

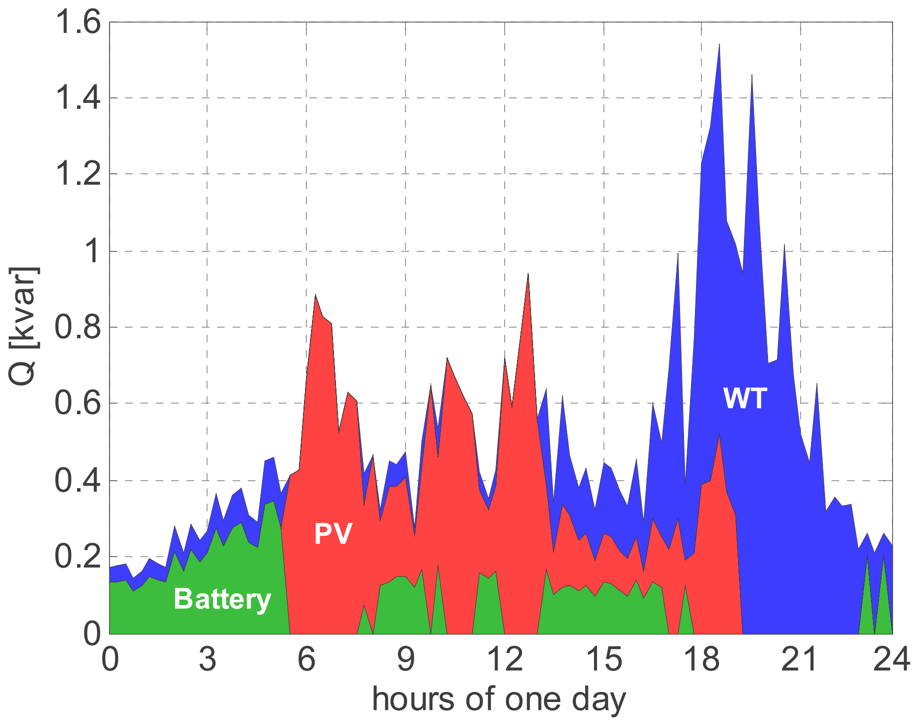


Figure 6-12: Reactive power supply of battery, PV and WT according to optimum distribution with minimum costs

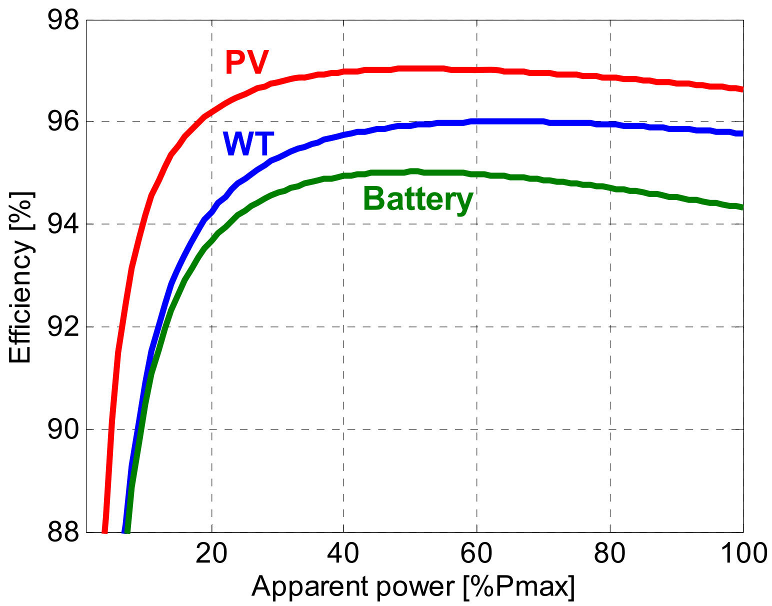


Figure 6-13: Efficiency curves of the battery, PV and WT

The following droop concept is applied in the next step. On the one hand, grid-forming units change the voltage according to their reactive power supply; and on the other hand, grid-tied units change the reactive power supply according to their terminal voltage. The droop functions:

- for the grid-forming battery:

$$u(t) = 1 - 0.1 \cdot q(t) \tag{6-6}$$

- and for the grid-tied PV and WT (if P(t) > 0): :

$$q(t) = 50 \cdot (1 - u(t)) \tag{6-7}$$

with the actual terminal voltage *u(t)* of the unit in pu, the actual active power supply *P(t)*, and the actual reactive power supply of the unit *q(t)* in pu are applied in a network simulation with PowerFactory from DigSILENT (see Figure 6-14) with the models as described in Annex: PowerFactory Models. This pragmatic approach includes the new insights of operational costs of reactive power supply and leads to costs of 0.29 €/d instead of 1.52 €/d if only supplied by the battery unit. More than 80% of the operational costs can be avoided by application of the proposed droop concept in the given example. Figure 6-15 shows the distribution of reactive power supply with application of the droop functions. Generally, the battery is used more often compared to Figure 6-12 because it is needed for setting the voltage that is required for providing the information of the reactive power demand to the PV and WT.

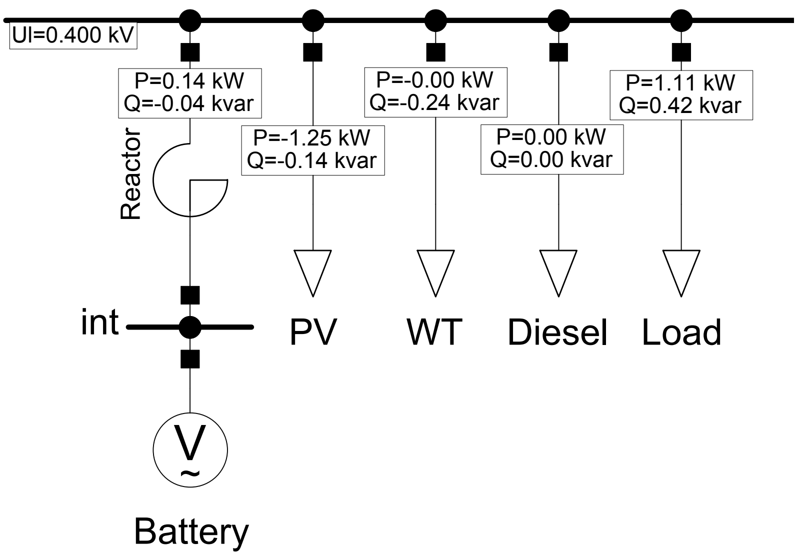


Figure 6-14: Hybrid system as simulated with PowerFactory

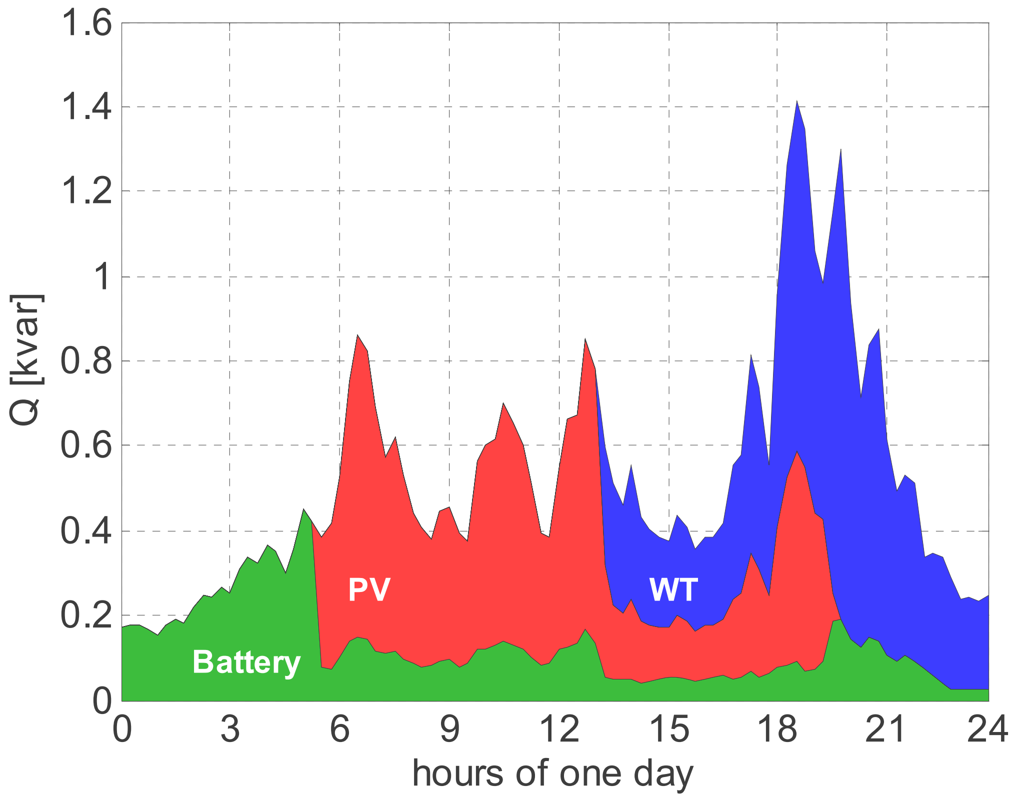


Figure 6-15: Reactive power supply of battery, PV and WT according to droop functions

The operational costs of reactive power supply in hybrid systems and mini-grids are often not considered because the additional losses are a marginal cost factor. This simulation demonstrates that these costs can be reduced considerably with little modifications of the reactive power control concept by application of simple linear droop functions. The droop functions are designed such that priority is given to the reactive power supply from active power generating PV plants, wind turbines, and hydro plants which have small operational costs. Losses and related costs can be avoided by this enhanced but simple control approach contributing to increase the overall efficiency of hybrid systems and mini-grids using renewable energy sources.

## 6.4. Summary of Chapter 6

This chapter presents three different approaches that allow reducing operational costs that arise from reactive power supply in network operation. The lowest operation costs of reactive power supply can be obtained by centralised control approaches that are based on the full knowledge of network operators on the cost structure of all devices.

However, also decentralised approaches result in significant reductions of the costs without the need of knowing the cost structure exactly and without having a continuous communication between the controller and the component. The droop mode which couples voltage and reactive power is applied with modified droop functions in order to integrate information on the cost structure of the different components. Calculations with the network simulation software PowerFactory show considerable cost reductions by these approaches.

In particular an approach for hybrid systems and mini-grids is developed that allows reducing the costs by more than 80% in the given example and that uses predominantly PV systems and WTs for reactive power supply. The extension of reactive power supply from grid-forming to grid-tied units not only reduces the costs but also increases the redundancy and by relieving the grid-forming unit also the reliability of the system.

Centralised and decentralised approaches of optimised reactive power supply are demonstrated with distributed energy units and network components in the DeMoTec laboratory. The results are described in the next chapter.

# 7. Laboratory Demonstration of Technological and Economic Capabilities

Laboratory experiments are performed in order to provide hardware demonstrations of the discussed reactive power supply concepts. ISET provides with the Design Centre for Modular Supply Technology (DeMoTec) a well-equipped laboratory for such experiments. This chapter first describes the infrastructure in section 7.1.

Two hardware experiments are performed in DeMoTec to demonstrate the capabilities of reactive power supply and approaches of an economic optimisation. Two different approaches are looked at:

- a centralised approach in section 7.2 where the network operator calculates the optimal reactive power dispatch of the connected CDE units and provides the optimised reactive power profiles to the generators via their aggregating entity (here: SCADA); and
- a decentralised approach in section 7.3 where neither calculations nor communication is necessary but where locally defined droop functions adjust the reactive power dispatch according to the measured terminal voltage that is varied by the grid-forming CDE unit.

## 7.1. Description of the Laboratory Infrastructure

The DeMoTec Infrastructure is explained in this section. Firstly, the developed Information, Communication and Control Technology (ICCT) infrastructure is described with regard to the local controls of the generators and the central control unit. Secondly, the controllable distributed generators are presented that are used in the experimental setup. Finally, the electrical power network of DeMoTec that is used in the experiments is described.

### 7.1.1. Information, Communication and Control Infrastructure

The ICCT infrastructure is designed for controlling distributed energy units with regard to active and reactive power. Figure 7-1 depicts the ICCT infrastructure that consists of a central Supervisory Control and Data Acquisition (SCADA) unit as well as four local (decentralised) Remote Terminal Units (RTUs) for the different CDE units. These five units are programmed with LabVIEW and installed on standard Windows Personal Computers (PCs). In addition, a central measurement server on a Windows PC provides data from the measurement devices A2000 that are installed at different nodes in the DeMoTec grid. The communication is based on two levels: with standard open protocols and with proprietary protocols.

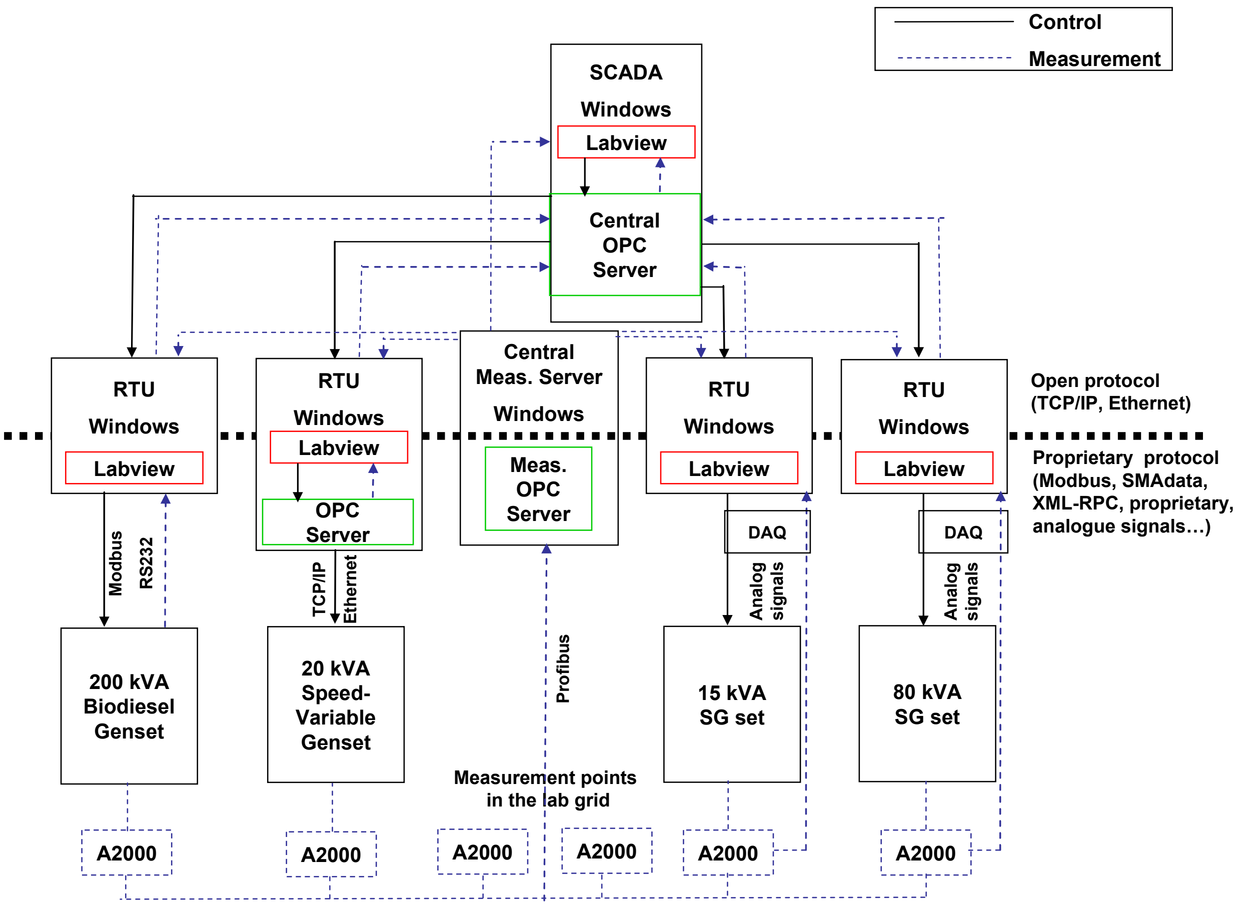


Figure 7-1: ICCT Infrastructure of Laboratory Experiment

As standard protocols the TCP/IP and Ethernet is used for communication between the PCs. The information is exchanged on the OLE for Process Control (OPC$^{TM}$) protocol [Open Task Force 1998] that provides a standard mechanism for communicating with numerous devices and databases. The information architecture of the OPC approach comprises field management, process management and business management. Field devices (field management) present their information consistently to any application and can receive configuration parameters from any application. SCADA systems can be one type of application (process management). Other applications can be business systems (business management) or control systems. The information is exchanged with a server-client-architecture where the server makes the data available and the applications with their client have access to the server to read and write the data.

In the experimental architecture, the central SCADA system communicates with the Central OPC Server that is installed on the same PC in order to control the connected RTUs. In addition it communicates with the central Measurement OPC Server to acquire data from other points of A2000 measurements in the DeMoTec. The RTUs can be controlled via the Central OPC Server by the SCADA in a centralised approach or they can be controlled independently in a decentralised approach. This allows analysing different ways of integrating CDE units in network operation as the whole spectrum from decentralised to centralised control can be implemented in the experiments. Moreover, it is possible to connect professional SCADA systems to the experimental setup by using the standard OPC interface.

### 7.1.2. Controllable Distributed Generators

The DeMoTec comprises different distributed energy units. A schematic overview is given in Figure 7-2 (status: August 2007).

Four different generators in DeMoTec are extended to be controllable with regard to active and reactive power. These are the

- 200 kVA Biodiesel Genset,
- 20 kVA Speed-Variable Diesel Genset,
- 80 kVA Synchronous Generator (SG) Set, and
- 15 kVA Synchronous Generator (SG) Set.

They are depicted in Figure 7-1 as the controlled units with their respective RTU controller. The following paragraphs provide a description of these components.

#### *7.1.2.1. 200 kVA Biodiesel Genset*

The 2007 installed 200 kVA Biodiesel Genset from Polyma (see Figure 7-3) is a type of emergency genset that provides 5 different operational modes. These include grid-tied operation that allows giving set values for active power and power factor as well as grid-forming operation. The whole genset has a rated power of 200 kVA and consists of a KHD motor with 183 kW and a Marelli Motori generator with 220 kVA.

A local LabVIEW control is developed that allows controlling active and reactive power in grid-connected operation as well as voltage and frequency in grid-forming operation. In both operation modes, the inclusion of droop functions (active power – frequency droop and reactive power – voltage droop) is possible. The local control by LabVIEW is enabled by Modbus communication with the genset-internal SYMAP control device from Stucke GmbH. In addition to stand-alone operation of the genset, also the integration in the central control architecture is possible by OPC communication with the SCADA system (cf. Figure 7-1).

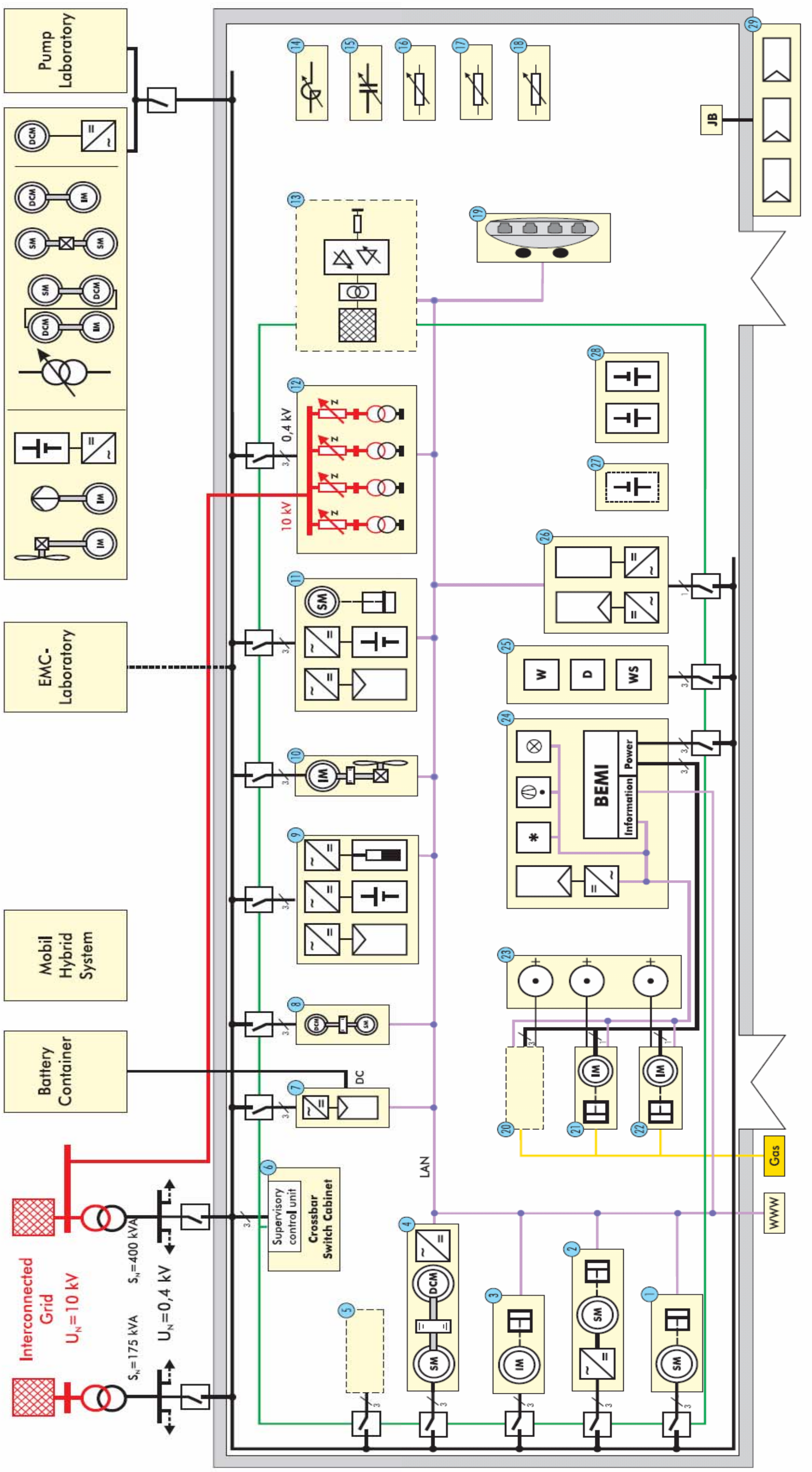


Figure 7-2: Schematic Overview of the DeMoTec Infrastructure

The 200 kVA Biodiesel Genset is not used in the two experiments that are explained in the next two sections of this chapter because a stable operation is only possible at a higher power range. This power range does not fit well with the power range of the other units in the experiment. However, the genset can be used in further experiments with other objectives.

Figure 7-3: 200 kVA Biodiesel Genset (Picture)

### *7.1.2.2. 20 kVA Speed-Variable Diesel Genset*

The 20 kVA speed-variable genset (see Figure 7-4) was developed by SMA Regelsysteme GmbH and Kirsch GmbH. It consists of a 30 kW diesel engine from Deutz with a variable speed range of 1100-3000 rpm, a permanently-excited synchronous generator and a 22 kVA static three-phase back-to-back-converter. The active power generation is limited to 16 kW. As an inverter-coupled generator it can be used for representing all types of inverter-coupled generators such as PV systems and WTs.

The developed local LabVIEW control allows controlling active and reactive power in grid-connected operation and the inclusion of droop functions. The local control by LabVIEW is enabled by OPC communication with the genset's internal control. In addition to stand-alone operation of the genset, also the integration in the central control architecture is possible by OPC communication with the SCADA system (cf. Figure 7-1).


Figure 7-4: 20 kVA Variable Speed Genset (Picture)

### *7.1.2.3. 80 kVA Synchronous Generator Set*

The experimental setup of a 97 kW DC motor from Baumüller and an 80 kVA self-excited synchronous generator from Siemens allows different operational modes: grid-forming as well as grid-tied operation. Due to the limitation of the power supply for the DC motor, the generators rated power is limited to 25 kVA instead of the possible 80 kVA. The DC motor can provide a driving and braking torque so that the SG can be operated in all four operation quadrants generating/consuming active/reactive power.

The developed local LabVIEW control allows controlling active and reactive power in grid-connected operation and the inclusion of droop functions. The local control by LabVIEW is enabled by giving analogue voltage signals to the genset’s internal control for speed and torque as well as to a DC voltage source for controlling the excitation voltage of the SG. In addition to stand-alone operation of the genset, also the integration in the central control architecture is possible by OPC communication with the SCADA system (cf. Figure 7-1).

Figure 7-5: 80 kVA SG set (Picture)

*7.1.2.4. 15 kVA Synchronous Generator Set*

The experimental setup (Figure 7-6) of a 17.3 kW drive-controlled induction motor from Siemens and 16 kVA self-excited synchronous generator from Kemmerich allows different operational modes: grid-forming as well as grid-tied operation. The power supply is provided by a controllable static drive inverter. The induction motor can provide a driving and braking torque so that the SG can be operated in all four operation quadrants generating/consuming active/reactive power but consuming active power is limited by the genset's internal layout so that only the generation of active power is of interest and the operation area is limited to the respective two quadrants.

Very similar to the 80 kVA SG set, the developed local LabVIEW control for the 15 kVA SG set allows controlling active and reactive power in grid-connected operation and the inclusion of droop functions. The local control by LabVIEW is enabled by giving analogue voltage signals to the genset's internal control for speed and torque as well as to a DC voltage source for controlling the excitation voltage of the SG. In addition to stand-alone operation of the genset, also the integration in the central control architecture is possible by OPC communication with the SCADA system (cf. Figure 7-1).

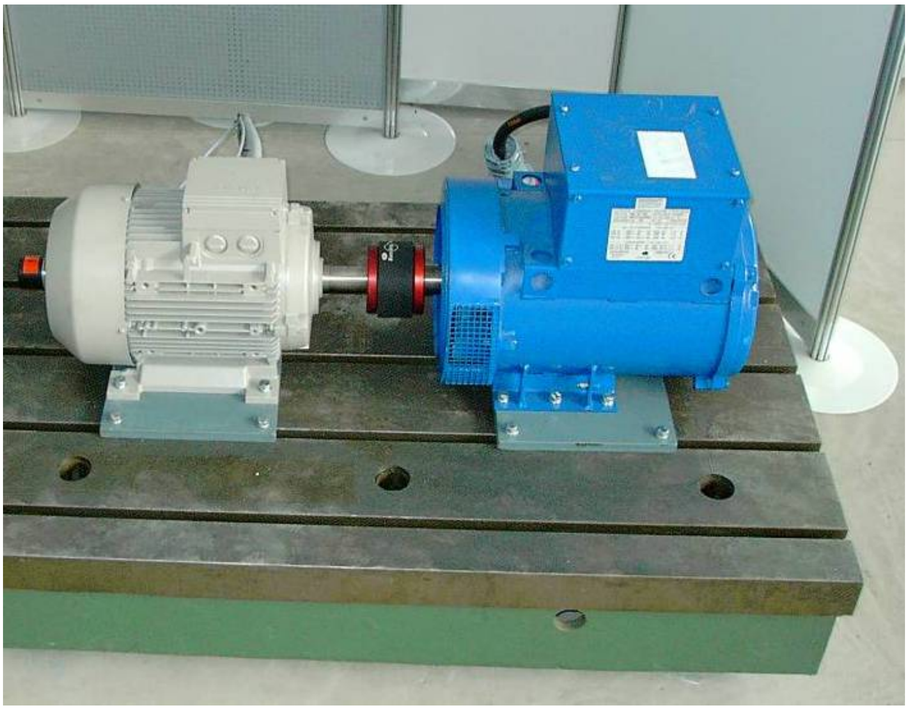

Figure 7-6: 15 kVA SG set (Picture) with the driving induction motor (left) and the synchronous generator (right)

*7.1.2.5. 10 kVA Sunny Island Battery Inverters*

The 10 kVA three-phase bi-directional Sunny Island Battery Inverter system consists of three one-phase Sunny Island 4500 from SMA with a rated power of 3300 VA (see Figure 7-7). Overloading is possible with 4500 VA for 30 minutes and 6600 VA for 20 seconds.


Figure 7-7: SMA Sunny Island 4500 (picture)

The Sunny Islands have three different operating modes. These are the grid-tied mode (operation as a current source), the grid-forming mode (operation as a voltage source) and the droop mode (operation as a voltage source with power-dependent voltage and frequency).

In droop mode, the Sunny Island varies the grid's frequency depending on its current active power supply and the grid's voltage depending on its current reactive power supply. In case that the active power supply increases, the battery inverter reduces the frequency starting from the nominal frequency. In case that the capacitive reactive power supply rises, the battery inverter reduces the voltage starting from the nominal RMS voltage. If the power generation on the AC terminal of the system is higher than the power consumption, all Sunny Islands will charge their batteries and let the idle frequency slightly rise, and vice versa.

### 7.1.3. Electrical Power Network

The DeMoTec power network allows connecting the available CDE units at four different busbars in the 400 V LV network and interconnecting them over a 10 kV MV hardware network simulator as given in Figure 7-8.

Indicated with a "Z", three adjustable impedances allow simulating different types and lengths of MV lines that are physically represented by their respective T-equivalent-circuit. The three 100 kVA transformers have a short-circuit voltage of 4% and the 250 kVA transformer 6%. Measurements are performed on both sides of the adjustable line impedances as well as at the connection point to the external network (indicated as interconnected grid). For the experiments here, the three adjustable line impedances have the configuration as given in Table 7-1.

| | ***Z1*** | ***Z2*** | ***Z3*** |
|---|---|---|---|
| *R/2* [Ω] | 11.5 | 4.35 | 2.2 |
| *L/2* [mH] | 3.9 | 1.35 | 0.92 |
| *C* [µF] | 0 | 0 | 0 |

Table 7-1: Configuration of Line Impedances

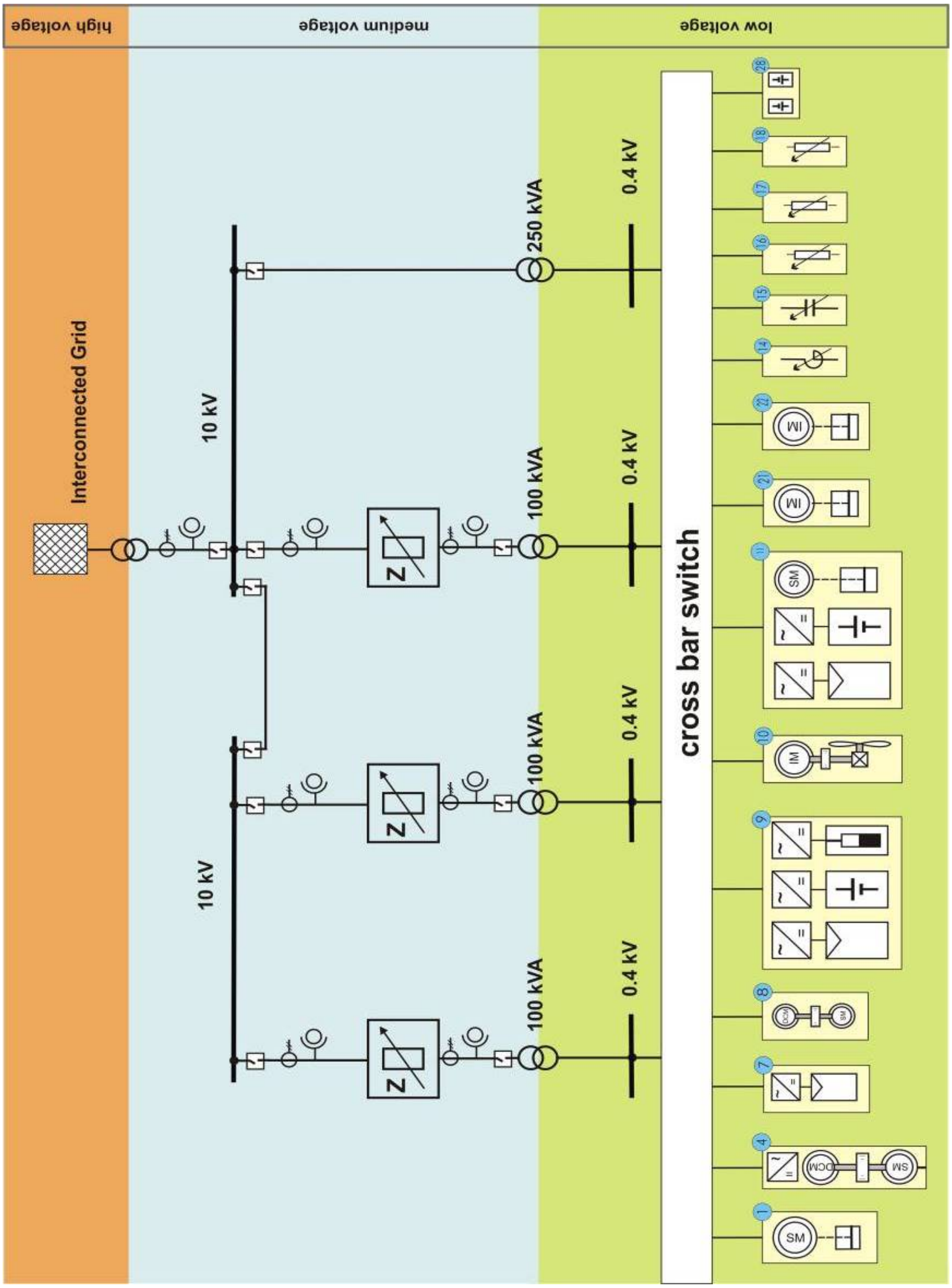


Figure 7-8: Medium Voltage Hardware Network Simulator in DeMoTec

## 7.2. Experiment 1: Centrally Optimised Reactive Power Supply

The first experiment demonstrates the approach of centrally optimizing the reactive power supply to the network operator who calculates an optimised reactive power dispatch taking into account network elements, network losses, and the reactive power supply costs and the capabilities of each of the connected CDE units.

In this case study, congestions in the external grid are assumed. The (DeMoTec) network operator aims at compensating the full reactive power flow at the grid connection point in order to reduce these congestions. Three distributed generators are controlled in this experiment:

- a 20 kW Biogas plant (Biogas)
  represented by the 80 kVA SG,
- a 8 kW Wind turbine (WT)
  represented by the 15 kVA SG, and
- a 16 kWp photovoltaic generator (PV)
  represented by the 20 kVA (inverter-coupled) speed-variable genset.

The active power generation of these three units is given in Figure 7-9 and basic parameters to calculate the operational costs of reactive power supply of the generators are given in Table 7-2. All three units are assumed to be installed in the LV network and have active power purchase costs for consumption of 20 c€/kWh (similar to the German average household tariff). Additional losses have to be compensated when reactive power is supplied in addition to active power generation. This reduces the amount of active power generation that has a value similar to the feed-in tariff in Germany.

The resulting operational costs of reactive power supply for each of the three generators are depicted in Figure 7-10 within their respective loading capability chart. It can be derived from these charts, that reactive power supply by the WT is the cheapest solution and by the PV system the most expensive one.

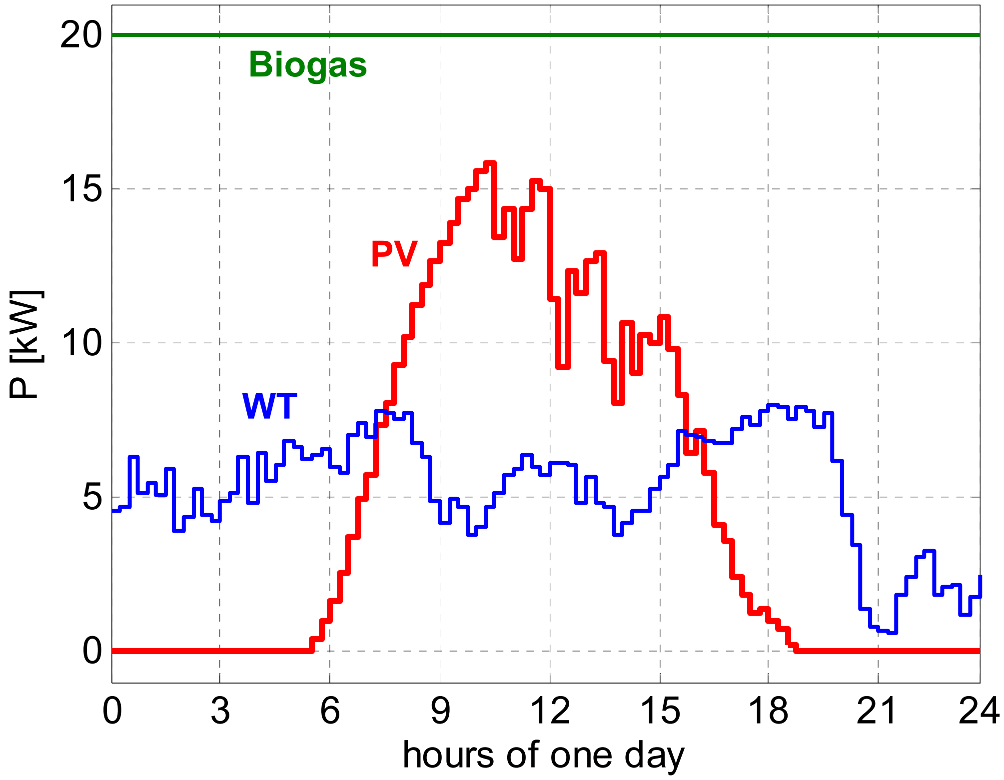


Figure 7-9: Active power generation from a PV (red), WT (blue) and Biogas (green) over one exemplary day (15 min mean values)

| | PV | WT | Biogas |
|---|---|---|---|
| Maximum converter efficiency $\eta_{max}$ | 97% | 96% | 95% |
| Maximum active power $P_{max}$ | 16 kW | 8 kW | 20 kW |
| Sizing ($S_{max}/P_{max}$) | 1 | 1 | 1.25 |
| Guaranteed $Q_{max}$ | 0 kvar | 0 kvar | 15 kvar |
| Type of grid-coupling converter | Inverter | SG | SG |
| Deactivation | At night | No | No |
| Feed-in Tariff (generation) | 40 c€/kWh | 10 c€/kWh | 20 c€/kWh |
| Power purchase costs (consumption) | 20 c€/kWh | 20 c€/kWh | 20 c€/kWh |

Table 7-2: Parameters of represented generators

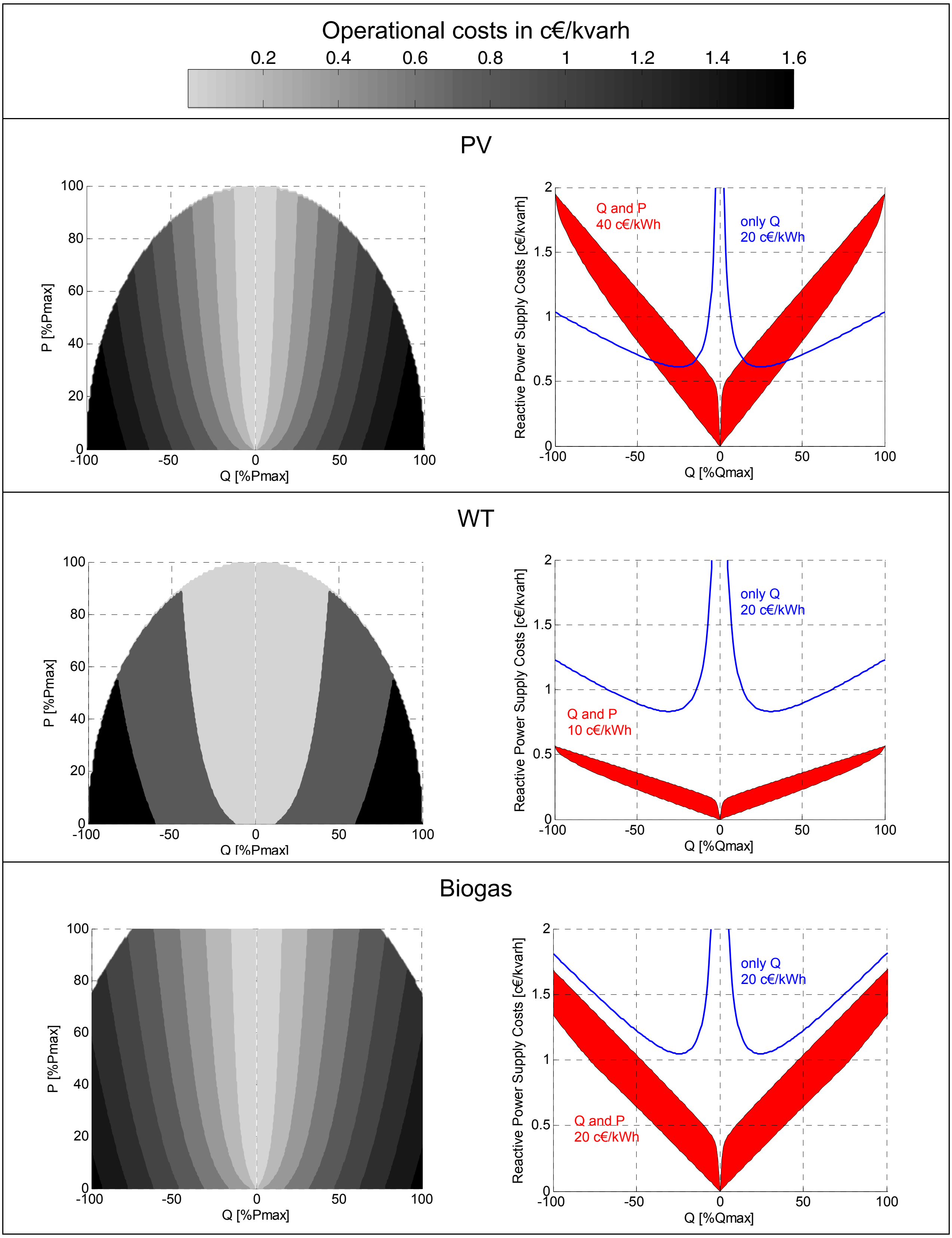


Figure 7-10: Operational costs [c€/kvarh] of the three generators depending on their respective active and reactive power supply

These units are connected at the LV network of the DeMoTec grid. They are coupled by 100 kVA transformers to the MV network of the DeMoTec. The DeMoTec network configuration is given with a PowerFactory scheme in Figure 7-11. The three CDE units are connected with overhead lines to the common connection point in the MV network. With reference to Table 7-1, the WT is connected with *Z1*, the Biogas plant with *Z2* and the PV system with *Z3*.

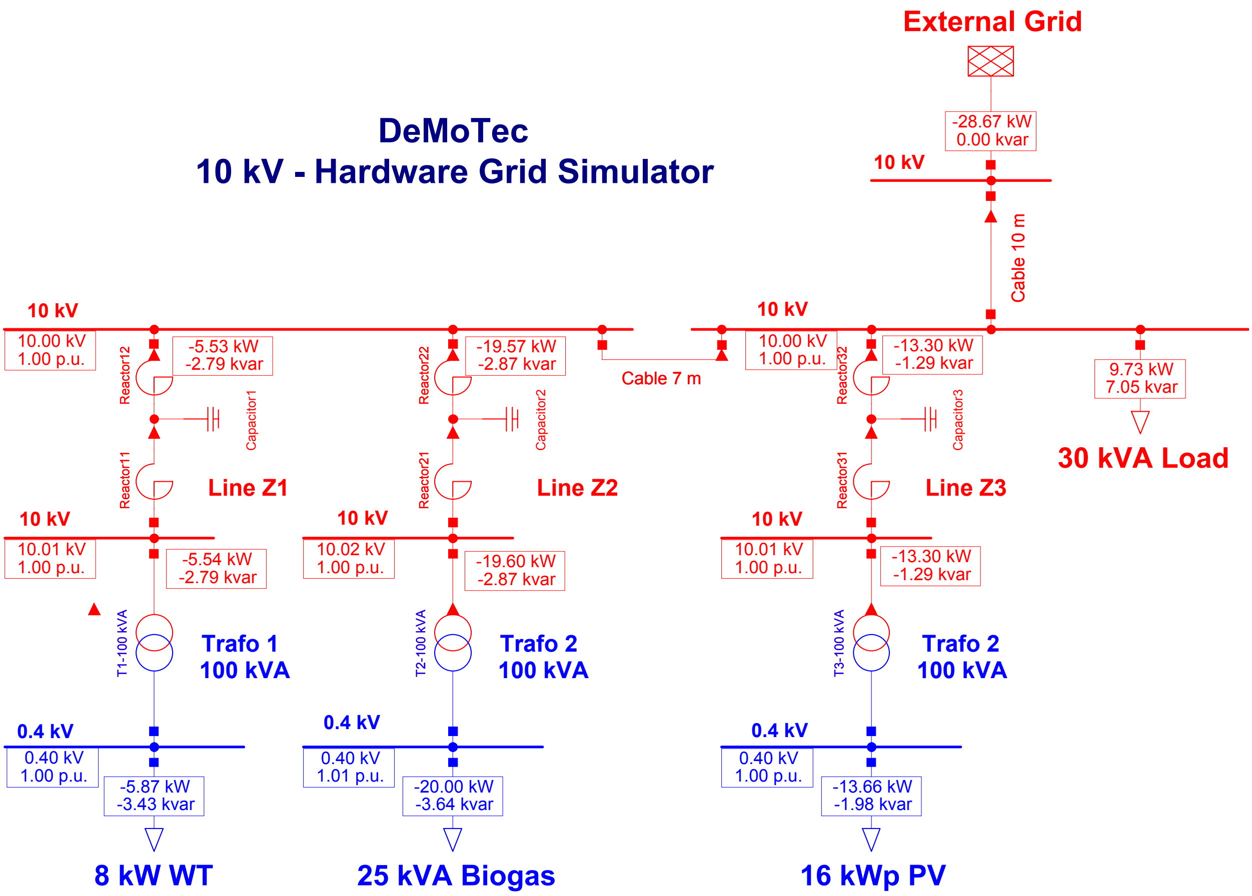


Figure 7-11: DeMoTec network configuration (with load flow results at 12 h)

The reactive power that needs to be compensated is not represented by hardware components because of limited availability of DeMoTec components during the testing period. Consequently, it is simulated software-based that in addition to the three generators also a 30 kVA LV feeder with consumer loads is connected at the connection point to the external grid. The active power demand of this LV feeder as well as the reactive power demand of the DeMoTec network is compensated by the three generators in order to reduce the congestions in the superior network. The active and reactive power flow of the LV feeder with consumer loads is given in Figure 7-12.

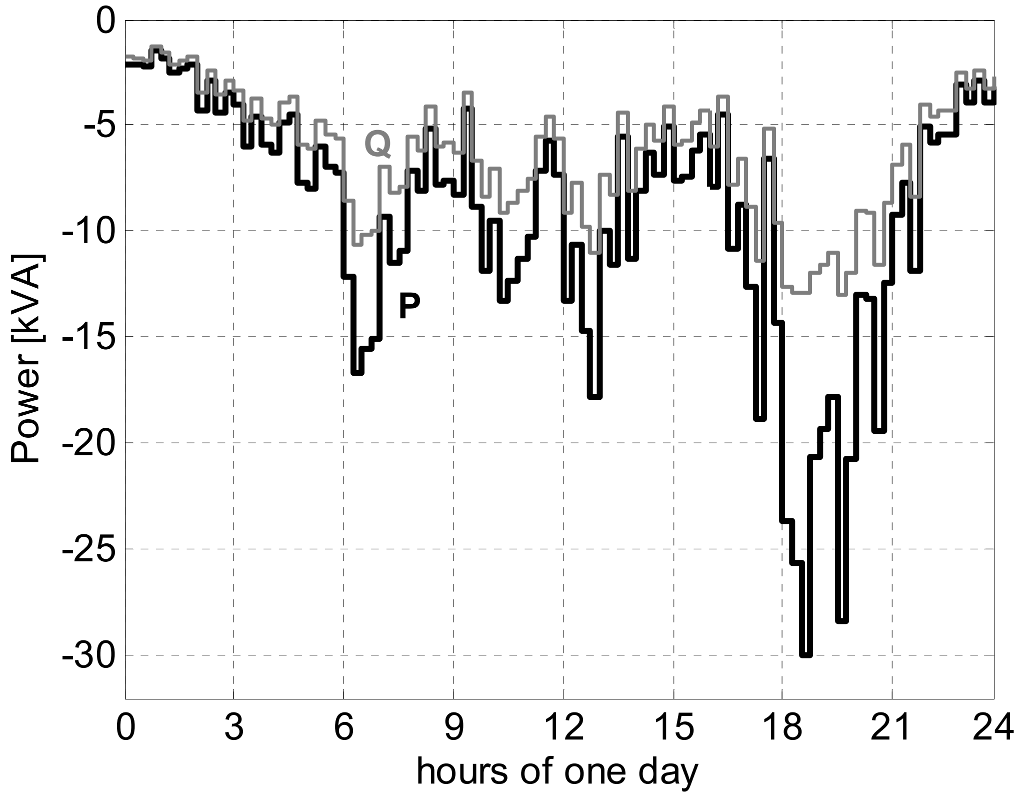


Figure 7-12: Active and reactive power consumption over one exemplary day (15 min mean values)

In one approach the biogas plant can be used for reactive power control because it has a guaranteed reactive power capacity of 15 kvar. In a second approach, the network operator takes into account the PV plant and the WT as well. The distribution of reactive power supply between all three units is optimised with the objective to minimise the operational costs of reactive power supply. Here, it is calculated with MATLAB®. In reality, it can be calculated by the network operator. These optimised set values for reactive power supply are then forwarded by the SCADA system to the generators.

Figure 7-13 provides this optimised schedule for reactive power supply from the PV plant, the WT and the biogas plant. In addition, Figure 7-14 provides the schedule in per unit values in order to provide a better basis for understanding the optimisation. As the WT has the lowest operational costs it is used at the highest rate. The biogas plant provides reactive power at a lower rate because of its lower efficiency and the higher opportunity costs from lost feed-in payments. Finally, the PV generator stays deactivated in situations without solar irradiation because the costs would be much higher when all the losses need to be covered than only the additional ones (cp. Figure 7-10). During the day, it is used as well but at the lowest rate because of the highest costs of lost feed-in payments. At 18-20 h, the share of the WT is reduced because it operates near rated active power and the generator is not oversized. In this case, the other plants have to supply a higher share of the reactive power.

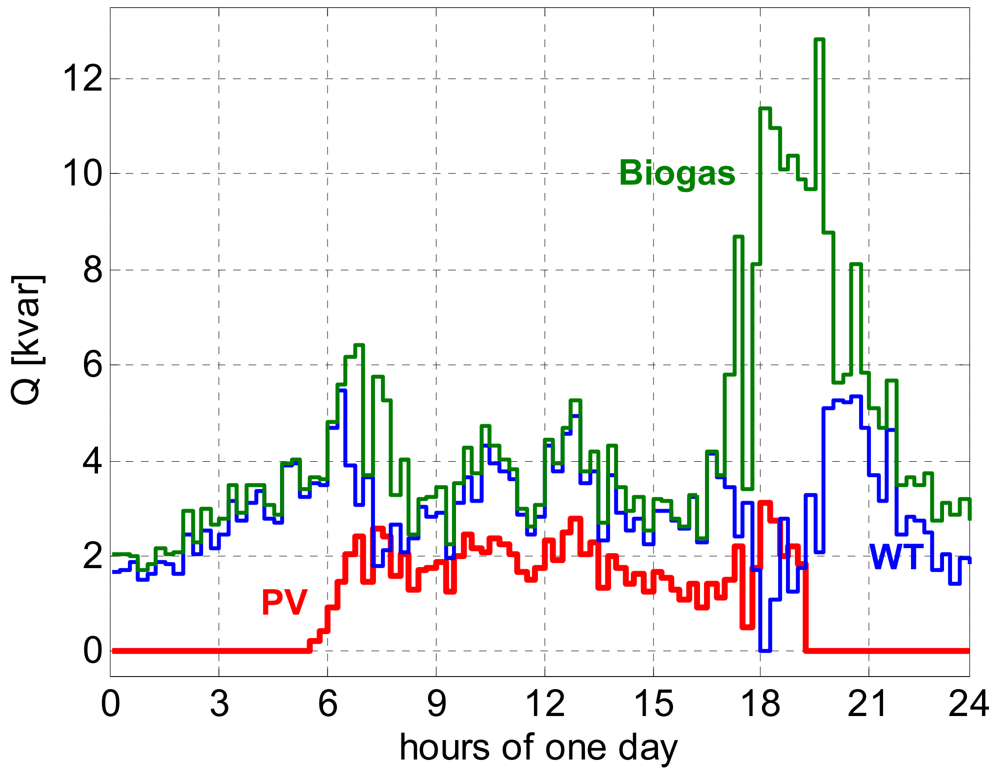


Figure 7-13: Reactive power supply [kvar] from a PV (red), WT (blue) and Biogas (green) over one exemplary day (15 min mean values)

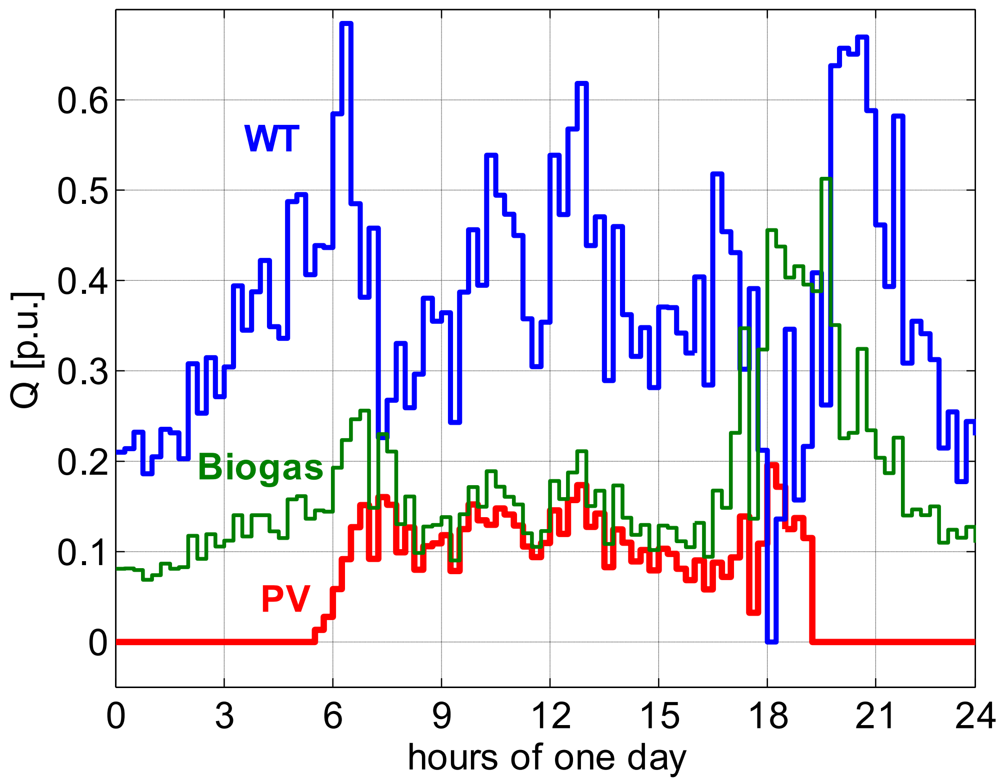


Figure 7-14: Reactive power supply [p.u.] from a PV (red), WT (blue) and Biogas (green) over one exemplary day (15 min mean values)

The distribution of reactive power supply between all three units instead of using only the biogas plant reduces the operational costs of reactive power supply in the given scenario by approx. 46% according to MATLAB calculations.

The network behaviour is simulated with PowerFactory (description of the models in Annex: PowerFactory Models). As the result of the reactive power supply from the generators the objective of minimizing the reactive power flow at the connection point to the external grid is achieved as given in Figure 7-15 where the value at the external grid is near zero.

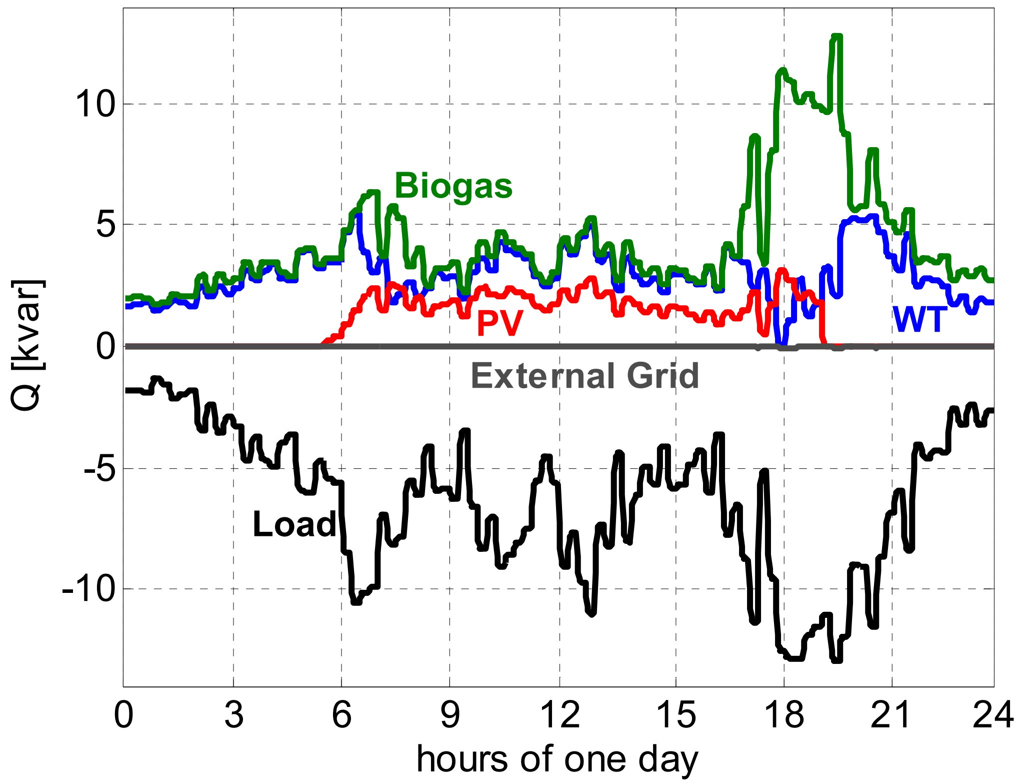


Figure 7-15: Reactive power supply [kvar] from PV (red), WT (blue) and Biogas (green), as well as reactive power demand of the Load (black) and the summation at the External Grid (grey) with compensation as a PowerFactory simulation

The expected behaviour according to the target values is compared to measurements in the DeMoTec with the described experimental setup. One test run representing 24 h is performed within 48 min with 30 s for each 15 min step and with a resolution of 0.5 s between each measurement point in average. The measurements of the SCADA system do not have an exact time stamp so that the measured values are slightly distorted in time compared to the target values.

Figure 7-16 provides the comparison for active power generation. The figure shows that the measured values follow the target values quite close. Also the measured reactive power supply given in Figure 7-17 follows the target values presented in Figure 7-13. They are not compared in the same graph because the values are quite near to each other that causes indistinguishable overlaps. The reactive power supply of the speed-variable diesel genset that is coupled with an inverter to the network and that represents the PV plant shows a certain noise in Figure 7-17. It also supplies in the period 9-13 h approx. 0.5-1 kvar less reactive power than given by the set values. In the period 19-21 h, the reactive power supply of the PV plant did not change to zero because the control system crashed in this test run. The same happened independently for the Biogas plant whose control system crashed in the period 20-24 h.

The objective of this central control approach was to compensate the reactive power demand of the load at the external grid connection. To verify the achieved result, the reactive power flow in the DeMoTec experiment is measured at the connection point to the external grid and compared with the reactive power demand of the assumed load at this point. Figure 7-18 provides the comparison that demonstrates the accomplishment of the reactive power compensation. There are some differences between both curves that mainly result from the time-distortion and difficulties of the reactive power control systems of the PV and Biogas generator as explained in the two paragraphs before. In summary the objective of this DeMoTec experiment is achieved.

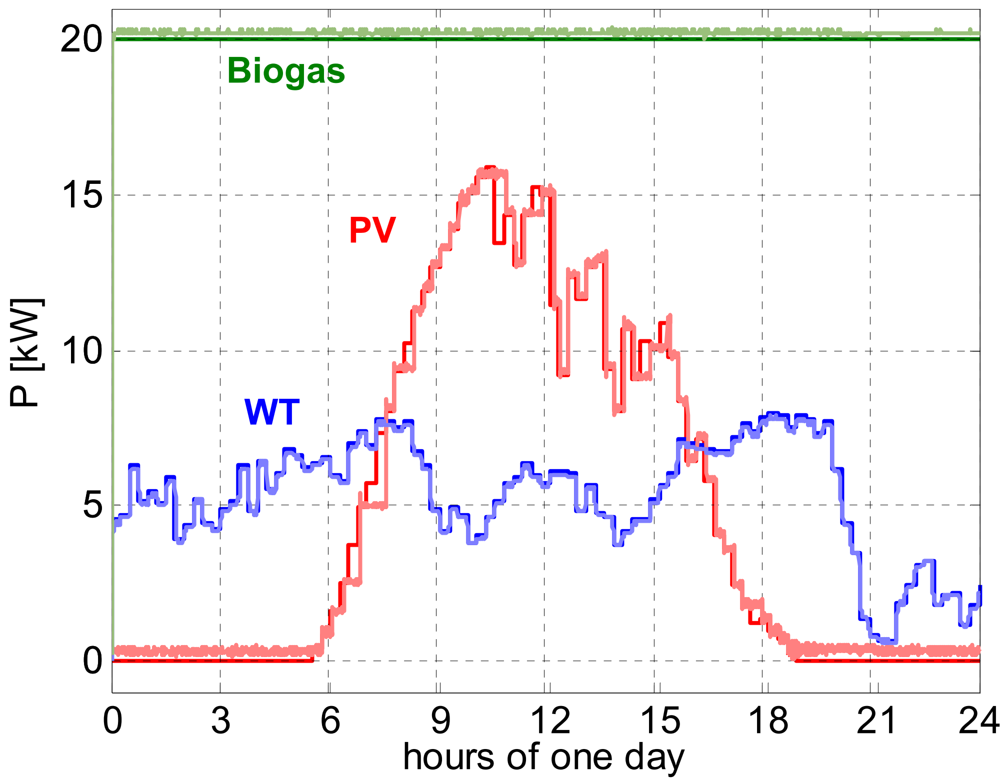


Figure 7-16: Active power generation from a PV (red), WT (blue) and Biogas (green) measured in DeMoTec (lighter) compared to target values (darker)

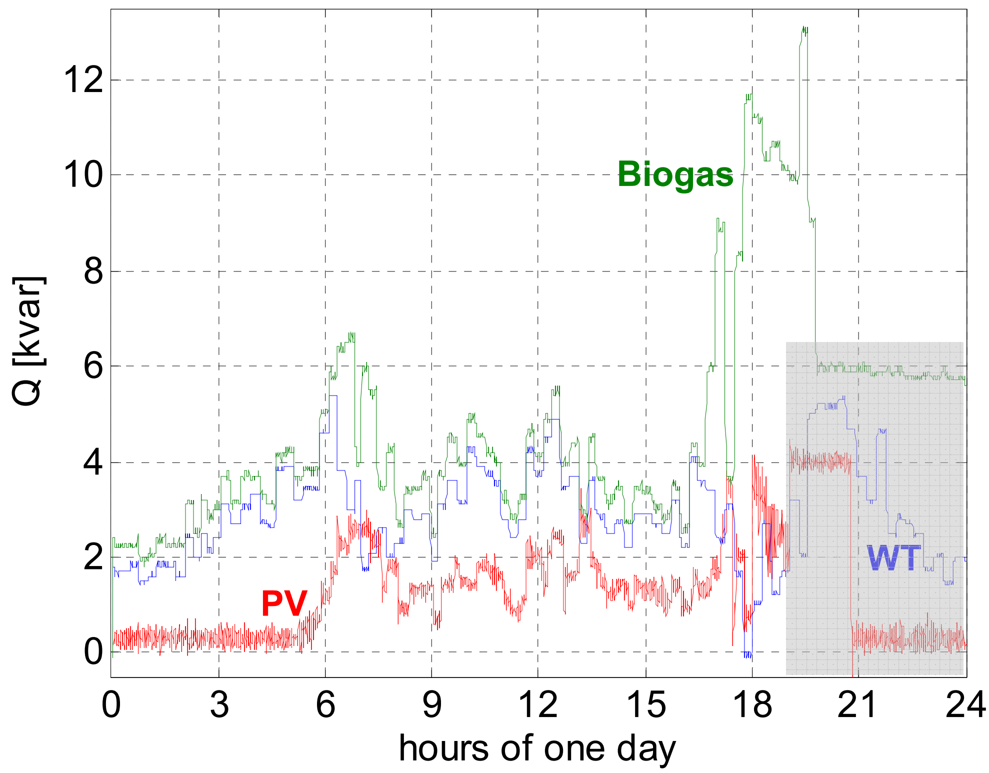


Figure 7-17: Reactive power supply [kvar] from a PV (red), WT (blue) and Biogas (green) measured in DeMoTec

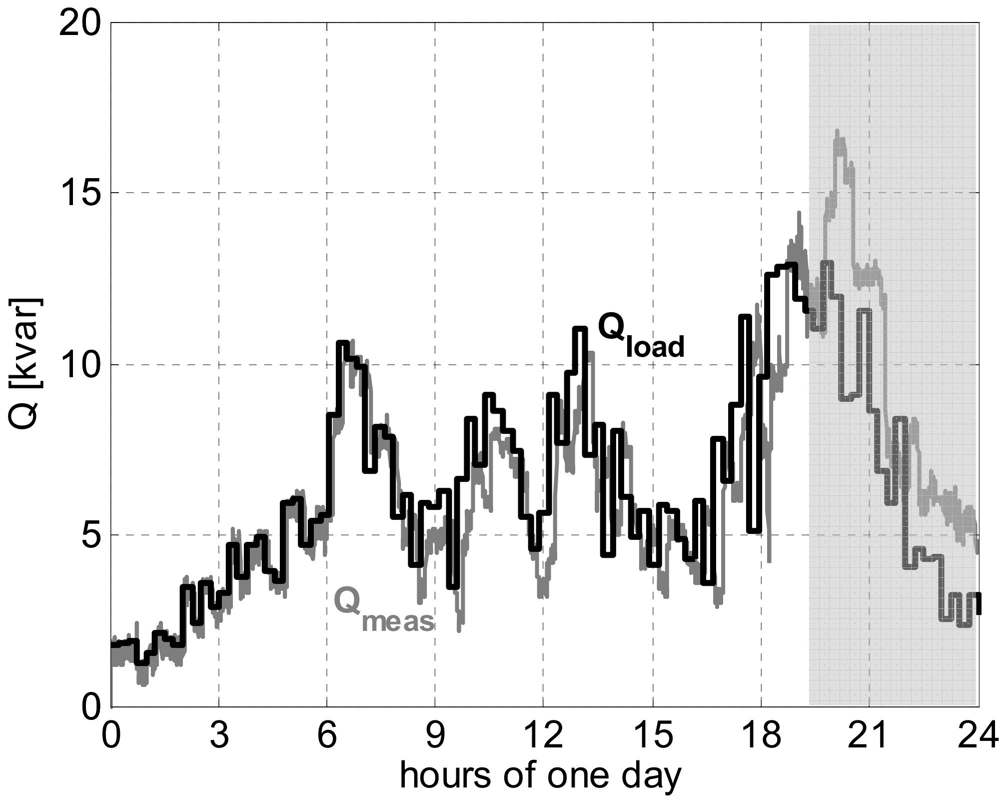


Figure 7-18: Reactive power supply [kvar] measured in DeMoTec at the external grid connection $Q_{meas}$ (grey) and reactive power of the assumed load $Q_{load}$ (black)

### 7.3. Experiment 2: Decentralised Optimised Reactive Power Supply

The second case study applies an approach as already presented in section 6.3 by simulation. Decentralised optimisation neither requires network simulations and calculations of optimal reactive power dispatch nor extensive ICCT infrastructure for communicating the dispatch results to the controllable distributed energy units. Based on the droop concept [Engler 2005], the voltage is used as an information signal that coordinates the reactive power supply. The voltage of the grid-forming units is variable dependent on its own reactive power supply. This voltage variation in the network is recognised by those generators that participate in reactive power supply. These participating generators change their reactive power supply according to the measured terminal voltage.

This decentralised concept is applicable in islanded operation where the general voltage can be influenced by the grid-forming unit. The three-phase Sunny Island cluster is chosen as the grid-forming unit in DeMoTec. It changes the voltage by 6% when it supplies rated reactive power.

Three distributed energy units are controlled in this experiment:

- a 12 kVA Load (simulating a feeder with diverse loads)
  represented by the 80 kVA SG that is operated as a motor,
- a 8 kW Wind turbine (WT)
  represented by the 15 kVA SG, and
- a 8 kWp photovoltaic generator (PV)
  represented by the 20 kVA (inverter-coupled) speed-variable genset.

The active power generation of the two generators is given in Figure 7-19. Table 7-3 gives an overview of the characteristics of the two generators and the battery unit. In addition, Table 6-3 provides the operational costs that are assumed to be similar to the case study in section 6.3. It should be avoided supplying reactive power from the battery inverter when the battery is also loaded with a diesel generator that has high variable operational costs.

Figure 7-20 shows the active and reactive power demand of the consumer loads that are served most of the exemplary day by the two generators and in the evening by the battery.

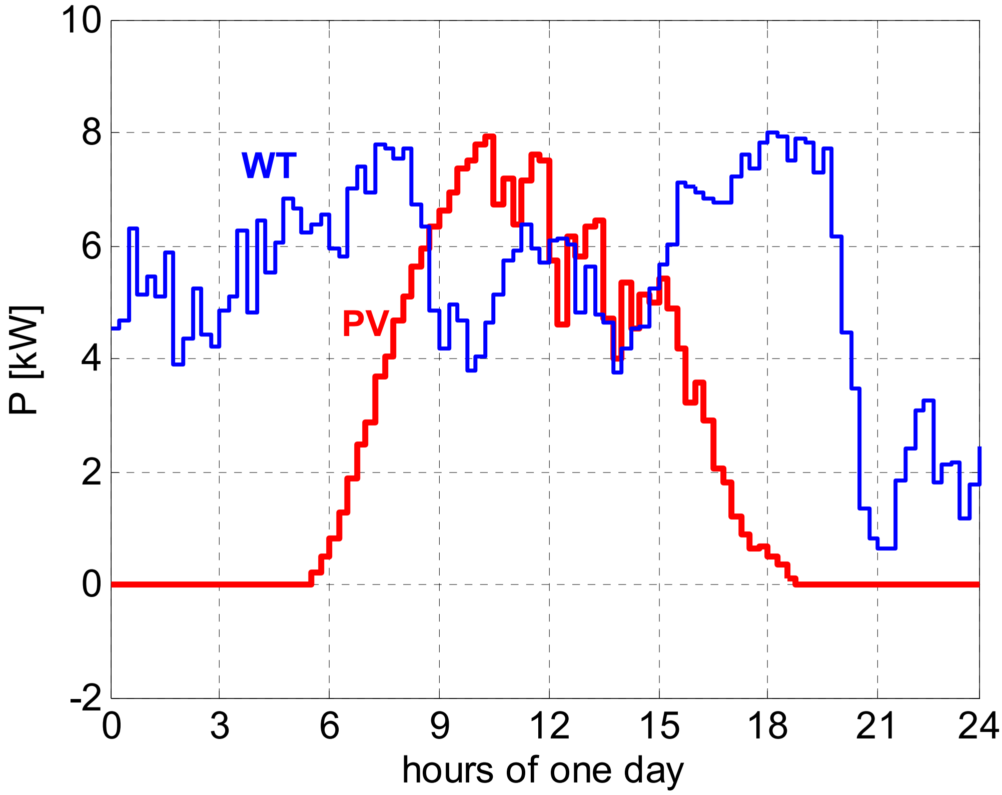


Figure 7-19: Active power flow of a PV (red) and WT (blue) over one exemplary day (15 min mean values)

| | PV | WT | Battery |
|---|---|---|---|
| Maximum converter efficiency $\eta_{max}$ | 97% | 96% | 95% |
| Maximum active power $P_{max}$ | 8 kW | 8 kW | 10 kW |
| Sizing ($S_{max}/P_{max}$) | 1 | 1 | 1 |
| Guaranteed $Q_{max}$ | 0 kvar | 0 kvar | 0 kvar |
| Type of grid-coupling converter | Inverter | SG | Inverter |
| Deactivation | At night | No | No |

Table 7-3: Parameters of reactive power sources

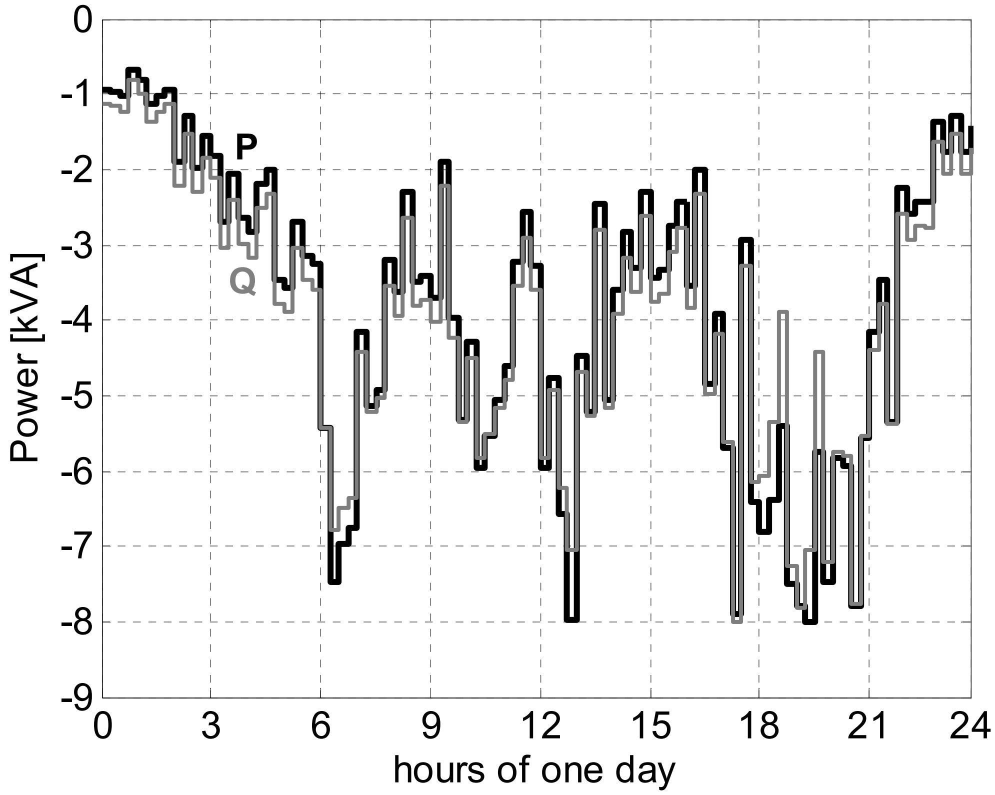


Figure 7-20: Active and reactive power consumption over one exemplary day (15 min mean values)

These units are connected at the LV network of the DeMoTec grid. They are coupled via 100 kVA transformers to the MV network of the DeMoTec grid. The DeMoTec network configuration is given with a PowerFactory scheme in Figure 7-21. The four distributed energy units are connected with overhead lines to the common connection point in the MV network. With reference to Table 7-1, the WT is connected with *Z1*, the LV load feeder with *Z2* and the PV system with *Z3*. Also the Sunny Island battery inverter cluster is connected with *Z3*.

In order to include the PV system and the WT in the reactive power supply, two kinds of reactive power / voltage droop functions are applied:

- for the grid-forming battery: $u(t) = 1 + 0.06\, q(t)$
- and for the grid-tied PV and WT (if $P(t) \neq 0$): $q(t) = 50\,(1 - u(t))$

with the actual terminal voltage $u(t)$ of the unit in pu, the actual active power supply $P(t)$, and the actual reactive power supply of the unit $q(t)$ in pu.

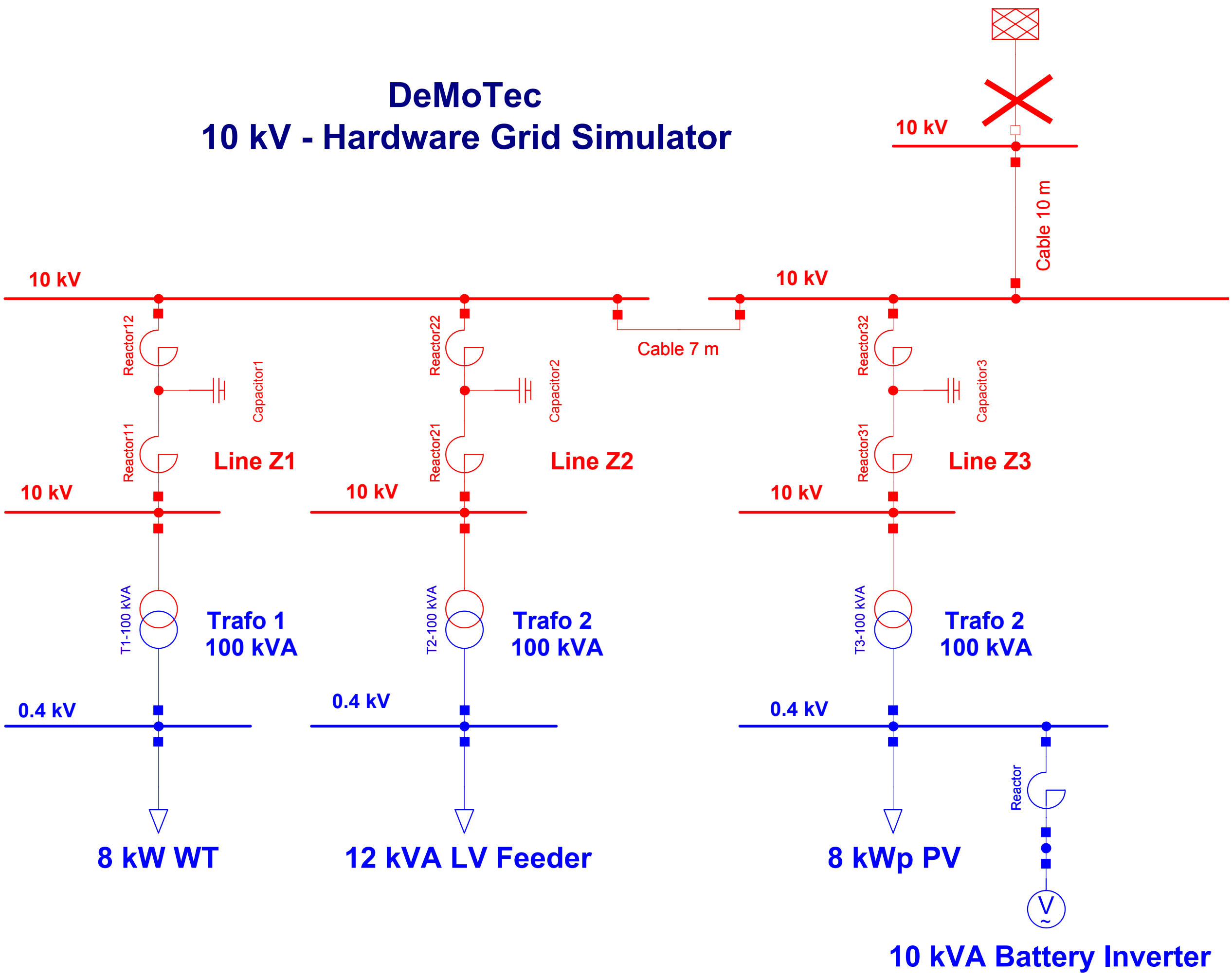


Figure 7-21: DeMoTec network configuration (island mode)

This case study is simulated with PowerFactory (description of the models in Annex: PowerFactory Models) and measured during the experiment in DeMoTec. The simulation does not use adapted models to the DeMoTec components because the DeMoTec control system is still under development. Therefore, the simulation should be understood as a first energy flow analysis under consideration of the droops. It is expected that the measured and simulated values are different but in future the control system will be optimised and models developed. Then, the simulation should represent the real measurements in a better manner.

The resulting active power flows are given in Figure 7-22 as simulated with PowerFactory and in Figure 7-23 as measured in DeMoTec. In comparison it can be seen that the WT is modelled very well following the target values in Figure 7-19 smoothly. The PV system follows in principal the target values but it has a certain content of noise in the measured signal that is not modelled appropriately. This noise results from the generators internal control as can be seen when the target value of 0 kW is applied in the period 0-5 h or 19-24 h. The load follows the target values in Figure 7-20 very well. Compared to the simulation there are sometimes larger transients when new target values are set in discrete steps. This can be reduced by decreasing the velocity of the active power control. Also more realistic loads should be used for such experiments and not just a synchronous motor representing them. But during the testing period the other loads were not applicable. The battery does not receive any set values and operates as the grid-forming unit. Comparing the simulation with the measurements shows that the real behaviour is represented very well with the PowerFactory model. There is only one period 11-12 h where the measured active power flow of the battery inverter is significantly smaller than the simulated one. This difference results mainly from the PV system that operates at an active power that is in the same magnitude lower than the target values.

The reactive power flows are given in Figure 7-24 as simulated with PowerFactory and in Figure 7-25 as measured in DeMoTec. The load follows the target values in Figure 7-20 very well. Compared to the simulation there are sometimes transients when new target values are set in discrete steps. This can be reduced by decreasing the velocity of the reactive power control. The other three reactive power flows only result from the interactive droop control as discussed before. This causes significant differences when the control dynamics are not modelled appropriately. Especially the PV system has a control behaviour that is strongly influenced by the generator's internal control characteristic. The internal control is not considered in the simple PowerFactory models used here for comparison, esp. not the noise on the reactive power flow. Another difficulty is that the real control only operates in control cycles of up to 20 s because of time lags in the communication between the local LabVIEW control and the generator's internal control. Such long cycles are not adequate for fast dynamic control actions as required here, where each 30 s another target value for the reactive power demand of the load changes the situation. Consequently, the applied droop characteristic cannot be followed very well because the voltage fluctuates (see Figure 7-27) heavily within the range of the droop function. Despite these drawbacks, the basic simulated reactive power flow behaviour of the PV system is similar to the measured one. In contrast, the reactive power droop behaviour of the WT and the battery inverter is smooth and modelled well as can be seen in the first (0-5 h) and last (22-24 h) period when the PV system only produces noise but has negligible influence in the system.

Figure 7-26 provides the simulated voltage profile and Figure 7-27 the measured one. The voltage signal directly interacts with the reactive power flows according to the applied droop functions. However, the droop function of the battery inverter cannot be derived from the measurement data exactly. The function has a bandwidth of approx. 0.01 pu as can also be seen in Figure 7-27. This uncommon behaviour may be influenced by the synchronous generators that represent the load and the WT and have a similar capacity as the battery inverter. As synchronous generators the reactive power control directly leads to voltage changes at the terminal.

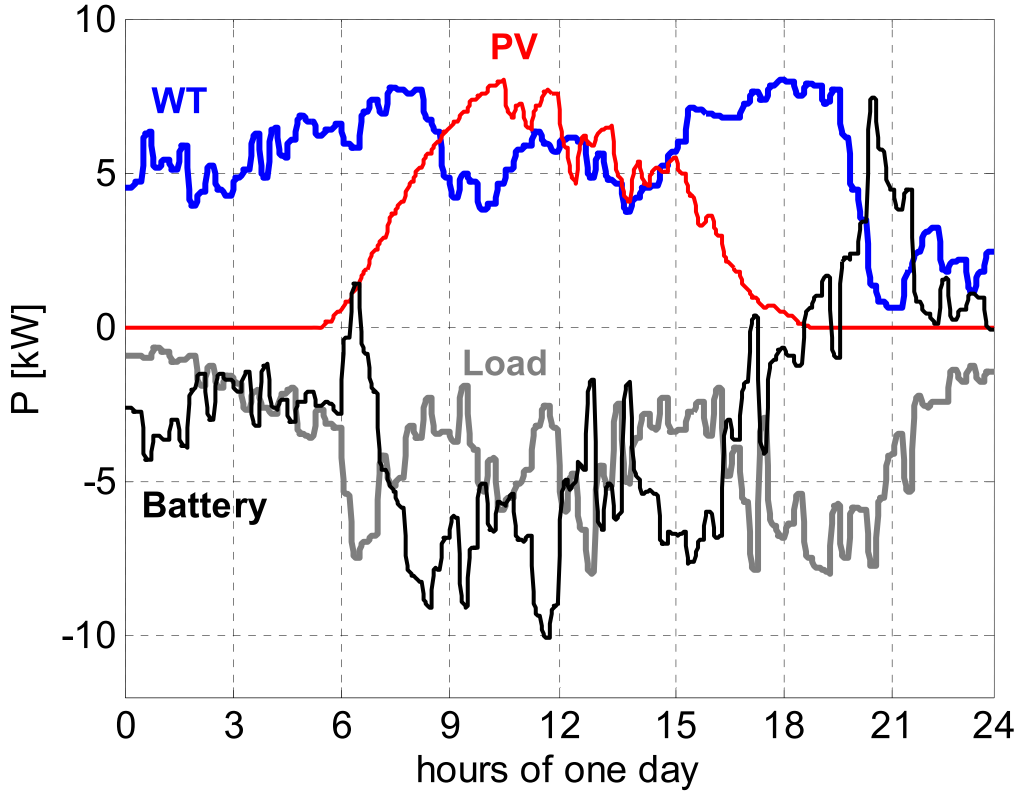


Figure 7-22: PowerFactory Simulation of the active power flows

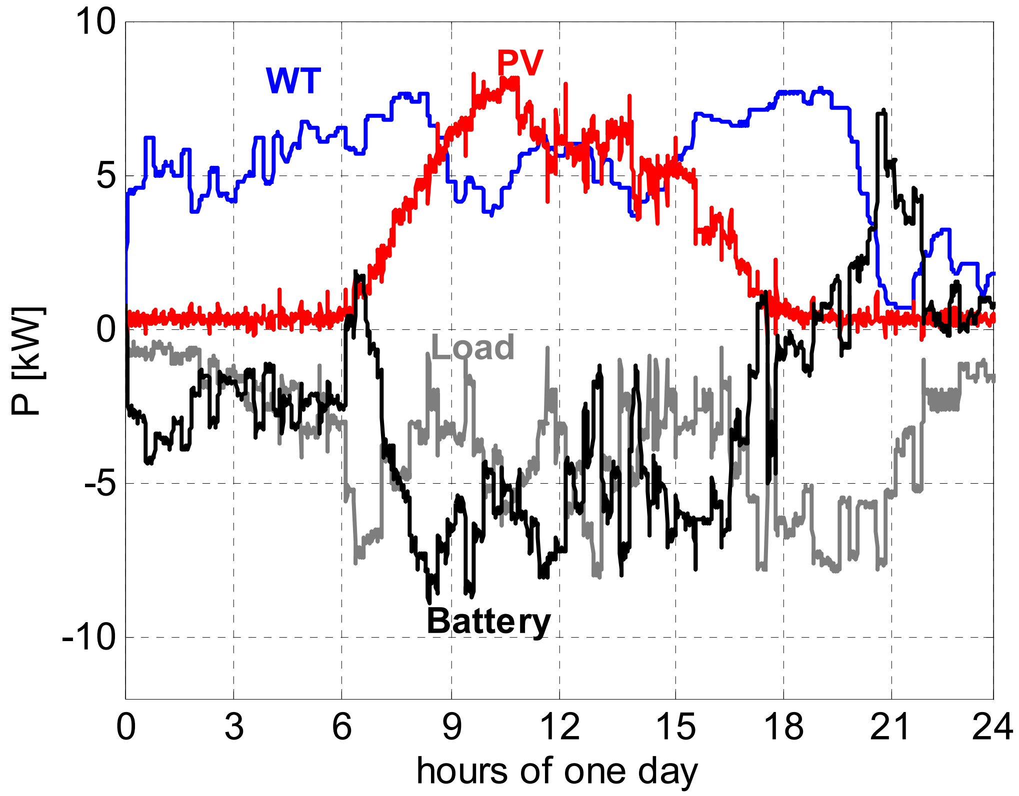


Figure 7-23: DeMoTec measurements of the active power flows

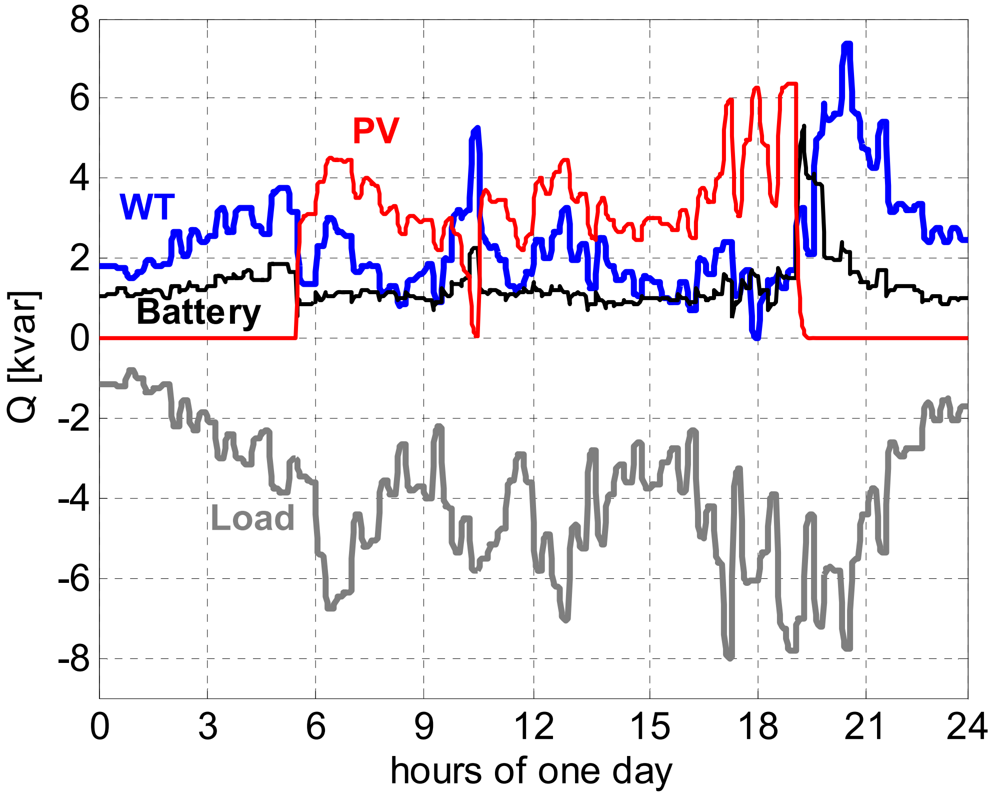


Figure 7-24: PowerFactory Simulation of the reactive power flows

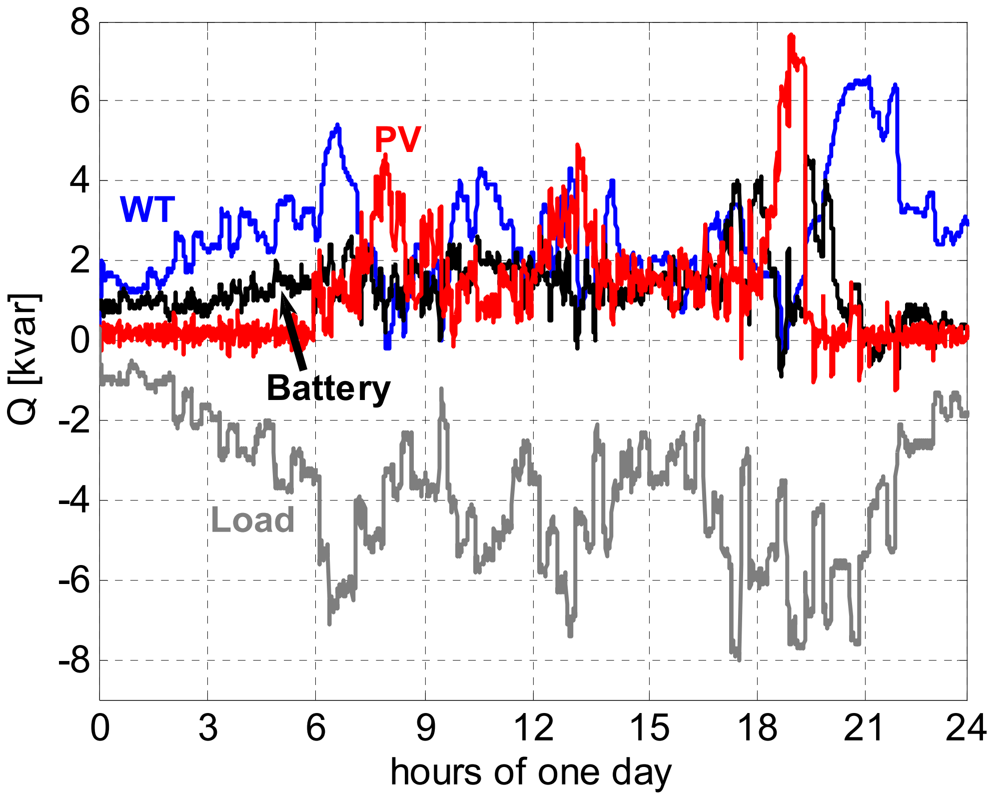


Figure 7-25: DeMoTec measurements of the reactive power flows

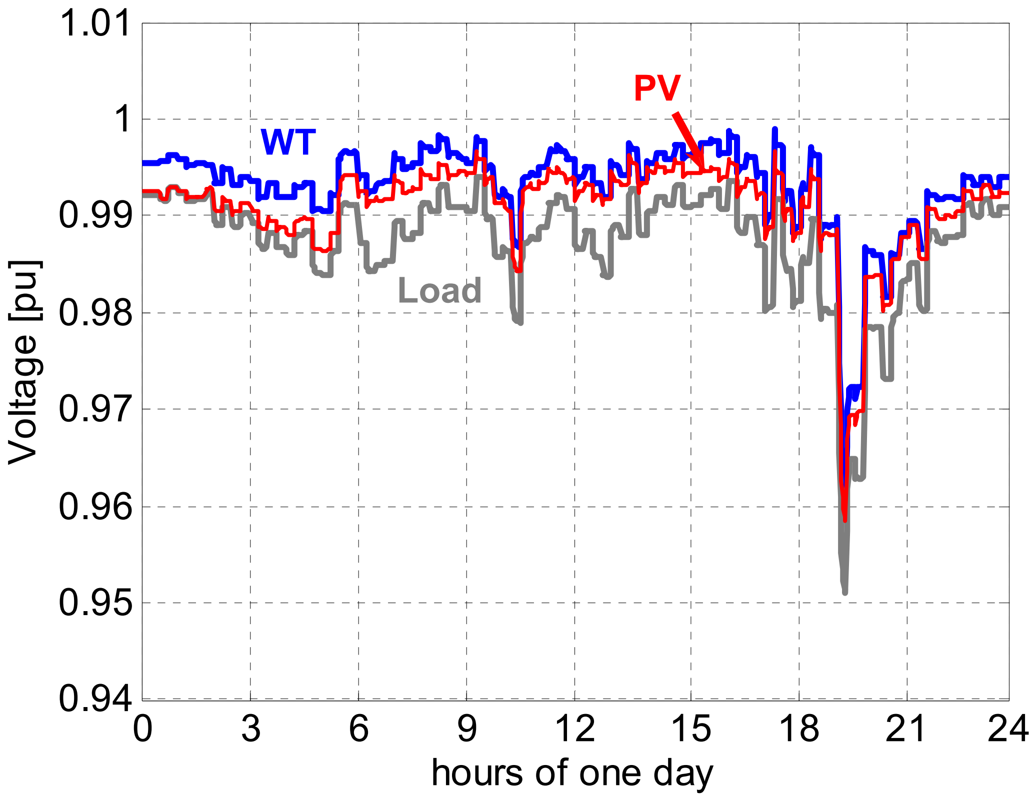


Figure 7-26: PowerFactory Simulation of the voltage profile at different nodes

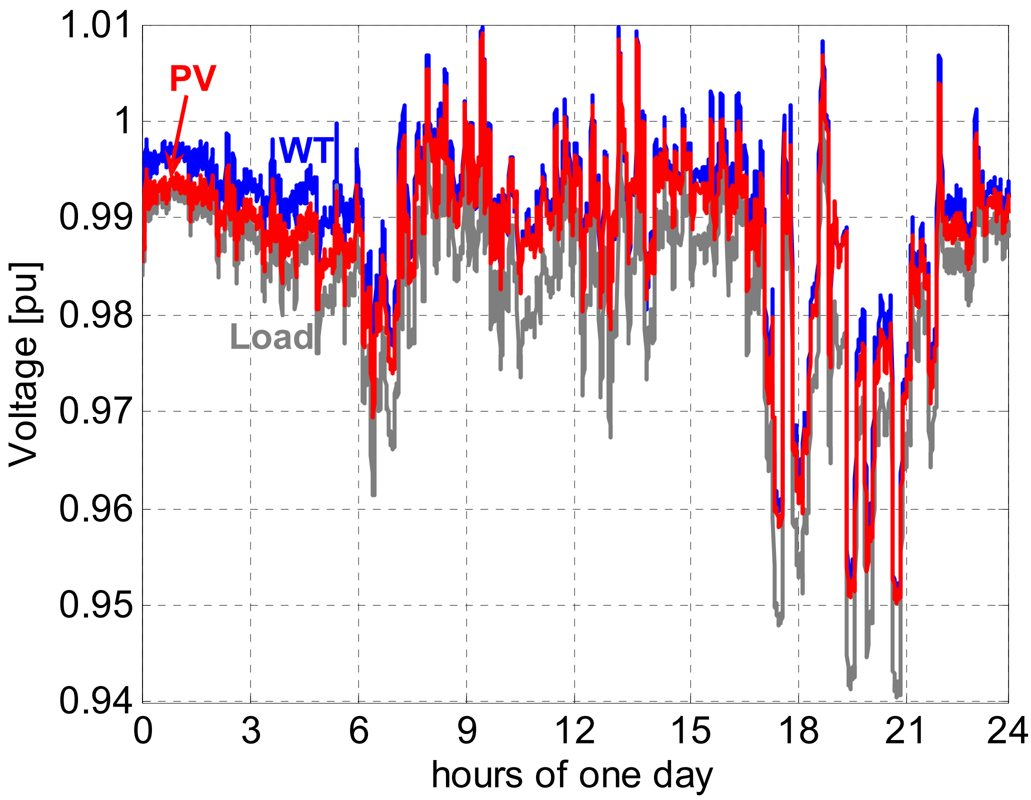


Figure 7-27: DeMoTec measurements of the voltage profile at different nodes

In future the experiment should be repeated with more adequate components for representing the PV system and the load. However, the island network is operated stable and the simulated voltage profile has a similar behaviour as the measured one if the fluctuations with 0.01 pu are taken into account as well.

In the simulation 76% and in the measurement 75% of the reactive power demand is supplied by the PV system and the WT. This reduction of reactive power supply by the battery inverter can reduce considerably the costs compared to the conventional way of reactive power supply. An example of the economic benefit is given in Section 6.3. Also the reactive power capacity and therewith the redundancy is enhanced significantly by including generating units into reactive power supply services. Another benefit is that the voltage stays in a narrower bandwidth than in the situation when only the battery inverter supplies reactive power.

## 7.4. Summary of Chapter 7

The experiments show the technical capability of controlling active and reactive power of inverter- and synchronous-generator-coupled distributed energy units in DeMoTec. Different control approaches are implemented and demonstrated in the experimental setup. These are autonomous local (decentralised) control and centralised control with a SCADA system. The droop mode is one particular control mode that allows automatic local primary voltage and frequency control by controllable distributed energy units. The droop mode can be applied in decentralised or centralised control approaches.

These control modes are used to demonstrate two optimisation approaches that minimise the costs of reactive power supply in interconnected network and island network operation. The scenarios are simulated with PowerFactory and the results are compared with measurements of the experimental demonstration in DeMoTec. Both approaches have similar results and complement each other.

The extended control infrastructure allows many more scenarios being demonstrated with modified configurations and control functions. In addition, these experiments can be simulated with PowerFactory in order to prepare, extend and complement the demonstration activities. In future, further components are integrated in the control infrastructure. These are controllable loads and a controllable inverter-coupled generator. They enhance the capabilities significantly and allow using more adequate components for the second experiment.

# 8. Conclusions and Recommendations for Further Research

The future power system may have a large number of distributed generators and variable power generation from renewable energy resources. Many approaches are investigated that may facilitate the system integration of controllable distributed energy units with the aim of improving the efficiency and security of the system operation. A set of definitions and a structure for basic aggregation approaches is proposed in Chapter 2 on the basis of a literature review.

Operators of controllable distributed energy units can provide services for the operation of the public network by autonomous operation, or by letting them be aggregated technically in private active customer networks or public active distribution networks. Finally, operators of controllable distributed energy units can also hand over the control of the unit to a commercial aggregator (e.g. a VPP operator) who is contracted to sell possible services to other parties of the power system.

The proposed structure for basic aggregation approaches provides a framework for further analyses on the integration of distributed energy resources and loads as well as renewable energy resources in future power systems.

Presently, ancillary services are mainly provided from large power plants to the transmission network operator. In future also ancillary services can be provided by controllable distributed energy units to active distribution network operators. Chapter 3 characterises ancillary services that can be provided by controlled distributed energy units to distribution and transmission network operators.

The characterisation is considered as a reference for further analyses, esp. in the presented work, because the definitions and regulations are not harmonised yet and are different from country to country and network to network.

The technological capabilities of providing ancillary services by distributed energy units depend mainly on the type of unit and its grid-coupling converter. Many studies are available that investigate partly the capabilities but not comprehensively. Chapter 4 proposes an assessment approach that considers the grid-coupling converter separately and allows providing a comprehensive overview of technological control capabilities of providing ancillary services by distributed generators.

Principally, all types of ancillary services can be provided by controlled distributed generators. Limitations such as availability of single units with variable power generation can be reduced by technical aggregation and inclusion of advanced forecast approaches. Further limitations exist for thermally-driven combined heat and power systems that cannot control active power without additional storage equipment. Distributed generators that are coupled directly with induction generators cannot control reactive power without additional equipment such as capacitor banks. All other systems can provide the full range of ancillary services with the exception of power quality that only can be improved by inverters or doubly-fed induction generators. Generally, inverter-coupled distributed generators can be controlled and equipped to provide the full range of ancillary services.

This comprehensive assessment of technological control capabilities of distributed energy units shows the large technical potential that is available to support network operation by provision of ancillary services. Individually looked at, single units can have restrictions but aggregated a portfolio of different units reduces or even compensates these disadvantages. The results are purely from a technological perspective. But on this basis, the economic potential can be analysed in order to indicate those units that can provide ancillary services most economically.

Based on the technological potential, the economic potential of distributed generators is analysed in Chapter 5 with regard to frequency control and reactive power supply. Assessment approaches are developed and cost-benefit-analyses are performed.

An assessment approach is developed that allows performing a cost-benefit-analysis of the participation on frequency control services markets by distributed generators that use renewable energy sources and receive feed-in tariff reimbursements in Germany. The cost-benefit-analysis shows two main results. On the one hand, the participation in primary control, positive secondary control, and positive tertiary reserve is presently not attractive for the analysed units because the required reduced power generation causes high opportunity costs. On the other hand, the participation in negative secondary control and negative tertiary reserve can be attractive because the basic operation mode is not changed.

Not analysed here is the potential of re-dimensioning generation units in order to optimise their participation on frequency control markets. Especially, biomass plants and hydro power plants have potentials to reduce their capacity costs for low frequency services by decoupling power generation from pre-processes. Also the internalisation of external costs, esp. of $CO_2$-emissions, can change the situation significantly. These changes in framework conditions should be analysed in further studies.

An assessment approach is developed that allows determining the investment and operational costs of reactive power supply. Investment costs caused by additional capacity requirements and variable operational costs caused by additional losses are looked at in detail for distributed generators and their different types of grid-coupling converters. The generalised method and the technical implementation of the assessment of operational losses of reactive power supply are under examination to grant patent rights. In particular, the variable operational costs are analysed for distributed generators that are grid-coupled with inverters, synchronous generators and doubly-fed induction generators. Compared to the costs of conventional reactive power sources, distributed generators are evaluated to be cost competitive in general, especially when they increase their reactive power capacity modestly and share reactive power supply between each other so that reactive power supply causes only small additional loading levels.

Including the capabilities of reactive power supply and their costs in network calculations allows assessing the optimal placement of reactive power capacity and the cost-efficient supply of reactive power. Further investigations should evaluate the real potential of distributed generators in network studies that consider the full relevant power system and the possible distribution of generators and alternative reactive power supply equipment.

Additional cost categories are discussed in the economic assessment: ICCT infrastructure, transaction costs and external costs. These costs are difficult to estimate in general. They need to be taken into account in further investigations in order to complete the picture of the economic potential of providing ancillary services by distributed generators. Moreover, studies are necessary that analyse the economic potential of other types of ancillary services and other types of economic framework situations. Also the consideration of all types of controllable distributed energy units is required in further investigations. Loads and storage systems have an interesting economic potential that should be analysed as well.

The cost-benefit-analysis of reactive power supply shows the large range of variable operational costs depending on the amount of reactive power supply, the actual active power generation, the available reactive power capacity and the type of distributed generators and their grid-coupling converters. In order to reduce the costs of reactive power supply, different approaches can be considered that distribute reactive power supply between participating units adequately. Two optimisation approaches are discussed in Chapter 6. The lowest operational costs of reactive power supply can be obtained by centralised control approaches that are based on the full knowledge of network operators on the cost structure of all devices. However, also decentralised approaches result in significant reductions of the costs without the need of knowing exactly the cost structure and having a continuous communication between the controller and the component.

The droop mode that couples voltage and reactive power is further developed and modified droop functions are applied in order to integrate information on the cost structure of the different components. In particular in hybrid systems and mini-grids reactive power supply can be extended from grid-forming units to grid-tied units by application of the modified droop concept. This extension reduces the costs but also increases the redundancy and by relieving the grid-forming unit also the reliability of the system. Calculations with the network simulation software PowerFactory from DIgSILENT and MATLAB® from The MathWorks show considerable cost reductions.

Each of the analysed optimisation approaches can be further developed, e.g. with regard to optimised droop parameters. Improved concepts allow further cost reductions. Especially hybrid approaches that apply in parallel centralised and decentralised optimisation approaches are promising. Also the implementation of such optimisation approaches in real network operation is a challenging task that has to be investigated in the future.

A control system is developed that allows demonstrating centralised and decentralised control approaches in ISET's Design-Centre for Modular Supply Technology (DeMoTec). The centralised and decentralised optimised reactive power supply is demonstrated and first results are presented in Chapter 7. The experiments show the technical feasibility of controlling active and reactive power by distributed energy units that are coupled by inverters and synchronous generators in DeMoTec. Two control approaches are implemented and demonstrated in the experimental setup. These are autonomous local (decentralised) control and centralised control with a SCADA system. The two scenarios are simulated with PowerFactory and the results are compared with measurements of the experimental demonstration in DeMoTec. Both study approaches have similar results and complement each other.

The extended control infrastructure allows many more scenarios being demonstrated with modified configurations and control functions. In addition, these experiments can be simulated with PowerFactory in order to prepare, extend and complement the demonstration activities. In future, further components are integrated in the control infrastructure. These are controllable loads and a controllable inverter-coupled generator. They enhance the capabilities significantly and allow using adequate components for the experiments.

**According to the investigations in the presented thesis, controllable distributed generators have the technological potential to provide ancillary services. They also have an attractive economic potential that can be used to full capacity by different types of technical and commercial aggregation approaches. Thereby, distributed generators can substitute conventional power plants, not only in terms of active power generation but also in terms of providing ancillary services.**

**Distributed energy units can be integrated in network operation contributing to cost-efficient and secure power system operation. A future power system based on a significant share of distributed generators and renewable energy sources seems to be feasible, not only technically but also economically.**

# I. Annex: PowerFactory Models

The PowerFactory simulations in this work use simplified models of grid-tied and grid-forming distributed energy units. These simplified models are sufficient in the presented studies because mainly the energy flow is of interest. The dynamics analysed consider the behaviour over one day that represents the changes in variable power generation and load consumption. Therefore, the Balanced RMS Simulation that is based on effective values is used as the calculation method in the time-domain simulation. *“The balanced RMS simulation function considers dynamics in electromechanical, control and thermal devices. It uses a symmetrical, steady-state representation of the passive electrical network. Using this representation, only the fundamental components of voltages and currents are taken into account”* [DIgSILENT 2008].

The grid-tied distributed energy unit is modelled by making use of the general PowerFactory load model (ElmLod) [DIgSILENT 2007a] as depicted in Figure A-1. In RMS Simulation, the load model has two input variables *Pext* and *Qext* that allow controlling the active and reactive power of the ‘Load’. They can also be set to negative values that allow representing generators that inject power to the network. The set value profile for active power *P* and reactive power *Q* over the time is provided by the measurement file object (ElmFile) ‘PQ Profile’. Measurement data of active power *Pmeas* and reactive power *Qmeas* at the grid connection point of the energy unit is delivered by the ‘Power Measurement’ device (StaPqmea). Having the set values and the measurement data allows applying a standard control function with a proportional plus integral (PI) controller with the gain and the integration time constant as the parameters to influence the dynamic control behaviour. The ‘PI controller’ is programmed as a Block Definition (BlkDef) in the DIgSILENT Simulation Language (DSL).

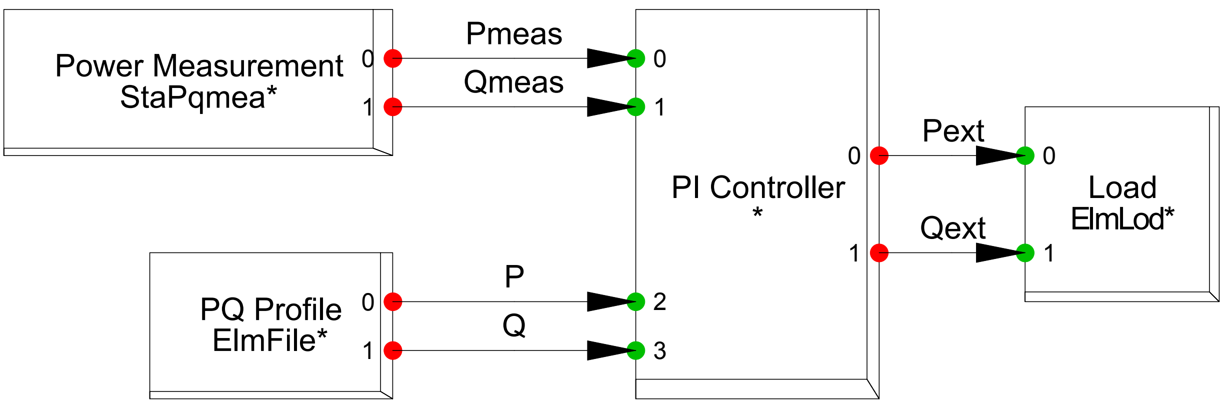


Figure A-1: PQ-controlled model in PowerFactory for grid-tied distributed energy units

The grid-tied distributed energy unit may also have a droop function implemented that changes the reactive power supply according to the terminal voltage. Figure A-2 shows the modified model with the voltage measurement device (StaVmea) 'Voltage Measurement' that measures the voltage *u* at the terminal. Based on this voltage signal, the 'Droop Function' that is implemented as a Block Definition (BlkDef) in DSL calculates the corresponding reactive power *Qt*. According to possible limitations of reactive power supply due to the maximum capacity another Block Definition (BlkDef) is implemented in DSL that is named 'Limits Dynamics' that changes the target values *Pt* and *Qt* according to the unit's control limitations to the set values *P* and *Q.*

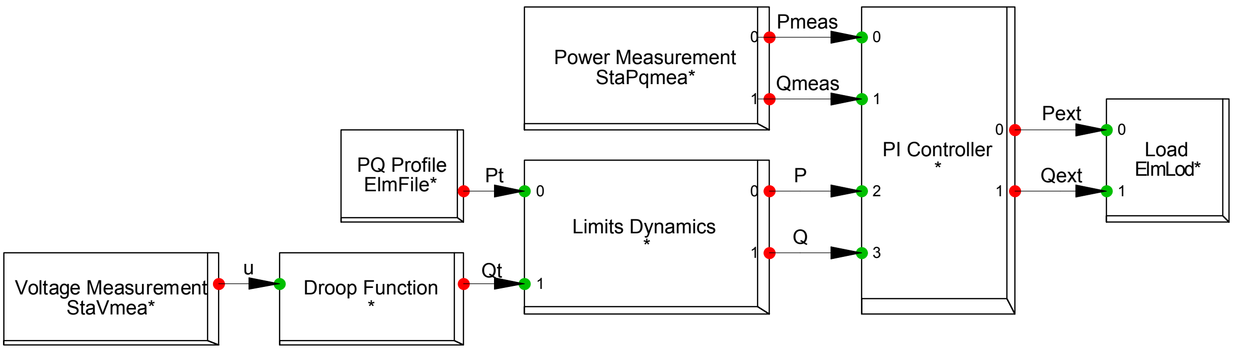


Figure A-2: PQ-controlled model in PowerFactory for grid-tied distributed energy units with droop function

The grid-forming distributed energy unit, e.g. the battery inverter, is modelled by making use of the general voltage source model (ElmVac) that is grid-connected with a reactor (see Figure A-3). In RMS Simulation, the voltage source has the voltage magnitude *u0* as input variable. The voltage of the voltage source can thereby be controlled based on the reactive 'Power Measurement' device (StaPqmea) for *q* at the terminal. The 'Voltage Controller' that is implemented as a Block Definition (BlkDef) in DSL calculates the corresponding voltage magnitude with the implemented droop function.

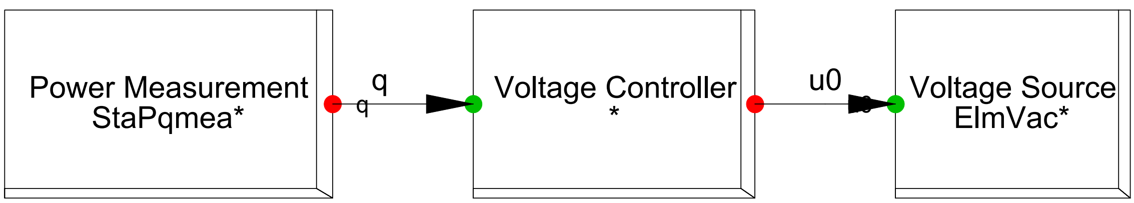


Figure A-3: V-controlled model in PowerFactory for grid-forming distributed energy units with droop function

Figure A-4 shows the graphical representation of the grid-tied model (PV) and the grid-forming model (Battery) in the PowerFactory network graphic as an example.

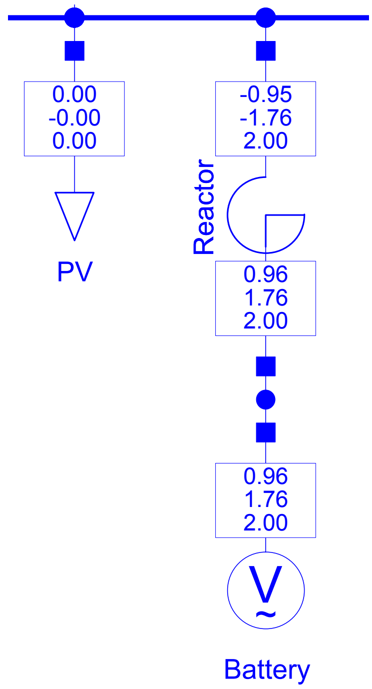


Figure A-4: Example of the graphical representation of the grid-tied model (left) and the grid-forming model (right)

# II. Annex: Characterisation of Ancillary Services

This annex provides a characterisation of ancillary services as used in the thesis. It extends Chapter 3 with more detailed descriptions on

- Frequency control,
- Voltage control,
- Congestion management,
- Improvement of power quality,
- Reduction of power losses,
- Black start, and
- Islanded operation.

## II.1. Frequency Control

The frequency is managed by a combination of continuous and occasional response services. Continuous response is provided by generation equipped with appropriate governing systems which control their outputs to neutralise the frequency fluctuations which arise from relatively modest changes in demand and generation. The objective of occasional response is to reduce significant and abnormal frequency excursions, which are caused by sudden mismatches in the generation/demand balance.

The commonly used term “frequency control” subsumes different control approaches that are illustrated in Figure II-1:

- Direct frequency control,
- Primary power/frequency control,
- Secondary power/frequency control, and
- Tertiary power/frequency control.

Nearly each country has its own definitions and specifications of active power reserve services [Rebours;Kirschen 2005a]. Here, the definitions of the Union for the Co-ordination of Transmission of Electricity (UCTE) are used [UCTE 2004].

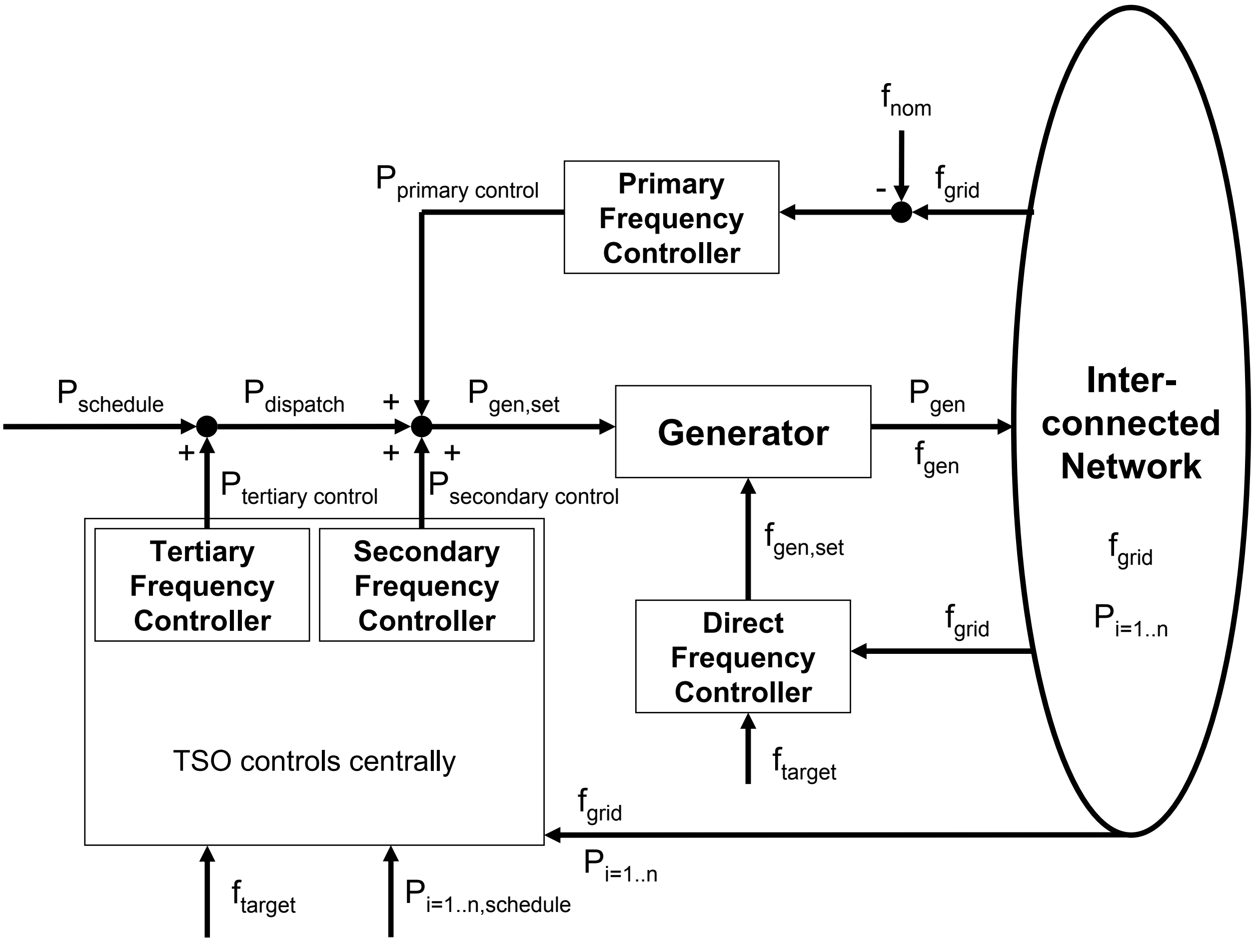


Figure II-1: Organisation of frequency control

### II.1.1. Direct Frequency Control

Prime mover speed control is fundamental for all directly-coupled synchronous generators in the power supply system because the turbine speed is proportional to the electrical grid frequency. Direct frequency control is possible by use of speed control. Inverter-coupled distributed generators have to be controlled specifically to emulate the speed control of synchronous generators as they are so called “static” generators. The direct frequency control is necessary in case of black start or islanded operation (see Table 3-1) because the grid-forming generators control their electrical frequency $f_{gen}$ in order to establish the target frequency $f_{target}$ as the grid frequency $f_{grid}$ (see Figure II-1). In addition, grid-formers have to control the voltage (see Section II.2.1).

Direct frequency control is a fundamental ancillary service for electrifying an electrical network by grid-forming units. If the electrical frequency is established and stable the power/frequency control is applicable.

### II.1.2. Power/Frequency Control

Power/Frequency Control does not control the speed of the generator but the active power generation. Because of the typical static regulation characteristic of a power system formed by synchronous generators the increase of active power generation leads to a decrease of the network frequency (as well as the speed of the connected synchronous generators) and vice versa. The detailed power/frequency control is described in [Saccomanno 2003]. If one generator only constitutes a small capacity compared to the full system capacity it cannot influence the frequency directly by changing the generator's speed but indirectly it can influence the grid frequency $f_{grid}$ by changing the active power generation $P_{gen}$.

Power/Frequency control is structured hierarchically in primary, secondary and tertiary control. Primary control aims at stabilising the frequency in case of power imbalances. Secondary control aims at bringing back the frequency to its target value and thereby restoring the primary control reserve. Tertiary control, finally, restores secondary control reserve and brings back the interchange programs between control areas to their target schedules.

#### *II.1.2.1. Power/Frequency Control*

"*The objective of primary control is to maintain a balance between generation and consumption within the synchronous area, using turbine speed or turbine governors. By the joint action of all interconnected undertakings, primary control aims at the operational reliability of the power system of the synchronous area and stabilises the system frequency at a stationary value after a disturbance or incident in the time-frame of seconds, but without restoring the reference values of system frequency and power exchanges*" [UCTE 2004].

Primary power/frequency control is a decentralised automatic active power control. Governors change the active power output of a generator by $P_{primary\ control}$ depending on the deviation of the grid frequency from its nominal value $f_{grid}$ - $f_{nom}$ in order to balance demand and generation (see Figure II-1).

Figure II-2 shows that the generated active power is reduced from the rated active power $P_n$ to $P = P_n – \Delta P$ if the frequency deviates from the rated frequency $f_n$ to $f = f_n + \Delta f$. This is called high frequency response as the frequency is higher than the rated frequency. Analogously, the injected active power is increased from the rated active power $P_n$ to $P = P_n + \Delta P$ if the frequency deviates from the rated frequency $f_n$ to $f = f_n - \Delta f$. This is called low frequency response as the frequency is lower than the rated frequency. Due to this droop function of the generators the system's frequency stabilises on a new level. The reaction time has to be within less than 30 seconds and active power is controlled linearly if the frequency deviation exceeds +/- 20 mHz up to

+/- 200 mHz when the full secondary frequency control reserve is activated [UCTE 2004].

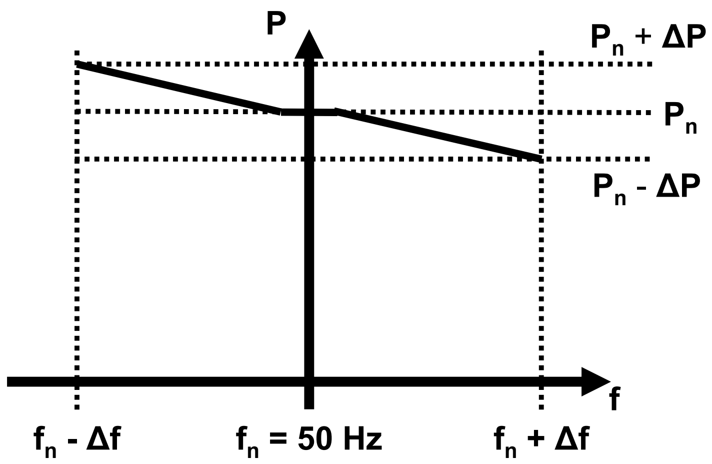


Figure II-2: Active power/frequency droop

*II.1.2.2. Secondary Power/Frequency Control*

"*Secondary control maintains a balance between generation and consumption within each control area as well as the system frequency within the synchronous area, taking into account the control program, without impairing the primary control that is operated in the synchronous area in parallel but by a margin of seconds. Secondary control makes use of a centralised automatic generation control, modifying the active power set points in the time-frame of seconds to typically 15 minutes. Secondary control is based on secondary control reserves that are under automatic control. Adequate secondary control depends on generation resources made available by generation companies to the TSOs*" [UCTE 2004].

The secondary frequency control is an automatic control that is centrally coordinated by the Transmission System Operator (TSO). Due to the central coordination the lead time is longer up to several minutes but allows a frequency recursion. Because the frequency is normally not at its nominal value the control is nearly all the time active aiming at reaching the target but normally disturbed by further imbalances.

The TSO analyses the grid frequency $f_{grid}$ compared to the target grid frequency $f_{target}$ and the area control error that is derived from the actual power flows $P_{i=1..n}$ compared to the scheduled power flows $P_{i=1..n,schedule}$. An automatic PI control function that is applied at the TSO control centre activates secondary control reserve $P_{secondary\ control}$ of the participation generators and releases thereby activated primary control reserve.

#### *II.1.2.3. Tertiary Power/Frequency Control*

"*Tertiary control uses tertiary reserve {15 minute reserve} that is usually activated manually by the TSOs after activation of secondary control to free up the secondary reserves. Tertiary control is typically operated in the responsibility of the TSO*" [UCTE 2004].

Different to the automatic secondary frequency control, the tertiary frequency control is manually activated but also centrally coordinated by the TSOs. This causes even longer lead times of, for instance, 15 minutes.

The TSO analyses the area control error that is derived from the actual power flows $P_{i=1..n}$ compared to the scheduled power flows $P_{i=1..n,schedule}$. Manually, the TSO activates tertiary control reserve $P_{tertiary\ control}$ of the participation generators that substitutes activated secondary control reserve. The actually dispatched active power generation $P_{dispatch}$ changes then from the scheduled active power generation $P_{schedule}$ to $P_{schedule}$ + $P_{tertiary\ control}$.

### II.2. Voltage Control

In any AC power system the voltage and current are, normally, not in phase. Hence, reactive power will flow. Reactive power is considered as being absorbed by inductive components (e.g. transformers, overhead lines, induction machines) and generated by capacitive components (e.g. over-excited synchronous machines and capacitors).

The reactive power flow can be compensated with sources and sinks of reactive power, e.g. synchronous generators, shunt capacitors, shunt reactors, synchronous condensers, and static var compensators, as well as line reactance compensators such as series capacitors. This compensation of reactive power reduces the voltage fall over the network impedances. Moreover, the voltage variation caused by the active power flow can be compensated by supplying reactive power because capacitive currents cause a voltage rise while inductive currents cause a voltage drop. Consequently, a control in both directions is possible [Kundur 1994].

In a high voltage grid whose reactance exceeds its resistance, reactive power transfer depends mainly on voltage magnitudes (cf. Chapter 3.2). It is transmitted from the side with higher voltage magnitude to the side with lower voltage magnitude. Reactive power cannot be transmitted over long distances since it would require a large voltage gradient to do so. Therefore, voltage control has to be locally distributed.

The commonly used term “voltage control” subsumes different control approaches that are illustrated in Figure II-3:

- Direct voltage control,
- Primary power/voltage control,
- Secondary power/voltage control, and
- Tertiary power/voltage control.

### II.2.1. Direct Voltage Control

Grid-forming generators have to provide direct voltage control by defining the terminal voltage value. This voltage is reduced due to the voltage fall over the grid impedances until the power flow reaches the sinks (loads). In between, voltage levels can be changed via transformers. These transformers (regarded as sinks for the upper voltage level and regarded as sources for the lower voltage level) can change their winding ratio by tap changers to set a new starting voltage value for the lower voltage grid.

If the grid voltage is established by grid-forming units, the indirect control of voltage by apparent power injection and extraction can be applied. This indirect control is called power/voltage control and can be separated in three control levels as described in the following.

### II.2.2. Power/Voltage Control

Maintaining voltages within tolerances is an absolute technical obligation for DNOs. If voltages are found to be outside statutory limits (e.g. EN-50160), DNOs must remedy such situations or interrupt supplies to customers. The voltage can be changed indirectly (see Section 3.2) by power extraction/injection because this changes the power flows through the grid impedances [Kundur 1994].

Three different levels of voltage control can be distinguished and are explained in the following subsections:

- Primary power/voltage control,
- Secondary power/voltage control, and
- Tertiary power/voltage control.

The explanations (as well as Figure II-3) focus on reactive-power/voltage control that is the most common approach of voltage control. It should be kept in mind that also active power control can influence the voltage and may be controlled in addition to provide optimal control results.

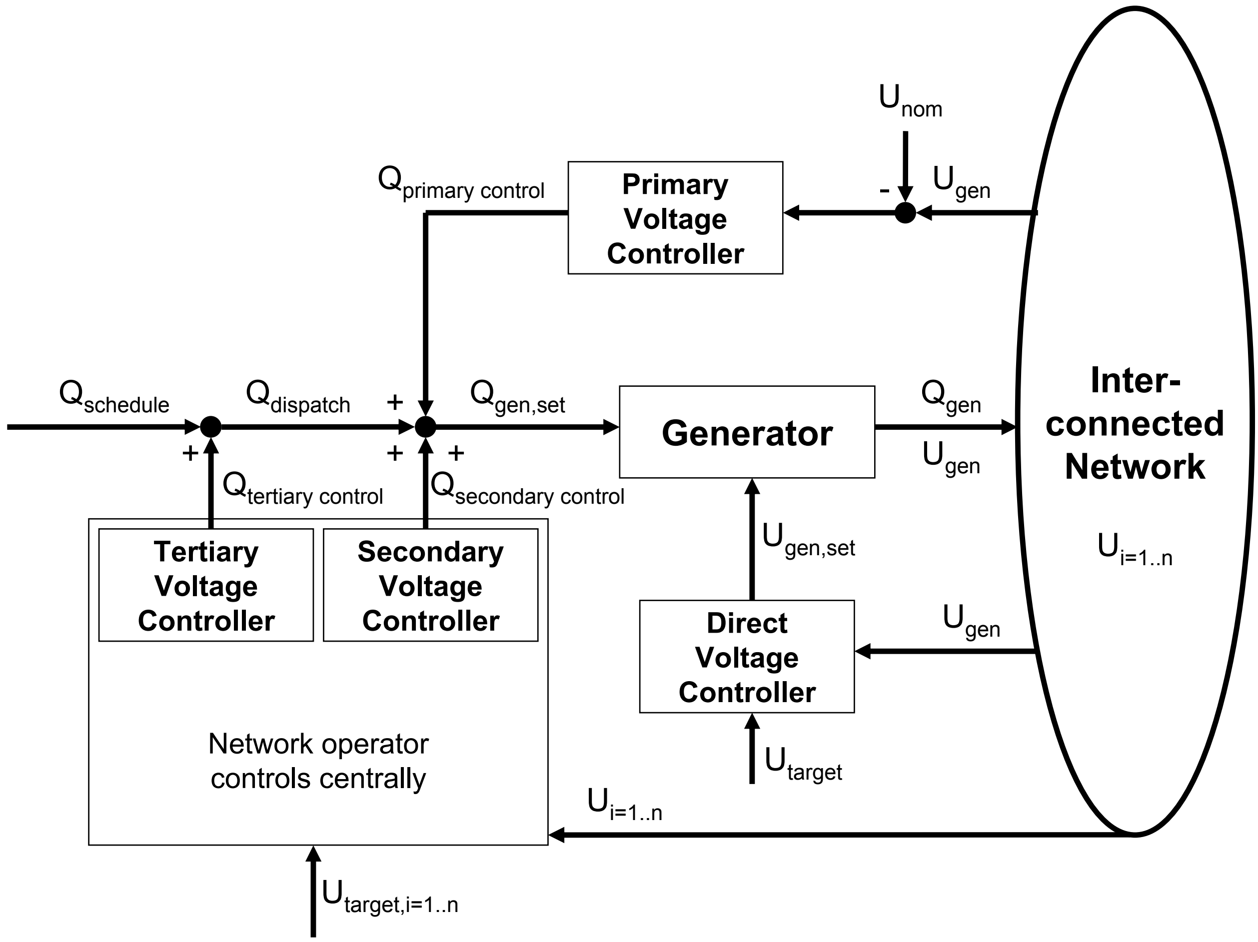


Figure II-3: Organisation of voltage control

### *II.2.2.1. Primary Power/Voltage Control*

Similar to primary frequency control, primary voltage control is an automatic local control of the reactive power source itself. Generally, droop functions as given in Figure II-4 are applied to stabilise the voltage at the unit's terminal by feeding-in capacitive currents up to $+\Delta Q$ if the voltage reaches its minimum acceptable limit of $U_n - \Delta U$. In contrast, if the voltage reaches its maximum acceptable limit of $U_n + \Delta U$ inductive currents of $-\Delta Q$ are injected. These reactive power control actions have indirectly an influence on the voltage within seconds or even faster.

According to Figure II-3, the reactive power set point of the generator is adjusted by $Q_{primary\ control}$ that is calculated from the difference between the nominal voltage value $U_{nom}$ and the actual value $U_{gen}$ according to the applied droop function.

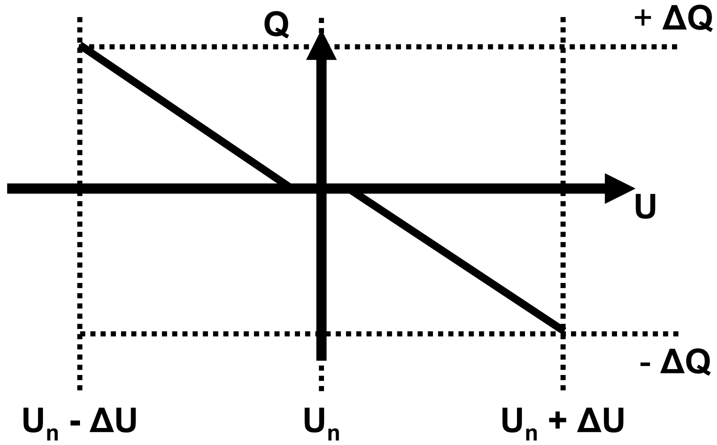


Figure II-4: Reactive power / voltage droop

### *II.2.2.2. Secondary Power/Voltage Control*

Secondary Voltage Control "*consists on the measurements of the voltage magnitude in some critical buses of the system, these buses are known by the operator as the result of its experience in the control of the system. So, if the voltages at these buses are out of range, the operator is going to change the settings points of the voltage regulators (generators) in order to recover a voltage profile in the normalised interval. The time response of the voltage secondary control goes up to one minute and less than several minutes*" [CRISP 2004].

The secondary power/voltage control analyses measured voltages at critical grid nodes $U_{i=1..n}$ compared to the target values $U_{target,i=1..n}$ and calculates the required reactive power $Q_{secondary\ control}$ that brings theses voltages back to the target values (see Figure II-3). Similar to secondary power/frequency control, also secondary power/voltage control is controlled centrally but automatically in the control centre of the network operator.

### *II.2.2.3. Tertiary Power/Voltage Control*

Tertiary Voltage Control is used by the network operator. The network "*operator optimises, with it, the system voltage profile and provides reference values of the secondary voltage control. Normally the tertiary control operates in a 15 minutes cycle*" [CRISP 2004].

The tertiary power/voltage control is applied in the control centre of the network operator who calculates changes $Q_{tertiary\ control}$ of the reactive power control schedule $Q_{schedule}$ in order to modify the reactive power dispatch $Q_{dispatch}$ in such way that the voltage profiles are optimised (see Figure II-3).

### II.3. Congestion Management

The security of supply is in danger if the current of grid components exceeds over a certain time period its maximum value. Congestion management is applied in the control centre of the network operator in order to find these critical components in the observed grid and solve the congestions. Three different approaches are applied in congestion management:

- network reinforcement,
- reconfiguration of the network, or
- re-dispatch of the power flows of controllable energy units.

### II.4. Improvement of Power Quality

[IEC 60050-617] defines ‘quality of the electricity supply’ as the *“collective effect of all aspects of performance in the supply of electricity […] The quality of the electricity supply includes security of electricity supply as a prerequisite, reliability of the electric power system, power quality and customer relationships*”. This corresponds to the three general dimensions of the quality of service in electricity supply according to the Council of European Energy Regulators [CEER 2001]:

- commercial quality (or customer relationships),
- continuity of supply (or reliability), and
- voltage quality or (power quality).

The commercial quality concerns the quality of relationships between a supplier and a customer and can be neglected here because it cannot be considered as an ancillary service of controllable energy units.

The ‘reliability’ of an electric power system is defined as the “*probability that an electric power system can perform a required function under given conditions for a given time interval*” [IEC 60050-617]. Continuity of supply (reliability) is characterised by the number and duration of interruptions. Different indicators are used to evaluate the continuity of supply, e.g. interruption frequency [1/year], interruption duration [minutes/interruption] and unavailability of supply [minutes/year]. The continuity of supply can be actively increased by making use of voltage control and frequency control services as well as services for congestion management. In active customer and distribution networks islanded operation can also be considered as an ancillary service that increases continuity of supply in critical grid-connected situations (see Section II.7).

Also the third aspect of the quality of service, the power quality (voltage quality), has an influence on the continuity of supply because in case of insufficient voltage quality sensitive customer's equipment can disconnect or be damaged. 'Power quality' is defined as the "*characteristics of the electric current, voltage and frequencies at a given point in an electric power system, evaluated against a set of reference technical parameters*" [IEC 60050-617]. It is in the focus of this section.

Non-linear currents cause a non-linear voltage fall across the grid impedance which is superposing the ideal sine curve. Electrical equipment such as switching power supplies cause harmonic spectra that endanger the tripping of other sensitive equipment. A selective compensation of harmonics can prevent additional voltage drop, additional loading, and additional losses and improve the power quality.

The EN 50160 describes the expected voltage characteristics in low and medium voltage networks, under normal operating conditions. The main parameters of power quality are frequency, voltage magnitude and its variation, voltage dips, temporary or transient overvoltages and harmonic distortion.

The impact of the improvement of power quality is limited to a local network region. In active customer and distribution networks that are decoupled or operated as islands, e.g. highly-sensitive industry networks, it is possible to improve power quality actively by reducing or even compensating voltage/current disturbances. This has been demonstrated in [DGFACTS 2005] and [Jahn 2007]. By introducing a (de)coupling serial inductor in the network connection, voltage quality improvements can be achieved by parallel connected devices. The voltage in a local area can be (within certain limits) controlled independently of the grid voltage and sensitive loads can benefit of the lowly distorted voltage profile.

In addition to the selective improvement of power quality in decoupled or islanded networks, also a non-selective improvement of the voltage in the (entire) network can be achieved if sufficient distributed energy resources improve power quality. The resulting effect depends on the composition of the grid impedance [Jahn 2007].

## II.5. Reduction of Power Losses

The main objective of the optimisation/minimisation of power losses is to reduce the costs of the power transmission and distribution due to transmission and distribution losses. IEC 60287 provides a standard for the determination of line losses. The line losses $P_L$ can be calculated with the simplified equation:

$$P_L = P'_L \cdot l = 3 \cdot R' \cdot I^2 \cdot l = 3 \cdot R' \cdot \left( \frac{S}{\sqrt{3}U} \right)^2 \cdot l = \frac{R' \cdot (P^2 + Q^2)}{U^2} \cdot l \qquad \text{(II-1)}$$

The specific resistance *R'* and the length *l* is given by the line's characteristics and the current *I* is expressed by the active power flow *P* and the reactive power flow *Q* over the line with a voltage level *U*. This equation shows that the line losses are basically dependent on the:

- length of the line *l*,
- resistance of the line *R'*,
- active power flow over the line *P*,
- reactive power flow over the line *Q*, and
- the voltage level of the line *U*.

Whilst the losses due to the resistance, the length and the voltage level can only be optimised during the network planning process, the losses due to active and reactive power flows can be optimised during the operation by power dispatch strategies.

## II.6. Black Start

Power system restoration is the procedure for recovery from total or partial shutdown of electrical supplies in a network area. [Ancona 1995] provides a compilation of reviewed papers resulting in a framework for power system restoration. He proposes the following sequence of restoration actions:

1) Start restoration
2) Prepare initial cranking source
3) Prepare restoration path
4) Build stable sub-system (here: black start)
5) Tie island sub-system into bulk power system
6) Tie neighbouring island sub-systems together
7) Restore unsupplied load
8) Follow-up after restoration

[Pham et al 2005] and [Pham et al 2006], for instance, present a restoration procedure with the inclusion of a large scale of distributed generation. The "deep build - together" strategy is proposed to simultaneously consider this rebuilding in the distribution and transmission network in order to serve the maximum of customers in a minimum of time.

Black start capability is the ability of a generating unit to go from a shutdown condition to an operating condition and start delivering power without assistance from the network. Power plants need for start up some form of independent auxiliary supply (cranking source) with sufficient capacity to supply the unit's auxiliaries while the main generator is prepared for operation. This additional power source is usually provided by a smaller peripheral black start generating plant, which is started from a battery or other energy storage device. Once operational, the power plant can then be used to energise part of its local network, providing supplies for other plants within the area to enable them to start up. Two ancillary services are of particular importance for a black start: direct frequency control and direct voltage control. Black start only works if the unit is able to define the voltage form by its magnitude and its frequency and only if it has the active and reactive power capacity to provide the required energy for energising the desired network area. Black start service comprises grid-forming (islanded operation) in which it goes over fluently after starting up.

## II.7. Islanded Operation

Islanded operation is also part of the above mentioned power system restoration process as a follow up of the black start. The capability of islanded operation (grid-forming) has the same requirement of defining the voltage and balancing demand as the black start capability but it does not necessarily include the capability of starting up independently from an existing network. Active customer and distribution networks (cf. Chapter 2) can be operated as an island if grid-forming controllable distributed generators with sufficient capacity are available. These grid-forming generators can be supported by grid-tied generators or loads that operate synchronised to the grid's voltage and provide active and reactive power control for power/frequency and power/voltage control (cf. Subsection II.1.2 and Subsection II.2.2).

# III. Annex: Review on Control Capabilities of Distributed Generators

Annex III reviews the capabilities of DER units, considering

- wind turbine generator (WTG) systems,
- photovoltaic (PV) systems,
- hydroelectric power (Hydro) stations,
- combined cooling, heating and power (CCHP) systems, and
- storage systems,

with focus on their

- active power control capability considering
  - active power availability,
  - active power predictability,
  - system reliability, and
  - capability to control active power,
- reactive power control capability, and
- capability to provide ancillary services as defined in Annex II.

## III.1. Wind Turbine Generator (WTG) Systems

According to IEC 60050-415, a 'wind turbine generator system' is defined as a "*system which converts the kinetic wind energy into electric energy*" [IEC IEV 2008]. Principal WTG designs [CIGRE 2003] are (see also Section 4.1)

- directly-coupled induction generators (IGs) in fixed speed or variable slip design with capacitor banks;
- doubly-fed induction generators (DFIGs) with a power electronics converter between the point of grid connection and the rotor circuit of the IG (designed only with a fraction of the rated power of the IG);
- directly-coupled synchronous generators (SGs) with a dynamic gearbox and with excitation system; and

- inverter-coupled generators with a full power electronics converter (FC) that couples different designs of induction and synchronous generators.

The Wind Energy Report 2005 [ISET 2005] shows for 2004 in Germany that 8% of all WTGs are IGs, 50% are DFIGs and 42% inverter-coupled SGs.

Small WTGs that presently have a small market share are WTGs with a rotor swept area of less than 200 m² [IEC 2006]. Most of the small WTGs use permanently-excited synchronous generators and are grid-coupled with inverters. The other smaller part of manufacturers uses IGs [Kühn 2007]. Further analyses on small WTGs provide [Cano et al 2006].

### III.1.1. Active Power Control Capability

The active power control capability takes into account active power availability, active power predictability, system reliability and the capability to control active power.

#### *III.1.1.1. Active Power Availability*

In Germany, the monthly averaged capacity factor, which relates the actual energy supply to the theoretical maximum energy supply at full load, shows long-term average values of 15% in the months May to August and 30% in the months January and February (see Figure III-1). Over the years 1990 to 2004, the maximum monthly value was 45% and the minimum monthly value 7%. The winter in Germany shows significant more wind than the summer. These values vary significantly for different locations and different installations of individual WTGs.

Figure III-2 presents the percentage frequency over the relative variation in the supplied wind power in Germany. The frequency of power changes increases with increasing time intervals. Extreme values of power changes for 15 minutes intervals are approx. 6%, for 1 hour intervals approx. +12/-17% and for 4 hour intervals approx. +27/-40%. Table III-1 shows the resulting probability of active power changes of [< 1%, < 2%, <5%] for [¼, 1, 4] hour intervals.

The levelling of the power generation in widely spread WTG groups is displayed in Figure III-3 with percentage frequencies. It shows large fluctuations of a single WTG as a result of turbulent local weather conditions and the individual plant behaviour. The aggregation of a group of regional WTGs levels the regional weather variations and shows significantly smaller power variations and gradients of the cumulative power generation. These variations are even more smoothed considering the cumulative output of all German WTGs and the compensation of regional weather situations.

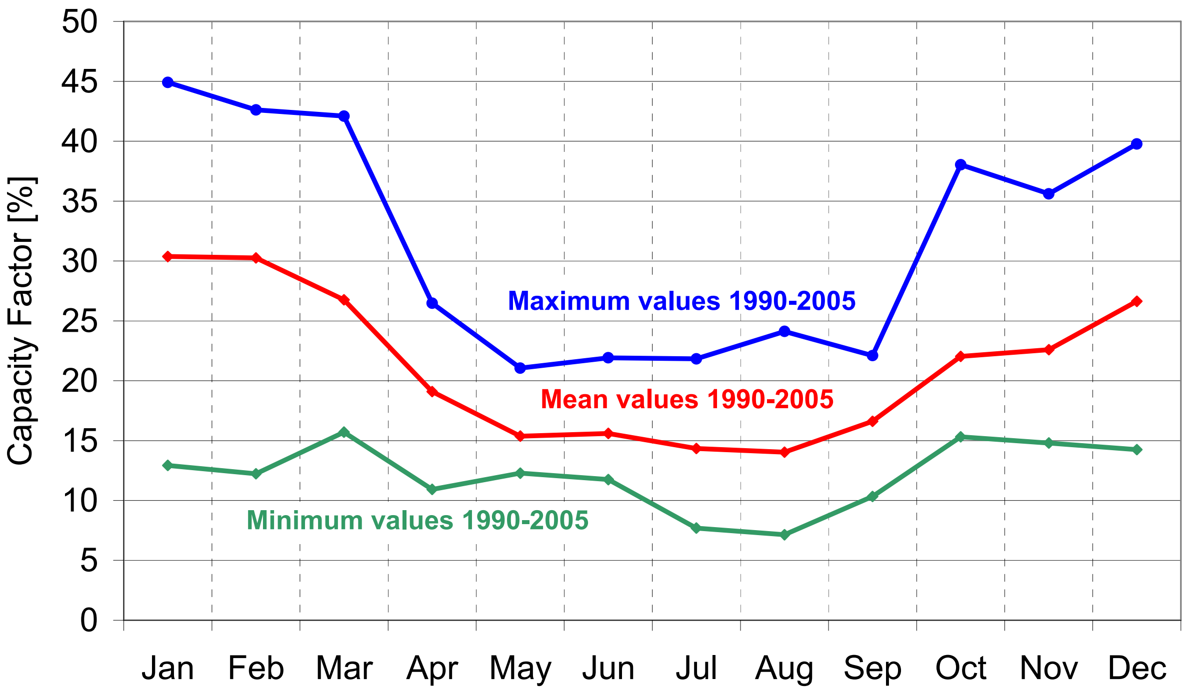


Figure III-1: Monthly averaged capacity factor of analysed WTGs in Germany (with data according to [ISET 2005])

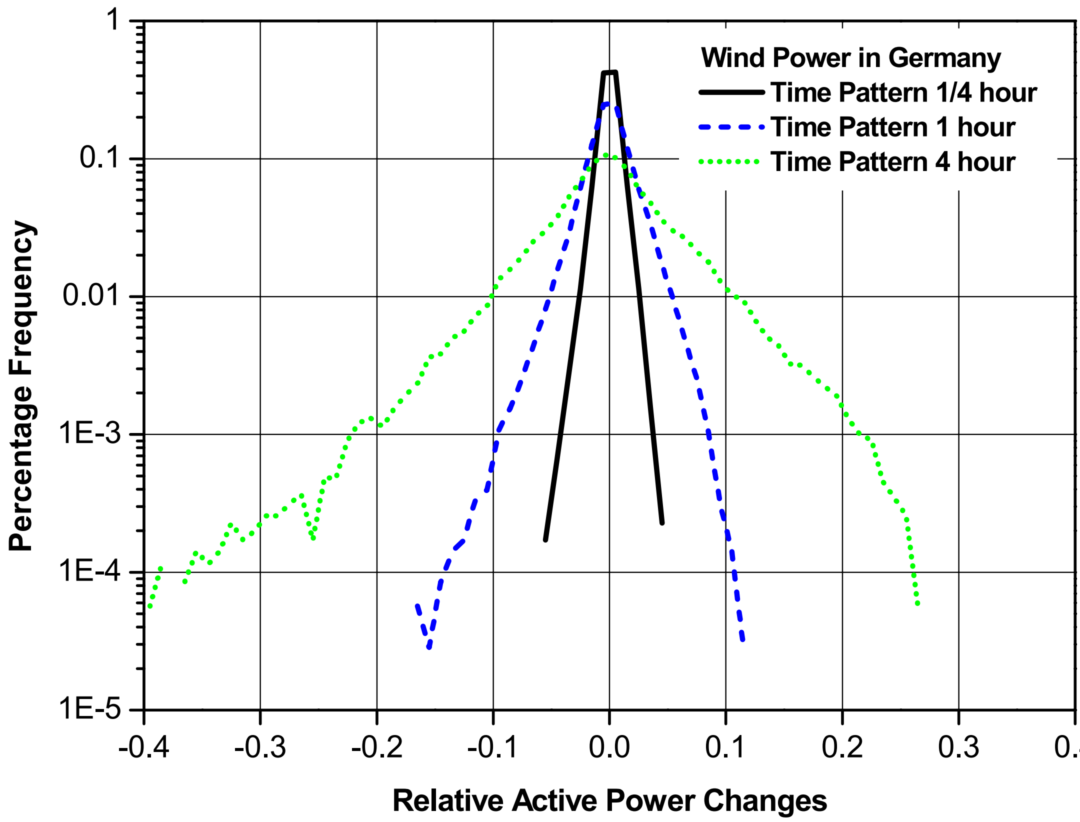


Figure III-2: Percentage frequency of relative power changes in time intervals of 0.25 h (solid black line), 1 h (dashed blue line) and 4 h (dotted green line) in Germany (with data according to [ISET 2005])

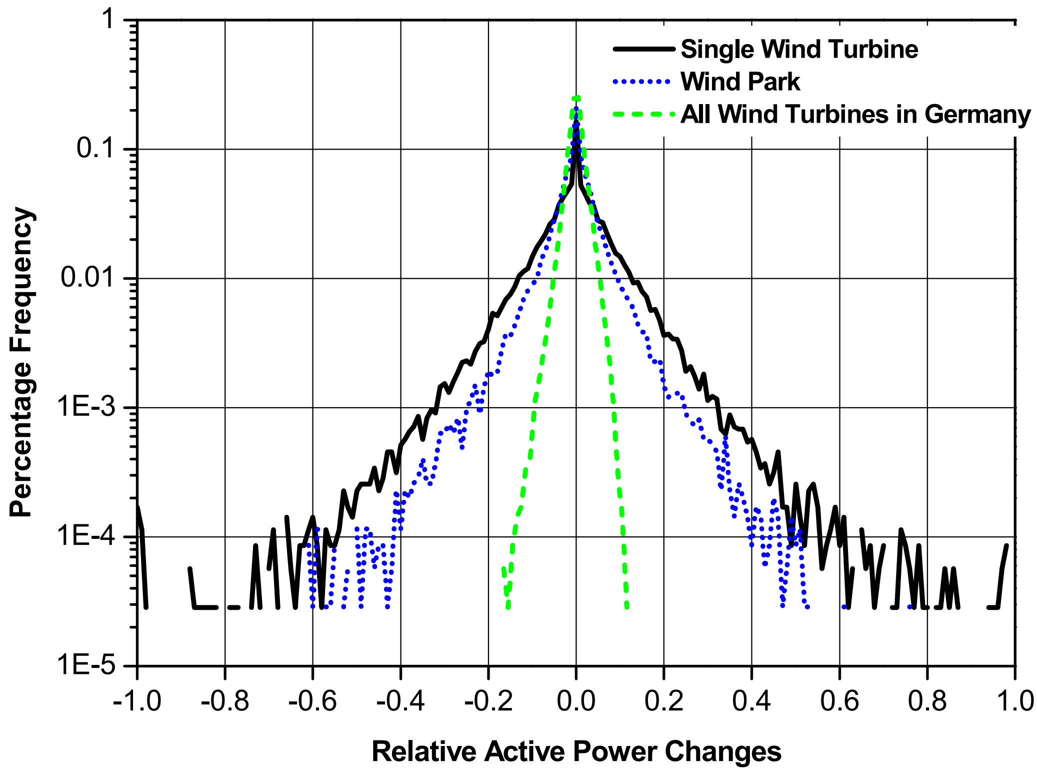


Figure III-3: Percentage frequency of relative power changes in time intervals of 1 hour for a single WTG (solid black line), a group of WTGs (dotted blue line) and all WTGs in Germany (dashed green line) (with data according to [ISET 2005])

| **Active Power Changes of [< 1%, < 2%, <5%] with a probability of … for [ ¼, 1, 4 ] hour intervals** | **< 1%** | **< 2%** | **< 5%** |
|---|---|---|---|
| ¼ hour intervals | 84% | 97% | 100% |
| 1 hour intervals | 50% | 75% | 96% |
| 4 hour intervals | 21% | 38% | 69% |

Table III-1: Probability of Active Power Changes up to [< 1%, < 2%, < 5%] for [¼, 1, 4] hour intervals of the German wind park (with data according to [ISET 2005])

### *III.1.1.2. Active Power Predictability*

[Rohrig et al 2005] present the quality of wind energy forecast. Table III-2 lists the rated Root Mean Square Error (RMSE) for different time horizons (Day-Ahead, 4-Hours-Ahead and 2-Hours-Ahead) and different grid areas (German mains grid and ENE control area). The RMSE is in the range of 2.6 - 6.9% of the medium power. Two general dependencies can be stated:

- The forecast error decreases with decreasing forecast time horizon.
- The forecast error decreases with an increasing number of WTGs.

| | **Medium Power [MW]** | **RMSE rated to Medium Power [%]** | **Installed Power [MW]** | **RMSE rated to Installed Power [%]** |
|---|---|---|---|---|
| Day-Ahead German mains grid | 2995 | 32.4 | 15387 | 5.7 |
| Day-Ahead ENE control area | 1383 | 36.6 | 6741 | 6.9 |
| 4-Hours-Ahead German mains grid | 2972 | 20.3 | 15387 | 3.6 |
| 4-Hours-Ahead ENE control area | 1354 | 24.9 | 6741 | 4.6 |
| 2-Hours-Ahead German mains grid | 2974 | 14.9 | 15387 | 2.6 |
| 2-Hours-Ahead ENE control area | 1352 | 18.8 | 6741 | 3.5 |

Table III-2: Wind prognosis (April 2004 - March 2005) of different areas and for different time horizons (with data according to [Rohrig et al 2005])

*III.1.1.3. System Reliability*

[ISET 2005] provides data for the technical availability of WTGs in Germany in 2004. Technical availability is the period of availability over the nominal period (in percent). The period of non-availability is the period during which a plant is not functioning due to scheduled maintenance or unscheduled failures. Altogether, a technical availability of 98.1% is assessed in the nominal period 2004 which corresponds to a technical non-availability of 167 hours per wind turbine and year.

[Kühn 2007] analysed the Scientific Monitoring and Evaluation Programme (WMEP) with regard to 235 small WTGs which have been monitored by the WMEP for at least 10 years. The comparison with newer and larger WTGs shows that the analysed small

WTGs have been more susceptible to storms and strokes of lightning. Moreover, small WTGs have an availability of 96% which is less than in case of larger ones. One drawback of the analysed database is that the WTG technology has progressed enormously and the analysed small WTGs generally represent older turbines.

#### *III.1.1.4. Capability to Control Active Power*

The majority of the installed WTGs are actively pitch-controlled (95% of the new installed WTG in Germany in 2004 [ISET 2005]). Active pitch control allows a control of the mechanical power by changes of the blade angles as described in [Abdad et al 2005], [Holdsworth et al 2004], [Prillwitz et al 2003] and [Prillwitz et al 2004]. In contrast, passively stall-controlled WTGs have a fixed blade angle without control possibilities. Actively stall-controlled WTGs have pitchable blades which allow similar to pitch-controlled WTGs a control of the mechanical power that is limited by the potential power according to actual wind conditions.

In contrast to large WTGs, small WTGs are rarely actively pitch-controlled. In addition, they are highly dynamic in their operation because their inertia is quite small. These characteristics leave little opportunities for smooth active power control. Nevertheless, a deactivation and activation allows discrete active power control.

State-of-the-art of pitch-controlled WTGs is the limitation to maximum active power gradients which are normally set to some percent of nominal active power per second of decrease and increase of active power output in order to reduce stress to the network [DEWI 2003]. Due to the pitch control speed some ten percent per second are possible. In emergency situations, almost instantaneous decrease rate can be achieved dependent on the breaker speed. Generally, WTGs have a maximum active power output of the rated active power. The actual maximum active power output can be lower depending on the wind situation or limitations of maximum power injections given by the system operator.

An active power control is possible with all pitch-controlled wind turbines independent from their grid-coupling converter. As given by [Hartge et al 2005], the active power control changes are fast enough to fulfil the requirements of primary frequency control. Even in case of critical situations for the voltage limits, active power of wind turbines can be changed fast enough to participate in primary voltage control, also in Fault-Ride Through situations.

Presently, WTGs operate generally at the maximum available active power. In case of severe problems of network operation, network operators can limit the active power feed-in. This new maximum active power output value is reached within a couple of seconds. Moreover, a frequency dependant active power limitation can be applied to provide high frequency response.

WTGs with active power control reserve for low frequency control cannot operate at the maximum available or maximum allowed active power operation point. They have to operate below the maximum. Control algorithms are implemented therefore as described in [Abdad et al 2005], [Holdsworth et al 2004], [Prillwitz et al 2003] and [Prillwitz et al 2004].

Basically, the mechanical power $P$ of the WTG is defined by

$$P = \frac{1}{2} \cdot \rho \cdot \pi \cdot R^2 \cdot v^3 \cdot C_P(\lambda, \beta) \text{.} \qquad \text{(III-1)}$$

This equation comprises the air mass density $\rho$, the rotor radius $R$, the wind speed $v$ and the power coefficient $C_P$ that is dependent on the tip speed ratio $\lambda$ and the pitch angle $\beta$. The pitch angle can be changed by the pitch control, the tip speed ratio can be modified by changing the rotation speed $\Omega$ of the wind turbine:

$$\lambda = \frac{\Omega \cdot R}{v} \text{.} \qquad \text{(III-2)}$$

At the maximum power coefficient, the maximum power from the available wind condition can be generated by the WTG. By varying the pitch angle and/or the tip speed ratio they are able to operate below the maximum to provide positive active power control. According to the studies in [Abdad et al 2005], both strategies produce similar results but pitch variation has advantages in terms of stability, control capacity and control speed.

### III.1.2. Reactive Power Control Capability

As already discussed in Section 4.1, the reactive power control capability mainly depends on the grid-coupling converter. WTGs can have all four types of grid-coupling converters. To fulfil grid codes, manufacturers implement more and more enhanced reactive power control functionalities (see [Hartge, Fischer 2006] and [Wachtel;Hartge 2007]). According to the loading capability charts in Section 4.1, the availability of reactive power depends on the actual active power.

Intermittent DGs (also WTGs) have time-variable active power generation $P_{act}(t)$. As one example of the time-variable reactive power capacity equation 4-7 is used in the following. The actual active power generation $P_{act}(t)$ influences the actual reactive power capacity $|Q|_{max}(t)$. If the grid-coupling converter's sizing matches exactly the rated active power generation there is no capacity for reactive power left if $P_{act}(t) = P_n = S_{max}$. Oversizing the converter leads to a certain guaranteed reactive power control capacity. These dependencies are depicted in Figure III-4 for a converter with the only restrictions of $S_{max}$ and $P_{max}$ (here $P_n$). An oversizing of 10% for instance allows a secured reactive power control of ± 46% of $P_n$ and an oversizing of 20% even ± 66% of $P_n$. These values increase significantly in case of a part-loaded active power generation $P_{act} < P_n$. The lighter lines in Figure III-4 show larger reactive power supply capacities when the converter operates part-loaded with regard to active power.

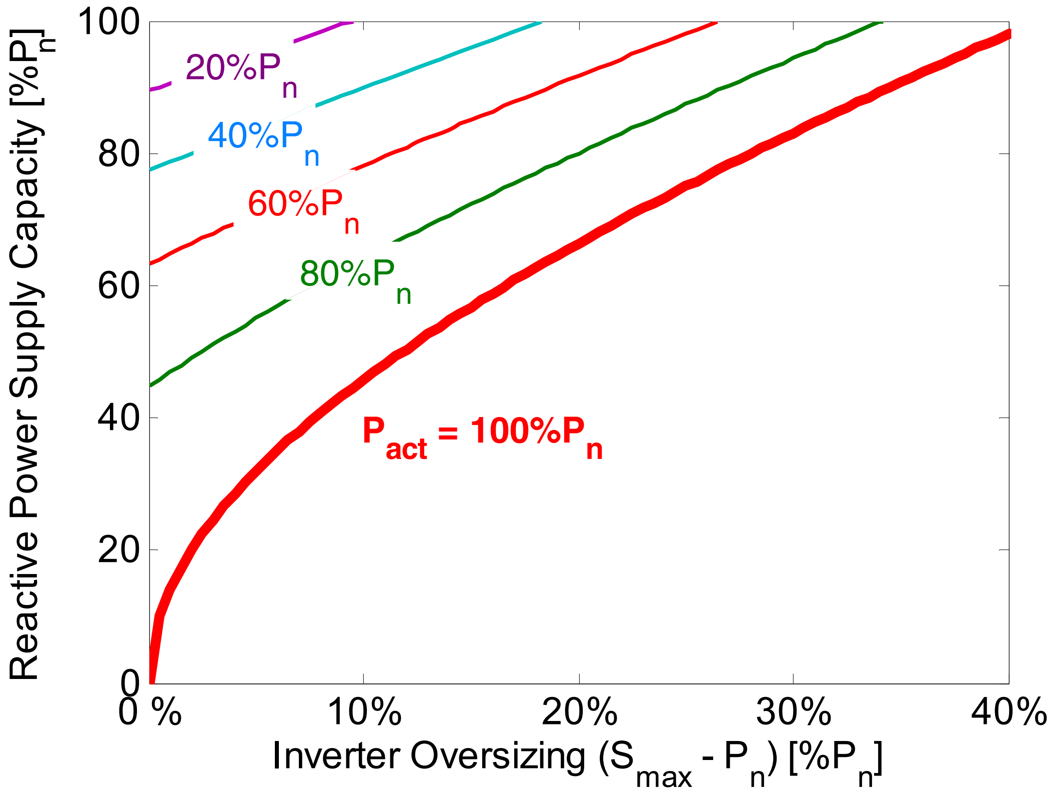


Figure III-4: Reactive power supply capacity [%$P_n$] depending on the converter's oversizing ($S_{max} – P_n$) [%$P_n$] with different $P_{act}$ [%$P_n$]

As an exemplary database, the measurements of an inverter-coupled Enercon E-66 WTG (with an assumed maximum active power $P_{max}$ = 1300 kW) in Germany are analysed [data source: ISET measurements]. For each five minute interval, the active power is measured in the years 2001-2003. The maximum reactive power $Q_{max}$ is calculated with equation 4-7 for different inverter sizing $S_{max}$. This leads to the availability of a certain reactive power Q as displayed in Table III-3 showing the influence of oversizing the inverter. With $S_{max}$ = 1400 kVA = 1.077 $P_{max}$ it is possible to guarantee 520 kvar and with $S_{max}$ = 1500 kVA = 1.154 $P_{max}$ even 748 kvar for the full active power operation range. More reactive power can be supplied but the availability is less than 100% but still more than 90% up to 1000 kvar.

This data analysis with real measurement data and with assumption of the inverter sizing shows a high potential of reactive power production/absorption because of the variable wind power generation that utilises most of the time not the full capacity of the inverter. The specific potential depends on the inverter sizing, the WTG characteristics and the wind characteristics of the respective plant site.

| Reactive Power Q | Availability of Q with | | |
|---|---|---|---|
| | $S_{max}$ = 1300 kVA | $S_{max}$ = 1400 kVA | $S_{max}$ = 1500 kVA |
| 100 kvar | >99% | 100% | 100% |
| 200 kvar | >99% | 100% | 100% |
| 300 kvar | >99% | 100% | 100% |
| 400 kvar | 99% | 100% | 100% |
| 500 kvar | 97% | 100% | 100% |
| 600 kvar | 95% | >99% | 100% |
| 700 kvar | 94% | 98% | 100% |
| 800 kvar | 94% | 95% | >99% |
| 900 kvar | 93% | 94% | 97% |
| 1000 kvar | 92% | 93% | 94% |
| 1100 kvar | 89% | 92% | 94% |
| 1200 kvar | 84% | 90% | 93% |
| 1300 kvar | 5% | 85% | 90% |
| 1400 kvar | 0% | 5% | 86% |
| 1500 kvar | 0% | 0% | 5% |

Table III-3: Availability of reactive power Q [kvar] of an Enercon E-66 WEC (with $P_{max}$ = 1300 kW) in Germany with different inverter sizing $S_{max}$

WTGs with IGs may have capacitor banks to compensate the reactive power consumption. However, the definition in Section 4.1.3 sees the compensation unit separated from the IG which itself cannot provide reactive power control.

WTGs with DFIG utilise an inverter for advanced control capabilities (see Section 4.1.4). This inverter has only a fraction of the size of the rated power of the WTG (typically 10 – 30%). In addition to a more flexible speed variation also reactive power can be supplied. Gamesa's G80 WTG [Gamesa 2008] with a DFIG provides, for instance, control capability from $0.95 < \cos\varphi < 1$ (inductive or capacitive).

An emerging type of WTGs uses directly-coupled SGs. They use a dynamic gearbox which allows speed variation [EU Energy 2006]. According to the capabilities presented in Paragraph 4.1.1.2, SG-coupled WTGs can provide reactive power in addition to active power by their excitation control. The characteristics with oversizing and security of reactive power capacity are similar to those discussed beforehand for inverter-coupled WTGs.

### III.1.3. Capability to Provide Ancillary Services

Due to the active power control capability of WTGs presented in Section III.1.1 power/frequency control support of all time scales is technologically possible. The main disadvantage is the availability and variability of power generation. This disadvantage can be reduced by forecasting and aggregation: the shorter the time scale and the higher the aggregation the smaller the forecast error.

Power/voltage control, congestion management and reduction of power losses by WTGs is mainly based on the reactive power control capability which is described in Section III.1.2 and Section 4.1. Dependent on the point of connection in the power system, also active power control may be used for these ancillary services. Based on these capabilities these ancillary services can be provided effectively by DFIG-, SG- and inverter-coupled WTGs. In contrast, IG-coupled WTGs themselves do not have reactive power control capability. However, external reactive power sources such as capacitor banks are often installed. In addition, active power control is possible.

Improvement of power quality depends on the grid-coupling converter as described in Section 4.1. Inverter-coupled WTGs have the highest potential for power quality improvement. DFIG-coupled WTGs use the grid-side inverter with only a fraction (in the order of 10 – 25 %) of the rated power of the whole DFIG. IG and SG-coupled WTGs cannot improve power quality actively.

Also the capabilities of islanded operation depend on the grid-coupling converter as described in Section 4.1, but, in addition, on the active power control capability that is limited by the availability of wind. Black start by WTGs using SG-, DFIG- and inverter-coupled WTGs is possible because they can start without the network due to the available kinetic energy source (wind), the converter’s capability of direct frequency and voltage control, as well as active and reactive power control capabilities. Some type of storage system can be necessary to activate the control system and the excitation system of SGs as well as magnetising and energising the IG of a DFIG. [Skytt et al 2001] demonstrate the black start of inverter-coupled WTGs and [Aktarujjaman et al 2006] propose a control system of providing black start by DFIGs.

## III.2. Photovoltaic (PV) Systems

A 'Photovoltaic System' is defined as an "*assembly of components that produce and supply electricity by the conversion of solar energy*" [IEC 61836]. PV systems are always coupled with inverters to the grid because the PV modules convert the irradiation into direct current which has to be transformed into AC power.

### III.2.1. Active Power Control Capability

The active power control capability takes into account active power availability, active power predictability, system reliability and the capability to control active power.

#### *III.2.1.1. Active Power Availability*

Similar to WTGs, PV systems are dependent on a primary energy source with its variations. The wind in Germany is more intensive in the winter months but PV systems produce more energy in the summer months (see Figure III-5 in comparison to Figure III- ). PV systems show also a typical behaviour each day. At night, they do not operate at all and in the hours of sunshine their generation varies according to the irradiation of the sun. The availability of active power depends on the site, the system itself (module orientation, cell technology, inverter etc.), the season, and the actual weather conditions.

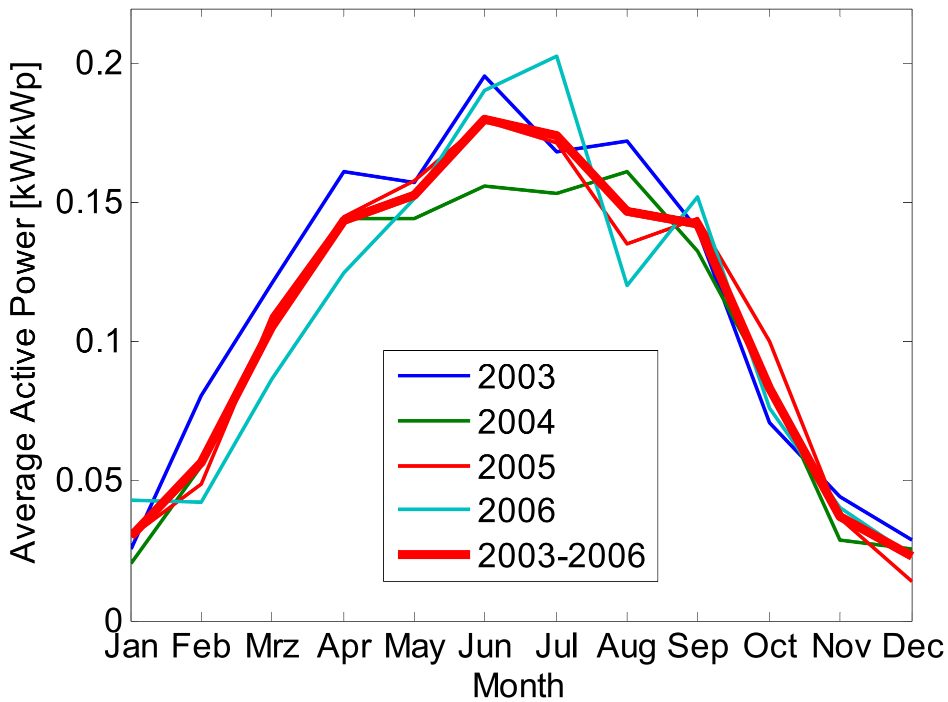


Figure III-5: Monthly PV active power generation in Kassel, Germany, in the years 2003 – 2006 [data: ISET measurements]

Figure III-6 presents the percentage frequency over the relative variation (rated to the installed capacity) of the supplied PV power in Germany in the year 2005 based on the model developed in [ISET;ISE 2008]. The frequency of power changes increases with increasing time patterns. Extreme values of power changes for 15 minutes intervals are approx. 8%, for 1 hour intervals approx. +20% and for 4 hour intervals approx. +36%.

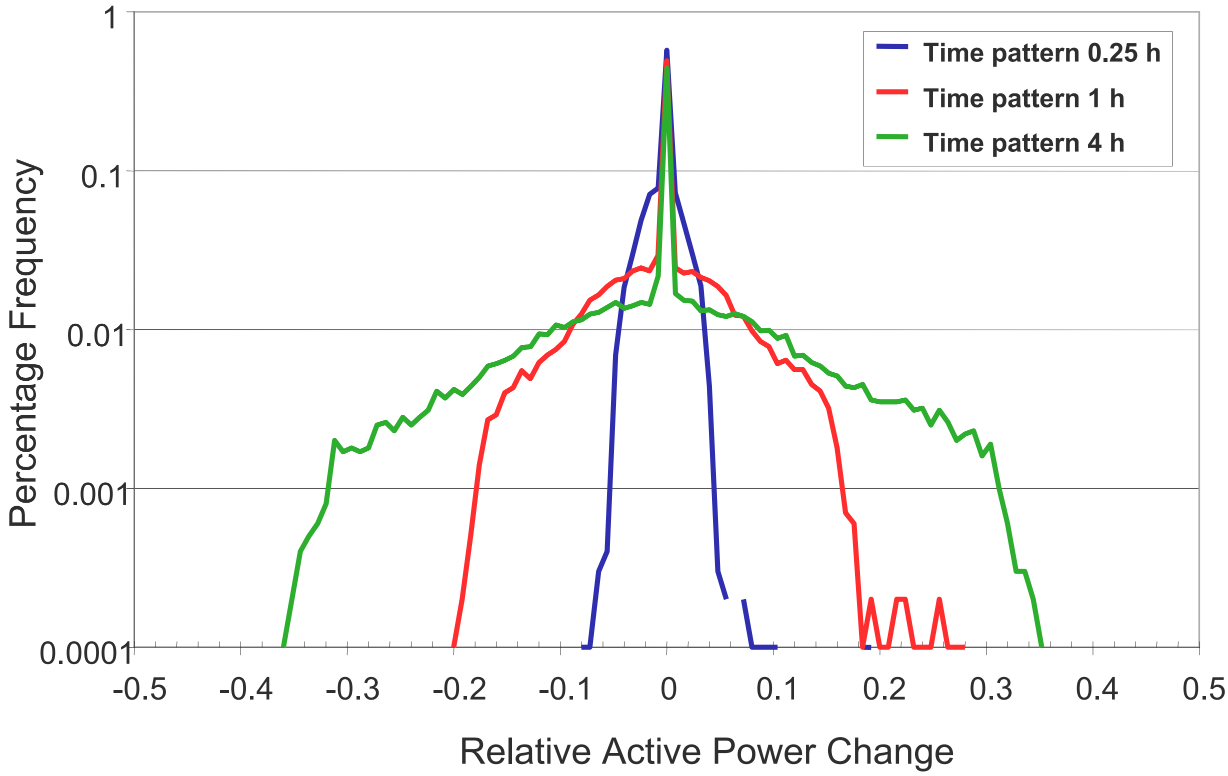


Figure III-6: Percentage frequency of relative power changes in time patterns of 0.25, 1 and 4 hours (with 15 minutes average values) for Germany in 2005 [ISET;ISE 2008]

### *III.2.1.2. Active Power Predictability*

[Lorenz et al 2007] present and evaluate an approach to forecast regional PV power production for the next days. With their approach they get an RMSE of 0.13 Wh/Wp for single PV systems. This value is reduced to an RMSE of 0.05 Wh/Wp for an ensemble of the size of Germany. Their forecasting scheme is based on irradiance forecasts up to 3 days ahead provided by the European Center for Medium range Weather Forecasts (ECMWF) with a temporal resolution of 3 hours and a spatial resolution of 25 km x 25 km. For evaluation of the forecast data they compare the results with a database of about 4500 operating PV systems in Germany.

The power forecast for 11 PV systems resulted in an rRSME (relative RMSE: normalised with mean PV power production of the period) of 49% (absolute RMSE = 0.12Wh/Wp) for April with predominant cloudy weather situations and an rRMSE of 30% (absolute RMSE=0.10 Wh/Wp) in July with predominant clear sky weather situations.

The forecast preciseness is improved by spatial averaging effects. So the forecast preciseness increases significantly if all PV systems of one network are taken together instead of only looking at single systems.

#### *III.2.1.3. System Reliability*

[Jahn 2003] analysed the technical reliability of 116 PV systems in Germany, Switzerland and Italy. The analysis shows that the reliability between the older (installed 1983-1994) and newer (installed 1996-2001) analysed systems has increased from an average of 94.6% to an average of 95.6%. 55% of the newer installations have a reliability of more than 99%.

#### *III.2.1.4. Capability to Control Active Power*

A PV system has similar restrictions like a WTG with respect to primary energy variations. However, the characteristic of these fluctuations is different because at night there is no power generation. With appropriate forecast, a probabilistic use of active power control is possible, however, limited with respective uncertainties. The active power can be controlled by changing the DC-link voltage and moving on the VI-curve of the PV modules within milliseconds. Presently, PV systems use maximum power point (MPP) tracking to generate maximum active power.

### III.2.2. Reactive Power Control Capability

The reactive power control capability of PV inverters has been analysed in detail in [Braun 2007b]. Reactive power control is possible because all grid-connected PV systems use inverters for grid-coupling. Normally, PV inverters are operating in stand-by at night to reduce losses. In this situation the power electronic control is deactivated so that power control is not possible. Therefore, reactive power supply of PV systems is limited to an active system. An active system is able to control reactive power in a large range as given by the loading capability chart in Section 4.1.2.2. The system reaches its maximum active power generation only for a short period of time during the year. Even if the inverter is not oversized the part-load operation behaviour leaves sufficient reactive power control capacity.

Assuming a theoretical maximum apparent power for a PV system and an active/reactive control capability as presented in Figure 4-3 with the full circle of the loading capability chart allows calculating the possible maximum reactive power production/absorption depending on the actual active power generation according to equation 4-7. With the solar irradiation in Kassel, Germany, in the year 2005 a 100 kVA PV generator would have had the capability to provide reactive power up to 40 kvar for more than 99.9% of the year. The performance data is analysed with mean values of 15 minutes. An overview gives Table III-4 with inverter sizing of 100 kVA and 110 kVA (oversized). The table shows that the availability depends on the dimensioning of the PV inverter. With only 10 kVA more (oversized), additional 20 kvar are available over 99.9%.

| **Reactive Power Q** | **Availability with 100 kVA Inverter** | **Availability with 110 kVA Inverter** |
|---|---|---|
| 10 kvar | > 99.9% | 100% |
| 20 kvar | > 99.9% | 100% |
| 30 kvar | > 99.9% | 100% |
| 40 kvar | > 99.9% | 100% |
| 50 kvar | 99.9% | > 99.9% |
| 60 kvar | 99.3% | > 99.9% |
| 70 kvar | 97.1% | 99.8% |
| 80 kvar | 93.7% | 98.3% |
| 90 kvar | 88.4% | 94.7% |
| 100 kvar | 55.0% | 89.1% |

Table III-4: Available Reactive Power Potential of a 100 kVA PV generator in Kassel, Germany in 2005 [data: ISET measurements]

This comparison with real measurement data and with assumption for the inverter sizing shows a high potential of reactive power production/absorption. This reactive power capacity results from the variable PV power generation that utilises most of the time not the full capacity of the inverter. The exact potential depends on the inverter dimensioning, the PV system characteristics and the irradiation characteristics of the respective site. Oversizing the inverter leads to guaranteed reactive power capacity.

### III.2.3. Capability to Provide Ancillary Services

Their active power control capability allows PV systems participating in frequency control support of all time scales. The main disadvantage is the availability and variability of power generation. This disadvantage can be reduced by forecasting and aggregation: the shorter the time scale and the higher the aggregation the smaller the forecast error.

The reactive power control capability is the basis for the capabilities to provide power/voltage control, congestion management and reduction of power losses. Also active power control can be used for these ancillary services if necessary. In the situation of 0% active power supply (pre-dominantly at night), the inverter can be in standby mode (with deactivated stack control) in order to minimise losses. An activation of the inverter is necessary to provide reactive power supply. Therefore, only active PV systems can supply reactive power.

The improvement of voltage quality can be provided by PV systems due to the inverter-coupling as described in Chapter 4.1.2.3. However, this is also limited to an active system.

Most of present PV systems are based on self-commutating inverters. They can provide black start and islanded operation due to the inverter's capability of direct frequency and voltage control within the constraints of the availability and variability of the primary energy source.

## III.3. Hydroelectric Power (Hydro) Station

A 'hydroelectric power station' is defined as "a power station in which the gravitational energy of water is converted into electricity" [IEC IEV 2008]. Hydro stations have a large range of system sizes. Here, the focus lies on run-of-river power stations that are connected to distribution networks with a size up to some MW. They are classified as small hydro power (SHP) stations. 'Run-of-river power stations are defined as "*a hydroelectric power station which uses the river flow as it occurs, the filling period of its own reservoir by the cumulative water flows being practically negligible*" [IEC IEV 2008]. The majority of SHP stations are connected by induction generators to the mains grid, larger ones normally by synchronous generators. Only a few of them use a full inverter for network coupling (mostly with permanent-magnet synchronous generators) [EC 2000]. Present research also considers DFIGs as grid-coupling converters for hydro stations, esp. for SHP, because hydro power has similar characteristics as wind power [Okafor;Hofmann 2004].

### III.3.1. Active Power Control Capability

The active power control capability takes into account active power availability, active power predictability, and the capability to control active power.

#### *III.3.1.1. Active Power Availability*

Smaller river power plants are classified as intermittent. Consequently, they have similar constraints of availability compared to wind or solar power. The variations depend on the characteristics of the river flow and the catchment's puffer capacity. [Bernard 2004] shows the variability of the water flows in France over different time horizons aggregated over all EDF hydro power plants. While the yearly averaged fluctuations are only +/- 30% of the yearly mean value, the fluctuations inside a year are +130%/-60% of the mean value in the given example. Generally, the active power availability of one considered small hydro power plant is site-, season- and weather-dependent. In Germany, typical full load hours of small hydro power plants are in the range of 3000 to 5000 per year.

#### *III.3.1.2. Active Power Predictability*

[Ferri et al 2004] show a comparison of the simulation results and the observations of the water flow for two different locations of the Brenta river at Bassano, Italy. This comparison shows the influence of the distance from the source on the forecast model preciseness. The farther the hydroelectric power station is located from the primary source the more complex the forecast becomes. Forecast for large hydroelectric power stations is applied in many cases (e.g. [Weber et al 2006]) and for small hydro power plants in few cases.

#### *III.3.1.3. Capability to Control Active Power*

A run-of-river power station is technological capable to provide high frequency response by spilling water or reducing the turbines efficiency by turbine blade angle control. Low frequency response requires part-loaded operation which is achieved by reducing the water flow through the turbine (additional spilling of water) or operating the turbines with a sub-optimal blade angle. A hydroelectric power station has similar constraints as a WTG system with respect to availability and variability of primary energy. The short-term variability can be reduced if a water reservoir can be used in the upstream of the water flow.

### III.3.2. Reactive Power Control Capability

The capability of reactive power control of hydro power plants depends on the grid-coupling converter, which can be considered to be similar as for WTGs due the variability of primary energy supply and range of grid-coupling converters. The restrictions and dependencies have already been discussed in Section III.1.2 and can be transferred analogously to run-of-river power stations.

### III.3.3. Capability to Provide Ancillary Services

The capability of providing ancillary services can be considered to be analogue to the ones described in Section III.1.3 for WTG systems. One difference is that a reservoir may be used to reduce the variability of the water flow.

Generally (with the exception of IG-coupled units), black start is possible (see also [Delfino et al 1996], [Izena et al 2005], [Tung et al 2006]) because they can start without the power system similar to WTG systems.

## III.4. Combined Cooling, Heat and Power (CCHP) Systems

‘Combined heat and power’ is defined as *“the production of heat which is used for non-electrical purposes and also for electricity”* [IEC IEV 2008]. Combined (Cooling,) Heat and Power (CCHP) systems are distinguished from WTG systems, PV systems and hydroelectric power stations because of their heat conversion process. The heat conversion process requires considering an additional energy flow next to electric power.

CCHP plants are normally coupled with IGs, SGs or inverters according to their specific characteristics.

Fuel cells and microturbines are normally inverter-coupled. Fuel cells generate direct current from chemical energy. This direct current needs to be converted by a DC/AC-inverter into the correct voltage form to feed into the AC power system. Operating speeds of microturbines can exceed 100,000 rpm. The speeds are generally variable over a wide range (i.e., from 50,000 rpm to 120,000 rpm). Microturbines drive a high-frequency generator that can be synchronous or asynchronous and that generates a three-phase, high frequency voltage, typically in the range of 1 - 3 kHz. This high frequency voltage must be converted with an AC/AC-converter to grid frequency before the generated power becomes usable [Ozpineci;Staunton 2003].

Steam turbines, gas turbines, gas engines and piston internal combustion engines are normally SG-coupled. Micro-CHP in the size of 1-5 kW, e.g. with stirling engines, often use IG for grid-coupling. These units are sometimes equipped with power electronic converters aiming at enhancing their capabilities.

### III.4.1. Active Power Control Capability

The active power control capability takes into account active power availability, active power predictability, and the capability to control active power.

### *III.4.1.1. Active Power Availability*

The fuel of the CHP plant, which could be liquid fossil, gaseous fossil, biomass, biogas, landfill gas etc., is assumed to be available without fluctuations. Consequently, the fuel does not restrict the active power generation. This is a big advantage for the active power availability in comparison to systems with variable primary energy flow such as the three previous ones. Solar thermal systems that depend on the variable solar irradiation are one exception that needs to be mentioned here.

CCHP systems can have different priority settings for the exploitation of heat and electricity. The interdependences between these two energy flows can be relaxed by storage devices (mostly thermal storage).

First of all, it has to be decided if the CCHP system is

- thermally-driven without storage,
- thermally-driven with storage, or
- electricity-driven.

In case of a thermally-driven CCHP system without storage, the thermal process is optimised. Electricity is only a sub-product. In most cases it is not possible to control the active power because this influences the thermal process as well.

If the thermally-driven CCHP can be equipped with storage for the thermal processes it becomes possible to vary the active power output within the limitations given by the storage capacity. The storage can be sized with sufficient capacity to fulfil the requirements for active power control services. In this situation, the thermally-driven process (from the thermal point of view) can be considered as electricity-driven (from the electrical point of view).

Finally, an electricity-driven CCHP plant can vary the active power flexibly. The thermal energy output is only a sub-product. One example is a condensing plant that does not use the heat for any important purposes.

An electricity-driven CCHP system has an active power availability that only depends on the fuel availability and the system availability. In contrast, a thermally-driven CCHP system without storage has an active power availability that is directly coupled with the heat demand. If the heat demand varies the active power availability varies as well. This direct coupling can be dampened by storage devices.

Different types of heat demand can be considered ranging from constant industrial process heat demand to variable heat demand of households. [Sievers et al 2006b] analysed small-scale CHP systems up to 2 MW and looked at typically used motor-CHP fuelled by Diesel or gas. In Denmark such units are operated for district heat supply, in

Spain they are often applied in industrial plants for process heat, and in the United Kingdom and in Germany they can be found for space heating and hot water consumption in buildings. In households, the user's behaviour determines the hot water consumption and the space heat demand, but the last one is mainly determined by the insulation standard and ambient temperature. Both together determine the degree of variation and are expressed by the ratio between constant and varying demand. The heat storage capacity influences considerably the flexibility of the CHP plant.

#### *III.4.1.2. Active Power Predictability*

The predictability is important for thermally-driven CCHP systems because it is helpful to know the possible active power generation which is coupled with the heat demand. Therefore, the prediction of the heat demand is necessary. Storage devices enable to improve the heat demand forecast and guarantee a more flexible active power generation. Small residential CCHP installations are difficult to be predicted automatically because it depends on the individual consumer behaviour. Large industrial CCHP installations for process heat demand can be predicted more easily because industrial processes are often scheduled. Due to dispersion, an aggregation leads to better predictability because the averaging effect smoothes the variations of single systems.

In case of electricity-driven CCHP systems it can be assumed that active power is available with sufficient fuel capacity and within the plant's reliability. Forecast is not necessary for electricity-driven CCHP systems.

#### *III.4.1.3. Capability to Control Active Power*

The active power control capability of electricity-driven CCHP systems is not restricted because of their flexibility based on the consideration of heat as a sub-product. By contrast, thermally-driven CCHP systems do not show any active power control capability as they have to follow exactly the heat demand without flexibility. This heat demand profile can fit to the electricity demand profile leading to a good power generation characteristic but it does not enable a deviation from the heat demand which would be necessary to contribute actively with active power control. In between these two extreme situations lies the thermally-driven CCHP plant with storage. Depending on the storage capacity and the heat demand profile, this type of CCHP systems have a certain capability of active power control. Also peak load boilers can be installed in addition to decouple the generation of heat from the demand. [Sievers et al 2006b] show examples for the capability of active power control.

### III.4.2. Reactive Power Control Capability

The capability of reactive power control depends on the grid-coupling converter as described in Chapter 4.1. SG- and inverter-coupled CCHP units can provide reactive power while IG-coupled units can not. The reactive power control capacity also depends on the active power variations and the sizing of the grid-coupling converter.

### III.4.3. Capability to Provide Ancillary Services

CCHP systems are only capable to provide power/frequency control if they operate electricity-driven which allows a flexible control of the active power output. Thermally-driven CCHP systems cannot provide power/frequency control because they have to follow the heat demand. In between, thermally-driven CCHP systems with thermal storage have certain control capabilities which are basically limited by the storage capacity.

Steam turbines, gas turbines, gas engines, microturbines, sterling engines, piston internal combustion engines and flexible fuel cells are capable to change the energy transformation for the active power control within seconds. Some types of high temperature fuel cells can have active power gradients that are not fast enough to provide primary frequency control support. Also other types of primary energy conversion technologies can have restrictions of the required dynamics. For instance, biogas plants have a biogas conversion process which operates adjusted to the rated demand. Significant variations of this demand have to be compensated by biogas storage capacity that allows decoupling the biogas generation process from the electricity generation process.

High frequency control can be provided by all operating units if the fuel supply can be reduced. In order to provide low frequency control, the generator has to be operated part-loaded and it has to be possible to increase fuel supply and active power output.

According to the reactive power control capability that depends on the grid-coupling converter as described in Section 4.1, power/voltage control, congestion management and the reduction of power losses can be provided effectively by SG- and inverter-coupled CCHP systems.

The improvement of power quality can be provided by inverter-coupled CCHP systems as described in Chapter 4.1.2.3. IG- and SG-coupled units cannot provide this ancillary service.

Generally, SG- and inverter-coupled CCHP systems have the capability of direct frequency and voltage control. Together with the active and reactive power control capabilities, grid-forming and islanded operation is possible. Only electricity-driven CCHP systems are able to operate islands. Thermally-driven CCHP systems do not have the necessary active power control capability. However, a re-definition of the thermally-driven CCHP systems to electricity-driven ones is possible if it is more important restoring or forming the grid than supplying the heat. Different to WTG systems, PV systems, and hydroelectric power stations, the rated active power of electricity-driven CCHP systems can be considered as available all the time. This enhances the active power control capabilities significantly.

In contrast to WTG systems, PV systems and hydroelectric power stations, CCHP systems (except fuel cells) have a thermal process that drives the prime mover which then drives the generator. Fuel cells do not use a thermal process for driving a prime mover. They convert chemical energy directly into electrical energy. But this process also needs a certain temperature that is delivered by the heating system. Consequently, all CCHP plants need some kind of storage device to start and heat the system without grid connection. This storage can be very small, e.g. to ignite a diesel engine, or very large, e.g. to heat up a high temperature fuel cell. With such storage devices, CCHP systems can provide black start as long as they are capable of grid-forming. This is not the case for thermally-driven CCHP systems.

### III.5. Storage Systems

Storage systems can be operated similar to generators as well as similar to loads. Hence, they have characteristics which are formed of the other two. One important limitation is the storage capacity that only allows an alternating operation between generation (discharging) and consumption (charging). This bidirectional operation is particular for storage system in contrast to pure generators and loads. The objective of the majority of presently installed battery storage systems is islanded operation in various applications such as small stand-alone applications, hybrid systems or emergency power supplies. A large variety of storage technologies are available.

Lead acid batteries, lithium batteries, supercapacitors, nickel batteries, redox flow batteries and all other types of electrochemical batteries are DC sources. They need an inverter for grid-coupling. Also flywheels with their large speed variations require power electronic converters between the mechanical generator and the power system. Only pneumatic and hydraulic storage, which are based on a mechanical energy conversion process, allow a direct coupling via a rotating generator which can be an IG, a SG or an inverter-coupled generator.

One type of storage has to be added: mobile storage which comprises storage devices of plug-in or electric vehicles. Even if this type of storage is not always connected to the network it can be used when connected. Due to the higher overall efficiency of electrical motors in comparison to combustions motors a significant growth can be expected in the coming decades. In future analyses it has to be included.

The limitations of active power availability are given by the storage capacity: the larger the storage, the larger the active power control flexibility. The storage management system knows the actual status and the limitations of the storage that enables to predict the actual storage capacity. Their active power control capability makes them suitable for power/frequency control services.

All SG- and Inverter-coupled storage devices can supply reactive power as discussed in Chapter 4.1. With this functionality (and their active power control capability in addition) they can provide power/voltage control services, congestion management and reduction of power losses. In addition, inverter-coupled storage devices have the capability to improve power quality (Chapter 4.1.2.3).

All SG- and Inverter-coupled storage devices together with their active and reactive power control capability can define voltage and frequency directly and thereby forming the grid and operate islands within the limits of their storage capacity. Due to their inherent storage capacity they are also able to provide black start services.

# IV. Annex: Derivation of the Approximation Function for Power Losses in Static Converters

The losses of an inverter can be approximated by a second order polynomial function [Schmidt;Sauer 1996]:

$$P'_{loss}(P_{AC}) = c_{self} + c_{Vloss} \cdot P_{AC} + c_{Rloss} \cdot (P_{AC})^2 \tag{IV-1}$$

with self losses (standby losses) $c_{self}$, terminal voltage dependent losses over the power electronic components $c_{Vloss}$ (proportional to current $I$), and current dependent losses over the impedances $c_{Rloss}$ (proportional to squared current $I^2$).

Looking at present standard inverter designs, this approximation can be derived from the average total power dissipation. As an example, the B6-Bridge configuration of typical three-phase inverters that are connected to the low voltage grid is analysed. Figure IV-1 provides the topology, the B6-Bridge, with three active legs. This voltage source inverter (see [Bülo et al 2007]) is a switched voltage source with capacitors $C_{in}$ in the DC-link that is coupled inductively to the grid with the filter inductances $L_{a,b,c}$ and the filter capacitors $C_{a,b,c}$. Each of the three legs consists of two IGBTs ($T_{1,\dots6}$) with an inverse diode.

The average total power dissipation $P_{av}$ (the inverter losses) of the IGBT and the inverse diode consist of conduction losses $P_{cond}$ (energy: $E_{cond}$) and switching losses $P_{sw}$ (energy during on-state $E_{on}$ and energy during off-state $E_{off}$) during one period of time $T_0$ [Infineon 2008]:

$$P_{av} = \frac{1}{T_0} \cdot \left( \sum E_{cond} + E_{on} + E_{off} \right) = P_{cond} + P_{sw} \tag{IV-2}$$

These losses are calculated separately for the IGBT and the reverse diode as given with the following equations.

The conduction losses $P_{cond,IGBT}$ of the IGBT are calculated by:

$$P_{cond,IGBT} = \frac{1}{T_0} \cdot \int_0^{T_0} \left[ V_{CE0} + R \cdot i(t) \right] \cdot i(t) \cdot \tau'(t) \cdot dt \tag{IV-3}$$

with the threshold voltage $V_{CE0}$, the slope of the saturation voltage (at 125°C) $R$ and the function of the IGBT pulse pattern $\tau'(t)$ with the IGBT turned-on = 1 and turned-off = 0.

The switching losses $P_{sw,IGBT}$ of the IGBT are calculated by:

$$P_{sw,IGBT} = \frac{1}{T_0} \cdot \left[ E_{on,IGBT}\left(I_{nom}, V_{nom}\right) + E_{off,IGBT}\left(I_{nom}, V_{nom}\right) \right] \cdot \frac{i(t)}{I_{nom}} \cdot \frac{V_{DC}}{V_{nom}} \qquad \text{(IV-4)}$$

with the rated current $I_{nom}$ and the nominal blocking voltage $V_{nom}$ of the device as well as the DC-Link voltage $V_{DC}$.

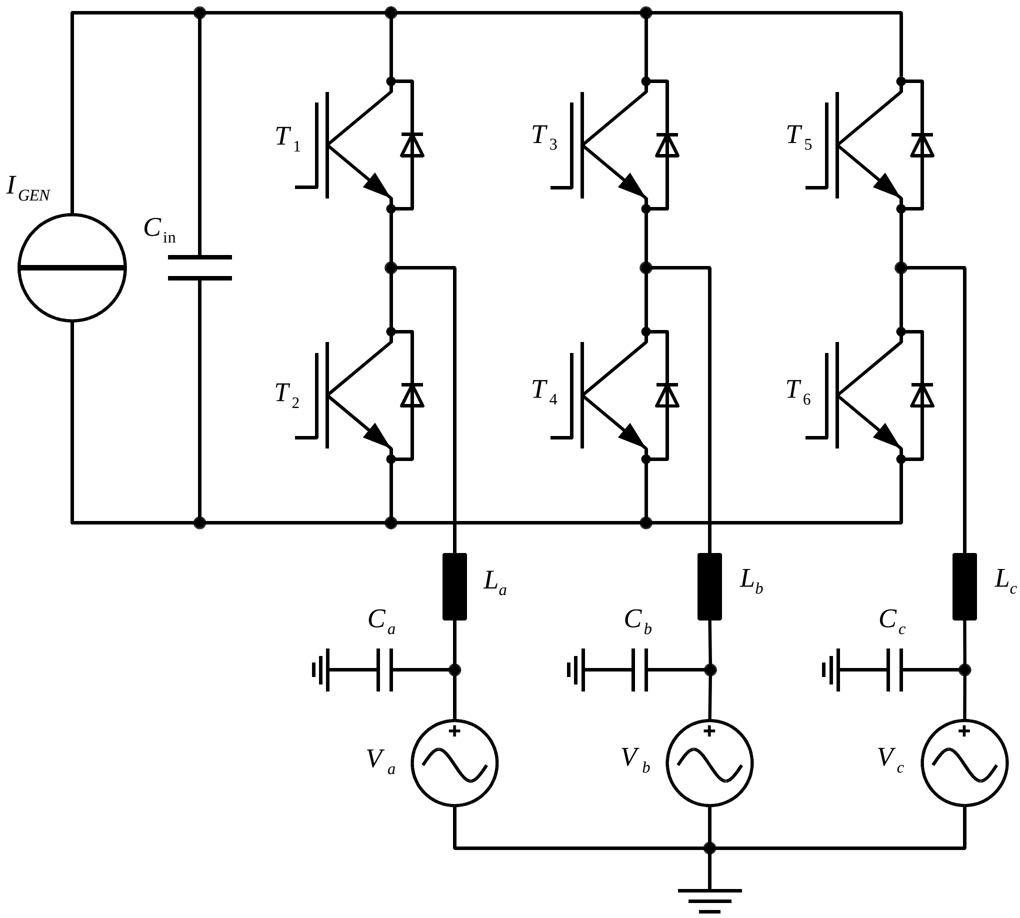


Figure IV-1: B6-Bridge as a typical three-phase inverter design [Notholt;Coll 2007]

The conduction losses $P_{cond,Diode}$ of the inverse diode are calculated in a similar way:

$$P_{cond,Diode} = \frac{1}{T_0} \cdot \int_0^{T_0} \left[ V_0 + R_d \cdot i(t) \right] \cdot i(t) \cdot \left[ 1 - \tau'(t) \right] \cdot dt \qquad \text{(IV-5)}$$

with the threshold voltage $V_0$ and the slope of the saturation voltage (at 125°C) $R_d$.

Normally, the turn-on losses of the diode are neglected for the diode and the switching losses are known as reverse recovery (turn-off) losses that are calculated by:

$$P_{sw,Diode} = \frac{1}{T_0} \cdot E_{off,Diode}\left(I_{nom}, V_{nom}\right) \cdot \frac{i(t)}{I_{nom}} \cdot \frac{V_{DC}}{V_{nom}} \tag{IV-6}$$

or by:

$$P_{sw,Diode} = \frac{1}{T_0} \cdot E_{rec}\left(I_{nom}\right) \cdot \left[0.45 \frac{i(t)}{I_{nom}} + 0.55\right] \cdot \frac{V_{DC}}{V_{nom}} \tag{IV-7}$$

with the reverse recovery losses $E_{rec}$.

Also the losses over the wires that connect the power module have to be considered and can be calculated as normal resistive copper losses:

$$P_{cu} = \frac{1}{T_0} \int_0^{T_0} R_{cu} \cdot i(t)^2 \cdot dt \tag{IV-8}$$

with the resistance $R_{cu}$.

Summing up all these loss components leads to the average power dissipation:

$$P_{av} = P_{cond,IGBT} + P_{sw,IGBT} + P_{cond,Diode} + P_{sw,Diode} + P_{cu} + P_0 \tag{IV-9}$$

with additional losses (for the control system, the fans etc.) $P_0$. The average dissipation can be written in a second order polynomial function

$$P_{av}(t) = c'_{self} + c'_{Vloss} \cdot i(t) + c'_{Rloss} \cdot i(t)^2 \tag{IV-10}$$

dependent on the current $i(t)$. Consequently, the approximation equation IV-1 is given in dependency of the root-mean square (RMS) current $I$ instead of the RMS active power $P_{AC}$. With the assumption of constant terminal voltage $V_{AC}$ the current $I$ can also be substituted by the apparent power $S$.

## List of Figures

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# Publications for the Thesis

The list of publications provides an overview of published papers that are re-used partly in this thesis.

| Chapter | Paper |
|---|---|
| Chapter 2 | M. Braun, P. Strauss: "A Review on Aggregation Approaches of Controllable Distributed Energy Units in Electrical Power Systems", International Journal of Distributed Energy Resources, Vol 4, No 4, pp 297-319, 2008 |
| Chapter 3<br>Chapter 4<br>Annex II<br>Annex III | M. Braun: "Technological Control Capabilities of DER to Provide Future Ancillary Services", International Journal of Distributed Energy Resources, Vol. 3, Number 3, pp 191-206, 2007 |
| Chapter 4.1 | M. Braun: "Reactive Power Supply by Distributed Generators", IEEE PES GM, 20-24 July 2008, Pittsburgh, USA |
| Chapter 5.1 | M. Braun: "Systemdienstleistungen für den Netzbetrieb", BWK, 59, 12, December 2007, pp 53-58 |
| Chapter 5.2 | M. Braun: "Reactive Power Supplied by PV-Inverters - Cost-Benefit-Analysis", 22nd European Photovoltaic Solar Energy Conference, Milan, Italy, 3-7 September 2007<br>M. Braun: "Verfahren und Vorrichtung zur Bestimmung der Verluste eines Energiewandlers, insbesondere eines Stromrichters oder Synchrongenerators", Patent No DE 10 2007 041 793.6, pending, patent application 3 Sep 2007<br>M. Braun: „Reactive Power Supplied by Wind Energy Converters - Cost-Benefit-Analysis", European Wind Energy Conference (EWEC), Brussels, Belgium, 31 March – 3 April 2008.<br>M. Braun: "Reactive Power Supply by Distributed Generators", IEEE PES GM, 20-24 July 2008, Pittsburgh, USA |
| Chapter 6.1<br>Chapter 6.2 | M. Braun: "Reactive Power Supply by Distributed Generators", IEEE PES GM, 20-24 July 2008, Pittsburgh, USA |
| Chapter 6.3 | M. Braun: "Reactive Power Control in Mini-Grids', 4th European PV-Hybrid and Mini-Grid Conference, Glyfada, Greece, 29-30 May 2008 |

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  German Project supported by the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety
  http://www.multi-pv.de

Only the author is responsible for the content of the thesis.

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# List of Abbreviations

| | |
|---|---|
| AC | Alternating Current |
| ACN | Active Customer Network |
| ACN-DN | Active Customer Network connected to Distribution Network |
| ACN-TN | Active Customer Network connected to Transmission Network |
| ADN | Active Distribution Network |
| AS | Ancillary Services |
| AS-CN | Ancillary Services to the private Customer Network |
| AD-DN | Ancillary Services to the public Distribution Network |
| AS-TN | Ancillary Services to the public Transmission Network |
| AVR | Automatic Voltage Regulator |
| B | Battery |
| BEMI | Bidirectional Energy Management Interface |
| BNetzA | Bundesnetzagentur (German regulator) |
| BPP | Bulk Power Plant |
| CCHP | Combined Cooling, Heat and Power |
| CDE | Controllable Distributed Energy |
| CEER | Council of European Energy Regulators |
| CEU | Controllable Energy Unit |
| CHP | Combined Heat and Power |
| $CO_2$ | Carbon Dioxide |
| CSI | Current Source Inverters |
| CVPP | Commercial Virtual Power Plant |
| D | Diesel Generator |
| D-VAR | Dynamic VAR |
| DC | Direct Current |
| DeMoTec | Design Centre for Modular Supply Technology (one of ISET's laboratories in Kassel, Germany) |
| DEMS | Decentralised Energy Management System |

| | |
|---|---|
| DER | Distributed Energy Resources |
| DFIG | Doubly-Fed Induction Generator |
| DG | Distributed Generator / Distributed Generation |
| DMS | Distribution Management System |
| DN | Distribution Network |
| DNO | Distribution Network Operator |
| DSL | DIgSILENT Simulation Language |
| DSO | Distribution System Operator |
| DWD | Deutscher Wetterdienst |
| EDF | Électricité de France |
| EEG | Erneuerbare-Energien-Gesetz<br>(Renewable Energy Sources Act in Germany) |
| EEX | European Energy Exchange |
| EHV | Extra High Voltage |
| ES | Energy Services |
| EU | European Union |
| f | Frequency |
| FLH | Full Load Hours |
| FRT | Fault-Ride-Through |
| GB | Great Britain |
| GSP | Grid Supply Point |
| GTO | Gate Turn-Off Thyristors |
| HV | High Voltage |
| ICCT | Information, Communication and Control Technology |
| ICT | Information and Communication Technology |
| IEEE | Institute of Electrical and Electronics Engineers |
| IEC | International Electrotechnical Commission |
| IEV | International Electrotechnical Vocabulary |
| IG | Induction Generator |
| IGBT | Insulated-Gate Bipolar Transistor |

| | |
|---|---|
| ISET | Institut für Solare Energieversorgungstechnik |
| LSVPP | Large-Scale Virtual Power Plant |
| LV | Low Voltage |
| MAS | Multi-Agent Systems |
| MGCC | MicroGrid System Central Controller |
| MV | Medium Voltage |
| NRMSE | Normalised Root Mean Square Error |
| OPC | OLE for Process Controll |
| P | Active power |
| p.u. / pu | Per unit |
| PC | Personal Computer |
| PCC | Point of Common Coupling |
| PI | Proportional plus Integral |
| PV | Photovoltaic |
| Q | Reactive power |
| R | Resistance |
| REE | Red Eléctrica de España |
| RES | Renewable Energy Sources |
| RMS | Root Mean Square |
| RMSE | Root Mean Square Error |
| RTU | Remote Terminal Unit |
| S | Apparent Power |
| SCADA | Supervisory Control and Data Acquisition |
| SG | Synchronous Generator |
| SHP | Small Hydro Power |
| STATCOM | Static Compensator |
| SVC | Static VAR Compensator |
| TC | Total Costs |
| TCP/IP | Transmission Control Protocol/Internet Protocol |
| THD | Total Harmonic Distortion |

| | |
|---|---|
| TN | Transmission Network |
| TNO | Transmission Network Operator |
| TSO | Transmission System Operator |
| TVPP | Technical Virtual Power Plant |
| U | Voltage |
| UCTE | Union for the Co-ordination of Transmission of Electricity |
| vOC | Variable Operational Costs |
| V | Voltage |
| Var | Unit for reactive power (voltage ampere reactive) |
| VDN | Verband der Netzbetreiber<br>(association of network operators in Germany) |
| VPP | Virtual Power Plant |
| VSI | Voltage Source Inverters |
| VU | Virtual Utility |
| WT | Wind Turbine |
| WTG | Wind Turbine Generator |
| X | Reactance |
| Z | Impedance |
| ZSI | Z-Source Inverters |

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