Eidgenössische Technische Hochschule Zürich
Swiss Federal Institute of Technology Zurich

Technical
University of
Denmark

Characterization and Modeling

Balancing Power in the European System (BPES)

Report on Work Package 2

Matthias A. Bucher
Stefanos Delikaraouglou
Kai Heussen
Göran Andersson

EEH – Power Systems Laboratory
Swiss Federal Institute of Technology (ETH) Zurich

CEE – Center for Electrical Engineering
Danish Technical University (DTU) Copenhagen

Authors and Contact

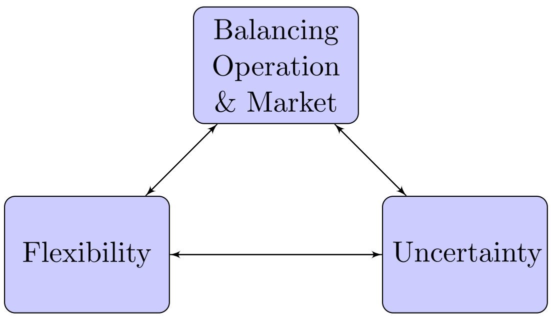
Matthias Bucher	Power Systems Laboratory, ETH Zurich	mb@eeh.ee.ethz.ch
Göran Andersson	Power Systems Laboratory, ETH Zurich	andersson@eeh.ee.ethz.ch
Stefanos Delikaraoglou	Center for Electrical Engineering, DTU Copenhagen	stde@dtu.dk
Kai Heussen	Center for Electrical Engineering, DTU Copenhagen	kh@dtu.dk

Contents

Chapter 1

Introduction

This report deals with different modeling approaches that are needed in the context of issues dealing with balancing markets and operation of reserves. The goals of this report are to highlight, characterize and give suitable models for three pillars relevant in the context of balancing. The three pillars are the *balancing operation and market*, i.e. the market, where diverse products related to reserves can be procured, *operational flexibility*, i.e. the ability of the system to withstand certain disturbances in the power production and consumption, and *uncertainty* introduced mainly by fluctuations (e.g. load) and forecast errors (e.g. wind). Future work on the interactions between different pillars can be based on the models given in the respective chapters.



The report is structured in three parts corresponding to the three pillars. The first part is on the characterization and modeling of flexibility in a balancing power context. This part provides first a definition and general a introduction to operational flexibility as well as a metric for its quantification. In the second chapter, generalized models for units are presented using the Power Nodes framework. In that context, the parameters that are relevant for the corresponding unit is given. A special part deals with demand response. For the grid side, linear power flow formulation and sensitivity factors are discussed as well as models for HVDC interconnections.

The chapter concludes with dynamic line rating approaches and a formulation for probabilistic power flows that considers the influences from reserve operation. The last chapter of the first part deals with the characterization the flexibility availability, especially, a method is presented that allows the determination of the locally available operational flexibility using the same metric as for the uncertainty. The method is exemplarily applied and a few results are discussed.

The second part deals with the modeling and characterization of balancing needs, i.e. the uncertainty and fluctuations of the system. We therefore illustrate a methodology to model forecast uncertainties, e.g. from wind forecast errors, using copulae. The remainder deals with a method that allows to characterize uncertainties using a metric consisting of ramping rate, power and energy.

In the last part, we focus on the status quo of balancing markets. Therefore control reserves are classified and important parameters related with balancing markets summarized. The parameters are identified for a few selected markets in Europe. Additionally, the examples of Denmark and Switzerland are looked into in more detail. Finally, predictive activation methods as well as other market setups are discussed.

Part I

Characterization and Modeling of Flexibility in a Balancing Power Context

Chapter 2

Flexibility: Terminology and Definitions

We first briefly define and discuss what we mean by flexibility, then introduce the used flexibility metric. The metric will be used in the subsequent chapters.

2.1 What is flexibility?

We define *operational flexibility* as the ability of the system to react appropriately on a specific disturbance on the system. Flexibility can be considered on different time-scales from seconds (e.g. spinning reserves) up to years (e.g. operation of a seasonal hydro storage power plant). Sufficient, adequate operational flexibility needs to be available in every time instant in order to guarantee a secure operation of the power system. We focus mainly on the secure operation with respect to frequency stability. Similar considerations should however also be made regarding for example voltage stability, transient stability, etc.

We can distinguish between flexibility providers and consumers. Typical providers would include controllable generation units such as hydro storage power plants or gas-fired power plants but also the curtailment of wind turbines or PV can be seen as provision of flexibility. Moreover, also possibilities to change the grid topologies or capacities (e.g. dynamic line rating) or even actively control the power flows (e.g. HVDC) adds flexibility to the system. The consumption of flexibility arise mainly from load fluctuations, outages of generators or the increasing uncertainty due to the emerging renewable energy sources. Most of the units are ambiguously providers in some situations and consumers in other situations or other time scales.

Generally, we can distinguish the flexibility into different classes:

- Physically available flexibility: The flexibility that is physically possible. This class is limited only by technical constraints and units that are in maintenance (or have an outage).
- Economically available flexibility: This is a subclass of the physically available flexibility. Some provision of flexibility might lead to high economic costs and are thus omitted as much as possible, e.g. abrasive operation of a coal-fired power plant.
- Flexibility available on the market as a product: Part of the economically available flexibility can be sold as a product on the market such as control reserves. Usually these products have strict requirements and thus not all the flexibility can be sold as such.
- Flexibility procured: It is preferable that the markets for flexibility products have a certain liquidity and thus the bought flexibility represents only part of the flexibility in the market. This flexibility can directly be used/activated either by a TSO or other parties responsible for balancing.

With the general trend of merging the power system operation and markets on an European wide scale as well as the integration of generation units in the lower voltage grids, the grid aspects move to a central position. Considering possible congestions or security margins (e.g. N-1 criterion) in the transmission system, aside from the temporal availability also the *locational availability* is important.

2.2 Flexibility Metric

In order to quantify the operational flexibility, a suitable metric is needed. Different metrics have been proposed. Following a similar approach as presented in [1] we use ramping rate R, power capacity P and energy E as a metric. The parameters of the metric are briefly described. The $+$ and $-$ refer to positive, respectively negative changes compared to the current setpoints.

Ramping Rate R^+, R^-: The ramping rate of becomes more important. Especially with increasing shares of renewable energy sources, steep changes in the power infeed are observable. For example during sunset the PV production is reduced fast and forecasts of a squall line might be wrong leading to high ramping requirements.

Power Capacity P^+, P^-: The capacities available to ramp up or down some generation units is crucial. Usually substantially more capacity is available than used. The units are usually in different states (e.g. switched off, fully-dispatched, etc.). Due to different ramping time requirements, different types of reserves are procured, e.g. fast reserves are usually provided by fast-ramping units that are online.

Energy absorption/release E^{+}, E^{-}: In earlier times, the energy constraint was basically given implicitly by the generation limit or in the case of hydro storage by the size of the reservoir. However, with the intended wide-spread deployment of demand side participation possibilities, energy constraints might increase in importance.

Different authors use this or similar metrics to describe operational flexibility, e.g. [2]. The metric shown above will be used in the next chapters.

Chapter 3

Modeling of Units and Grids

This chapter summarizes modeling approaches used in various applications within the project. The first part focuses on the modeling of generation and load units, the second part is on the modeling of the transmission grid.

3.1 Unit Flexibility

3.1.1 Generalized Flexibility Modeling

In order to characterize and estimate the available operational flexibility as well as for the development of operational strategies that coordinate and operate the balancing power a framework is needed. The framework should allow to efficiently estimate the available flexibility, i.e. balancing capabilities, from various sources of the system as well as the uncertainty. It is necessary to be able to represent the flexibility in a generalized way, for example by using the flexibility metrics introduced above, based on the units of the power systems. For the estimation of the available operational flexibility as well as the uncertainty we first need a modeling framework for the units that suffices some requirements:

- The modeling should allow to represent the predominant characteristics and constraints of the units.
- The framework should be generalizable for various types of units ranging from storage devices over hydro power plants to concentrated solar power plants.
- The modeling should exhibit values related to flexibility, such as ramping limitations or energy storage constraints.
- Further, if possible, the resulting mathematical representation should have suitable properties, e.g. such as linearity, which makes large-scale optimization feasible.

- As balancing comprises system-wide aspects, the interconnection over a transmission system should be easy to model.

Various modeling frameworks are described and compared for example in [3]. In the next sections, we describe the framework that has been used for the modeling of the units as well as provides a list with characteristic values.

3.1.2 Unit Flexibility with Power Nodes approach

The Power Nodes Framework is a generic modeling framework developed by DTU and ETH in earlier collaborations. It allows to represent the most common units in power systems to be expressed by a differential equation of first order that is represented in a discrete-time representation and some constraints in order to represent physical and operational limits. A detailed description, derivation and application of the modeling framework can be found in [4], [5], [6]. For completeness we state the basic equations.

$$\begin{aligned} C\left(x_{k+1}-x_k\right) = \eta_l P_{load} - \frac{1}{\eta_g} P_{gen} + \xi - v - \omega \\ \text{subject to} \\ 0 \leq x \leq 1 \\ 0 \leq P_{gen,min} \leq P_{gen} \leq P_{gen,max} \\ 0 \leq P_{load,min} \leq P_{load} \leq P_{load,max} \\ R_{gen,min} \leq \dot{P}_{gen} \leq R_{gen,max} \\ R_{load,min} \leq \dot{P}_{load} \leq R_{load,max} \\ \xi \cdot \omega \geq 0 \\ |\xi| - |\omega| \geq 0 \\ v \geq 0 \end{aligned} \tag{3.1}$$

C represents the storage capacity of the device. If $C > 0$ the device can store energy, otherwise it can't. The state of charge is denoted by variable x, which is limited to be within the range of 0 and 1. The state of charge is influenced by different variables. Some of them are controllable to a certain extent and others are determined by the physical nature of the unit. The variables P_{gen}, P_{load} are the variables that are interacting with the grid side, i.e. they represent the amounts of (electrical) power that is injected or drawn from the grid side. ξ and ω are variables associated with the demand/supply side. ξ represents the energy that is provided, e.g. the potential energy stored in a hydro-storage lake or the wind energy that a wind turbine can harvest. v represents storage losses and ω is used to express curtailments, i.e. energy that is available but not converted into electrical energy, e.g. when a wind turbine is shut down. The first two constraints ensure that the injection and consumption to/from the grid are within the physical limits. The ramping rates are calculated by taking the first time derivative of P_{gen} and P_{load}. They are also bounded correspondingly. The last constraints ensure that the curtailment works properly and the losses are non-negative.

The appeal of the modeling framework lies on the one hand in the general formulation which allows to represent different units in a unified way. On the other hand, due to the discrete-time formulation, dynamic processes can be approximated and the resulting linear formulation is suitable for the inclusion in established optimization methods. Due to the linearity, also large scale problem can be tackled efficiently.

3.1.3 Relevant Parameters

Table 3.1 displays how certain units can easily be modeled using this framework. The columns are:

- Unit: Unit Type
- Dynamics: Predominant dynamic part of the unit described using Power Nodes framework.
- Controllable Variables: Variables that can be influenced by an operator. These variables introduce controllability and thus flexibility in the system.
- Constraints: The parameters that are typically relevant in constraints
- Temporal Pattern: Typical pattern of changes in the power output of the units.

In the case of DSM no numbers are given as the parameters are highly dependent on the operation scheme. This overview provides only coarse models. Depending on the applications, it might need additional constraints and parameters. For example instead of only considering the ramping rate, depending on the purpose of the study, one could also consider start-up time, maximum step changes, etc. However, for many holistic modeling purposes, this linear model should provide sufficient accuracy.

Table 3.2 provides typical values for certain techno-economic variables.

Unit	Dynamic	Controllable Variables	Constraints	Temporal Pattern
PV	$P_{gen} = \eta_g \xi - \omega$	ω	$R_{gen,max}$ $P_{gen,max}$	daily seasonal
Wind	$P_{gen} = \eta_g \xi - \omega$	ω	$R_{gen,max}$ $P_{gen,max}$	seasonal
Coal	$P_{gen} = \eta_g \xi$	P_{gen}	$R_{gen,max}$ $P_{gen,max}$ η_g	base load
Lignite	$P_{gen} = \eta_g \xi$	P_{gen}	$R_{gen,max}$ $P_{gen,max}$ η_g	base load
Nuclear	$P_{gen} = \eta_g \xi$	P_{gen}	$R_{gen,max}$ $P_{gen,max}$	base load
Biomass	$P_{gen} = \eta_g \xi$	P_{gen}	$R_{gen,max}$ $P_{gen,max}$ η_g	
Run-of-River	$P_{gen} = \eta_g \xi - \omega$	ω	$R_{gen,max}$ $P_{gen,max}$ η	base load
Storage Hydro	$C\left(x_{k+1} - x_k\right) = -\frac{P_{gen}}{\eta_g} + \xi + \omega$	P_{gen}, ω	$R_{gen,max}$ $P_{gen,max}$ η C	peak load
Pumped-Storage Hydro	$C\left(x_{k+1} - x_k\right) = \eta_l P_{load} - \frac{P_{gen}}{\eta_g} + \xi - \omega$	$P_{gen}, P_{load}, \omega$	$R_{gen,max}$ $P_{load,max}$ C η_l, η_g	peak load
Gasturbine/Oil	$P_{gen} = \eta_g \xi$	P_{gen}	$R_{gen,max}$ $P_{gen,max}$ η_g	peak load
CCGT	$P_{gen} = \eta_g \xi$	P_{gen}	$R_{gen,max}$ $P_{gen,max}$ η_g	peak load
CSP	[6]	P_{gen}	[6]	daily, seasonal
Load	$\eta_l P_{load} = -\xi + \omega$	ω	$P_{load,max}$	-
DSM	$C\left(x_{k+1} - x_k\right) = \eta_l P_{load} - \frac{P_{gen}}{\eta_g} + \xi - \omega$	P_{gen}, P_{load}		-

Table 3.1: Unit Modeling

Generation Technology	Load Factor (%)	Ramping Capability (% max output/h)	CO2 (t/MWh)	Efficiency (%)	OPEX (€/KW)	Fuel Cost (€/MWh)	Startup Cost (k€/startup)
Coal Conventional	86	40	0.77 (0.95)	45 (42-44)	18-22	20-25	28
Gas Conventional	60	50	0.36	58	13-27	45-50	10
Coal CCS	85	40	0.080	33-37	60-80	26-31	31
Gas CCS	60	50	0.055	46-50	35-45	55-60	11
Oil	21	60	0.74	32	15-20	100-150	10
Nuclear	90	40	0	-	90-110	7-9	0
Wind Onshore	30	-	-	-	20-25	0	-
Wind Offshore	37	-	-	-	80-100	0	-
Solar PV	10-17	-	-	-	20-25	0	-
Solar CSP	47	40	-	-	180-220	0	-
Biomass	80	40	0.010-0.060	35 (80)	13-15	45-55	52
Geothermal	91	40	-	-	90-110	0	-
Hydro	35	Fully flexible	-	-	5-10	0	-

Table 3.2: Techno-economic unit data.

3.2 Demand Response

Here the main control mechanisms and modeling approaches for Demand Response (DR) are described. In addition, some concepts proposed in the relevant literature, regarding the controlability classes and the taxonomy of DR resources are briefly outlined.

3.2.1 Traditional Demand Response applications

Until recently electricity demand was considered as highly inelastic and uncontrollable. However, some simplified concepts of demand response have been applied in the operation of the power system for many years already. The most common traditional Demand Response applications are:

1. Time-of-use (ToU) pricing. The retail electricity prices are composed by numerous levels, instead of a flat rate, in order to reflect more accurately the actual cost of electricity over different periods. Consumers are exposed to higher tariffs during peak load hours in order to incentivize a demand shift towards the off-peak periods.

2. Commercial/industrial programmes. Under specific tariff schemes, load curtailment of commercial or industrial consumers can occur during peak-load hours or in the event of unexpected contingencies, i.e., generation or transmission outage. This approach is implemented by the CalISO [1] in the form of Critical Peak Pricing (CPP) programs.

3. Frequency regulation. During contingency events, when system frequency deviates from its nominal value, power consumption is directly affected according to the frequency characteristic of the load.

3.2.2 Control of Demand Response

Demand Response control mechanisms

The two main categories of demand response control architectures are the following:

1. Direct control enables direct communication with specific appliances that can be turned off or cycled for relatively short periods of time [7]. Typical devices where direct control can be applied are air-conditions, heat pumps etc., which can be switched off for a limited amount of time without violating the comfort zone of the end users. This control type allows more precise response and highest possible resolution [8].

[1] Californian Independent System Operator

2. Indirect control, where demand response is activated through price signals that are issued from an aggregator to his demand portfolio. The main rational of this mechanism is that end users will adjust their consumption according to the real cost of the system. However, the estimation of the appropriate price signal to the consumers is far from trivial, given that the demand portfolio may include different types of loads [9].

Controllability classes

The work in [10] proposes a categorization of distributed energy resources (DER), including demand response, according to their type of controllability. The main features of each class are summarized here.

1. Stochastic operation devices, whose power input/output is stochastic, e.g., wind or solar systems. These devices are uncontrollable and thus they have to accept any market price.

2. Shiftable operation devices, which they can vary their load within certain limits but their total energy consumption is constant over time, e.g. ventilation systems.

3. External resource buffering devices can produce also other types of energy (apart from electricity) and have some kind of buffering, e.g. heat pumps.

4. Electricity storage devices, that are connected to power network and they can feed-in or consume electricity, e.g., batteries and flywheels.

5. Freely-controllable devices, that their operation is controllable subject to technical constraints,e.g. diesel generator.

6. User-action devices, which are directly controlled by the end user, e.g., lighting. This type of devices is similar to stochastic operation devices, since their operation is partially predictable and has limited flexibility.

3.2.3 Taxonomy

A taxonomy of the different demand response resources is proposed in [3]. The suggested taxonomy is based on four constraints, namely i) power capacity ii) energy capacity iii) energy level at a specific deadline and iv) minimum runtime. Three types of flexibility models are identified and their properties are briefly summarized here.

1. The *Bucket*, which is a power and energy constrained integrator, such as a house with heat pump used for energy storage.

2. The *Battery*, which has the same properties as the *Bucket* with an additional constraint that the state of charge should be maximum at a specific time, e.g., an electric vehicle.

3. The *Backery*, which is similar to the *Battery* but includes an extra constraint that the unit must operate in one continuous stretch at constant power consumption.

The above framework imposes a hierarchical relationship between the three models defining as higher quality of services, those which are less restricted, taking into account not only the number of constraints but also the values of specific parameters in the system. The complete mathematical definition of these models is given in [3].

3.2.4 Demand response modeling approaches

Various different approaches are proposed in the literature for modeling the demand response. Each methodology is based on certain assumptions and thus it is suitable for different kind of studies. Three common modeling methods of demand response are:

1. Exact representation of the system. Here the market architecture and the demand model are assumed to be perfectly known, like in [11] and [12]. These methods can provide detailed results for specific cases but their outcome cannot be directly generalized for the whole system, given the high diversity in the properties of the electricity consumers [13].

2. Negative generation. This is a common approach in studies carried out on the system level, where demand response is modeled by a set of units assuming that many individual loads can be perfectly controlled by an aggregator [14], [15]. This method can give high level indications about the effect of demand response in the operation of the power system but it neglects any concerns on how the required flexibility will be achieved.

3. Demand elasticity. The main assumption of this approach is that consumers are able to adjust their demand level according to an elasticity value and thus affect the cleared quantity and prices of the market (see figure 3.1). Despite that this concept is directly applicable to the existing market structure (using demand bids), the appropriate selection the demand elasticity value is far from trivial. In particular, the demand flexibility is related with external environment conditions [16], e.g., temperature, as well as the response saturation where beyond a certain point demand becomes unresponsive to price signals [17].

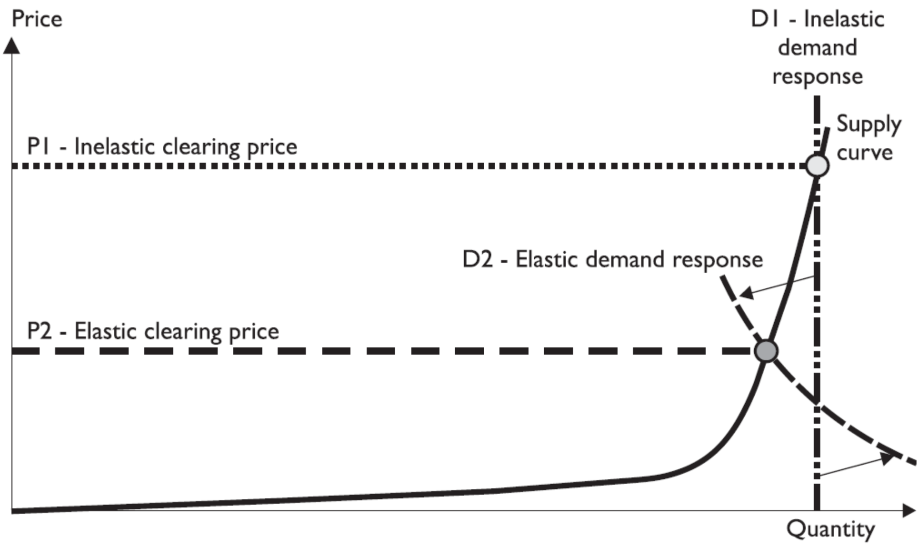


Figure 3.1: Impacts of Demand Elasticity on Wholesale Price (from [9])

For instance, if the comfort limits of a house using a heat pump are violated, the heat pump should remain on until the temperature is restored.

3.3 Grid Modeling for Balancing Power

3.3.1 Introduction

Historically the transmission grid was designed and dimensioned for a centralized production from large nuclear or fossil power plants and consumers in the vicinity. In newer times, with the goal of liberalized power markets and the increase of renewable energy sources, basically two challenges arise: first, due to the dependence on the weather, renewable energy sources such as wind farms or PV, CSP plants are placed were the yield is maximized. Thus, the energy might be transported over long distances, maybe involving multiple control areas. Together with the urge to liberalize and couple energy wholesale markets, the power flow patterns are changing more rapidly leading a congested grid with local bottlenecks. On the other hand, the aging infrastructure needs replacement. The grid reinforcement as mentioned, e.g. by the ENTSO-E [18], should also consider not only the changing production portfolios but also the resulting operational flexibility. So far, in most of the balancing operation strategies, the grid was not essential as for the reserve operation, a "copperplate assumption" was mostly sufficient. However, with a congested transmission grid and scattered flexible resources, the grid topology should be incorporated in operational strategies and market operation in a suitable way. In other words, the grid model is supporting the balancing decision problem. The grid can be represented in different complexity and detail. For our purposes, it should capture the relevant characteristics with respect to the power flows but be as simple, i.e. linear, as possible in order to be included in optimization problems. In the next section, the basic modeling approach of the grid is outlined.

3.3.2 Linearized Grid Modelling and Sensitivity Factors

For the grid representation we use a linearized power flow formulation [19]. The assumptions are that the voltage is around the nominal operation set-point of 1 p.u. and reactive power flows are not considered. This leads to a linear formulation of the power flow as a function of the voltage angle differences. For light loading situations, i.e. small voltage angle differences, the linearized power flows deviate little from the full AC formulation. For heavy loading conditions, the differences grow larger. With respect to control reserve operation, one should remark two points: first, the power flows are influenced by the operation of control reserves, however, the influence is comparably small and shows a (locally) linear behavior. Secondly, for the determination of an initial power flow, also the full non-linear power flow equations can used and then approximated around the set point. This is a remedy to still keep the linearity but not losing too much accuracy compared to the full AC solution.

Sensitivity factors, i.e. factors that describe the influence of changing a certain parameter on another, can be a very useful tool in order to estimate the effects of e.g. a certain control strategy. We use three different sensitivity factors, that are based on a reformulation of the above stated linearized power flow equations.

PTDF

PTDF stands for power transfer distribution factor. It is a straightforward reformulation of the linearized power flow equations. Details can be found in [20]. These linear sensitivity factors describe the influence of a change in injection at a certain bus on the power flow on a certain transmission line when the change is compensated by a slack bus. Due to linearity the power flow equations can thus be written as:

$$P_L = HP_{Bus} \tag{3.2}$$

Where P_L is a vector with the line flows, H is the PTDF matrix and P_{Bus} is a vector with the active power injections in every bus.

LODF

LODF stands for Line outage distribution factor [20]. It describes the change in the power flow on a certain transmission line, if another line trips.

GGDF

GGDF stands for generalized generation distribution factor [21]. It describes the change in the power flow on a certain line, if a certain unit trips and is compensated by certain other units (e.g. control reserve operation).

All three sensitivity factors were used in the methodology in [22].

3.3.3 Modeling of HVDC Interconnections

HVDC interconnections enable additional operational flexibility as their power flow is controllable to a certain extent. HVDC interconnections are already being installed in a few regions of the European interconnected system, but it is anticipated that a future transmission system will incorporate substantially more HVDC interconnections [18]. The model, valid for steady-state operation, is given as:

$$-P_{DC,max} \leq P_{DC} \leq P_{DC,max} \tag{3.3}$$

$$P_{Bus} = P_{gen} - P_{load} + B \cdot P_{DC} \tag{3.4}$$

The first equation limits the maximum power that can be transferred. Limitations from voltages are not directly considered. The injections/extractions from the HVDC lines are added/subtracted to the net power injection of every bus. B is a matrix that describes the connections between the buses:

$$B_{ij} = -1 \text{ if DC line } j \text{ starts at bus } i \tag{3.5}$$

$$B_{ij} = 1 \text{ if DC line } j \text{ ends at bus } i \tag{3.6}$$

This linear model integrates well in the linearized AC-model. It has also been applied in [23] and can also be extended to multi-terminal HVDC grids. However, some more aspects as mentioned in [24] should be considered.

3.3.4 Dynamic Line Rating

Dynamic Line Rating (DLR) is considered a promising way of increasing the thermal limitations of transmission lines under some conditions. Traditionally, the thermal line limit was fixed such that it would not overheat also under very bad weather conditions, i.e. low wind speeds, high solar irradiation. DLR considers current weather conditions and adapts the thermal limit dynamically. Thus, in suitable weather conditions, e.g. strong winds during winter, the capacity can increased substantially. Some research has been done already, e.g. [25], [26], [27], and also some standard thermal line models are available [28], [29], [30]. In [31] we present a method how to couple DLR models with the linearized models presented above in a probabilistic dispatch problem that considers weather forecasts in a risk-averse manner.

3.3.5 Probabilistic Power Flow

In [23] we describe a probabilistic power flow. Probabilistic in the sense that some of the injections may are of fluctuating nature, e.g. intermittent renewable energy sources. We propose the following general probabilistic power flow formulation:

$$\begin{aligned} P_{ac} &= S\left(P_g - P_l + P_\Delta + B_{dc}P_{dc} + P_T - d\left(\sum \Delta P_i + P_{T,i}\right)\right)\dots \\ &= S\left(P_g - P_l + B_{dc}P_{dc}\right) + NP_\Delta + NP_T \end{aligned} \tag{3.7}$$

Where P_g and P_l correspond to the scheduled production and consumption at every bus, $B_{dc}P_{dc}$ is the injection or extraction of HVDC interconnections according to the modeling approach described above, P_T relates to the activates manual reserves and the remaining term represents the automatically activated reserves, i.e. the total deviation minus the part compensated by manual reserves. The uncertainty of the bus, e.g. due to forecast errors is represented by the random variables in P_Δ. This can be reformulated resulting into a matrix operation on a deterministic part and in the stochastic part $N \cdot P_\Delta$. This formulation can be applied in different problem settings. More details can be found in [23] as well as its application in an operational algorithm that procures the reserves in suitable locations such that likely bottlenecks can be counteracted.

Chapter 4

Determination of Locational Flexibility

In this chapter, we present a method that is able to identify the operational flexibility that is available in a given location in the grid.

4.1 Methodology to Determine Locational Flexibility

We present a method that is able to characterize the locational flexibility at a certain point in the grid. The detailed description and formulation can be found in [32]. The method is briefly outlined and applied exemplarily in the following:

4.1.1 Outline of the proposed method

The methodology's goal is to determine the operational flexibility in terms of the above described metric $R^{+,-}$, $P^{+,-}$, $E^{+,-}$ at a certain point in the grid. Equivalently the question could be: "What is the largest disturbance at certain point in the grid the system can withstand?"

The methodology follows four steps:

1. Expression of the operational flexibility of every unit
2. Attach generic disturbance to the bus(es) of interest
3. Impose system-wide constraints
4. Find limits of the generic disturbance using polytopic projection

In the next sections we will discuss briefly each step. The first three steps are needed to prepare the flexibility set. The flexibility set is the set of all possible combinations of deviations from the schedule that the whole system can withstand. The last step is then a projection on the relevant dimensions in order to find the boundaries of the disturbance that can be stabilized.

4.1.2 Step 1: Single unit flexibility

The flexibility of a unit can vary depending on the type as well as its current state. For example a fully-dispatched hydro unit cannot provide any upwards ramping although it has high ramping rates. We model a single unit based on the equations of the Power Nodes framework described above. Based on its current dispatch, we can directly express the available operational flexibility, i.e. the amount we could increase/decrease the production, the corresponding limits on the ramping rates as well as the energy that could additionally be charged (until the storage is full) or discharged (until the storage is empty). The flexibility is calculated for one or more timesteps. In the case of more timesteps, we explicitly allow the re-dispatching strategy to change after some timesteps, therefore enabling more flexibility.

4.1.3 Step 2: Flexibility Drain

At the bus of interest, we attach a unit that should represent a generic disturbance. We call that unit *flexibility drain*. In order to characterize the locally available flexibility, we instead determine the largest locally disturbance that can be balanced by resources available to the grid. This unit has no limits, but the constraints are implicitly given by system-wide coupling constraints.

4.1.4 Step 3: System-wide coupling constraints

Basically, we are faced with two system-wide constraints that have to be fulfilled with respect to active power:

1. Transmission constraints
2. Power Balance

The first constraint makes sure, that only feasible transmission are considered and the second constraint ensures that the active power balance is kept and thus frequency remains stable. It should be noted that the imposed grid constraints complicate the calculation of the flexibility. In case of no imposed transmission limits, i.e. "copperplate approach", the flexibilities from the single units can be summed up using a Minkowski sum. In a similar fashion, in [33] the flexibility is calculated.

4.1.5 Step 4: The projection methodology

Based on step 1-3 we can build the *flexibility set*. The structure of this set can be formulated as follows:

$$F = \{(f_d, f_s) \in \mathbb{R}^{n_d+n_s} | C_s f_s + C_d f_d \leq b\} \tag{4.1}$$

where the vector f_s corresponds to all state variables associated with units providing flexibility and the vector f_d contains the state variables associated with the flexibility drain. These variables are associated with the system states in different timesteps, i.e. power infeed of generators, state-of-charge of storage units. In the case of the flexibility drain, also variables associated to ramping limitations and energy constraints are needed. n_d and n_s are the dimensions of the vector and C_s, C_d, b are appropriately stacked versions of the constraints outlined above.

The goal is then to find the feasible limits of the flexibility drain. Formally this can be written as:

$$\begin{aligned} F_d &= \{f_d \in \mathbb{R}^{n_d} | \ \exists \ f_s, (f_d, f_s) \in F\} \\ &= \{f_d \in \mathbb{R}^{n_d} | \ G f_d \leq g\} \end{aligned} \tag{4.2}$$

In other words: we are looking for all the feasible combinations of the metric $\{E, P, R\}$ of the flexibility drain, such that the portfolio of generators is able to keep the system stable. Illustratively speaking, this is nothing else than the projection of the flexibility set on the dimensions of the flexibility parameters of the flexibility drain. This methodology has also been applied in [22]. Fig. 4.1 shows a simple flexibility set in red and the corresponding projection in green on the dimensions $E1, E2$. The green area is basically the feasible region for $E1, E2$, i.e. a $I1$ can be found such that the point is in the red box. The dimension to project on would be the parameters of the flexibility drain and the (many more) parameters giving flexibility to the power systems would be $I1$. Methods to perform this projection are well-known [34].

The complete formulation of the methodology and more detailed description can be found in [32]

4.1.6 Case Study

We show a brief example of a possible application. Further examples can be found in [32].
In order to illustrate some of the features of the proposed methodology we apply it exemplarily to a small power system as shown in Fig. 4.2 [35]. It can be considered to be a simplified representation of the interconnected system

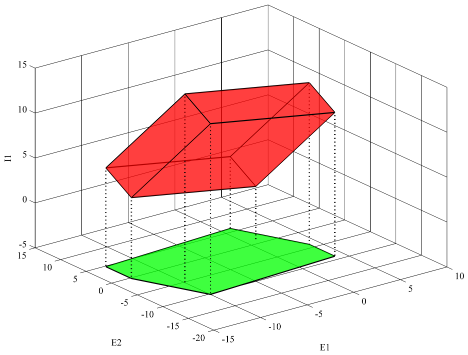


Figure 4.1: Illustration of the Projection Methodology.

of France (buses 3,4,5,6), Italy (7,8,9,10) and Switzerland (1,2). Large generation units are attached to bus 3 and 5, corresponding to nuclear power plants in France. At bus 2 hydro power units, which are generally very fast, are connected and at buses 8 and 10 mainly fossil fuel power plants are attached. The ramping rates are considered to be substantially larger at bus 2 than at the other buses. Loads are considered constant. The horizon is 6 time steps and all results are in p.u. with a base of 1 GW.

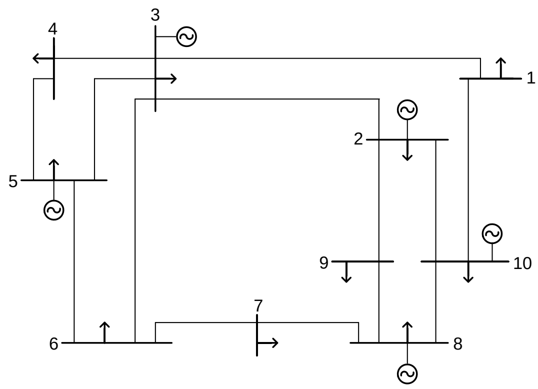
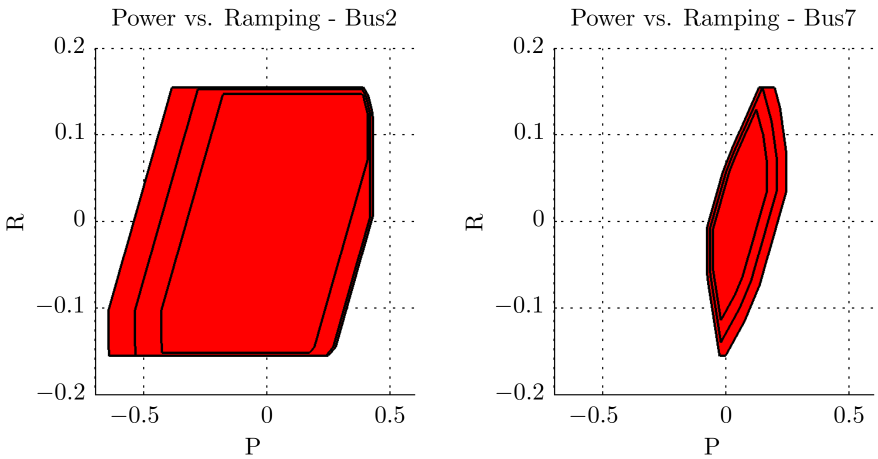


Figure 4.2: Grid setup with 10 buses and 5 generators.

4.1.7 Evolution of Power vs. Ramping over the last 3 time steps

In a first small case study, the flexibility drain is attached to two different buses - namely, 2 and 7. For every bus, three projections on the variables associated with the power P and the ramping rate R of the flexibility drain are performed, i.e. for the last three timesteps $t = \{4, 5, 6\}$. The following is observed:

- The possible combinations of power and ramping rates grow with the timesteps, i.e. with the time we allow for ramping or prepare for faster ramping.
- At bus 2 the flexibility is large, i.e. the area of the projection is large, as it is next to the most flexible unit in the system. At bus 7, which is further away from bus 2, the flexibility is reduced as not that much flexibility can be exported to bus 7.



From this small case study, we can conclude, that the flexibility can be different in different locations, mainly due to limited transmission capacities. Another important factor is the time that is given for ramping.

Future work would apply the methodology to a more real case study. Especially interesting it would be to compare the available flexibility from different types of reserve products with the flexibility needed at different locations in the grid.

Part II

Modeling and Characterization of Balancing Needs

Chapter 5

Characterization of Balancing Needs

In this chapter, first a method to model forecast uncertainty using copulas is demonstrated. Secondly, a method to quantify uncertainty using the metric described previously is shown.

5.1 Modeling of Forecast Uncertainty using Copula

We briefly present a method in order to model the dependencies between forecasted and actual values. The methodology is applicable to a variety of problems. We use the method to capture the dependencies in meteorological data. With increasing shares of weather dependent production, such as PV or wind farms, uncertainties from weather forecasts transform more and more to uncertainties in system operation. The method allows to generate possible scenarios of the actual value based on a given forecast, e.g. wind speed forecast. The method is briefly outlined next.

5.1.1 Copulae in Weather Forecasts

The meteorological data exhibits strong correlations, both temporal, i.e. between forecast and actual values, and spatial, i.e. measurements of different weather stations. The goal is to find the probability distribution of every meteorological quantity considered when its forecast is known. Not only the local forecast of one quantity should be considered but also the forecasts of stations with high correlation. Thus we capture the additional information on the local quantities given by surrounding stations. In order to model the dependence of multiple random variables, i.e. the actual value, its forecast and corresponding forecasts from other stations, multivariate probability distributions have to be approximated. We therefore employ a *copula* approach [36]. Copulas have been used extensively in risk management and finance [37], [38], but also in weather research [39] and in the modeling of correlated wind power in Europe [40]. We use copulas to represent multivariate distributions that capture the correlations between forecasts and actually realized values from different locations in the grid. The method can be applied not only for wind but for general forecast error characterization, if there is a significant correlation.

A copula is a multivariate distribution with uniform marginal distributions, which describes the dependence between random variables. A joint probability distribution can be expressed as its marginal distributions and their dependence given by the copula. There are different families of copulas. We demonstrate the concept for a normal copula.

Let X be a vector of random variables which follows a multivariate distribution where the entry X_i, $i \in [1, m]$, is a random variable with distribution function F_{X_i} and probability density function f_{X_i}. The transformation $U_i = F_{X_i}(X_i) \sim \mathcal{U}(0,1)$ leads to an uniformly distributed U_i in $[0,1]$. Using the transformation $Z_i = F^{-1}_{\mathcal{N}(0,1)}(F_{X_i}(X_i)) \sim \mathcal{N}(0,1)$ leads to a standard normally distributed random variable Z_i. A m-dimensional normal copula can thus be written as $C_X(u_1, \ldots, u_m) = F_{\mathcal{N}(0,\Sigma)}\left(F^{-1}_{\mathcal{N}(0,1)}(u_1), \ldots, F^{-1}_{\mathcal{N}(0,1)}(u_m)\right)$ with Σ being the covariance matrix , which describes the dependance of the random variables [39]. The corresponding density function is denoted with $c_X(u_1, \ldots, u_m)$. The joint probability f_X of an m-dimensional distribution can thus be written as:

$$
\begin{aligned}
& f_X\left(\overbrace{F^{-1}_{X_1}(u_1)}^{x_1}, \ldots, F^{-1}_{X_m}(u_m)\right) = \\
& \underbrace{c_X(u_1, \ldots, u_m)}_{\text{Copula}} \times \underbrace{f_{X_1}\left(F^{-1}_{X_1}(u_1)\right) \times \ldots \times f_{X_m}\left(F^{-1}_{X_m}(u_m)\right)}_{\text{Marginal distributions}}
\end{aligned}
\tag{5.1}
$$

Using historic data we can estimate the density functions and fit the copula using the maximum likelihood method. Samples from a multivariate normal distribution, i.e. the copula, can easily be created and can then be transformed to the desired samples of X using (5.1).

Fig. 5.1 shows exemplarily the densities of wind speed forecasts and actual values. The samples are generated using a copula and exhibit a correlation and mean close to the one of the measured data. The diagonal pattern indicates a strong correlation between forecast and actual value.

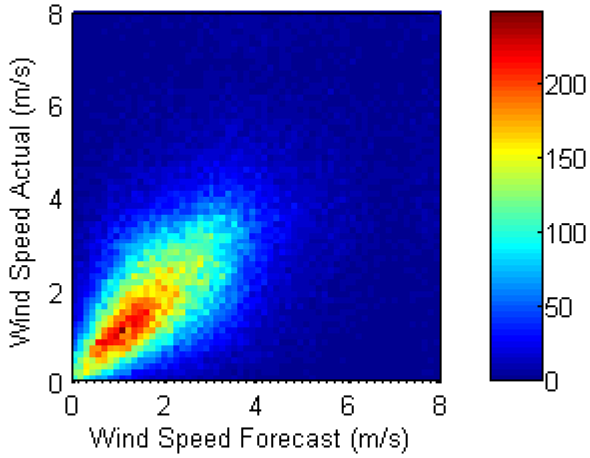


Figure 5.1: Density of 50000 samples from a copula model connecting actual and forecasted wind speeds. The more red the higher is the density.

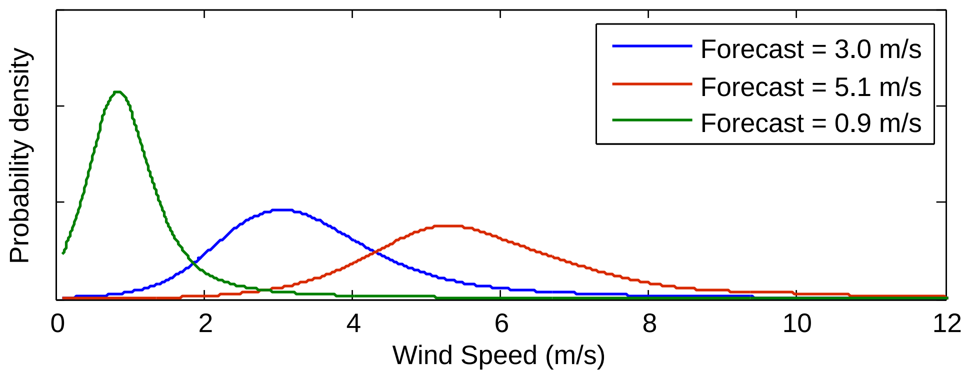


Figure 5.2: Influence of forecasts on marginal probability distributions.

Thus for a given forecast value the marginal distributions of the actual realization varies as is shown in Fig. 5.2 for three different forecasts.

We assign every transmission line to a weather station and build a copula for every of the considered meteorological values and every geographical location. This method has been used in [23], [31].

5.2 Methodology for Uncertainty Quantification

5.2.1 Motivation

The operation of the power system is inherently related with stochasticity both in production and consumption side due to partly predictable energy sources and load. This uncertainty requires that the power system has always enough flexibility in order to maintain the balance between generation and demand.

In this chapter, we focus on the characterization of uncertainty, whereas in the next chapter we focus on the available flexibility. The research question that arises is: "How much flexibility is needed at every grid location in order to cope with the uncertainty during the actual operation of the power system?"

5.2.2 Methodology

In order to answer this question we need a common framework for representing and quantifying the concepts of flexibility and uncertainty. The proposed framework uses the metrics of ramping rate, power and energy which are meaningful for both concepts considered here.

The methodology for the uncertainty quantification is based on statistical analysis of historical data (here for wind power but it can be generalized for any type of uncertainty). The basic steps of the methodology are:

1. Define wind power production classes e.g. P_{low}, P_{medium}, P_{high}.
2. For every time step, calculate the maximum and the minimum value of uncertainty trinity (ramping, power, energy) and assign it to the corresponding class (step 1).
3. For every uncertainty metric and every class, calculate the probability density function (PDF).
4. Calculate the corresponding cumulative distribution function (CDF) of the PDFs from step 3.
5. Find upper and lower bound of each uncertainty component for different confidence levels (expressed as quantiles α of the CDF).
6. Draw the uncertainty cube for each class.

The upper and lower bounds of uncertainty trinity (step 2) for each period are calculated using the following expressions:

Ramping:

$$R_{min/max} = min/max\,\{R_1, R_2, R_3\} \tag{5.2}$$

where

$$R_1 = P_{t+1} - P_t \tag{5.3}$$
$$R_2 = P_{t+2} - P_{t+1} \tag{5.4}$$
$$R_3 = P_{t+3} - P_{t+2} \tag{5.5}$$

Power:

$$P_{min/max} = min/max\,\{P_1, P_2, P_3\} \tag{5.6}$$

where

$$P_1 = P_{t+1} - P_t \tag{5.7}$$
$$P_2 = P_{t+2} - P_t \tag{5.8}$$
$$P_3 = P_{t+3} - P_t \tag{5.9}$$

Energy:

$$E_{min/max} = min/max\,\{E_n\} \tag{5.10}$$

where

$$E_n = \sum_{k=1}^{n} E_k, n = 1...N \tag{5.11}$$

And n are the linear segments defined by:

1. Two successive measurements if both are on the same side compared to the initial power level of P_t (see figure 5.3, n=1 and n=4)
2. Two successive measurements and the intersection of their connecting line with the initial power level of P_t (see figure 5.3, n=2 and n=3)

For example:

$$E_{(n=1)} = E_{(k=1)} \tag{5.12}$$
$$E_{(n=2)} = E_{(k=1)} + E_{(k=2)} \tag{5.13}$$
$$E_{(n=3)} = E_{(k=1)} + E_{(k=2)} + E_{(k=3)} \tag{5.14}$$
$$E_{(n=4)} = E_{(k=1)} + E_{(k=2)} + E_{(k=3)} + E_{(k=4)} \tag{5.15}$$

Once the PDFs and the CDFs for all uncertainty components and classes are calculated as described in steps 3 and 4, the minimum and the maximum values of each component can be found for different confidence levels. The confidence levels, i.e., the percentage of the extreme values we want to

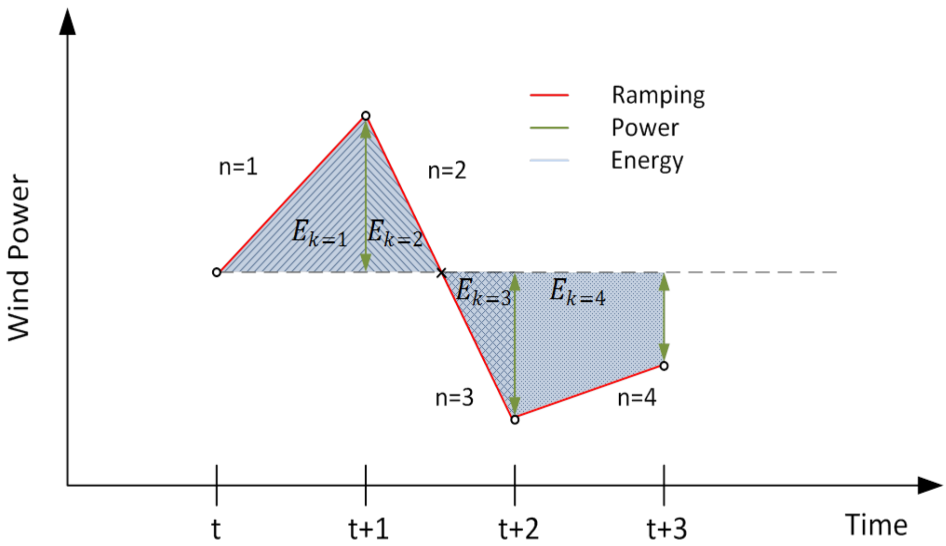


Figure 5.3: Calculation of uncertainty trinity

capture, is expressed as a certain quantile of the corresponding CDF.

The upper bounds of the uncertainty can be found directly from the value of CDF for a given quantile α. For the lower bounds of uncertainty the value that corresponds to confidence interval α is determined by the 1-α quantile of the CDF, as shown in figure 5.4.

Given the limits of each uncertainty component, the uncertainty cube can be drawn for different confidence intervals. The axes are normalized according to the installed wind power capacity.

An example of this methodology is given in figure 5.6. The uncertainty cube is drawn using a set of wind power measurements provided by the Australian Energy Market Operator [41]. The data set used in this example contains wind power time-series (see figure 5.5) values with 5-minute resolution for 3 onshore wind farms located in Western Australia and spread over an area approximately equal to Denmark. The total installed wind power capacity is 125 MW.

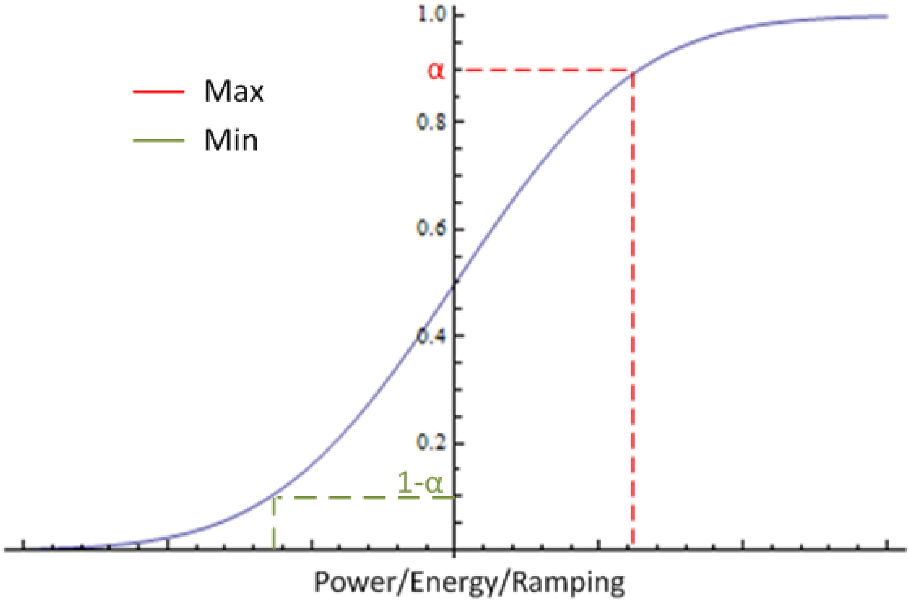


Figure 5.4: Upper and lower uncertainty bounds from CDF

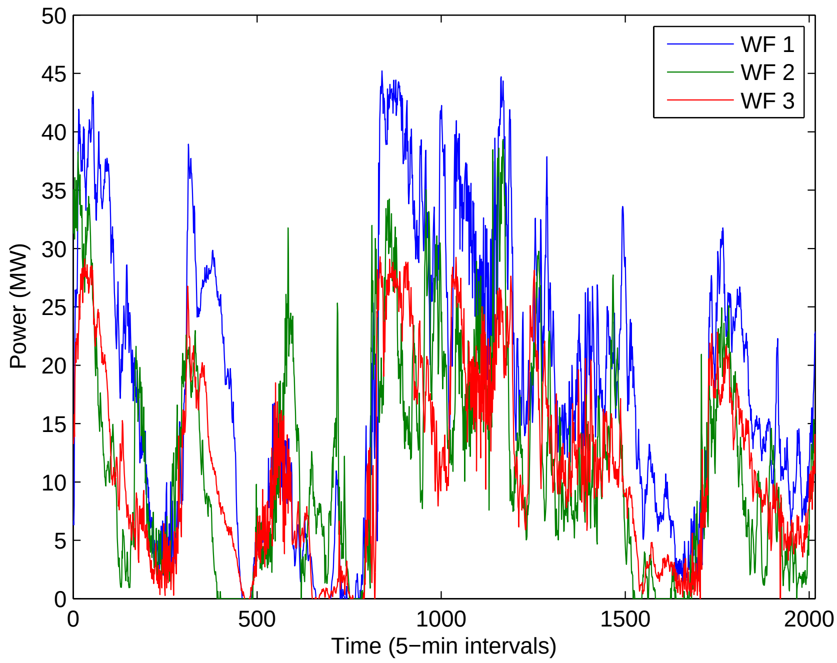


Figure 5.5: Time series of wind power production with 5 minutes time step (data from [41])

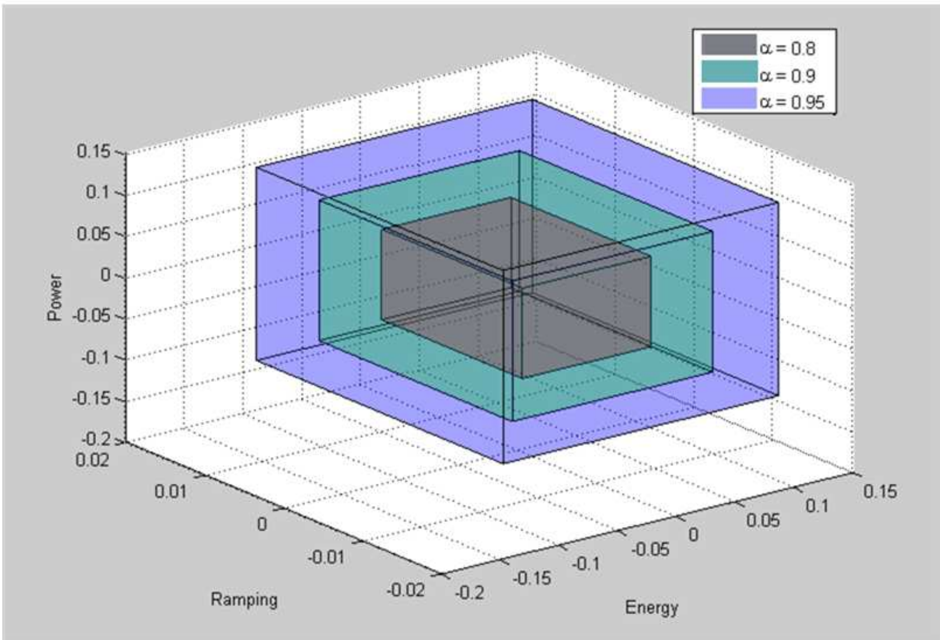


Figure 5.6: Uncertainty cube for different confidence intervals

Part III

Balancing Operation and Markets

Chapter 6

Balancing Operations and Markets

This chapter summarizes the basics on frequency control reserve operation. Different parameters relevant for balancing markets are listed and the markets of four countries are categorized accordingly.

6.1 Introduction

The reliable operation of the power system requires the instantaneous balance of active power production and demand. In the context of the European power system the Transmission System Operators (TSOs) are responsible to maintain the real-time system balance by activating manual and automatic reserves, which are procured in ancillary service markets.

Despite that the greatest volumes of electricity generation and consumption are scheduled and traded well in advance of the real-time operation, i.e., in day-ahead market which is cleared 12 to 36 hours before the actual delivery and in intraday market which closes one hour prior to real-time, a number of different factors can cause power or energy imbalances in the real-time such as:

1. Outages of generation units and transmission lines or load disconnection that exceed the N-1 security criterion.
2. Grid congestion issues that were not considered in the previous trading floors and prevent the power delivery in particular network locations and require balancing within separate zones.
3. Imbalances due to market architecture which are caused by generator ramping between two successive PTUs (this imbalance factor dimin-

ishes as the temporal resolution of the market increases, e.g., from 1 hour to 30 minutes).

4. Stochastic imbalances due to forecast errors of non-dispatchable and partly predictable RES and load. These imbalances can be characterized either as schedule deviations [1] or fluctuations[2] which take place over and within the Program Time Unit (PTU) of the market respectively.

6.2 Balancing power services

Balancing power products are defined as all services required by the TSO to maintain the integrity and stability of the power system. For historical reasons and divergent architectures of the power systems, different technical definition of control reserves exist today among various countries [43]. The recently introduced policy framework from ENTSO-E (European Network of Transmission System Operators for Electricity) [44] identifies three types of reserves[3]:

1. Frequency Containment Reserves (FCR)
2. Frequency Restoration Reserves (FRR)
3. Replacement Reserves (RR)

6.2.1 Frequency Containment Reserves

This type of reserves is a de-centralized automatic control that changes the production or consumption level of production units and controllable loads respectively in order to restore balance and stabilize the frequency at around 50 Hz. The provision of FCR is a common responsibility of all the TSOs participating in the synchronous area of ENTSO-E. The total amount of FCR in the European system is 3000 MW and the amount provided by each country is proportional to its size.

The participation of each generating unit in the FCR requirements is determined by its droop characteristic R as:

[1]Schedule deviation is a deviation of the mean of an actual process from a scheduled value in the same time scale [42]

[2]Power fluctuation is the deviation of a shorter timescale signal from the mean given by a longer time-scale [42]

[3]This terminology replaces the previous distinction of primary, secondary and tertiary reserves respectively

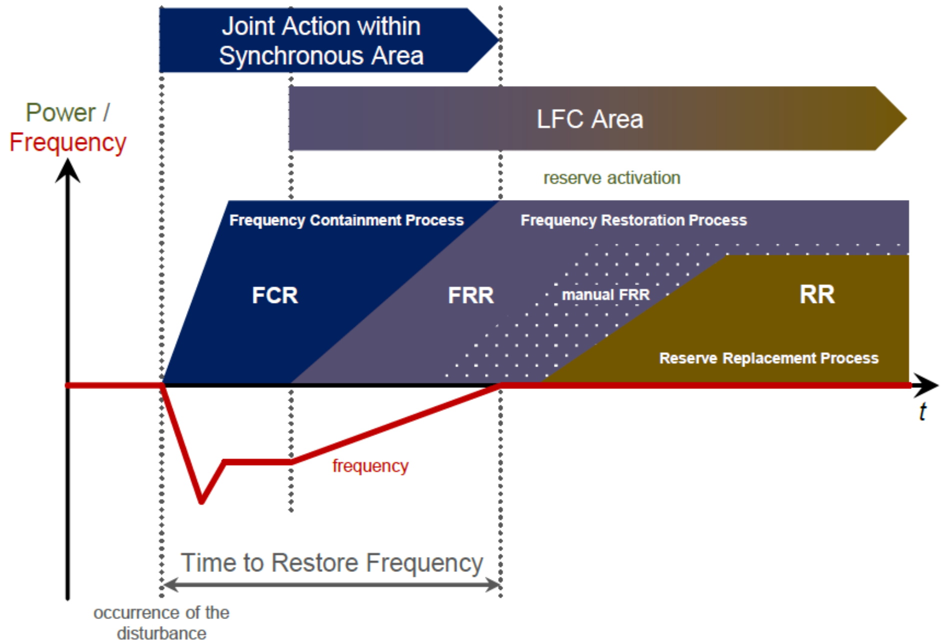


Figure 6.1: Dynamic hierarchy of reserves according to ENTSO-E (from [45])

$$R = -\frac{\Delta F/f_n}{\Delta P/P_n} \tag{6.1}$$

where ΔP is the change of power from the setpoint, P_n is the nominal power output of the unit and ΔF is the frequency deviation from the nominal frequency f_n. From this definition it follows that a higher droop value decreases the response of the unit in frequency deviations. The change in production ΔP represents the new steady state power the unit should reach in order to compensate for the frequency change in the system.

The participation of a single zone to a frequency deviation of the whole system is given by the frequency characteristic λ_{zone} of this control area defined [43] as:

$$\lambda_{zone} = -(P_{ae} - P_{se})/\Delta f \tag{6.2}$$

where P_{ae} denotes power exchange from this zone to the rest of the system for a frequency deviation equal to Δf. The term P_{se} represents the scheduled power exchange prior to the imbalance.

According to the product specification of the ENTSO-E for the FCR, these reserves should be fully available within 30 seconds and have ramping abilities of 50% within 15 seconds. FCR should be able to remain active for at least 15 minutes and provide regulation at a frequency deviation within the range of 49.8-50.2 Hz.

A total insensitivity of +/- 10 mHz is permitted, representing a deadband where the droop controller does not respond to frequency deviations and the generator output remains unchanged. Two types of insensitivity can be identified, namely intrinsic and intentional, and their sum defines the total insensitivity.

6.2.2 Frequency Restoration Reserves

This type of reserves is a centralized automatic or manual control used to bring the frequency back to its nominal value and restore the power flow of the tie-lines between neighboring systems to their target values. In addition, FRR[4] are used to replace FCR, considering that the later have limited availability. Each TSO is responsible to procure FRR in its control area and only the generators within the imbalance zone can provide this type of reserves (loads usually do not participate in FRR). It should be noted that some power systems, e.g., Eastern Denmark as a part of the Nordic system, do not employ FRR since the frequency regulation is based only on automatic FCR and RR control.

The activation of FRR aims to minimize the area control error (ACE) which is defined in [43] as:

$$ACE = P_{me} - P_{se} + K_{ri}(f_m - f_t) \tag{6.3}$$

where K_{ri} is the frequency characteristic of the control area (in MW/Hz), which is larger than the λ_{zone} in order to avoid conflicts with FCR. The term P_{me} denote the measured total power exchange with the neighboring zones, while f_t and f_m are the target and the measured network frequency respectively.

In order to restore frequency to the initial steady state, the power setpoint of each generator participating in the FRR must be changed in order to produce more/less power in the same frequency. Three different control approaches, namely centralized, pluralistic and hierarchical, can be used for the organization of FRR. The main difference between these approaches is whether or not they split the system into zones (for further explanation see [43] and [46]).

[4]FRR is also called Load Frequency Control (LFC) in the Nordic system and is similar to the Automatic Generation Control (AGC) used in North America.

According to the ENTSO-E product specification, FRR should be activated in the imbalance area no later than 30 seconds, and be fully available for 15 minutes. In addition, the FRR must be able to remain online as long as it is required.

6.2.3 Replacement Reserves

Replacement reserves refer to centralized manual changes in the dispatch of generating units which are used to relieve FCR and FRR and alleviate grid congestion. The procurement and activation of RR are primarily responsibilities of each TSO, but (partial) sharing of this reserve type is allowed between neighboring areas through a common reserve market, like for instance in the Nordic system. According to the ENTSO-E specifications, this reserve type should be fully activated within 15 minutes. Given that RR are a manually activated balancing resource their actual deployment in the event of a disturbance is subject to the operational strategy of each TSO.

6.3 Balancing power market

A number of different market structures are employed today on the European power system. This section provides the definitions of the main properties of the balancing market and an outline the pricing different pricing schemes. In addition, tables summarizing main parameters of the balancing/reserves market in the countries of interest are presented.

6.3.1 Balancing market properties definition

1. Procurement scheme.
   - Organized market. No mandatory provision of balancing services from the grid users, who can voluntarily participate in the market (tender, auction, power exchange).
   - Hybrid. A combination of mandatory offers/provision scheme with an organized market
2. Product resolution.
   - Time. The maximum time interval the product can be bid into the balancing market.
   - Capacity. The minimum bid size into the balancing market.
3. Symmetrical product. The upward and downward regulating bids should have the same size.
4. Settlement-pricing rule

- Marginal pricing. The price is settled by the marginal cost of the last bid accepted.
- Pay-as-bid. Contracted parties who provide a service are paid on their offer price.

5. Cost recovery.

    - Balance Responsible Party (BRP). The market player or its representative is charged for the imbalance.
    - Grid user. The physical or legal entity supplying or consuming power by a TSO or DSO.

6. Settlement time unit. Time unit used for scheduling and settlement of products of market participants.

7. Activation rule.

    - Pro rata. In proportion (parallel activation)
    - Merit order. Resources with lowest short run marginal costs are activated first.

8. Imbalance portfolios. A market design parameter regarding the number of imbalance volumes that are calculated and charged to BRPs per settlement time unit. Portfolio refers to a mix of generation and consumption which submits aggregated bids into the market.

9. Number of prices.

    - Dual pricing. Different prices for upward and downward regulation according to the total system imbalance.
    - Single pricing. Uniform price independent from deviation direction.

6.3.2 Pricing systems for balancing power

Two pricing systems for the allocation of balancing costs to the BRPs exist in the various European regulating markets - the one-price model and the two-price model. The main principles of these models are the following:

1. One-price model

    A single price π_{imb} is charged to all the system imbalances, regardless their direction, i.e., negative or positive deviation from the initial schedule. This price follows the marginal or the pay-as-bid pricing principle during each settlement period and reflects the procurement cost of balancing services.

	Switzerland	Denmark	Norway	Germany
Procurement Scheme	Organized Market	Organized Market	Hybrid	Organized Market
Product Resolution (Time)	Week(s)	Hour(s)	Hour(s)	Week(s)
Product Resolution (MW)	≤ 1 MW			
Capacity Provider	Generators & Pump storage	Generators Only	Generators Only	Generators & Pump storage & Load
Symmetrical Product	Yes	No	Yes	Yes
Settlement	Pay-as-bid	Marginal Pricing	Marginal Pricing	Pay-as-bid
Cost Recovery	Grid Users	Grid Users	Grid Users	Grid Users & BRP
Gate Closure	Day(s)			

Table 6.1: Capacity market FCR

2. Two-price model

Under the two-price model, separate prices for up (π^{+}_{imb}) and down (π^{-}_{imb}) regulation are determined using the following mechanism:

$$\pi^{+} = \begin{cases} min\left(\pi^{c}, \pi^{DN}\right) & \text{if } RP_i > 0 \\ \pi^{c} & \text{if } RP_i < 0 \end{cases} \tag{6.4}$$

$$\pi^{-} = \begin{cases} max\left(\pi^{c}, \pi^{UP}\right) & \text{if } RP_i < 0 \\ \pi^{c} & \text{if } RP_i > 0 \end{cases} \tag{6.5}$$

The term π^c denotes the day-ahead market price and π^{DN},π^{UP} are the prices for downward and upward regulation resulting from the merit order of the regulating market, with respect to the total amount of regulating power PR^{Tot} given as:

$$RP^{Tot} = \sum_{i \in I}(P_i^c - P_i^*) \tag{6.6}$$

where I is the set of the producers, P_i^c is the scheduled production and P_i^* is the production at the time of regulation from generator i.

	Switzerland	Denmark	Norway	Germany
Procurement Scheme	Organized Market			
Product Resolution (MW)	$1 \leq x \leq 5$	$x \leq 1$	$1 \leq x \leq 5$	$1 \leq x \leq 5$
Product Resolution (Time)	Week(s)	Week(s)	Day(s)	Week(s)
Capacity Provider	Generators & Pump storage	Generators & Load	Generators Only	Generators & Pump storage & Load
Symmetrical Product	Yes	No	No	No
Settlement	Pay-as-bid	Pay-as-bid	Marginal Pricing	Pay-as-bid
Cost Recovery	Grid Users			
Gate Closure	Day(s)	Day(s)	Week(s)	Day(s)

Table 6.2: Capacity market FRR - Automatic

The sign of the regulating power, according to the previous equation, determines whether an hour is considered as an upward or downward regulation hour.

Similarly, the imbalance RP_i of a single market participant is calculated as:

$$RP_i = P_i^c - P_i^* \tag{6.7}$$

It should be noted that the direction of the regulation is dictated by needs of the whole power system and not by the local imbalances.

Figure 6.2 shows an example of the two-price model. Three characteristic points are noted. Point 1 represents a situation when down regulation is needed. As a result the capacity has a negative sign and the related price is lower than the spot price. Point 2 corresponds in hour when the power system is balanced. Finally, point 3 shows an hour with up-regulation. Thus, the price is higher than the spot price and the capacity has a positive sign.

The main rationale of the two-price model is that deviations which offset the total system imbalance are not penalized and thus they receive the spot price. This also implies that participants who deviate from their schedules,

	Switzerland	Denmark	Norway	Germany
Procurement Scheme	Organized Market			
Product Resolution (MW)	$1 \leq x \leq 5$	$x \leq 1$	$1 \leq x \leq 5$	$1 \leq x \leq 5$
Product Resolution (Time)	Week(s)	Week(s)	Day(s)	Week(s)
Capacity Provider	Generators & Pump storage	Generators & Load	Generators Only	Generators & Pump storage & Load
Symmetrical Product	Yes	No	No	No
Settlement	Pay-as-bid	Pay-as-bid	Marginal Pricing	Pay-as-bid
Cost Recovery	Grid Users			
Gate Closure	Day(s)	Day(s)	Week(s)	Day(s)

Table 6.3: Capacity market FRR - Manual

	Switzerland	Denmark	Norway	Germany
Procurement Scheme	N/A	Market	Hybrid	Hybrid
Activation Rule	Pro Rata	Pro Rata	Pro Rata	Merit Order
Product Resolution (MW)	N/A	No min bid	$1 \leq x \leq 5$	$1 \leq x \leq 5$
Symmetrical Product	Yes	N/A	N/A	No
Settlement	Hybrid	Hybrid	Pay-as-bid	Marginal Pricing
Cost Recovery	BRP	Grid Users	Grid Users	BRP

Table 6.4: Energy market FRR - Automatic

even if they help the system, are paid only for energy and not for flexibility. On the other hand, the one-price system may reward imbalances (opposite to the system imbalance) both for energy and flexibility provision (as a premium on the day-ahead price). However, the latter could lead to distortion of the imbalance prices since it does not provide incentives to participants

	Switzerland	Denmark	Norway	Germany
Procurement Scheme	N/A	Market		
Activation Rule	N/A	Merit Order		
Product Resolution (MW)	N/A	$5 \leq x \leq 10$	$1 \leq x \leq 5$	≥ 10
Product Resolution (Time)	N/A	Hour	Hour	Hour
Symmetrical Product	N/A	No	No	No
Settlement	N/A	Marginal Pricing	Marginal Pricing	Pay-as-bid
Cost Recovery	N/A	BRP	BRP	BRP

Table 6.5: Energy market FRR - Manual

to balance their portfolios in the day-ahead market. It should be noted that the two-price system is not revenue neutral for the TSO, since during periods of opposite imbalances, TSO makes an operating profit which can be used to finance reserve payments and other system costs.

6.4 Balancing power in Denmark and Switzerland

6.4.1 Denmark

The procurement and activation of control reserves in the Danish power system are organized by the Danish TSO, Energinet.dk, according to the principles and guidelines described in [47] and [48]. Denmark is currently split into two synchronous areas, i.e., DK1 (Western Denmark) and DK2 (Eastern Denmark). The DK1 region is part of the Continental synchronous area, while DK2 belongs to the Nordic synchronous area and thus different requirements apply between the two zones. Following the uniform definitions of reserves on the European level proposed by ENTSO-E (see section 6.2), Energinet.dk works towards the harmonization of its operational standards. The following parts describe the specific types and the terminology of the reserves in the existing operational model of Energinet.dk as well as the product definition and the market structure for each reserve type.

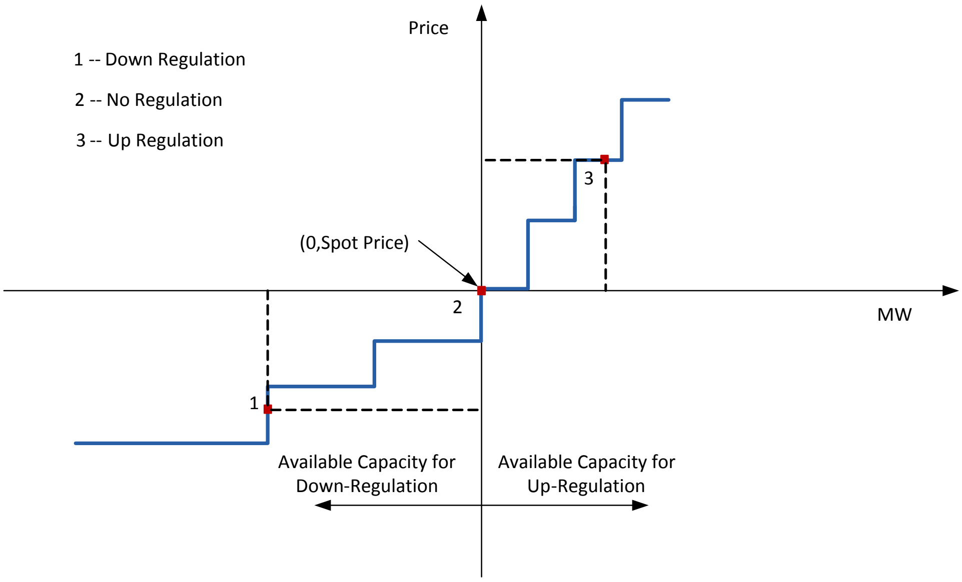


Figure 6.2: The two-price model for regulating power

	Switzerland	Denmark	Norway	Germany
Imbalance Portfolios	1	≥ 2	2	2
Settlement Time Unit (min)	15	60	60	15
Number of Prices (Generation/Demand)	Dual	Dual/ Single	Dual/ Single	Single
Settlement	BRP			
Same Load Participation Mechanism	Yes			

Table 6.6: Imbalance Settlement

Types and operation of reserves

1. Frequency-controlled reserves (similar to Frequency Containment Reserves (FCR)). This reserve category includes the primary reserves in area DK1 and the frequency disturbance reserves (FDR) and frequency-controlled normal operation reserve (FNR) in area DK2. The product specification of the primary reserves follows the ENTSO-E definitions for FCR and Energinet.dk procures an amount of ± 27 MW (this volume is reassessed every year according to the ENTSO-E requirements). The FDR reserve type is activated at 49.9 Hz and must be fully regulated at 49.5 Hz. According to the ramping requirements of FDR, 50% of the capacity should be available 5 seconds after the activation and fully deployed after 30 seconds. It should be noted that FDR is an upward regulation service only. The amount of FDR is determined on weekly basis for the whole Nordic region and the share of Energinet.dk is approximately 160 MW.

   The FNR reserves are fully activated at a frequency deviation up to ± 100 mHz from the nominal frequency and be fully active after 150 seconds with at least linear ramping rate. Energinet.dk has to procure ± 23 MW of FNR. According to the existing agreements in the Nordic system, TSOs are currently allowed to purchase up to one third of FNR and FDR volumes outside their control area, depending on the availability and the price of these resources.

2. Secondary reserves (similar to Frequency Restoration Reserves (FCR)). In case of the Danish power system this type of reserves is used only in DK1 area and follows the product requirements of ENTSO-E. The amount of these reserves is determined on a monthly basis, as a percentage of the expected maximum load and the international agreements at the ENTSO-E level. At present Energinet.dk procures about ± 90 MW of secondary reserves, but this amount is expected to decrease up to 50% in the future through a coordination agreement between the Danish and the German TSOs on the avoidance of counter activation of these reserves across the common interconnections. From 2014/2015 and onwards, Energinet.dk has established an agreement with the Norwegian TSO (Statnett) for the delivery of ± 100 MW of secondary reserves through the Skagerrak 4 interconnection.

3. Manual reserves (similar to Replacement Reserves (RR)). The manual reserve requirement in Western Denmark follows the N-1 security criterion considering the failure of domestic and cross border interconnections and generating units. The product definition of DK1 manual reserves is according to the ENTSO-E specifications for RR. Energinet.dk procures approximately 250 MW of manual reserves in DK1. The corresponding requirement for Eastern Denmark is based

on agreements between the Nordic TSOs on a basis of specific fault events in the Nordic system. A distinction is made between fast and slow manual reserves, where the first should be active within 15 minutes and the second up to 2 hours. Energinet.dk purchases 300 MW of fast and 375 MW of slow reserves in DK2.

Procurement of control reserve products (capacity)

1. Frequency-controlled reserves. Primary, FNR and FDR reserves are procured from Energinet.dk on a daily basis after the gate closure of the day-ahead market (Elspot) through auctions of six equally-sized blocks of four hours for each day. Separate auctions are held for upward and downward regulation for the first two balancing products (since FDR is only for up-regulation).

2. Secondary Reserves. The procurement of secondary reserve capacity is done in a form of symmetrical up and down regulation bids on a monthly basis.

3. Manual reserves. In Western Denmark manual reserve capacity is procured at daily auctions, while in Eastern Denmark it is purchased under five year contracts. The establishment of a capacity reserve market ensures a minimum availability of resources in a form of regulating power bids.

Reimbursement of control reserve products

The payment that each reserve resource provides can have two separate components for capacity (availability payment) and energy provision. The pricing mechanisms for each reserve type procured by Energinet.dk are the following:

1. Frequency-controlled reserves. These reserves receive a capacity payment at a uniform price equal to the marginal price of the highest bid accepted in the respective auction. The energy payments are settled as ordinary imbalances at the balancing price.

2. Secondary Reserves. The capacity payment for these reserves follows the pay-as-bid principle, while the energy payment is settled per MWh at the DK1 day-ahead market (Elspot) price +/- 100 DKK/MWh for up and down regulation respectively. The upper and the lower energy price limit is balancing price for up and down regulation respectively. Only secondary reserves that were sold in the capacity market can be activated.

3. Manual reserves and regulating power. This type of reserves receive availability payments for capacity, based either on the auction clearing price (DK1) or bilateral agreements (DK2). The resources which received capacity payments are obliged to place bids in the regulating power market, where the energy imbalances are settled. However, additional balancing resources, i.e., which have not received capacity payments, are also allowed to offer regulating power bids. The regulating bids are submitted on a common platform for the whole Nordic system (NOIS [5] list) up to 45 minutes before the actual delivery hour, with the minimum and the maximum bid size being 10 MW and 50 MW respectively. This market structure allows for asymmetric bids, i.e., separate bids for upward and downward regulation, with hourly resolution. Balancing resources receive energy payments upon their activation, based on the two-price system following the NOIS merit order [6]. Only under exceptional situations, e.g., local transmission congestion, interconnection bottlenecks or violation of trade conditions, Energinet.dk is allowed to bypass one or more bids of the NOIS list (then special regulation applies with pay-as-bid settlement). Orders of up/down regulation are communicated on the basis of 5-min power schedules between Energinet.dk and resource provider.

Strategic initiatives

Energinet.dk has defined some strategic initiatives for ancillary services described extensively in [47]. Here an outline of these initiatives is provided along with the main benefits and potential complications that are expected to arise.

1. Frequency-controlled reserves

    a. Joint purchasing of primary reserve with German & Swiss TSOs. This initiative will enhance competition and allow access to more balancing resources. However, some harmonization issues between the involved TSOs must be resolved, such as the temporal resolution of auctions (daily/weekly) and the product definition (symmetrical up/down regulation and minimum bid size).

    b. Joint purchasing of FNR and FDR with Swedish TSO (Svenska Kraftnat). This initiative aims to give access to the Danish reserve suppliers in the Swedish market and allow Energinet.dk

[5] Nordic Operational Information System - a common platform for all the regulating bids from Denmark, Norway, Sweden and Finland

[6] (One-price model is used for imbalance settlement by Energinet.dk for load imbalances)

to stop purchasing FDR in Eastern Denmark (see also initiative 3). The implementation of this initiative requires the establishment of common reserve products (symmetrical/asymmetrical bids) and pricing scheme (Svenska Kraftnat uses pay-as-bid pricing while Energinet.dk margninal pricing). In addition, the reserve sharing limit between areas should be reassessed beyond the existing one third of the total reserve requirement.

c. Terminate FDR daily auctions in DK2. Under this initiative, FDR reserves will be delivered via the DK1 - DK2 interconnection (Great Belt) using short-term overload capacity and enable more efficient reserve procurement.

2. Establishment of common market across the synchronous areas. This is a long term initiative that requires the wide collaboration of TSOs in the ENTSO-E level and is expected to bring benefits both to TSOs and producers through the efficient market integration.

3. Secondary Reserves

   a. Cooperation with German TSOs for secondary reserve activation. This initiative focuses on the enlargement of the secondary reserves market and the reduction of balancing needs due to counter activations across interconnections. The first component of the initiative requires some harmonization of the technical characteristics of the bids, e.g., German activation requirement is 5 minutes while Danish requirement is 15 minutes. In addition, for the cross border activation of secondary reserves, special arrangements have to be made on the reservation of transmission capacity of the interconnectors. For the second part of the initiative, the implementation of an automatic avoidance of counter activation between Western Denmark and Germany is in progress.

4. Manual reserves and regulating power

   a. Broader regulating power product definition. This initiative aims to ensure regulating resource availability through the establishment of broader and more flexible market products. In particular, Energinet.dk will examine the possibility of manual reserve provision from units with than 15 minutes activation time. In addition, a market mechanism able to assess various quality factors of the regulating offers, i.e., apart from the bid price, will be investigated.

b. International regulating power markets. In the absence of a European target model for regulating power, Energinet.dk suggests a cross border regulating market based on bilateral TSO cooperation (TSO-TSO model) as well as the establishment of a single European regulating power market with a minimum level of harmonization. In a pan-European market, the manual reserve requirements should be calculated on the basis of congestions (instead of the current national requirements). In connection to this, a transmission capacity reserve mechanism in the day-ahead and intraday markets should be investigated.

6.4.2 Switzerland

The Swiss TSO Swissgrid is responsible for the operation and procurement of control reserves [49], [50].

Types and Operation of Reserves

Primärregelleistung (Primary Control Reserves) Fast reacting automatic reserve according to ENTSO-E rules [51]. Activation is done locally by the turbine controllers using predefined droop. It amounts to currently $\pm 66MW$.

Sekundärregelleistung (Secondary Control Reserves) Centrally activated control reserve acting after a few seconds. It is fully deployed after 15min. Activation is coordinated from a central PI-controller and the activation is proportional to the contracted power. Around $\pm 400MW$ are procured with symmetrical power bands. The amount needed is determined by Swissgrid.

Tertiärregelleistung (Tertiary Control Reserves) In case, the secondary control reserve is not sufficient, after approximately 15min, tertiary control reserves are activated. The activation is done manually by the operators. With some exceptions, this reserve has to be fully deployed around 15min after the activation. Is is procured asymmetrically amounting to $+450MW$ and $-390MW$. The amount needed is determined by Swissgrid. Activation is according to the energy price and compatibility with the disturbance, e.g. no N-1 violations if a certain reserve is activated.

Procurement of Control Reserve Products

Primärregelleistung This product has to be offered over a period of one week. There are common auctions together with Austria, Germany and France. However the amounts that are procured in a neighboring country are subject to some constraints, i.e. only a certain portion can be procured abroad.

Sekundärregelleistung Secondary control can only be procured on the local market. It is procured for a period of one week.

Tertiärregelleistung Tertiary control reserve is also procured locally. It is possible to offer in specific 4h blocks, which are auctioned daily or on a weekly bases for the whole week.

Reimbursement

For the reimbursement of the products it has to be distinguished between a capacity payment, i.e. a premium for keeping a certain amount of power available, and a energy payment, which corresponds to the reserves that are effectively activated.

Primärregelleistung Capacity is reimbursed pay-as-bid. There is no payment for energy.

Sekundärregelleistung Capacity is reimbursed pay-as-bid. Energy is reimbursed based on the hourly spot market price $\pm 20\%$.

Tertiärregelleistung Capacity is reimbursed pay-as-bid. If capacity is procured, the provider is obliged to set an energy price. These prices can be adapted intraday until gate-closure. If a provider is activated, his energy is reimbursed pay-as-bid.

6.5 Extensions of the existing balancing power framework

6.5.1 Predictive versus Reactive balancing dispatch

The existing market architecture and the operational model for balancing were primarily adapted to the requirements of the conventional generators and meant to deal mainly with the imbalance factors 1 to 3 (see section 6.1), since the penetration of intermittent RES was limited in the past. As a result, the balancing operation was mainly reactive and focused on load following and system restoration in case of contingencies. This operational approach implies that automatic reserves are initially deployed to cover the imbalances and then manual reserves are activated in order to restore the availability of the former. In that case, the reserve requirements are mostly static and driven by conditions that are not affected as we get closer to the real-time operation, e.g., the probability that a large power plant or a transmission line trips is constant through time.

Today, high shares of intermittent RES are integrated in the power system. The power output of these generators is highly fluctuating but it can be partly predicted. This allows to revise dynamically the reserve requirements considering that the the forecast accuracy of RES production improves as we approach the real-time operation. The activation of control reserves altered from reactive and restorative to predictive dispatch using forecasts with smaller prediction errors. Following this operational strategy, the TSO tries to predict the imbalances and deploy manual reserves in advance of the imbalance realization. As a result, the utilization of automatic reserves is reduced, providing multiple benefits in the power system in terms of cost reduction and automatic resource availability.

Various predictive strategies can be formulated with respect to the needs, the available balancing resources of power system and the decision-making policies of the TSO. The work in [52] proposes a framework for the definition of operational strategies as shown in figure 6.3. The key components of an operational strategy are:

1. The TSO Policy.
   (a) The objective function J^M.
   (b) The grid constraints h^O and g^O.
   (c) The operation timing T^O.
2. The reserve product definition
   (a) Market timing T^P.
   (b) Product constraints h^P and g^P.

The objective function reflects the interests of the TSO during the balancing operation. The grid constraints h^O and g^O represent the technical limitations of the power network, e.g., transfer capacities and voltage limits, that should be respected during the operation. The operation timing T^O refers to the scheduling horizon and the lead time T^{lt}, i.e., the time interval between decision-making and actual operation. The term market timing T^P includes the temporal parameters of the balancing market such as the gate closure time and the interval between two consecutive clearings. Finally, product constraints h^P and g^P are related to the bid structure of the regulating market.

The predictive dispatch of regulating power can be implemented using either deterministic or stochastic forecast of the power imbalances. The SIMBA model presented in [53], developed by the Danish TSO Energinet.dk, focuses on regulating power dispatch using a purely deterministic approach

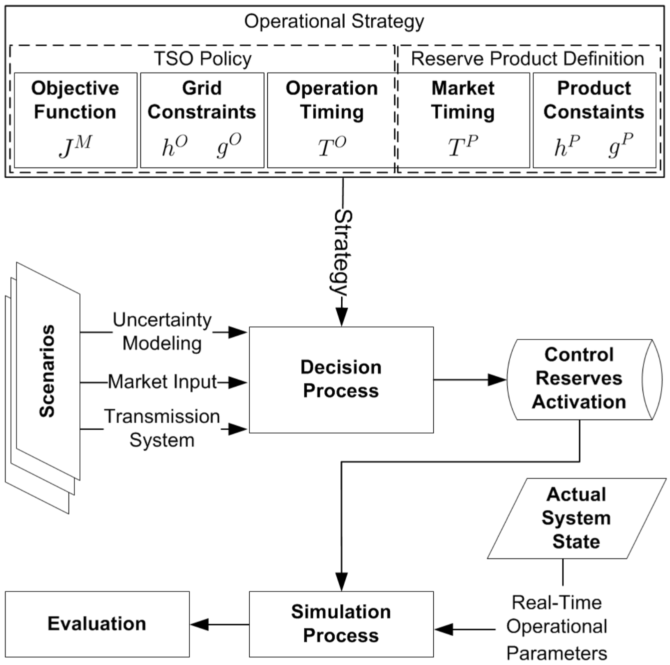


Figure 6.3: Illustration of operational strategies concept for control reserves activation.

for the intra-hour balancing of the power system. However, the main advantage of the stochastic approach is that can take into account full information about the imbalance uncertainty in terms of spatial and temporal interdependence structure of the forecast errors, e.g., in case of wind or solar power production. A complete mathematical formulation of operational strategies as a two-stage stochastic programming problem as well as a case study for balancing wind power uncertainty can be found in [52].

An effective formulation of the operational strategy for predictive dispatch should consider the specific characteristics of each power system such as i) the penetration level of non-dispatchable generation, ii) the interconnections with the neighboring systems, iii) the composition of the controllable generation portfolio and iv)the existing market scheme. The performance of a strategy applied in a particular power system should be assessed with respect to different criteria such as i) total operating cost, ii) energy utilization iii) maximum power capacity of manual and automatic reserves.

6.5.2 Joint clearing of day-ahead and balancing markets

Apart from the sequential clearing of day-ahead and balancing markets employed today in the European power system, several studies have focused on the optimal reserve procurement in presence of uncertainty. Specifically, [54] formulates a two-stage stochastic unit commitment model for determining reserve requirements in systems with high wind penetration. The impact of more frequent scheduling of the system is analyzed in [55] where a stochastic scheduling tool (WILMAR) is employed using updated wind and load forecasts in a "rolling planning" type of operation. A stochastic programming model for the joint clearing of day-ahead and reserve markets is solved in [56] minimizing the expected cost of the system. An alternative approach of this problem is proposed in [57] where adaptive robust optimization is used, aiming to minimize the cost of the worst case scenario.

Chapter 7

Conclusion

This report has focused on four aspects important to modeling and characterization of balancing of power systems and their corresponding markets. The Power Nodes framework, a simplified modeling approach for various types of generation and load units is summarized and a suitable modeling approach using sensitivity factors is given in the first part. Additional models for HVDC interconnections, dynamic line ratings as well as a probabilistic power flow formulation, that considers reserves operation, are provided. These models can be seen as tools that already have been used in various applications and will be used for future work.

In the next part, classical balancing power operation is repeated and basic properties of balancing power markets are given. The properties are listed for the four countries Switzerland, Denmark, Norway and Germany. For Denmark and Switzerland a detailed summary is given. A classification framework is introduced as part of the special chapter on predictive and reactive reserve operation.

The last chapters focus on operational flexibility in a more general manner: a general discussion and a metric to quantify flexibility is used to introduce in the topic. This metric is further used to also quantify uncertainty. The corresponding method that produces *uncertainty cubes* is illustrated. As uncertainty and flexibility have the same metric, it is possible to directly compare then and discuss adequacy. A method to represent locational flexibility, that is the flexibility that is available in a certain point in the grid, is used to determine operational flexibility.

Future work will attempt to compare uncertainty and flexibility. The specifications of the balancing markets will play a crucial role in this regard.

Bibliography

[1] Y.V. Makarov, C. Loutan, Jian Ma, and P. de Mello. Operational impacts of wind generation on california power systems. *Power Systems, IEEE Transactions on*, 24(2):1039–1050, 2009.

[2] A. Ulbig and G. Andersson. On operational flexibility in power systems. In *Power and Energy Society General Meeting, 2012 IEEE*, pages 1–8, July 2012.

[3] Mette Petersen, Kristian Edlund, Lars Henrik Hansen, Jan Bendtsen, and Jakob Stoustrup. A taxonomy for modeling flexibility and a computationally efficient algorithm for dispatch in smart grids. In *American Control Conference 2013*, 2013.

[4] K. Heussen, S. Koch, A. Ulbig, and G. Andersson. Energy storage in power system operation: The power nodes modeling framework. In *Innovative Smart Grid Technologies Conference Europe (ISGT Europe), 2010 IEEE PES*, pages 1–8, Oct 2010.

[5] K. Heussen, S. Koch, A. Ulbig, and G. Andersson. Unified system-level modeling of intermittent renewable energy sources and energy storage for power system operation. *Systems Journal, IEEE*, 6(1):140–151, March 2012.

[6] K. Dallmer-Zerbe, M.A. Bucher, A. Ulbig, and G. Andersson. Assessment of capacity factor and dispatch flexibility of concentrated solar power units. In *PowerTech (POWERTECH), 2013 IEEE Grenoble*, pages 1–6, June 2013.

[7] Goran Strbac. Demand side management: Benefits and challenges. *Energy Policy*, 36(12):4419–4426, 2008.

[8] Ed Koch and Mary Ann Piette. Direct versus facility centric load control for automated demand response. *Grid Interop*, 2009.

[9] International Energy Agency. *The Power to Choose - Demand Response in Liberalized Electricity Markets.* International Energy Agency, 2003.

[10] JK Kok, MJJ Scheepers, and IG Kamphuis. Intelligence in electricity networks for embedding renewables and distributed generation. In *Intelligent infrastructures*, pages 179–209. Springer, 2010.

[11] Marco Zugno, Juan Miguel Morales, Pierre Pinson, and Henrik Madsen. A bilevel model for electricity retailers' participation in a demand response market environment. *Energy Economics*, 36:182–197, 2013.

[12] Wei Zhang, Karanjit Kalsi, Jason Fuller, Marcelo Elizondo, and David Chassin. Aggregate model for heterogeneous thermostatically controlled loads with demand response. In *Power and Energy Society General Meeting, 2012 IEEE*, pages 1–8. IEEE, 2012.

[13] Bente Halvorsen and Bodil M Larsen. How serious is the aggregation problem? an empirical illustration. *Applied Economics*, 45(26):3786–3794, 2013.

[14] Anthony Papavasiliou and Shmuel S Oren. A stochastic unit commitment model for integrating renewable supply and demand response. In *Power and Energy Society General Meeting, 2012 IEEE*, pages 1–6. IEEE, 2012.

[15] Andrew Keane, Aidan Tuohy, Peter Meibom, Eleanor Denny, Damian Flynn, Alan Mullane, and Mark O Malley. Demand side resource operation on the irish power system with high wind power penetration. *Energy Policy*, 39(5):2925–2934, 2011.

[16] Hunt Allcott. Rethinking real-time electricity pricing. *Resource and Energy Economics*, 33(4):820–842, 2011.

[17] Mardavij Roozbehani, Munther A Dahleh, and Sanjoy K Mitter. Volatility of power grids under real-time pricing. *Power Systems, IEEE Transactions on*, 27(4):1926–1940, 2012.

[18] ENTSO-E. *TEN-YEAR NETWORK DEVELOPMENT PLAN 2010-2020*. IENTSO-E, 2010.

[19] G. Andersson. *Modeling and Analysis of Power Systems*. Lecture Notes. ETH Zurich, 2011.

[20] R.D. Christie, B.F. Wollenberg, and I. Wangensteen. Transmission management in the deregulated environment. *Proceedings of the IEEE*, 88(2):170 –195, feb. 2000.

[21] Wai Y. Ng. Generalized generation distribution factors for power system security evaluations. *Power Apparatus and Systems, IEEE Transactions on*, PAS-100(3):1001–1005, 1981.

[22] Matthias Bucher, Spyros Chatzivasileiadis, and Gï¿½ran Andersson. Managing flexibility in multi-area power systems. *submitted to Power Systems Computation Conference (PSCC)*, 2014.

[23] Matthias Bucher and Goeran Andersson. Balancing reserve procurement and operation in the presence of uncertainty and transmission limits. *Universities' Power Engineering Conference (UPEC)*, 2013.

[24] Roger Wiget and G. Andersson. Dc optimal power flow including hvdc grids. In *IEEE Electical Power and Energy Conference (EPEC) 2013, Halifax, NS, Canada*, pages 1–6, August 2013.

[25] Walter Sattinger et al. Leiterseiltemperaturmessung am Lukmanier - Grundlagen für ein schweizweites Monitoring. *VSE Bulletin*, pages 45–49, 05 2010.

[26] T. Yip, Chang An, G. Lloyd, M. Aten, and B. Ferri. Dynamic line rating protection for wind farm connections. In *Integration of Wide-Scale Renewable Resources Into the Power Delivery System, 2009 CIGRE/IEEE PES Joint Symposium*, pages 1 –5, july 2009.

[27] J. Fu, S. Abbott, B. Fox, D.J. Morrow, and S. Abdelkader. Wind cooling effect on dynamic overhead line ratings. In *Universities Power Engineering Conference (UPEC), 2010 45th International*, pages 1 –6, 31 2010-sept. 3 2010.

[28] IEEE Standard for Calculating the Current-Temperature of Bare Overhead Conductors. *IEEE Std 738-2006 (Revision of IEEE Std 738-1993)*, pages c1 –59, 30 2007.

[29] Overhead electrical conductors- calculation methods for stranded bare conductors. *IEC TR 61597*, 1995.

[30] CIGRE. Thermal behavior of overhead conductors. *Working Group 22.12*, 2002.

[31] Matthias Bucher, Maria Vrakopolou, and Goeran Andersson. N-1 security assessment incorporating dynamic line ratings. *IEEE Power and Energy Society General Meeting*, 2013.

[32] Matthias Bucher. A method to determine the locational flexibility in electric power systems. *Working Paper*, 2014.

[33] K. Trangbaek, M. Petersen, J. Bendtsen, and J. Stoustrup. Exact power constraints in smart grid control. In *Decision and Control and European Control Conference (CDC-ECC), 2011 50th IEEE Conference on*, pages 6907–6912, 2011.

[34] Colin N. Jones, Eric C. Kerrigan, and Jan M. Maciejowski. Equality set projection: A new algorithm for the projection of polytopes in half-space representation. Technical report, Dept. Eng., Univ. Cambridge, Cambridge, U.K., 2004.

[35] Thilo Krause. *Evaluating Congestion Management Schemes in Liberalized Electricity Markets Applying Agent-based Computational Economics.* PhD thesis, ETH Zurich, 2006.

[36] Attilio Meucci. A Short, Comprehensive, Practical Guide to Copulas. *GARP Risk Professional*, pages 22–27, 2011.

[37] A. Meucci. A new breed of copulas for risk and portfolio management. *Risk*, 24(9):122–126, 2011.

[38] U. Cherubini, E. Luciano, and W. Vecchiato. *Copula Methods in Finance.* The Wiley Finance Series. John Wiley & Sons, 2004.

[39] C. Schölzel and P. Friederichs. Multivariate non-normally distributed random variables in climate research - introduction to the copula approach. *Nonlinear Processes in Geophysics*, 15(5):761–772, 2008.

[40] S. Hagspiel, M. Papaemannouil, A.and Schmid, and G. Andersson. Copula-based modeling of stochastic wind power in europe and implications for the swiss power grid. *Applied Energy*, 96(0):33 – 44, 2012. Smart Grids.

[41] AEMO [Online]. Available: www.aemo.com.au.

[42] Kai Heussen, Morten Lind, and Hans Henrik Niemann. *Control Architecture Modeling for Future Power Systems.* Elektro-PHD. DTU Elektro, 2011. Phd thesis as defended.

[43] M. Trotignon Y. Rebours, D. Kirschen and S. Rossignol. A survey of frequency and voltage control ancillary services. *Power Systems, IEEE Transactions on*, 22(1):350–357, 2007.

[44] ENTSO-E. Network code on load-frequency control and reserves. Technical report, European Comission, 2013.

[45] ENTSO-E. Supporting document for the network code on load-frequency control and reserves. Technical report, 2013.

[46] UCTE. *Continental Europe Operation Handbook - Policy 1: Load-Frequency Control and Performance.* ENTSO-E, 2009.

[47] Energinet.dk. *Energinet.dk's ancillary services strategy.* Energinet.dk, 2011.

[48] Energinet.dk. *Regulation C2: The balancing market and balance settlement.* Energinet.dk, 2008.

[49] swissgrid AG. Überblick Systemdienstleistungen. PDF, 2010.

[50] swissgrid AG. Grundlagen Systemdienstleistungsprodukte. PDF, 2013.

[51] ENTSO-E. *Policy 1: Load-Frequency Control and Performance*, 2009. Taken from Operation Handbook.

[52] Kai Heussen Stefanos Delikaraoglou and Pierre Pinson. Operational strategies for predictive dispatch of control reserves in view of stochastic generation. In *Power Systems Computation Conference (PSCC'14). IEEE (under review)*, pages 1–8. IEEE, 2014.

[53] A.B. Hansen, A. Orths, K. Falk, and N. K. Detlefsen. Danish fossil independent energy system 2050 - from strategic investigations to intra-hour simulation of balancing issues. In *In Proc. 10th Internation Workshop on Large-Scale Integration of Wind Power into Power Systems, Aarhus, Denmark, October 2011*, 2011.

[54] Anthony Papavasiliou, Shmuel S Oren, and Richard P O'Neill. Reserve requirements for wind power integration: A scenario-based stochastic programming framework. *Power Systems, IEEE Transactions on*, 26(4):2197–2206, 2011.

[55] A. Tuohy, P. Meibom, E. Denny, and M. O'Malley. Unit commitment for systems with significant wind penetration. *Power Systems, IEEE Transactions on*, 24(2):592–601, 2009.

[56] Juan M Morales, Antonio J Conejo, and Juan Pérez-Ruiz. Economic valuation of reserves in power systems with high penetration of wind power. *Power Systems, IEEE Transactions on*, 24(2):900–910, 2009.

[57] M. Zugno and A. J. Conejo. A robust optimization approach to energy and reserve dispatch in electricity markets. Technical report, Technical University of Denmark, 2013.