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2019:00632- Unrestricted

Fundamental Multi-Product Price Forecasting in Power Markets

A literature review

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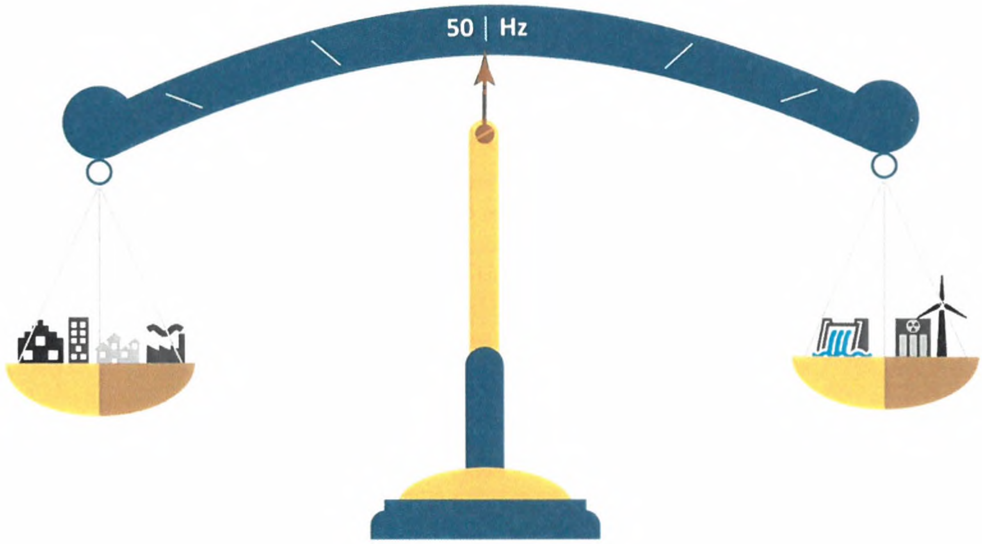

SINTEF Energy Research
Production Planning
2018-12-19

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Report

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KEYWORDS:
Power market
System balancing
Reserve capacity
Hydropower
Price forecasting
Fundamental model

VERSION
1.0

DATE
2018-12-19

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CLIENT(S)

CLIENT'S REF.

PROJECT NO.
502001606

NUMBER OF PAGES/APPENDICES:
53 + Appendices

ABSTRACT
This report has been prepared in the first phase of the project 'Pricing Balancing Services in the Future Nordic Power Market', and its purpose is two-fold. First, a review on expected future trends in European power markets is provided, focusing on the sequences and rules of existing and expected future markets. Second, a literature review on the topic of fundamental price forecasting is given. The focus is on modelling approaches for short-term physical markets, including several markets, such as the day-ahead intraday and balancing markets.

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REPORT NO.	**ISBN**	**CLASSIFICATION**	**CLASSIFICATION THIS PAGE**
2019:00632	978-82-14-06334-9	Unrestricted	Unrestricted

Document history

VERSION	DATE	VERSION DESCRIPTION
0.1	2018-12-19	Initial version
1.0	2019-06-06	Checked by QA

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APPENDICES

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1 Introduction

This report was prepared within the research project "Pricing Balancing Services in the Future Nordic Power Market (PRIBAS)" (2017-2020) and describes the activity of reviewing existing methods and applications that are relevant to the goals of this project.

As an initial project activity, we have reviewed scientific articles, technical reports, previous and ongoing research projects as well as existing power market models. We also review the current Nordic market design for short-term electricity markets (day-ahead, intraday and reserve capacity/balancing energy). By doing so we have sought to identify the state-of-the-art on fundamental power market modelling, emphasizing on aspects that are relevant for the project and the above-stated objective.

The report does not go in details about the PRIBAS project, but the reader should keep in mind the primary objective PRIBAS project, which is "*(...) to design, develop and verify a model concept able to compute marginal prices for all physical electricity products in the Nordic power market, including energy and different types of reserve capacity and balancing energy"*. By using the term "model concept" we indicate that this complex problem should not necessarily be solved using *one* complex model, but rather a chain of models. We will touch into this topic later in the report.

1.1 Background

Players in the Nordic power market have a long tradition of using fundamental stochastic market models for system analyses and price forecasting. EFI's Multi-area Power-market Simulator (EMPS) and the BID model from Pöyry (Pöyry, 2019) are typical examples of such models.

1.2 The Hierarchical Modelling Concept

Figure 1 shows a typical hierarchical modelling concept used in the Nordic market. It separates between long-, medium- and short-term models, and indicates possible couplings between the three model categories. The long-term model takes a fundamental[1] market modelling approach, whereas the medium- and short-term models are typically used for regional planning with a price-taker assumption. There are two major reasons for the particular form of the modelling concept.

Firstly, different players have different needs for decision aid. TSOs are mainly concerned with the long-term scheduling for system studies and sometimes use tools that integrate hydrothermal scheduling and detailed power flow studies. On the other hand, the producers naturally emphasize on the details in their respective water courses in the medium- and short-term scheduling. Consequently, the hierarchical division makes sense from a data perspective, allowing different agents to emphasize on their core business.

Secondly, the division into different layers is due to the computational complexity of the problem. Realizing that the planning horizon needs to be long enough to account for the storage dynamics of the largest hydropower reservoirs, the concepts of long-term strategic and short-term operational planning has been separated. In this context we consider the long- and medium-term models as strategic and the short-term models as operational. The long-term strategic models serve to estimate the value of the water through water values, e.g. by stochastic dynamic programming (SDP) or Benders cuts, e.g. by stochastic dual dynamic

[1] By *fundamental* models we refer to models that allow detailed representation of the market, such as supply, demand, network topology, and are able to reasonably replicate the inner workings of the same market.

programming (SDDP). These are stochastic models where uncertainties in inflows and exogenous market prices are represented. The treatment of uncertainty is important, but adds significant complexity to such models, and the tradition has therefore been to compromise on the level of detail in the system description to arrive at models with reasonable computation times.

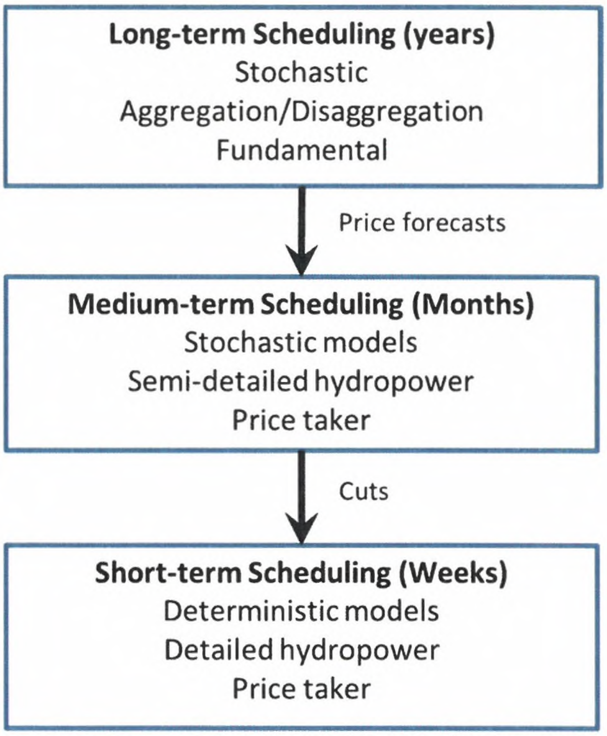

Figure 1 A typical modelling hierarchy used in the Nordic market.

The hierarchy in Figure 1 indicates that market prices found in the long-term scheduling does not "see" all the details in the medium- and short-term scheduling. The hierarchy has gradually evolved and found its form after the deregulation, but one should keep in mind that different setups and configurations has been discussed and tested throughout history. For example, previous work at EFI discusses the short-term hydrothermal scheduling considering unit commitment and dispatch subject to various component- and systems related constraints, see e.g. (Johannesen, Market Driven Hydro-Thermal Scheduling, 1998). This type of model has not been operationalized and is currently not a part of the typical Nordic hierarchy.

Looking to other hydropower-dominated countries, such as Brazil and Canada, one can find similar hierarchical divisions, although the market structure is different from the liberalized Nordic market. In centrally dispatched systems such as the Brazilian, all the long-, medium- and short-term scheduling activities are carried out for the entire system.

1.3 Long-Term Scheduling – The EMPS way

In the following we broadly introduce the basic principles of the EMPS model, serving as an example of a long-term scheduling model. The EMPS model has been under continuous development for several decades with the initial steps taken at Elektrisitetsforsyningens Forskningsinstitutt (EFI[2]) around 1975. It is widely used by most market participants in the Nordic market. Hence, it is a good starting point for describing principles behind the current price forecasting tools in the Nordic market.

[2] Later merged with SINTEF Energi into SINTEF Energiforskning AS, and today known as SINTEF Energi AS.

The basic characteristics and assumptions behind the EMPS model are summarized below. The EMPS model:

- Is a ***fundamental market model***. The physical system – comprising generation, transmission and demand – is explicitly modelled and technical and economic aspects are combined. Fundamental models normally aim at explaining electricity prices from the marginal generation costs.
- Assumes a ***perfectly competitive market***. Each supplier and consumer cannot affect the price by its actions, and thus the market participants take the price as given.
- Is a ***stochastic model***. Uncertainty in inflow, exogenous market prices, non-dispatchable power (such as wind and solar) and temperature-dependent demand can be modelled. Uncertainty is accounted for both in the computation of water values and in the simulation.

The EMPS model comprises two basic parts; a strategy evaluation and a system simulation, as illustrated in Figure 2, and briefly explained below. For more details see e.g. (Wolfgang, et al., 2009).

1) In the ***strategy evaluation*** the water values for each of a defined number of aggregate regional areas are found. These water values are computed based on the principle of stochastic dynamic programming (SDP) for each subsystem, with an overlaying hierarchical logic applied to treat the multi-reservoir aspect of the problem. Uncertainty in inflow, wind and demand (temperature related) are treated as stochastic variables.
2) In the ***simulation part***, the optimal operational decisions for a sequence of historical weather scenarios are found. The system operation is simulated week by week, using the water values from the strategy phase as valuation of reservoir content at the end of the week.

The EMPS model will normally be calibrated to the dataset at hand. In short, the calibration serves to establish a strategy that ensure acceptable simulation results.

Without going too much into the details of the EMPS model, we would like to emphasize on some characteristics of the model to shed light on the challenges faced by fundamental hydrothermal market models and some key points for the PRIBAS project.

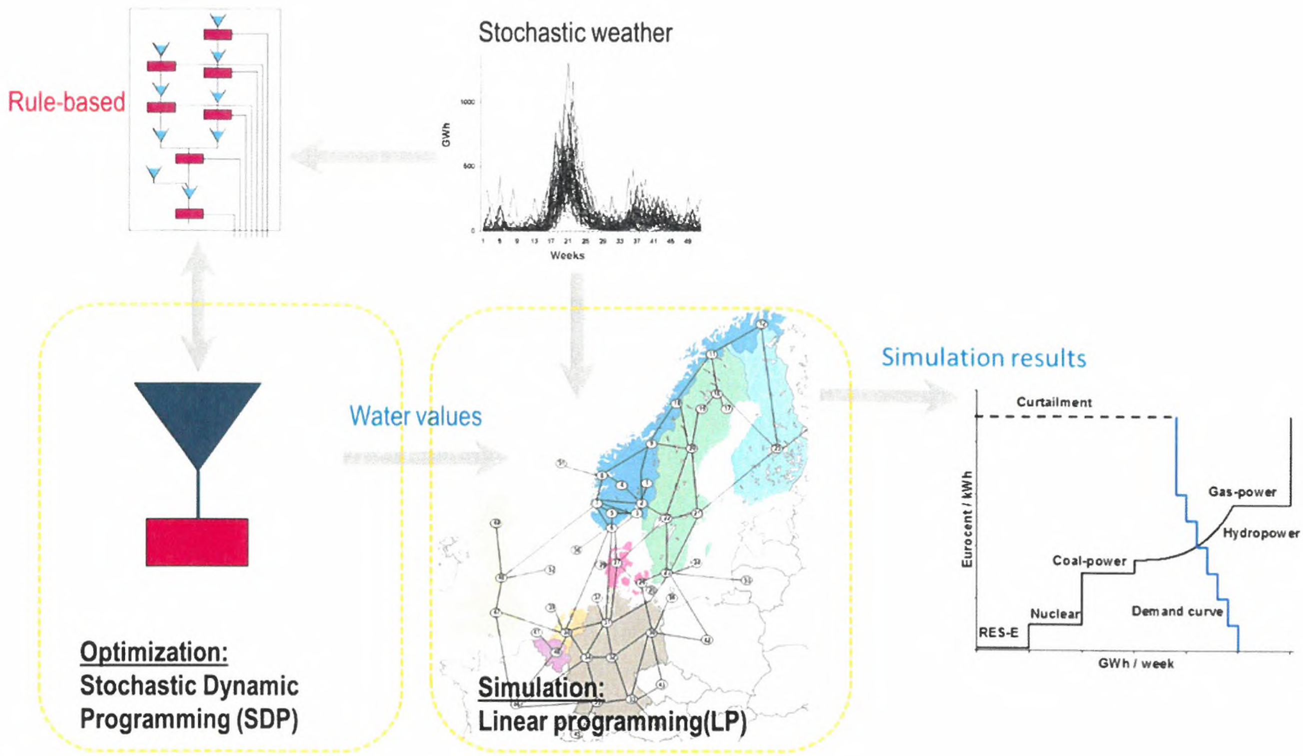

Figure 2 Illustration of the basic EMPS model concept.

1.3.1 Strategy Evaluation

The strategy evaluation algorithm has served as the inner core of the EMPS model and benefits from fast computation times. The strategy evaluation is done for a simplified system description. Water values are computed using stochastic dynamic programming (SDP) for one area at the time where the physical reservoirs and power stations are aggregated into an equivalent reservoir and a station for that area. This process is illustrated in the lower-left part in Figure 2. The simplification made by aggregating into one reservoir can to a certain degree be compensated for by use of model calibration.

SINTEF has explored multiple alternatives for a more detailed strategy computation. The recently developed FanSi model (Helseth, Mo, Henden, & Warland, 2018) is one such alternative, finding strategies by treating the detailed hydropower system. The FanSi model has shown that it is possible to find consistent strategies based on optimization, but that this task is extremely computationally demanding for the Nordic system. Therefore, we believe that there is still a need for fast, heuristic methods like the one used in the EMPS model. FanSi is further discussed in Section 1.4.

1.3.2 System Simulation

Once a strategy (in the form of water values or Benders cuts) has been computed, the system operation can be simulated using different historical weather scenarios. For each week all uncertain variables are considered known. Currently, the standard version of the EMPS model simulates the system by combining the use of an aggregate and a detailed hydropower representation. The weekly market clearing problem is first solved as a linear programming (LP) problem with hydropower on aggregate form. Subsequently, the aggregate hydropower generation is distributed to the individual stations based on a heuristic model (the detailed drawdown model), and in case the aggregate production is not feasible for the physical system and updated aggregate strategy is searched for.

For each time step within the week the LP problem matches supply and demand to find the power price for each price area. In the end time-series of energy prices are obtained as a result from the simulation part.

In a recent prototype (Hansen, 2018) of the EMPS model[3] known as EMPS-W the system simulation problem including detailed hydropower representation is formulated as an LP problem. This model extension allows more consistent treatment of detailed hydrological constraints and in turn more precise valuation of hydropower flexibility.

1.3.3 Mismatch between strategy and simulation

In general, the system simulation capability in the EMPS model has been greatly enhanced in the last decades, including e.g. finer time resolution, start-stop costs on thermal units, reserve requirements, etc. In the EMPS model these capabilities are not equally handled in the strategy evaluation part, leaving a growing gap between the system description seen in the strategy and simulation parts. Thus, one runs the risk of having a strategy based on too many simplifications, and the process of model calibration may become more complex and less transparent.

1.4 Long-Term Scheduling – The FanSi way

The FanSi model is built to solve the same fundamental market problems as the EMPS using the same input data, but the solution methodology differs. The model was developed within the SINTEF-led research project "Stokastisk optimaliseringsmodell for Norden med individuelle vannverdier og nettrestriksjoner (SOVN)", lasting from 2013-2017. The FanSi model treats the detailed hydropower by optimization when finding the strategy, and thus allows the same system representation in both the strategy evaluation and system simulation. See (Helseth, Mo, Henden, & Warland, 2018) for more details on the FanSi model.

The system operation in FanSi is simulated along historical weather years. For each year and each week, the uncertainty in weather is known for the whole week, but can follow a set of weather scenarios from week two and for the remaining scheduling period (known as scenario fans), as illustrated in Figure 3. The first-week operation is guided by evaluating multiple long-term scenarios. For each first-week we defined a two-stage stochastic LP problem and decompose the first week from the scenario problem by Benders decomposition. The results for the first week are recorded and the corresponding end-of week reservoir is passed on to the next week where a new two-stage stochastic LP is set up and solved. The FanSi model can be considered a rolling-horizon simulator where the simulated results come from the first-week solution and the operational strategy comes from solving the many scenario problems. Both the first-stage week and the scenario problems consider the detailed hydropower description without aggregation.

[3] Developed in the MAD (Methods for Aggregation and Disaggregation) research project.

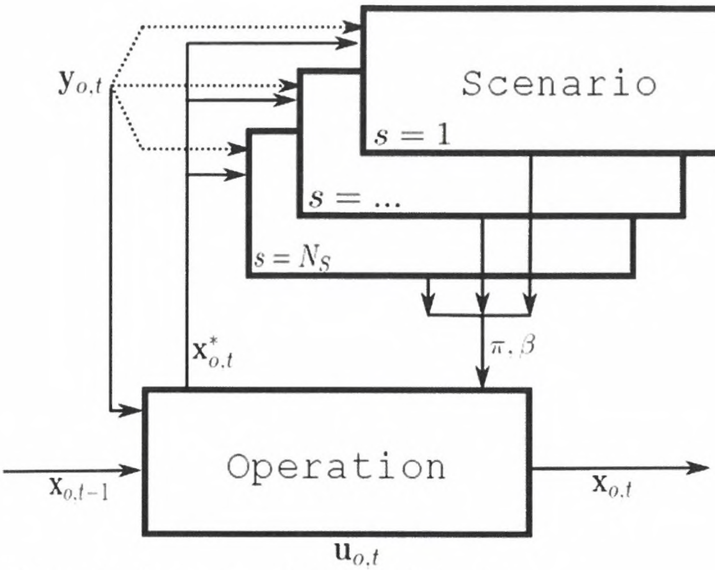

Figure 3 Illustration of the FanSi simulator.

1.5 Modelling challenges

Both the EMPS and FanSi models are designed to consider the product 'energy'. There is functionality for defining reserve requirements for up-regulation in the EMPS model (Warland, Haugstad, & Huse, 2008), but currently the shadow prices are not reported from the model.

In principle both the EMPS and FanSi market models can be further developed as multi-market models used for price forecasting in multiple markets. However, we believe there are three major challenges to such extensions.

1) Computation time. Solving the long-term hydrothermal scheduling problem is a complex task and doing this to perfection is extremely computationally demanding. This has been experienced through the development of the FanSi model. Further extending and refining such models to allow multiple products would significantly add to the computational challenge.

2) Lack of details in the system description. The EMPS and FanSi models are based on LP where all functional relationships are linear, and all variables are continuous. In a future market with more intermittent renewable generation we believe that the physical boundaries of the generation and transmission system will increasingly be exploited. Thus, it becomes more and more important to represent these boundaries in fundamental market modelling tools. To a certain extent this will be possible within LP-based models. The modelling of reserve capacity and balancing energy necessitates certain modelling details that are less important in purely energy models. One such example is the modelling of down-regulation reserve capacity which requires generators to be spinning. This feature is impossible to model precisely in an LP model formulation.

3) No uncertainty within the week. The EMPS and FanSi models operates under the assumption that all uncertainty is revealed in weekly steps. This can be seen as an approximation of the current market design. As explained in the previous point, the system boundaries are likely to be challenged more extensively in the future, and the physical limitations in the system will more frequently impact the market prices. Moreover, the increasing uncertainty through intermittent generation challenges the

weekly decision stages used in both the EMPS and FanSi models. With no uncertainty within the week these models are too optimistic about exploiting the system boundaries. In general, the value of flexibility (e.g. through storages) is likely to increase with increasing uncertainty. Another point is that, in order to facilitate a sequential treatment of multiple markets, the individual clearing of each market should be modelled as a separate decision, allowing updated information between decisions.

2 The Nordic Power Market

The purpose of this section is to give an overview of the different electricity market products being traded in the Nordic power market and the corresponding market clearing sequences.

The Nordic market is one out of the regional electricity markets in Europe. In the long run the European Union through its regulatory authorities aims to harmonize and integrate the separate markets into one internal market. These plans are not addressed in this report in detail.

The section reviews the physical markets comprising the day-ahead (DA), intraday (ID) and the different TSO-operated for reserve capacity and balancing energy. These TSO-operated markets are broadly referred to as *balancing markets*. The balancing markets are primarily organized by nation, where the focus in this report is on the Norwegian and Swedish arrangements and include some rules and regulations.

A majority of the material in Sections 2.1 - 2.4 is based on the report (Helseth, Fodstad, & Henden, Balancing Markets and their Impact on Hydropower Scheduling, 2016). With the rapid changing market structures we realize that this description fast become "yesterday's news".

2.1 European power market integration

The goal of the EU is to establish an internal European market for power. To achieve this internal market a number of projects for market coupling are established or under development. For the day-ahead market, the Price Coupling of Regions (PCR) has been established covering 19 countries and about 85% of European power consumption. For the intra-day markets a similar project is started involving TSOs from 12 different countries, called XBID. In the case of balancing markets, a number of bi-lateral and regional initiatives are started, with establishing a common FRR market for the Nordic among others.

(Brijs, Jonghe, Hobb, & Belmans, 2017) present a discussion of the development of short-term markets in reaction to flexibility needs in the central-west European power system. They conclude that such short-term markets become increasingly important. The authors identify a number of key design parameters and discuss the functioning of the short-term markets to provide an understanding of what is necessary to incentivise the availability of flexibility in the power system and provide insight for policy- and decision makers.

2.2 Day-ahead market

ELSPOT is Nord Pool's (NP) marketplace for trades in day-ahead physical electricity delivery. ELSPOT was established in 1993 as Statnett Marked AS, serving initially as a Norwegian market only. In 1996, Sweden joined the market and the exchange changed name to Nord Pool ASA. Later on, Finland and Denmark joined the exchange, and Nord Pool Spot AS was established as a separate company in 2002, while the financial markets were sold to NASDAQ. Currently, the rebranded Nord Pool AS is owned by the Nordic (Statnett, Svenska Kraftnät, Fingrid and Energinet.dk) and Baltic (Elering, Litgrid and Augstsprieguma Tīkls) TSOs.

The day-ahead spot market ELSPOT currently includes Norway, Sweden, Denmark, Finland and the Baltic countries. The division into ELSPOT areas, or price areas, is a result of the combination of the TSO's projections of which areas and interfaces that will experience power transmission demand exceeding the grid capacity. Currently ELSPOT comprises 15 price zones, as shown in Figure 4, with 5 in Norway, 4 in Sweden, one for each of the Baltic countries, one in Finland and two in Denmark. The term 'spot market' will usually refer to this market, which is also the norm in this document. In 2016 a total of 391 TWh was traded through ELSPOT.

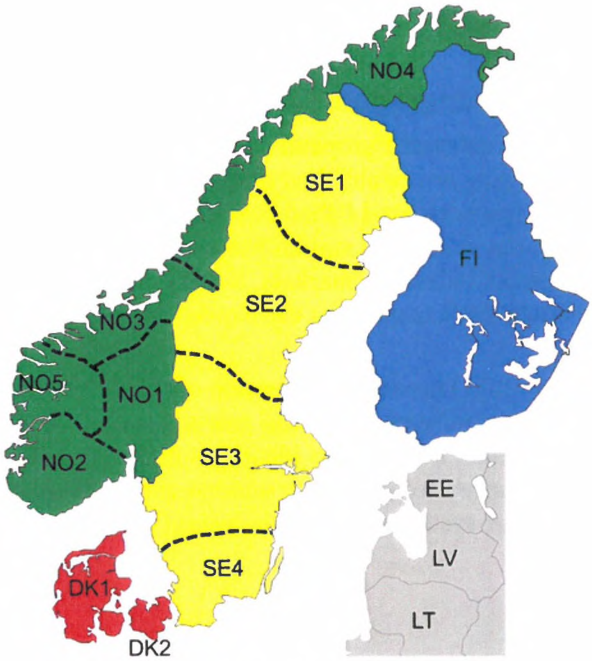

Figure 4 ELSPOT price-areas.

The market is cleared once a day as an auction with marginal pricing. Market players who want to trade energy on the ELSPOT market, must send their bid volumes and prices to NP before 12:00 the day before physical delivery. The time-delay between clearing and physical delivery ensures that slow-ramping technologies, such as thermal and nuclear power plants, are given sufficient time to plan the up- and down-regulation of production. The bidding does not refer to individual plants and units and is thus on portfolio basis for the given price area. The system price is calculated based on all bids for the entire exchange area for each delivery hour the following day. The bids for buying and selling power are gathered in one curve for supply and one for demand. The intersection point of these curves defines the unconstrained, hourly *system price*, which serves as a reference price for the entire market. In case any of the resulting flows between price areas exceed their respective maximum capacities in a given hour, the market is split to find valid flow values and separate *area prices* for that hour.

Trading is based several types of orders, as defined by NP[4]. The largest share of the day-ahead trading is matched based on single hourly orders, and we briefly describe this order type below. A market player specifies the purchase and/or sales order for each hour, represented by a bid curve of price/volume-pairs. Once the price for each hour is determined, a comparison with a player's order for that day establishes the delivery for the player. The minimum requirement for a single hourly order is two price-steps, at minimum price -€500 and maximum price €3000, also known as a price independent order. A price-dependent single hourly order may consist of up to 62 price steps in addition to the current ceiling and floor price limits set by NP. NP linearly interpolates volumes between each adjacent pair of submitted price steps.

The TSOs require that market players expect no imbalances when bidding into a price area in the spot market, cf. §8 in (Statnett, 2013). If a player acts in a way that causes significant imbalances in any direction over time, the regulator may withdraw its concession to produce. Thus, producers have strong incentives to be risk-averse when it comes to creating imbalances. In addition, imbalance settlement is done based on a two-price system, where deviations in the same direction of the imbalance are settled with the imbalance price, while imbalances in the other direction are settled with the spot-market price. This creates an additional incentive to be in-balance in the first place.

Adjustment towards physical operation

The ELSPOT market is often referred to as the spot market, but one may argue that this market is a forward market since the prices market players are finally exposed to are the real-time balancing market prices. However, ELSPOT is defined as a physical market as production and consumption have to send their day-ahead schedules to the according TSO. Although the market participants should not expect imbalances at the time of bidding, the time-delay between bidding and physical delivery allows imbalances to occur.

Since it is not possible to perfectly predict the weather and the system state for the next day, and since the cleared day-ahead volumes may not be feasible when considering physical operation, there will be a need to adjust the schedules. Balancing services are needed to continuously balance supply and demand at real time operation. More specifically, balancing services are needed to handle:

- Outages of power system components (power plants, transmission facilities, etc.). Such events are hard to predict and may cause severe system disturbances.
- Weather dependent exogenous factors (impacting e.g. demand and intermittent generation). Although forecasting methods continue to improve, weather forecast errors will always exist.
- Structural imbalances caused by the market design. These are imbalances that are due to the discrete time resolution of day-ahead and intraday markets. Obligations may change in large steps in between consecutive hours, whereas load and intermittent production changes are continuous. Both the granularity (hourly time resolution) and time difference between market closure and real-time operation leaves behind a need for balancing services.
- Congestions in the power grid that are not explicitly seen by the day-ahead and intraday markets. These are treated by use of manually regulated reserves.

When faced with an unbalanced portfolio, e.g. due to changes in weather conditions or (economically) unfortunate production plans, the Balance Responsible Parties (BRP) will in principle have two options:

a) Actively remove the imbalance by trading in the intraday market
b) Await the TSO's balancing service activation and imbalance settlement

[4] https://www.nordpoolgroup.com/

2.3 Intraday market

ELBAS (ELectrical Balancing Adjustment System) is an intraday market for the synchronous power system in the Nordic area organized by NP. The ELBAS market is expected to be gradually replaced by the European cross-border Intraday (XBID) market project to create a joint integrated intraday cross-zonal market. The purpose of the XBID initiative is to increase the overall efficiency of intraday trading. In the first phase named as the 10 Local Implementation Project which went live in March 2018, XBID delivered continuous trading of electricity across the following countries: Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Norway, The Netherlands, Portugal, Spain and Sweden. Most other European countries are due to take part in a second 'wave' go-live with XBID in Spring 2019. XBID market solution allows for orders entered by market participants for continuous matching in one bidding zone to be matched by orders similarly submitted by market participants in any other bidding zone within the project's reach as long as transmission capacity is available.

The ELBAS market was established in 1999 by Finland and Sweden, and Norway joined in 2009. It provides the opportunity for trading intraday power across country borders in the Nordic and Baltic regions, Germany and the Benelux countries (through the NorNed cable). After closure of ELSPOT market players can adjust their positions in the ELBAS market. ELBAS opens at 14:00, following the closing of the ELSPOT auction and publishing of day-ahead prices and trading volumes. Trades in ELBAS are allowed up to one hour before real-time, which gives the participants the opportunity to adjust for imbalances if production and consumption schedules deviate from the volume committed in ELSPOT. Thus, ELBAS functions as an after-market for ELSPOT.

A bid in ELBAS consists of the bid type (sell or buy), a price and a volume for a specific hour and price area. The trading process works as in a stock market, where the participants place their bids anonymously into a trading system. The trading system is developed for continuous trading, allowing the participants to follow the situation on the market, place bids and search trade and cash-flow information. Prices are set according to a pay-as-bid regime and based on a first-come, first-served principle. Nord Pool acts as the only counterpart for all trades on ELBAS, guaranteeing settlement and anonymity. The trading participants will only see the bids that are available after transmission constraints have been accounted for. Initially, all available transmission capacity is given to the ELSPOT market. The ELBAS cross-border capacity is known when the deadline for filing complaints on the ELSPOT has elapsed and the cross-border capacity that is left after ELSPOT clearing is known. The participants are obliged to report their ELSPOT trades to the relevant TSO. After a trade, the available capacities and offers in the entire ELBAS area are updated for market participants.

Similar to ELSPOT, the TSO states that all trade in the ELBAS should be done considering the associated BRPs to be in planned balance (Statnett, 2013).

The total energy traded in ELBAS in 2017 was 6.6 TWh, respectively. The traded volumes in the ELBAS market are rather small. According to (Weber C. , 2010), one possible explanation is in the market concentration. Large BRPs can find it advantageous to net imbalances using their own portfolio. The traded volumes are particularly low for Norway. A study of the ELBAS transactions in 2012 showed that the share of ELBAS volumes in total generation[5] differs significantly between Norway (0.1%) and Sweden (0.8%) (Scharff & Amelin, 2016). Several characteristics may explain this difference. The flexibility in most hydropower producers' portfolios seems to give no obvious preference for correcting imbalances in the ELBAS rather than in the balancing market (regulating power). (Scharff & Amelin, 2016) also points to the facts that Norway has a lower share of wind power, lower capacity towards the Continental Europa (when

[5] ELBAS volume is evaluated as 0.5*(*sales + purchase*)

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ELBAS trade has been accounted for), and lower export possibilities to the countries with higher balancing prices. One should also note that the two countries had different ELBAS gate closures in 2012[6].

2.4 Balancing markets

The day-ahead and intraday markets concern trading and physical delivery of energy for hourly time periods. Balancing markets aim at resolving the imbalances that may occur within the operational hours. Availability of and rules for the different types of balancing markets differ between countries within the Nordic market. In the following description we will focus on the Nordic synchronous system, where the four TSOs Statnett (Norway), Svenska Kraftnät (Sweden), Fingrid (Finland) and Energinet.dk (Denmark) are responsible for operational reliability and the balance between production and consumption of electricity. In particular we describe the Norwegian and Swedish markets and arrangements for providing balancing services. Some countries/regions are outside the Nordic synchronous system, but are interconnected through HVDC cables, e.g. Western Denmark. The frequency in Western Denmark is therefore not affected by Nordic imbalances, but this area can contribute to frequency control by delivering regulating power through the HVDC cables, and vice versa.

In the following we will describe the sequences and rules for the balancing markets. Much of the material is based on regulations found at the webpages of Statnett and Svenska Kraftnät. The operational requirements for the Nordic system are defined in a common system operation agreement (ENTSO-E 2013), which e.g. specifies how operational reserves should be maintained and distributed and in the according network codes, System Operation Guidelines (Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation, 2017) and Electricity Balancing (Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, 2017). The three different types of control (primary, secondary and tertiary) are illustrated in Figure 5, and described below. A frequency deviation is caused by an imbalance between generation and demand, and primary, secondary and tertiary reserves are used to sequentially restore the frequency to its nominal value. The figure illustrates that secondary control is used to restore primary reserves, and tertiary to restore secondary.

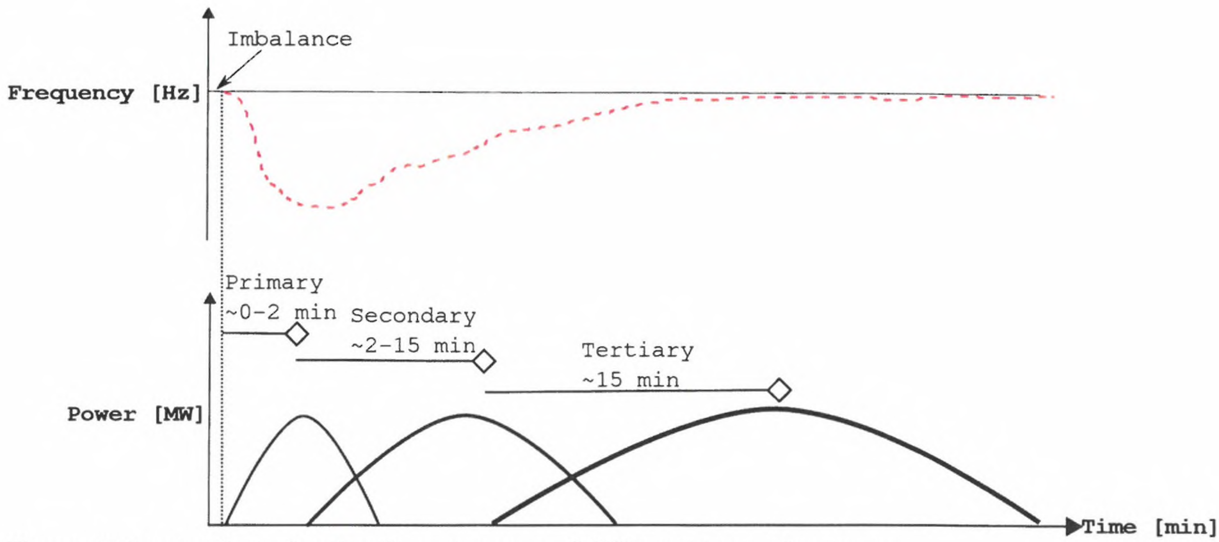

Figure 5 Illustration of activation sequence of different type of reserves.

[6] Sweden had one-hour gate closure in 2012, whereas Norway closed two hours before. Norway adopted the one-hour gate closure in 2013.

Generally, balancing services are divided into three different products/reserve types needed to provide the control principles in Figure 5. In parentheses the names of the Norwegian products currently corresponding to the general reserve types are given.

- Primary reserves (frequency containment reserves, FCR)
- Secondary reserves (automatic frequency restoration reserves, aFRR)
- Tertiary reserves (manual frequency restoration reserves, mFRR / replacement reserves, RR)

Primary reserves are activated due to a frequency deviation, while secondary reserves are activated to bring back the frequency to its nominal value. Both primary and secondary reserves are automatically activated/controlled and are normally characterized as so-called "spinning reserves". That is, these reserve types have to be running (synchronised with the grid) before called upon. In contrast, the tertiary reserves are manually controlled and do not need to be "spinning". To be available in real-time, these reserves are procured beforehand.

The importance of reserve procurement may vary greatly between hydropower- and thermal-dominated systems. Procurement of reserves is generally less critical in systems with a large share of hydropower than it is in typical thermal systems. Hydropower plants can normally be started up in short time and have their best efficiency below maximum production. Thus, when operating at their best efficiency, hydropower plants provide spinning reserve for both up- and down-regulation at low operational cost. Thermal power plants are generally slower to start-up and are most efficient at maximum production and will thus be more expensive to keep as spinning upward reserves. However, with an integrated European market in future sight, the separation between hydro and thermal will become less distinct. The stronger coupling between systems will open for increased exchange of balancing services between systems, and a growing potential for socio-economic benefits stemming from coordinated operation of hydro- and thermal-based systems.

The term "replacement reserves" does not seem to belong to the standard terminology in the Nordic market, and will not be used here. According to ENTSO-E, replacement reserves are used to restore the mFRR to prepare for additional system imbalances.

2.4.1 Market sequences

Figure 6 by (Veen & Hakvoort, 2016) schematically illustrates the structure of balancing markets and its inherent sequence. In general stakeholders in the balancing market can be divided into three different groups. Balance responsible parties' aggregate production and consumption in the power system and are responsible for the difference between the plans send to the (T)SOs and the production/consumption in real time. These differences are settled in the imbalance settlement at the imbalance cost. Balancing service providers offer balancing services to the (T)SOs and are paid for that according to the utilisation of this services. System operators, which can also own the transmission system (then called TSO), procure reserve capacity as well as continuously observe the balance in the power system and call upon reserves if necessary. TSO invoice imbalances to BRP and reimburse BSP for delivered balancing services. Within the balancing market all types of reserves are handled.

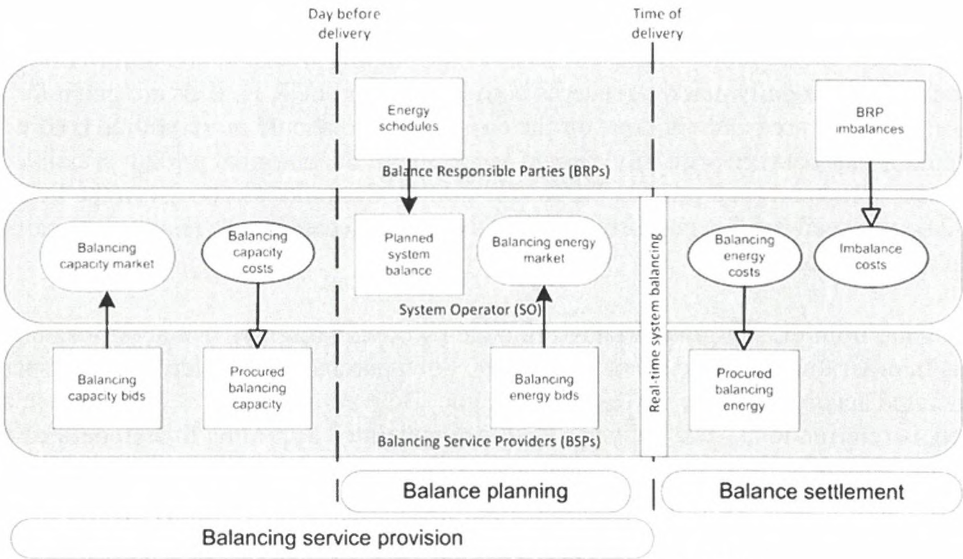

Figure 6: Basic structure of Balancing markets (Veen & Hakvoort, 2016)

2.4.2 Primary reserves

Momentary imbalances between supply and demand will firstly be regulated by use of primary regulation reserves. The system frequency is controlled by automatic activation of frequency containment reserves (FCR). Such reserves are currently assured by the droop setting in the turbine governors for generators exceeding 10 MVA (Norway). If they are spinning and not already operating at full load, generators respond automatically to changes in frequency according to their droop setting. TSOs need to assure that there are enough spinning reserves in the system and that these reserves are geographically distributed so that the risk of overloading the transmission system is limited.

Norway

In previous years, Statnett would ask Norwegian generators to adjust the droop in case of insufficient reserves. In that sense, primary control was considered a free service and there was no market for this type of service. In 2008 two primary reserve markets were established; a weekly and a daily market. These markets are operated by Statnett according to conditions stated in (Statnett, 2013). After introducing the marketplace for primary reserves, Statnett decides on a maximal droop setting to ensure a distributed supply of primary reserve from spinning aggregates. The producers can supply more reserves than the required lower limit by decreasing the droop setting or by running more aggregates than originally planned.

Two products are traded in the Norwegian primary reserve market, namely FCR for normal operation (FCR-N) and for contingencies (FCR-D). Both are automatically activated; FCR-N is activated when the frequency is within the "normal range" (49.90 - 50.10 Hz), whereas FCR-D is activated when the frequency falls below 49.90 Hz. For FCR-N both response directions (up and down) should be available for a given market bid. The FCR-N and FCR-D market products do not only differ in the frequency band, but also in the activation response time.

The division of the primary reserve market in a weekly and daily market can be seen as a compromise between the ability to secure sufficient reserves at early phase on the one hand, and the system cost and loss of flexibility in the production system by doing so on the other.

The weekly market only concerns FCR-N and is divided in 6 time periods (combinations of weekday and weekend with daily periods night, day and evening). Bids to the weekly market should be given per price area and should be delivered before Thursday 12:00 for the coming weekend and before Friday at 12:00 for the coming weekdays. The daily market concerns both FCR-N and FCR-D. Bids are given for the type of primary reserve, per price area and per hour for the day-ahead and should be submitted before 18:00. Both the weekly and daily markets are primarily cleared according to the marginal pricing principle. All accepted bids will then receive the marginal price in NOK/MW/period. Committed capacity in the FCR-N and FCR-D markets should be reserved for this purpose and should not be affected by the responsible party's contribution in other markets.

Statnett may deviate from the marginal pricing principle by buying reserves that are priced higher than the marginal price, in order to meet all relevant constraints. Such purchases are referred to as "special purchase" and are remunerated according to the pay-as-bid principle. Delivery of FCR that has not been a part of the market solution, is referred to as "rest delivery" and is remunerated according to a predefined price set by the TSO. The balance settlement is therefore divided in four categories; the weekly and daily markets, the special purchases and the rest delivery.

Sweden

In 2011 Svenska Kraftnät started procuring primary reserves according to the definitions of FCR-N and FCR-D above. Primary reserve bids should be delivered either the day before (D-1) or two days before (D-2) the day of operation and can be stated per price area or per regulating object. Unlike the case in Norway, Svenska Kraftnät uses the pay-as-bid principle when procuring reserves and provides guidelines on how to calculate bids. Bids shall be cost-based and provide some margin for profit- and risk premium (Svenska Kraftnät, 2019).

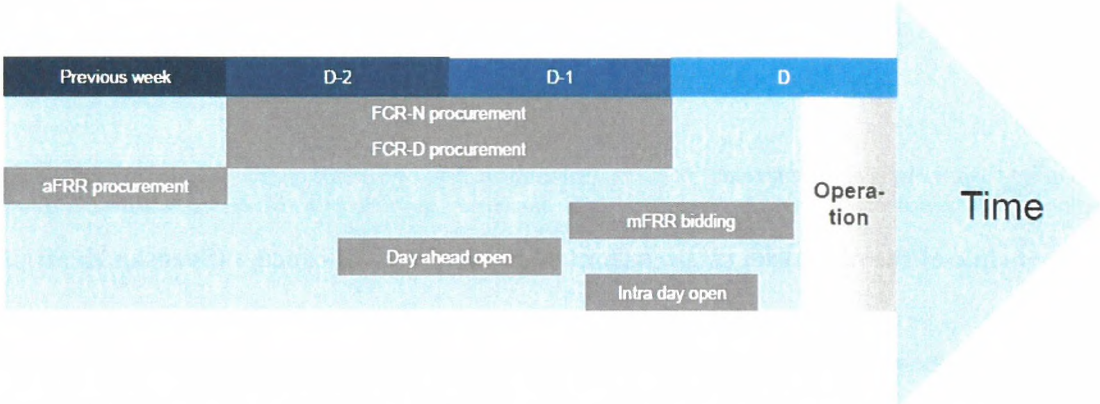

Figure 7: Timing of the reserve market of Svenska Kraftnät (Svenska Kraftnät, 2019)

2.4.3 Secondary reserves

In the cases of frequency deviations from its nominal value automatic Frequency restoration reserves are activated in the first place. The activation of these reserves is also called Load-Frequency-control (LFC). Activation of these reserves is intended to bring back the frequency back to its nominal value, hence restoration, and free up primary reserves. The activation of the reserves is based on the system frequency, which is the same all over the synchronous system. Hence, the imbalance causing the frequency deviation and activated reserves might not be situated at the same location, which can cause or violate bottlenecks in the transmission system. To account for that, the so-called Area-Control-Error (ACE) is introduced, which accounts for flow changes across area borders, to ensure that reserves are activated in the area, which causes the imbalance. Automatic Frequency Restoration Reserves (aFRR) was introduced in 2013 in the Nordic area. Reserves are activated due to a signal send from the TSO to the contracted reserve, which need to react within 120-240 seconds. Up to now aFRR is procured and activated by each Nordic TSO individually for specific hour-block during the day. The procurement process is held every quarter of a year.

The plan is to establish a common Nordic aFRR market including the procurement and activation of the reserves (Svenska Kraftnät and Statnett, 2017). Within that the establishing of a Modern Area Control Error (MACE) is planned, which instead of only maintaining the flows on cross-area interconnectors should take into account available transmission capacity or existing bottlenecks to utilise available reserves more efficiently. This should both happen during the procurement and the activation of the reserves.

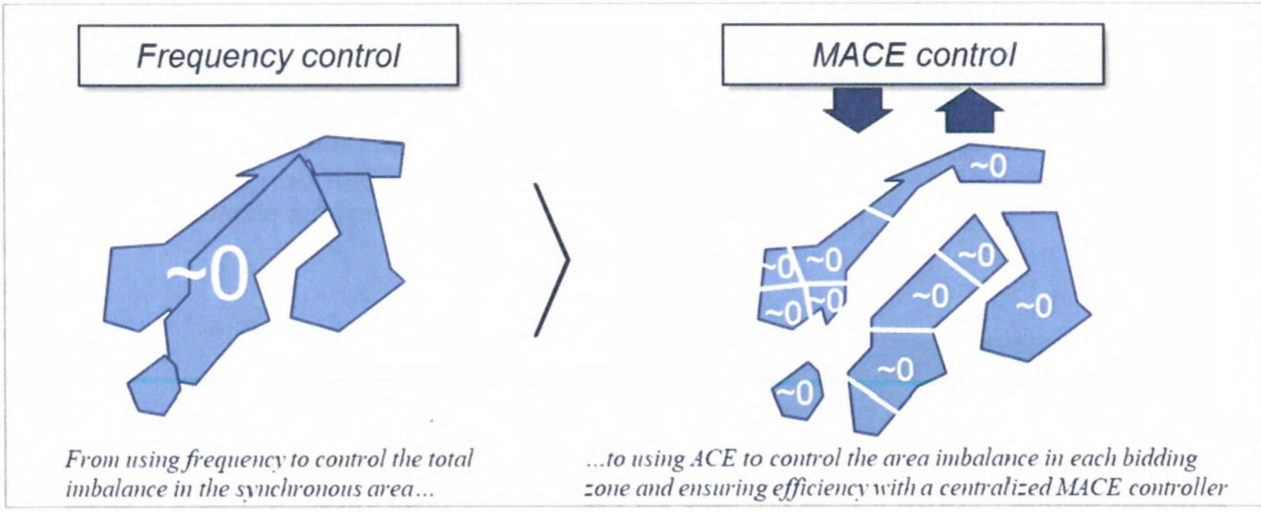

Figure 8: Principle of the new Modern Area Control Error (MACE) concept (Svenska Kraftnät and Statnett, 2017)

2.4.4 Tertiary reserves

In the Nordic area tertiary reserves comprise mFRR only, which are activated when manually called upon. mFRR is used for two main purposes 1) congestion management and 2) balancing, with the key functionality detailed below:

Congestion management:

- Prevent line overloading by redispatch / counter-trading
- Change flow patterns to increase the Available Transmission Capacity on certain lines

Balancing:

- Proactively compensate for expected imbalances
- Reactively active to free up aFRR and reset the ACE
- Handle larger disturbances

Actions for congestion management are separated (out of the merit-order) from balancing activation. The activations to resolve congestions are also called special activation.

2.5 Future balancing markets developments

In their report "Challenges and opportunities for the Nordic power system" (The Nordic Transmission System Operators (TSOs), 2016), the Nordic TSOs outlines the expected challenges for the system up to 2025, emphasizing on system flexibility, generation adequacy, frequency quality, inertia and transmission adequacy. Challenges related to system flexibility and frequency quality are of particular interest here, since those aspects highly influence the price formation in the future market.

2.5.1 Challenges

With respect to ***system flexibility***, some major challenges are:

- The demand for flexibility is increasing, both in the day-ahead market and in the operational hour;
- Flexibility provided by existing hydropower is limited and the thermal generation capacity is declining;

- Forecasting errors will affect a larger proportion of the total production and will increase the need for balancing closer to and within the operational hour.

The market impacts of these challenges are increased short-term price volatility and reduced price differences between the southern Nordic region and the European Continent. Moreover, one expects higher balancing costs. At wintertime (high-load periods) controllable generation resources will to a larger extent produce at full capacity. At summertime (low-load periods) intermittent generation resources will have a higher share of the total generation than today.

The TSOs point to some possible measures to deal with the flexibility challenges. It is possible to further develop power and reserve markets, e.g. with finer time resolution in day-ahead and balancing markets. Moreover, one could allow for more efficient utilization of the transmission capacity and further restricting the ramping allowed on HVDC cables.

With respect to ***frequency quality***, some main challenges are:
- Larger structural imbalances around the hour shift;
- Increasing forecast errors;
- Increasing demand and decreasing availability of reserve capacity;
- Increasing need for transmission capacity for exchanging reserves.

The TSOs except that faster, larger and more frequent changes in generation and power flow will give rise to more pronounced real-time imbalances. Combined with an expected reduction in system flexibility, The TSOs foresee increasing challenges in balancing the system and maintaining a high frequency quality.

The TSOs point to some possible measures to deal with the frequency quality issues. The structural imbalances around the hour-shift can be significantly reduced by introducing a finer time resolution in the day-ahead and balancing markets. The TSO operated markets for procurement of reserve capacity can be adjusted to ensure sufficient reserve capacity, e.g. as in the current development of a common Nordic market for aFRR.

It is also relevant to note that geographically unbalanced volumes of reserves can potentially lead to critical system operation due to constrained transmission capacity. As pointed out in (The Nordic Transmission System Operators (TSOs), 2016) the optimal solution would be to allocate transmission capacity for energy and reserve capacity simultaneously, which may be seen as a long-term objective. In the shorter-term solutions for more efficient allocation of transmission capacity for reserve markets are investigated.

2.5.2 Market design

There exist a large amount of literature on the development of market design for balancing markets. A throughout discussion of design choices for balancing markets is discussed by (van der Veen & Hakvoort, 2016) The study defines a set of performance criteria and the design space.
The performance criteria comprise:
- Security-of-supply (Availability of resources, balancing planning accuracy, balance quality)
- Economic efficiency (cost allocation, utilisation, pricing, operation)
- Market-facilitation (transparency, non-discrimination)

The design space for balancing markets comprises numerous variables, comprising:
- General variables (schedule time unit / imbalance settlement period, publication of information)
- Balance planning (zonal / nodal responsibility, net vs. dual position, gate closure time, BRP qualification)

- Balancing services (reserve requirements, reserve procurement, market timing, pricing mechanism, reserve activation / control, activation strategy, bid requirements, BSP qualification)
- Balance settlement (allocation of reserve capacity cost, allocation of balancing energy cost, pricing mechanism, non-delivery penalty, settlement timing)

In view of the wide variety of design options, the trade-offs among performance criteria, uncertainties about the effects of design options, and the inter-linkages between the balancing market and the overall electricity market, policy makers face a substantial design challenge. This challenge can be met by addressing key criteria and variables, by considering system and market conditions and expected future developments, and by identifying the design options that provide appropriate incentives to market participants given all of these considerations.

A report on the state of electricity balancing markets in Europe by the EU commission is presented in (EC DG ENER, 2013). The focus is on the description of key elements of balancing markets and their state space as well as on the integration of national balancing markets and the resulting effectiveness. The market design space covers:

- responsibilities of market participants,
- harmonisation pre-requisites for market integration,
- imbalance settlement pricing,
- cost allocation for capacity and energy with regards to balancing,
- procurement of Balancing Services,
- integration with day-ahead and intra-day markets,
- treatment of interconnection capacity and
- incentivisation of demand side participation

The results of the quantitative analysis support the view that there are potential welfare benefits from allowing cross-border trading of balancing energy and the exchanging and sharing of reserve capacity across the EU Member States borders. The report points towards an integrated model of a multilateral "TSOs-TSOs" platform for the exchange of balancing energy and reserves based on a Common Merit Order (CMO) where "security margins" can be imposed with minimum loss of economic efficiency. The scheme of "avoidance of counteracting secondary control" ("imbalance netting") should be the first step of integration where cost/benefit analysis provides the case for its implementation.

In his thesis (Nobel, 2016) assesses the technical and economical characteristics of different balancing market designs. The research identifies key elements and their effect on the market mechanisms, based on empirical data for the Netherlands and Germany. The identified key elements of balancing market design are within the energy settlement defined by volumes and price components, granularities (imbalance settlement period), and settlement mechanisms. Other elements are gate closure times, and the real-time feedback of system information to all users. The choice of the settlement mechanism is closely linked to the financial position of the system operator as a result of its energy settlements, and its cost relating to comply to operational standards. It is shown that some choices result in exclusion mechanisms or in inefficient mark-ups in prices.

A number of research studies assess the impact of market design for short-term / balancing markets. In the following a number of these studies are reviewed conclusions identified. Thereby it is divided into studies concerning the whole European power system and studies focussing on the Nordic power system. The conclusions will focus on suggested developments / market design variables, which also should be reflect in the market modelling.

2.5.3 Market design in the European power system

In this section we review a set of recent studies on the European power market design.

An overview over the design of balancing markets throughout Europe is provided by (Ocker, Braun, & Will, Design of European balancing power markets, 2016). It is concluded, that there is no predominant design among the European countries, but that there are three main drivers for the designs: 1) the share of variable renewable energy sources, 2) available short-term flexibility and 3) the pan-European market coupling. The inconsistency in auction characteristics among European countries seems to be caused by the complexity of multi-part auctions for balancing power procurement. It is concluded that national legislation has to decide if a further integration of European Balancing Power markets is desirable and adjust their market design accordingly, which requires the harmonization of market design. Within this integration the target of national energy independence is an important topic.

(Müsgens, Ockenfels, & Peek, 2014) assess the German balancing power markets. The assessment suggests changing the existing pay-as-bid rule in Germany to a uniform pricing, concluding that this payment principle is superior. In addition, it is suggested to still base the acceptance of the bids on the capacity price only, which is sufficient to reflect all relevant costs for the reserve procurement.

(Holttinen, et al., 2016) assess the impact of shorter gate closure times for wind power producer. To that imbalance costs based on day-ahead bidding are compared with imbalances resulting from 2-hours ahead forecasts. It is concluded, that bidding in day-ahead markets has a too long lead time for wind power production, while using 2h ahead forecast would reduce imbalance cost by up to 50%.

Arrangements and requirements that are necessary to reconsider in order to facilitate cross-border balancing in Europe are assessed by (de Haan, 2016). The research addresses the sizing and allocation of reserves, allocation of transmission capacity for reserve exchange and multilateral coupling of different synchronous areas. The last issue addresses the operation of HVDC lines in the case of cross-border balancing.
For the reserve sizing it is suggested to:

- Establish a N-2 criterion, accounting for an increasing size and complexity of the power system
- Do a dynamic reserve sizing, which also accounts for reserve performance
- Make use of passive balancing, which will reduce requirements (passive balancing requires the real time publication of imbalance state and price, so that actors can react)

Cross-border balancing requires:

- A harmonisation of national legislation as the first step, with harmonised gate-closure times to create common markets
- Establishing imbalance netting as the first step of market integration

For the balancing of non-synchronous systems, it is suggested to:

- Developing a central optimisation controller with advanced activation strategies
- Establishing of a common independent frequency operator, which has the responsibility for the central optimisation

Conclusions: There are a number of common conclusions from the above studies and development strategies of the EU.

- Pricing mechanisms shall be based as far as possible on marginal pricing to provide correct price signals.
- The integration of balancing markets is seen as beneficial, where special focus is put on the first step of cross-border imbalance netting.

- The dimensioning of reserves / reserve requirements has to be optimised, being dynamic, but also needs to take into account national security of supply
- A harmonisation of balancing markets with day-ahead and intra-day, especially regarding gate closure times

2.5.4 Market design in the Nordic power system

The basis for the potential future design of Nordic balancing markets is based on the two reports by Pöyry and Statnett, which provide a detailed description of a future market design.

Nordic market design forum

Pöyry presents a study from a Nordic market design forum, coming up with a proposal for the Nordic power market design (Pöyry, 2017). Among others the report includes suggestions for the development of the Nordic balancing market. The two main objectives for the balancing market identified are:

- Frequency stability by resolving real-time imbalances
- Congestion management to solve local grid constraints

The report discusses the roles and responsibilities between TSOs and the market. In the future, the market should and can help the TSO to manage the system, including:

- incentives for BSPs and BRPs to support system balance;
- increased transparency on market and system situation, especially during times of scarcity; and
- higher incentives to bid flexibility into RPM.

The roles and responsibility of the system operators and the stakeholders in the balancing market is illustrated in the figure below, where a more active role of market participants is envisioned, based on a better availability of information and faster information flow.

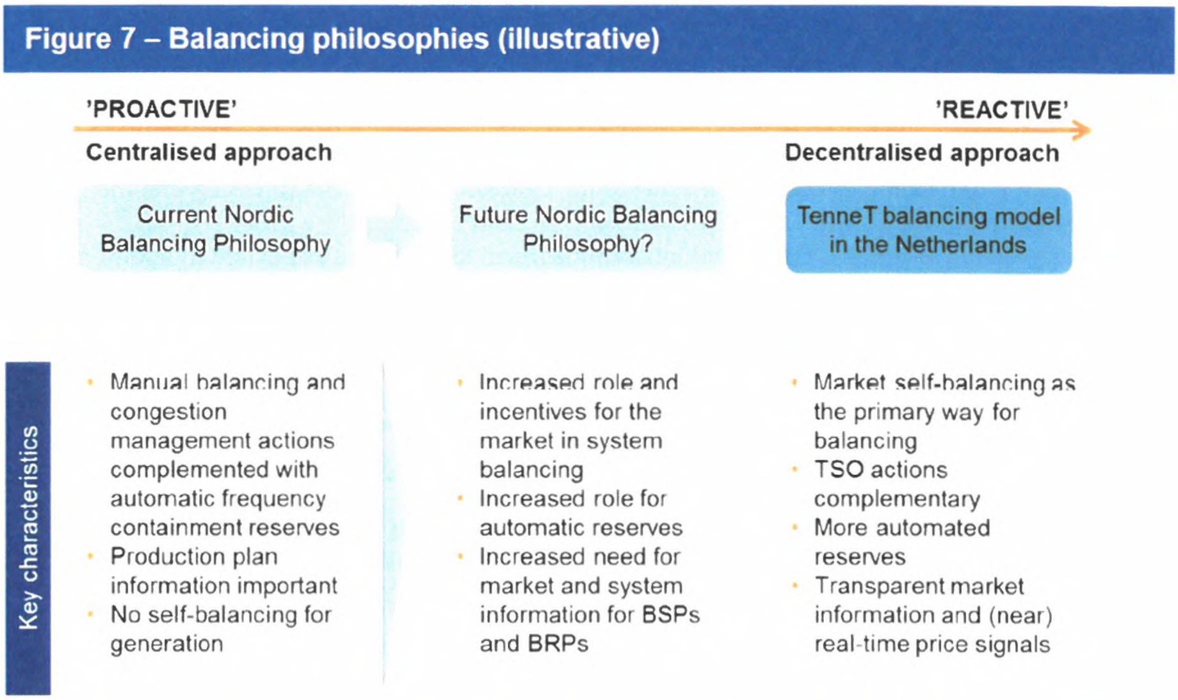

Figure 9: Options of design principals for the system balancing (Pöyry, 2017)

Furthermore, the suggested changes in the price formation for balancing and imbalance prices are:

- applying a single pricing for imbalance settlement, which will incentivise passive balancing
- setting the maximum price to VoLL, to activate all available resources
- include cost of load shedding in imbalance of BRPs and pricing, to reveal the true cost
- remove the direct link between DA and ID prices with balancing and imbalance prices (cap / floor)

Specifically, the topic of single pricing is emphasized, which shall provide a more efficient and transparent utilisation of all available balancing resources. However, this requires a near to real time publication of prices, so that these can be used as activation signal for the providers of balancing resources, as also indicated in the figure above. Furthermore, it is suggested to facilitate the market by opening up the market and making it more transparent. This means:

- remove obligation to be in balance at day-ahead
- reduce minimum bid sizes to 1MW
- information publication (system state and price) in real-time

Finally, two other alternatives to reflect scarcity in imbalance prices are proposed, 1) an adder based on the expected utilisation of reserves or 2) reserve scarcity pricing.

Nordic balancing market concept

Statnett in cooperation with the other Nordic TSOs published an outline for the future-proof concept for the Nordic balancing market, within the framework of the operational and balancing guidelines (Svenska Kraftnät and Statnett, 2017). Two main layers of system balancing are identified, being 1) security of supply and 2) economic efficient reserve utilisation with this priority. The main parts of the future balancing concept are:

- Introduction of MACE: The new control method will comprise the coordinated activation of aFRR and mFRR including a merit-order list and available exchange capacity constraints. This will also enable the exchange / activation of reserves across HVDC interconnectors to other synchronous areas. Finally, MACE should be used for a more efficient dimension of reserve requirements.
- Ensure capability of reserves (What, when, where): will result into the definition of specific reserve products, taking into account requirements due to the characteristics of variable RES and their geographic distribution.
- Balancing products: aFRR and mFRR will be established in the Nordic system and in addition a faster product (activation time 5 min) is suggested, which should complement aFRR. Furthermore, RR might be evaluated.
- Dimensioning of reserve requirements should be done based on historic imbalances and incidents for each bidding zone. Sharing options among TSOs can be applied to reduce the requirements. It should also be assessed if sufficient energy bids are available in the balancing market or if it is necessary to establish the reservation of capacity.
- Reserve activation for aFRR and mFRR as described below.
- Imbalance settlement, where the imbalance price shall have a strong link to the price of balancing energy, but is not necessarily a single marginal price, as several products will be used for balancing. Furthermore, scarcity pricing should be applied in imbalance settlement.

Based on the "Agreement on a Nordic Market for Frequency Restoration Reserves with automatic activation (aFRR)", the common Nordic market for aFRR balancing services will eventually include an activation market in addition to the existing (reserve) capacity market. As a first step, the aFRR market will consist only of a capacity market and bids will be activated on a 'pro-rata' basis, where all aFRR providing units are activated simultaneously. This means that there will be a transition period in the Nordic aFRR with two phases:

1. Without the energy activation market in the short term (only reserve capacity payment)
2. With the energy activation market, i.e. merit order list for aFRR activation in the mid to long term

Beside the discussion of balancing markets, the topic of inertia is target in the KUBE report by Statnett (Statnett, 2015). Within the report it is concluded that the decommissioning of nuclear power plants with a parallel commissioning of HVDC-cables can lead to periods with too low inertia in the Nordic power system, leading to unstable operation of the power system. Thus, establishing requirements on inertia in balancing market bids or the establishing of a market for inertia is suggested.

2.6 Importance for modelling

The main development for the Nordic balancing market will be the introduction of a common market with the reserve types of FCR, aFRR, mFFR and a potential faster product (activation 5 min). In the final design, an activation of reserves based on a merit-order list should be achieved. In addition, it is both suggested and foreseen to publish the balancing state/price near to real time, which can serve as activation signal for passive balancing. To achieve a better utilisation of reserves a PTU of 15 min is planned to be introduced in the future. Finally, a harmonisation (products, gate closure) of balancing markets with the DA and ID market is seen as beneficial, however removing artificial price floors and caps.

In the case of modelling balancing markets in the power market models this means:

1. A multi-market approach with rolling horizon should be implemented allowing to represent subsequent market clearing for DA, ID and BM.
2. Time steps need to be reduced to 15 min, potentially to 5 min, when also accounting for fast products.
3. Representing the MACE method, applying DC power flow (step wise) analyses / model-predictive control should be evaluated to capture the correct choice / activation of reserves.

3 Existing models and tools

In this section we review some selected power market models. We do not argue that the presented list is complete, the interested reader could e.g. visit (Carramolino, et al., 2017) for a thorough overview of power market and (Uhlen, et al., 2016) for balancing models. Furthermore, (Ringkjøb, Haugan, & Solbrekke, 2018) present any overview of energy and power system models, that target challenges due to integration of large shares of RES. We emphasize on models allowing multi-market fundamental modelling, and for which the basic principles are easily available at web pages or through technical publications.

Some of the presented models (IAEW, Fraunhofer, Competes) were presented in a separate Workshop at SINTEF/NTNU in February 2018. The EMPS and FanSi models were briefly reviewed in Section 1 and will not be revisited here. In addition, the review done within the CIGRE report "Analytical techniques and tools for power balancing assessments" is used as a source.

3.1 COMPETES

The COMPETES model (van Hout, Koutstaal, Özdemir, & Seebregts, 2017) simulates the day-ahead and intra-day decisions in the short term in addition to generation investment decision in the long-term. The model combines three steps, 1) capacity expansion, 2) dispatch in the EU day-ahead market and 3) redispatch in the national intra-day/balancing market. These steps a run sequentially, where the first step is an LP and the last two steps are both formulated as mixed integer linear programming (MILP), with hourly resolution.

In the final step the national intra-day market for the Netherlands is simulated, where a redispatch is done. To that, the exchange schedule to neighbouring countries are fixed as well as the dispatch of slow generators. The remaining dispatchable assets are then re-dispatched based on the realised wind power production and actual load, providing balancing prices.

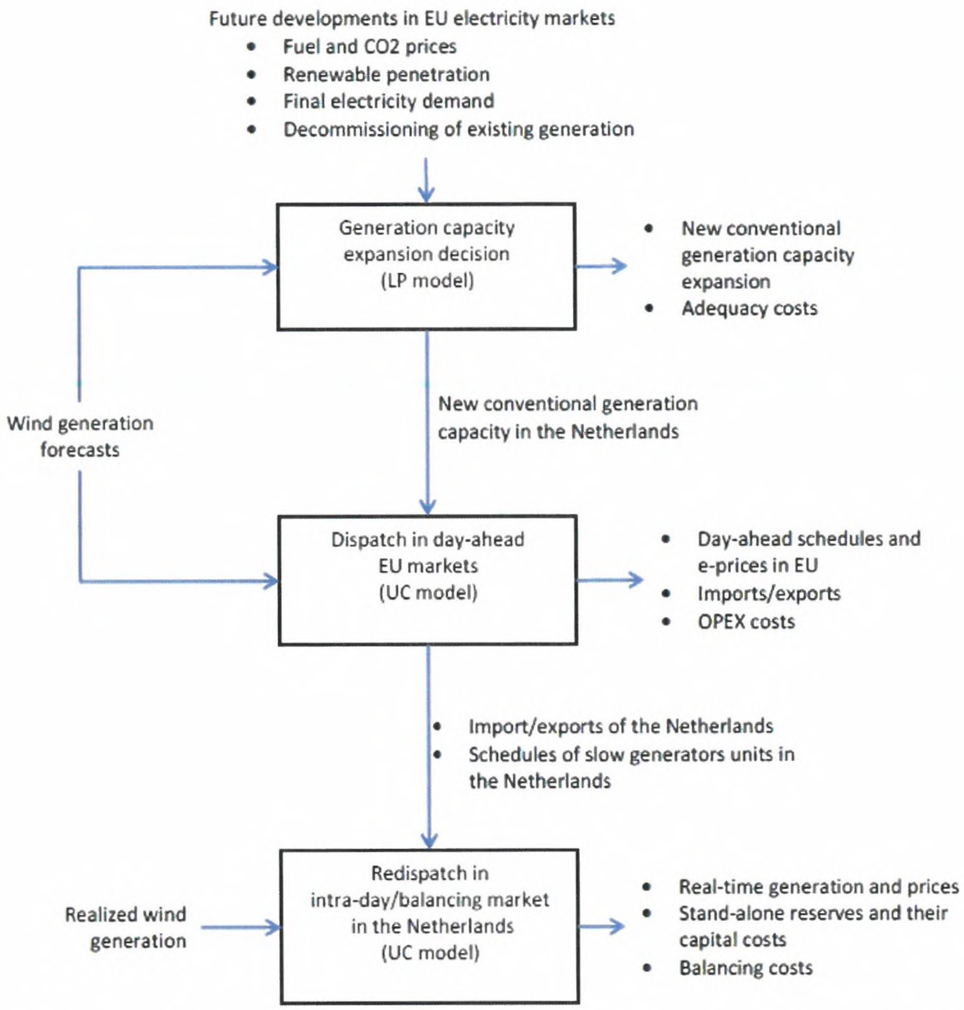

Figure 10: COMPETES model structure (van Hout, Koutstaal, Özdemir, & Seebregts, 2017)

3.2 WILMAR

The WILMAR[7] (Wind Power Integration in Liberalised Electricity Markets) project coordinated by Risø National Laboratory, developed a methodology comprising a long-term strategic (Ravn, 2006) and a short-term operational joint-market model (Meibom, et al., 2004) for the integrated handling of the day-ahead and the balancing market simulation considering both heat storages and local electricity storages.

The WILMAR methodology primarily focuses on thermal units and wind power, treating details on hydropower scheduling in a simplified manner. The coupling between the strategic and operational model layers is provided through water values per region from the strategic to the operational model, and simulated reservoir levels the other way. Both models are fundamental and see the same system boundary, but differ e.g. in time-resolution, representation of physical constraints and markets. Moreover, the long-term model does not include reserve capacity procurement. The need for a long horizon to schedule the dynamics in hydro storages on the one hand, and the need for details in the short-term model to accurately find the market prices on the other are not easily met in one single optimization model. We find the division into a long-term strategic and a short-term operational market model interesting and in-line with our reasoning within the PRIBAS project.

[7] http://www.wilmar.risoe.dk/

3.2.1 The Wilmar short-term market model

In the following a description of the short-term joint-market model is given, primarily referring to (Meibom, et al., 2006). The model aims at minimizing system costs assuming perfect markets. The model is based on LP and solves a planning problem with a horizon of 36 hours, using a time resolution of one hour. The system boundary typically includes the Nordic countries. Both wind power and demand can be considered uncertain.

A rolling-horizon planning approach is taken in this model, resembling the decision stages that the market players relates to in the Nordic market. The model plans for the next day (D) starting at 12:00 the day-ahead (D-1) and stepping forward in time with 3 hours per steps. The model is formulated as a multi-stage stochastic optimization model with a deterministic first stage. Between each decision stage the first-stage decisions from one period are passed to the next. For each new decision-stage the wind power forecasts are updated and represented as scenario trees by use of a scenario tree tool. The rolling horizon framework has similarities with that used in the FanSi model.

The model covers decisions related to the day-ahead market clearing, balancing through intraday markets as well as procurement of automatic reserves. The demand for reserves is provided as input to the model.

To account for the value of having power plants online as well as energy stored in heat and electricity storages at the end of the planning horizon, the model uses dual values obtained for these storages in the previous planning loop.

3.2.2 Case studies

The WILMAR modelling framework has been used in numerous case studies; we will emphasize on some of these here. In (Tuohy, Meibom, Denny, & O'Malley, 2009) the effects of stochastic wind and load on the unit commitment and dispatch of power systems with high levels of wind power were examined. The WILMAR short-term model was upgraded to a MILP formulation to deal with exact unit commitment, and a case study of the Irish system was presented. The authors simulated the system operation for one year, emphasizing on the improvements in schedules when refining the representation of uncertainty. The computation time for one full year was 8 days.

In (Meibom, et al., 2011) the operational impacts of high wind power penetration in Ireland is studied using the WILMAR model. A thorough model description is provided, and the study emphasize on the need for reserves for variable wind penetration levels. The authors simulated the system operation for one year and benchmarked the simulations against the PLEXOS tool. The computation time for one full year was 43 hours.

3.3 WILMAR and SIMBA

(Basit A. , Hansen, Altin, Sørensen, & Gamst, 2014), (Basit A. , Hansen, Altin, Sørensen, & Gamst, 2016) describe a novel approach to integrate wind power production into AGC, based on a coordinated control of WPP and CHP. The paper includes a description of the coupling of the models WILMAR and SIMBA, simulating the power system dispatch in real time.

(Litong-Palima, Cutululis, Detlefsen, & Sørensen, 2012) describe a wind power forecast module which is part of the SIMBA model. The method estimates the forecast error based on an ARMA model. The module provides forecasts with 5 min resolution for day-ahead and hour-ahead.

(Pinson, Madsen, Nielsen, Papaefthymiou, & Klöckl, 2009) describe a methodology of creating statistical scenarios for wind power production from probabilistic forecasts, which can be used as input to stochastic power market models.

The increased penetration of wind power in the Danish power system also causes an increased need for balancing power. This is because the wind power forecast errors also increase with the level of penetration of wind power. Energinet.dk has developed Simba to be able to simulate and thereby quantify the balancing process in the Danish power system, with special focus on the imbalances caused by wind power forecast errors.
According to Energinet.dk, "Simba models the intra-hour balancing of the power system and is based on the Danish principles of balancing. Traditionally, modelling issues have put the main focus on calculating hourly energy values, while intra-hourly modelling attracted little attention. SimBa has closed this gap."

The main source of imbalance in the Danish power system is the wind power uncertainty. Therefore, this uncertainty is key input to Simba balancing. DTU Wind energy is partner in the Simba project, contributing mainly with CorWind simulations of consistent time series of wind power production and wind power prognoses with day-ahead and hour-ahead

3.4 IAEW RWTH Aachen Models

The institute of power systems and power economics at RWTH Aachen University provided price forecasts in multiple electricity markets for the SINTEF-led HydroBalance project (Moser, Maaz, Baumann, & Schäffer, 2015). The model chain used combines simulations of the European power market and the detailed the German system, and is described in (Moser, Maaz, Baumann, & Schäffer, 2015) and (Grote, Maaz, Drees, & Moser, 2015).

First a European market model is run to provide generation dispatch, cross-border exchanges and power prices. The model covers most of the European market, including the Nordic market. It is formulated as a fundamental cost-minimizing optimization model based on MILP, considering load and reserve capacity constraints at hourly time-resolution for a horizon of one year. The model is deterministic and does not distinguish between different types of energy markets. A decomposition strategy is used to solve the large-scale MILP optimization problem comprising the following steps:

1. Solve the full relaxed LP market problem and fix cross-border exchanges
2. For each market area, provided the fixed cross-border exchange, the load and reserve capacity constraints are relaxed and a Lagrangian relaxation algorithm is used to decompose the unit commitment problem within the area for a given time step. The converged solution provides the unit commitment schedules.
3. The remaining continuous market problem is solved to obtain the power plant dispatch and prices.

For the detailed model of the German system, the cross-border exchanges to Germany are fixed based on the results from the European market model, and a detailed simulation considering coverage of load, different types of reserve capacity and balancing energy at 15 min resolution is carried out. The solution strategy is based on Lagrangian decomposition along the axis of time and markets, similar to that used in the second step for the European model. The converged Lagrangian multipliers are treated as prices.

3.5 ELMOD

The Spatial Optimization Model of the Electricity Sector (ELMOD) is maintained by DIW Berlin[8] and TU Berlin. It is a fundamental market model and comes with data representing the European electricity sector including the generation portfolio and the physical transmission network. A separate version of ELMOD, known as stELMOD addresses the stochastic multi-market challenge, and is thus of particular relevance for the PRIBAS project.

In (Abrell & Kunz, 2014) the stELMOD model is presented analysing the impact of stochastic wind generation on the unit commitment and generation dispatch while taking into account power flow constraints. A rolling horizon approach is taken to optimize the system operation over a horizon of 36 hours, sequentially solving the day-ahead and intraday markets, and updating wind power forecast. First, the day-ahead and reserve market schedules are found for the next day. Secondly, the schedules are re-optimized in the intraday market as wind power for the current time period becomes known information. The approach is inspired by the WILMAR short-term model. The valuation of storage is not explained in detail.

The model uses a rolling horizon approach including the day-ahead and the intra-day market plus a congestion management part. The planning horizon is 36 hours, comprising the next day and 12 extra hours, which should handle end-value conditions (Abrell & Kunz, 2015) At first the day-ahead market is solved, which includes reserve procurement. Then in the second stage the intra-day market is solved, where the horizon is moved one hour for each iteration. Within this solution the day-ahead schedule and reserves are fixed as a starting point, while the deviation from this schedule is optimise based on the revealed uncertain variables. For all future hours a scenario tree is applied, accounting for the stochasticity.

(Lorenz, 2017) The paper assesses the development of balancing cost in Germany up to 2050. The assessment is done based on a static vs. dynamic allocation of reserves and three different scenarios (pessimistic, conservative, optimistic) for reserve sizing and exchange of reserves. The main conclusion of the study is that balancing costs can be kept low, if a dynamic reserve sizing is introduced. The model dynELMOD is used for the study.

3.6 OPTIMATE

OPTIMATE (An Open simulation Platform to Test integration in MArkeT design of massive intermittent Energy) was a collaborative project as a part of EU FP7 research programme. The project developed a numerical test platform suitable for analysing and validating new market designs allowing integration of massive flexible generation dispersed in several regional power markets.

The Optimate model is an Agent-based tool that has the ability to represent different market designs and market sequences. The simulation of the system is done for a sample of hours. Due to the agent-based method a feedback loop from the balancing market to day-ahead and intra-day markets is possible. However, an optimal market solution is not guaranteed (Weber, et al., 2012).

[8] http://www.diw.de/de/diw_01.c.528493.de/forschung_beratung/nachhaltigkeit/umwelt/verkehr/energie/modelle/elmod.html

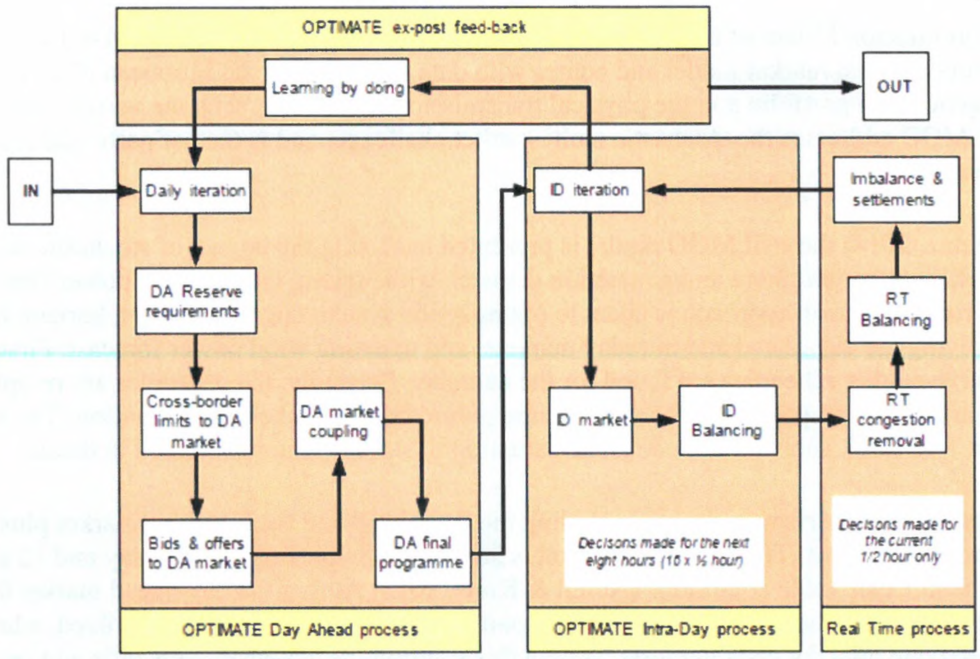

Figure 11: OPTIMATE model structure (Weber, et al., 2012)

(Schudel & Bourmaud, 2017) assess different market designs for reserving mFRR with the help of the OPTIMATE model. To extreme cases for reserve procurement are tested, where a minimum required amount is tender (according to the outage of the largest unit) and a maximum amount is tender (including the forecast of RES). It is observed, that the strategy (amount) of reservation (before day-ahead) has a significant effect on the day-ahead bidding curve and the outcome of the day-ahead market.

3.7 METIS

The METIS[9] short-term power market model is a fundamental model simulation of the successive clearing of physical power markets, including day-ahead, reserve procurement and intraday markets (Bardet, et al., METIS Power Market Models, 2016). METIS is a multi-model simulation software covering the electricity, gas and heat sectors, being developed by a consortium (Artelys, RWTH Aachen, ConGas, Frontier Economics) as part of Horizons 2020. The model is based on several modules for the different energy carriers. METIS is used by the European Commission to further support its evidence-based policy making, for electricity and gas. It uses fundamental data on the power systems and European market design rules. The METIS power market module uses weather scenarios to simulate the market clearing and reserve procurement in the European system (Sakellaris, Canton, Zafeiratou, & Fournie, 2018).

A simulation is typically carried out over one year with hourly time resolution. The optimization has a horizon of 48 hours. Day-ahead and intraday decision are jointly decided in a rolling-horizon manner. The decision sequences and representation of uncertainty is not expressed in detail in (Bardet, et al., METIS Power Market Models, 2016).

[9] https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis

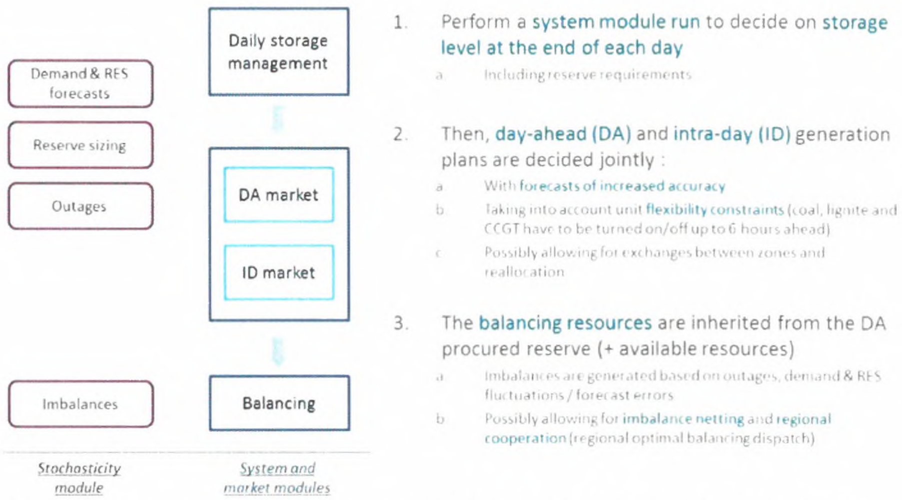

Figure 12: METIS model structure (Bardet, et al., METIS Technical Note T2, 2016)

The METIS short-term power market model is coupled (by volume targets) to a mid-term model to account for hydro storage. In the mid-term model, operation of hydro storages is set to respect exogenously given guide curves.

A separate model for balancing can be run to activate the procured reserves from the power-market model to balance forecast errors and outages at a 5 min resolution. The standard balancing products FCR, aFRR and mFRR are covered.

3.8 SiSTEM

SiSTEM (Mathieu, Petitet, Perrot, Ernst, & Phulpin, 2017) is a multi-level simulation model of European short-term electricity markets, covering day-ahead and intraday exchanges to balancing activations in real-time, and imbalance settlement. In this model, power companies interact by making offers, notifying their positions to the system operator and impacting the balance of the electric system. The system operator activates balancing energy to restore the balance of the system, using all balancing activation offers, including from balancing reserves. Imbalance settlement implies bidirectional transactions between the system operator and power companies depending on the direction of their imbalance. A simulation of the model is performed by sequentially considering each time step and simulating actors' decisions.

The objective of this model is to understand the problems behind decisions of the actors within the short-term electrical system operation, to provide insights on how these problems can be solved through market design and to see how the decisions are linked together to shape a coherent system. Results show the importance of considering steady-state constraints and notice delays of generation units when looking at short-term issues.

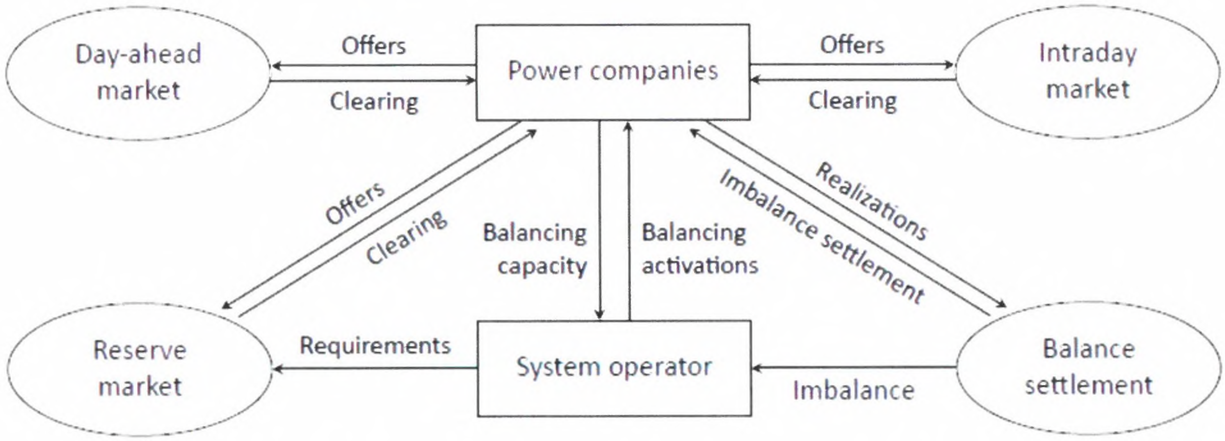

Figure 13: SiSTEM model structure (Mathieu, Petitet, Perrot, Ernst, & Phulpin, 2017)

3.9 Antares

The Antares (A New Tool for Adequacy Reporting of Electric Systems) simulator is an open source software, which is developed to execute multi-area adequacy studies for the European power system (Houghton, Bell, & Doquet, 2016). The simulator uses hourly time series of several years to establish representative sequences, that are used in a sequential Monte Carlo simulation. It models the dispatch of thermal, hydro and intermittent power generation sources accounting for transmission constraints. While first developed for adequacy analyses the model is developed to be used in economic and expansion analyses. Antares models available generation stochastically taking into account forced or planned thermal outages (without optimization of the maintenance scheduling) and variations in wind speed, solar power and water inflow. The transmission system is modelled with an OPF. Within both the adequacy assessment and the economic analyses Antares includes the procurement of spinning reserves, described with adjusted generation costs.

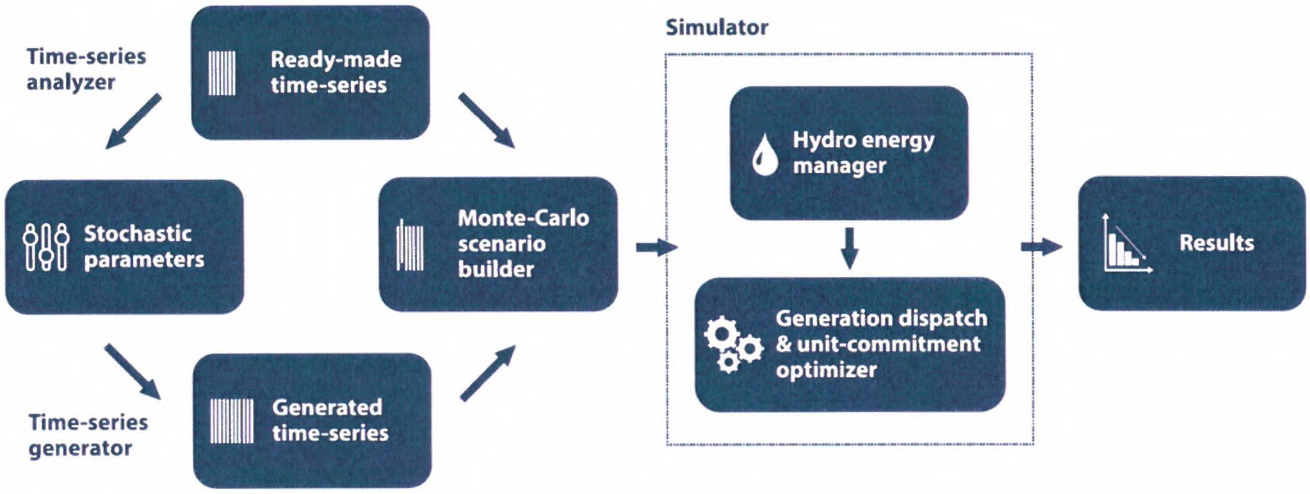

Figure 14: Antares model structure[10]

[10] https://antares-simulator.org/

3.10 Classification of the models

The following table provides a coarse classification of the reviewed models in terms of represented markets, methodology and technical characteristics.

Table 1: Power system model classification

	COMPETES	WILMAR	Simba	RWTH	ElMod	OPTIMATE	METIS	SiSTEM	Antares
Markets considered	DA, BL	DA, ID	BL	DA	DA, ID, R	DA, ID, R, BL	DA, ID, R, BL	DA, ID, R, BL	DA, R
Method	LP / MILP	MILP	Simu-lation	MILP	MILP	AB	LP	LP / AB	LP
Stochast. / determ.	Det.	Stoch.	Det.	Det.	Det.	Stoch.	Stoch.	Stoch.	Stoch.
Hydro strategy	-	Water values	-	-	-	-	Seasonal steering curve	Seasonal steering curves	Steering curves
Demand modelling	Price elastic	Price elastic	fixed	Fixed	fixed	Demand agent	Demand forecast	forecast	Forecast
Temporal resolution	1 h	1 h	5 min	15 min	1 h	15 min	1 h	15 min	1 h

4 Theoretic foundation of modelling methods

Beside the established power market models presented above, there are a significant number of scientific developments within the field of power markets, targeting price forecasting or simulation of short-term markets. The following will provide a brief overview, divided into statistical models and fundamental models.

4.1 Statistical price forecasting models

(Klæboe, Eriksrud, & Fleten, 2015) benchmark a number of models for forecasting of electricity balancing market prices based on time series approach. It is concluded, that the balancing market result depends significantly on the day-ahead market clearing. Furthermore, it is also concluded that the outcome of the balancing market is rather randomly distributed. However, the study suggests that the balancing state information is a crucial input to forecast the outcome of electricity balancing markets.

(Dimoulkas, Amelin, & Hesamzadeh, 2016) present a method to predict prices and trading volume in the balancing markets applying Hidden Markov Models. The proposed method provides forecast for 1h, 12h and 26h ahead in time. It is concluded that the 1h forecast is rather good, while the forecast longer ahead are not too well, as the balancing state is quite random distributed.

(Pape, Hagemann, & Weber, 2016) try to explain how much of the price variation in the day-ahead and the intraday power markets can be explained by fundamentals (supply stack). Other peculiarities such as must-run units (CHP) and a reduced supply stack in intraday due to shorter notice time are likewise taken into account. It is concluded, that about 75% of the price variance can be explained. In addition, the day-ahead price has a high explanatory value for the intraday price. Moreover, the results indicate that past price information seems to be used to predict future day-ahead and intraday prices for trading.

4.2 Fundamental multi-market modelling

In the following a number of novel approaches and studies are summarised, which apply a bottom-up modelling approach within the field of power markets analyses.

The selection of representative days/time periods in power system optimisation problem to account for their variability and their correlation is addressed by (Poncelet, Höschle, Delarue, Virag, & D'haeseleer, 2017). A novel approach is proposed minimizing the error term of representing the duration curve of the residual demand by calculating the weight of the selected days. The analysis of a test case shows more accurate results, while there is no increase of computational burden of the optimisation problem. However, the application of the selection methodology can be computationally costly.

4.2.1 Hydro storage modelling

(Zakeri & Syri, 2016) assess the value of energy storage in the Nordic power system based on several markets: day-ahead, intraday, ancillary services. The assessment is based on historic prices using arbitrage potential as well as assumptions for possible sale of ancillary services. It is concluded that there are significant differences in arbitrage possibility throughout the Nordic countries, where Finland and Denmark offer the highest potential in the day-ahead and the intraday markets.

(Wogrin, Galbally, & Reneses, 2016) propose a methodology of optimising storage within a duration curve approach, while keeping at least parts of the chronological information. To that so-called system-states framework is employed using a transition matrix for the system states. Instead of defining the storage level as a distinct variable, the change in storage is considered. A case study shows, that the computation time can be reduced by about 90%, while a good accuracy can be achieved.

4.2.2 Reserve capacity procurement

(Ocker & Ehrhart, The "German Paradox" in the balancing power markets, 2017) address a question raised about the "German paradox", i.e. that reserve requirements did not increase with an increasing share of RES in the power system. It is argued, that there are two reasons for this development. There were different flexibility trading options added to the market. In addition, the market area was increase by the International Grid cooperation. Hence, more imbalance netting can be achieved, while it is also seen that the volume in the intra-day market increase significantly, leading to less balancing actions required.

(Ocker, Ehrhart, & Ott, Bidding Strategies in the Austrian and German Secondary Balancing Power Market, 2017) present bidding strategies for balancing power markets. The analysis is based on the operating principles of the markets and it shows that the bids for capacity and energy are not independent. It is also concluded that bidding rules do not incentives suppliers to reveal their actual costs.

(van Stiphout, Vos, & Deconinck, The impact of operating reserves on investment planning of renewable power systems, 2017) study the impact of reserve requirements on the investments in power systems. The case study shows, that dynamic reserve sizing and provision of reserves from vRES can decrease reserve costs significantly. The proposed model is a LP including the operation and investment of the power system. At the same time, the operation state (in a linear form) of power plants as well as constraints such as ramping and minimum up- and down times are included in the optimisation problem.

(van Stiphout, Short-Term Flexibility in Long-Term Planning of Renewable Power Systems, 2016) in his dissertation addresses the effects of short-term operational flexibility on long-term generation expansion planning. The thesis includes the full model description of a power system planning model with short-term flexibility requirements. It studies different strategies to deal with intermittent RES and studies the role and alternatives of short-term flexibility providers. Amongst others the study concludes that a static reserve sizing will increase costs significantly in the future.

4.2.3 Balancing activation and imbalance settlement

(Håberg & Doorman, 2017) propose a MILP model for the activation of balancing energy, taking into account uncertainty. The model includes aFRR and mFRR. The model is formulated as a stochastic optimisation problem, where three different scenarios of imbalances for the next 90 min are used to activate the reserves. The paper concludes, that a proactive activation (especially of mFRR), can reduce balancing costs.

(Andersen, Kaut, & Tomasgard, 2015) propose a stochastic model for the activation of manual and automatic reserves using the forecast uncertainty for wind as stochastic input. The model is based on the deterministic version (Petersen, Heide-Jørgensen, Detlefsen, & Boomsma, 2016). They use 50 scenarios with a rolling horizon of 2 hours for one week. The scenario generation relies on (Pinson, Madsen, Nielsen, Papaefthymiou, & Klöckl, 2009).

4.2.4 Demand response for balancing services

While demand response in the power sector is a very broad topic, there is only a smaller amount of literature on the potential of demand response for providing balancing services. (Böttger, Götz, Theofilidi, & Bruckner, 2015) assess the participation of electric boilers for district heating in the in order to provide negative reserve capacity. The analysis is done with the MICOES-model, a power market model including the spot market and reserve procurement. The model is defined as MILP and includes a rather detailed description of heat supply system. It is concluded that district heating can provide negative reserves in a cost-effective manner.

(Herre, Kovala, Söder, & Papahristodoulou, 2016), (Herre & Söder, Enhancing market access of demand response through generation forecast updates, 2017) assess the potential of demand response in relation to their notice time. The study uses a Price Elasticity Matrix to describe different types of demand response. This matrix includes self-elasticities (price-elastic demand) and cross-elasticities (demand-shift). The paper proposes a model of an iterative market clearing algorithm, which sends updated forecasts for wind and imbalance. This results into a rescheduling of flexible generation and consumers. The proposed model is used to test demand elasticity in two chosen cases of wind forecast in Sweden.

4.3 Summary

Following Table 2 a classification of the modelling approaches presented above. The table shows a huge variety of the models addressing different issues of short-term power markets and system balancing. There is a substantial difference between fundamental models and statistical forecasting models.

Table 2: Classification of the modelling methods and characteristics of the reviewed scientific publications

	Objective	Modelling	Market design	Balancing products	Constraints	Fundamental / Forecasting	Deterministic / Stochastic	Uncertainties	Hydro power	Reserves & Activation	Temporal resolution	Horizon	Grid	System boundary	Demand response
(Andersen, Kaut, & Tomasgard, 2015)	System balancing	LP	Perfect market	aFRR mFRR	Transmission, reserves	Fundamental	Stochastic	Wind	-	Activation	Hour	1 Week, Rolling horizon	NTC	DK	-
(Basit A. , Hansen, Altin, Sørensen, & Gamst, 2016), (Basit A. , Hansen, Altin, Sørensen, & Gamst, 2014)	System imbalnce	AGC	-	aFRR	-	Simulation	-	Wind	-	Activation	Seconds	24h	NTC	DK	-
(Böttger, Götz, Theofilidi, & Bruckner, 2015)	System dispatch cost	MILP	Perfect market	Reserve capacity	Ramping, start up, transmission	Fundamental	Deterministic	-	PHES short term	Procurement & Act.	Hour	1 year roll. horizon	No	Europe	Marginal costs
(Dimoulkas, Amelin, & Hesamzadeh, 2016)	Price prediction	Markov Chain	-	Balancing energy	-	Fore-casting	Point forecast	Price	-	Activation	Hour	12h - 36h	No	SE	-

(Litong-Palima, Cutululis, Detlefsen, & Sørensen, 2012)	(Klæboe, Eriksrud, & Fleten, 2015)	(Håberg & Doorman, 2017)	(Holttinen, et al., 2016)	(Herre & Söder, 2017), (Herre, Kovala, Söder, & Papahristodoulou, 2016)
Wind power forecast	Price forecasting	Balancing costs	System costs due to gate closure	Decsripition consumer flexibility
Wind forecast	Time series	MILP	Historic prices	Generation forecast
Perfect market	Perfect market	Perfect market	Perfect market	Real time market
Imbalance	Balancing energy	aFRR mFRR	imbalances	-
Transmission	-	Reserve capacity	-	-
Forecast	Forecast	Funda-mental	Forecast	Fundamental
Point forecast	Stochastic	Stochastic	Deterministic	Deterministic
Wind power	Imbalance	System balance	wind	price
-	-	-	-	-
Activation	Activation	Activation	Procurement & Activation	Procurement & Activation
5 min	hour	5 min	hour	15 min
24h	36h	1h	1 year	24 h
no	no	no	no	no
DK	NO	NO	Countries	SE
-	-	-	-	Cross elasticities

(Lorenz, 2017)	System costs, reserve sizing	LP	Perfect market	Reserve capacity	Transmission, generation adequacy	Fundamental	Deterministic	Intermittent RES	Simpl.	Procurement	(repres.)hour	2050	NTC	Europe	-
(Müsgens, Ockenfels, & Peek, 2014)	Cost of market design	Historic prices	Imperfect	Reserve capacity	-	Forecast	Deterministic	System balance	-	Procurement & Activation	hour	1 year	no	DE	-
(Ocker & Ehrhart, 2017)	System balancing costs	Historic prices	-	Reserve capacity, balancing energy	-	-	-	System balance	-	Procurement & Activation	-	-	-	DE	-
(Ocker, Ehrhart, & Ott, 2017)	Bidding strategies	Historic prices	Imperfect	Reserve capacity, balancing energy	-	Forecast	-	System balance	-	Procurement & Activation	-	-	-	DE	-
(Petersen, Heide-Jørgensen, Detlefsen, & Boomsma, 2016)	Social welfare, proactive activation	LP	Perfect market	aFRR, mFRR	Ramping, transmission	Fundamental	Stochastic	wind	-	Activation	5 min	1 h	NTC	DK	-

(Poncelet, Höschle, Delarue, Virag, & D'haeseleer, 2017)	Clustering and representative days	MILP	-	-	-	Fundamental	Stochastic	Intermittent RES, load	-	-	hour	1 year	-	BE	-
(Schudel & Bourmaud, 2017)	Reserve management strategies	Agent-based	Various	Reserve capacity	-	Fundamental	Deterministic	-	-	Procurement	hour	1 month	no	EU	-
(Wogrin, Galbally, & Reneses, 2016)	Hydro operation, system cost	LP	Perfect market	Reserve capacity	Transmission, ramping	Fundamental	Deterministic	Intermittent RES	PHES	-	Repres. hour	1 year	no	ES	-
(van Stiphout, Vos, & Deconinck, 2017), (van Stiphout, 2016)	System costs	LP	Perfect market	Reserve capactiy	Transmission, ramping	Fundamental	Deterministic	Intermittent RES	-.	Procurement	hour	1 year	no	EU	-

4.4 Unit commitment in hydrothermal systems

As explained in Section 1.2, the short-term scheduling in a liberalized market is typically done on a portfolio basis. In many power markets, unit commitment decisions are often a part of the market clearing procedure, and consequently the need for short-term hydrothermal scheduling tools are more pronounced. In the following we review scientific literature on unit commitment methods and models applied to systems where hydropower plays a central part. We make a division between deterministic and stochastic approaches.

4.4.1 Deterministic

A recent review article (Taktak & D'Ambrosio, 2017) provides an overview of the problem formulation and solution techniques used in deterministic unit commitment problems. The authors emphasize on exact methods for solving the generally nonconvex short-term problem. The following physical relationships are considered the typical sources to nonconvexity:

- Turbine output characteristics, i.e. generation dependency on water discharge and head.
- Forbidden operational zones for generating units.
- Start-stop for generating units.

Several methodological approaches are reviewed, and two of these (MILP and Lagrangian relaxation) are pointed to as more applicable to large-scale realistic problems. Recent development in software for solving MILP problems has encouraged the use of this technique for large-scale problems. For certain problem structures, significant computational time reductions can be obtained by decomposing the problem. Lagrangian relaxation has proved to be an efficient technique for the deterministic unit commitment problems.

A literature review on similar premises was conducted by (Fahrat & El-Hawary, 2009) and may serve to extend the literature base found in (Taktak & D'Ambrosio, 2017). The former review takes a broader view on the topic, comprising also heuristic methodological approaches.

4.4.2 Stochastic

Stochastic approaches have gained popularity in many power markets around the world due to the increase in renewable generation, and the corresponding increase in flexibility requirements to account to rapid fluctuations in renewable production. Conventional thermal units provide limited flexibility due to technical constraints, and consequently needs to be supported by more flexible assets. In this context, the unit commitment decisions are made in the face of uncertainty, which in turn calls for stochastic models.

In (Scuzziato, Finardi, & Frangioni, 2017) different ways of applying Lagrangian relaxation techniques to the stochastic short-term hydrothermal scheduling problem are compared. Decomposition along units (thermal and hydropower) and along scenarios are compared on realistic data, finding that the computational burden associated with the former is advantageous.

In (Zheng, Wang, & Liu, 2015) stochastic optimization approaches for unit commitment are reviewed, relating these approaches to the US market context. Both two-stage and multi-stage models are covered, and uncertainty modelling (component failures, load, wind etc.) is discussed. The use of decomposition methods is reviewed. The techniques of stochastic programming, robust optimization and (approximate) stochastic dynamic programming are qualitatively compared. In conclusion, the authors state that the selection of a certain stochastic optimization method is case dependent and highly influenced by the risk preference by the system operator.

An interesting approach to the stochastic unit commitment problem is presented in (Costley, Feizollahi, Ahmed, & Grijalva, 2017). The system operator's actions are resembled in a rolling-horizon scheme, repeatedly solving the unit commitment problem under uncertainty with updated state and prognosis information. The developed mathematical model simulates a system operator, running a central dispatch. The planning procedure comprises the unit commitment (UC) problem and the economic dispatch (ED) of the whole system. To keep the problem tractable the UC and ED problem are solved with different frequency, with a resolution of one hour and ten minutes respectively. Thereby, updated forecasts are taken into account for the new runs of UC and ED. The optimisation of the system is done for 24 consecutive hours in form of a mixed-integer problem. There, integer variables are defined in the UC problem, while there are fixed in the ED.

4.4.3 Robust

Robust optimization offers a different approach to the unit commitment problem under uncertainty compared to stochastic optimization. The robust methodology is inherently conservative as it hedges the solution against the worst-case realization of the uncertainty. Though the robust formulation cannot be solved directly by current optimization solvers, it can often be reformulated to enable the use of efficient and tractable solution approaches.

The work in (Jiang, Wang, & Guan, 2012) formulates a two-stage robust unit commitment problem for a thermal system including pumped hydro storage and uncertain wind power production. The worst-case is formulated to capture the extreme wind power ramping events, and tight solution bounds are achieved with the proposed reformulation.

A multi-stage robust program for unit commitment with energy storage is presented in (Lorca & Sun, 2017), which also includes spatial and temporal correlations in the worst-case realizations of the uncertain wind power. An affine policy approach combined with approximations to handle intertemporal constraints introduced by the energy storage is used to solve the problem efficiently on a large-scale system.
Mixing stochastic and robust optimization can be done in many ways. The contingency constrained hydrothermal model in (Street, Brigatto, & Valladao, 2017) incorporates robust optimization into the stochastic dual dynamic programming framework to account for the worst-case contingency event under a "n-K" security criterion.

4.5 Pricing in non-convex models for power markets

A review on pricing schemes and algorithms in Europe and US is presented in (VanVyve, 2011). The focus is on pricing schemes for "non-convex markets". Due to restrictions in the unit commitment problem of a power system, such as start-up costs and the start-up state of power generation units, the system dispatch of a power system is nonconvex. In general, the objective of a power market is to solve the dispatch problem, using price as the signals for dispatching the generation units. However, due to the nonconvexity a pure application of linear or marginal prices does not solve the dispatch problem. This challenge is handled in different ways in the US and Europe. While in Europe, there generally is a self-dispatch of power generation, central dispatch is common in the US. In case of the self-dispatch, the non-convexities can be addressed in the form of block bids to the power market and otherwise lie in the responsibility of the unit operators. However, within the central dispatch of US system, such as PJM, mark-ups and pricing, which deviates from the uniform marginal price is used. This can however lead to not revealing the true costs when bidding.

Other approaches are implicit especially with the focus on finding the opportunity value of delivering reserves. (Böttger & Bruckner, 2015) include different types of reserve capacity in a power system dispatch and assess the difference in system costs to estimate the costs of reserve procurement. Based on the assessment, critical periods with high marginal procurement costs can be identified. (Just & Weber, 2008) study the economic trade-off between bidding for secondary reserves and the day-ahead spot market. The reserve prices are derived from the marginal costs around the spot market clearing prices. Thereby the steepness of the cost curves affects the opportunity costs for the secondary reserves, due to a must-run requirement of this reserves.

An estimation of the supply demand curve for spinning reserves in the Nordic area is done by (Gebrekiros, Doorman, Jaehnert, & Farahmand, 2015). The bidding prices for reserve capacity are again based on the opportunity costs for delivering this capacity. The opportunity cost is calculated based on simplified forecasts for the day-ahead spot market. Given reserve capacity prices a reserve procurement is executes by the system operator, which then provides must-run requirements in the day-ahead spot market bidding for units, that are selected to provide spinning reserves.

5 Modelling needs – Market review

In Section 1.5 we discussed some general points that are important when modelling balancing markets, and for which we recommended improvements in existing long-term models. In this section we try to relate these modelling improvements to the expected market trends. Section 2.5.2 reviewed and identified expected future developments for the European and specifically Nordic balancing markets.

Section 2.6 states a number of important developments, which are necessary to be accounted for in the future modeling of power markets. The following topics will be discussed, also referring to literature which targets the specific topics.

- Finer time resolution:
  As discussed, it is planned to reduce the resolution of balancing markets to 15 min, potentially even 5 min. The finer time resolution is a clear trend and needs to be accounted for. In addition, the different resolutions of DA, ID and BM might give unwanted effects, that have to be assessed.
- Implementation of technical constraints:
  In the case of specifying products aFRR, mFRR and other reserves, requirements for ramping are included. Furthermore, the physical flow in real-time may need to be accounted for, when activating balancing resources in critical situations. Hence this restriction needs also to be included in the models.
- Reserve activation procedures:
  The ongoing development of the Nordic balancing market foresees changing approaches for the activation of reserves, starting with a national focus and pro-rata activation of aFRR with the final aim to achieve a merit-order based system wide activation of reserves, accounting for MACE. Hence, the models should have the possibility to represent different types of activation methods also accounting for available transmission capacity.
- Short-term uncertainties:
  Many of the reviewed approaches are deterministic, and thus ignore the impact of short-term uncertainties. Some approaches quantify the importance of representing uncertainty, but often for simplified power system representations. With more pronounced short-term uncertainties represented on the generation side and the more short-term storages providing flexibility, the models should have shorter decision stages (i.e. decision periods with perfect knowledge).
- Market sequences: With an increasing need for flexibility it is important to account for the possibilities, which provide the possibility to adjust the plans. As described in Section 2.5.2 it is essential to achieve a better harmonization and interconnection of the different market stages DA, ID and BM. Modelling the sequence and gate closure times of these market correctly, will provide the possibility to assess the price development towards real-time. This will include energy and reserve prices.
- Local grid congestions and power flow:
  A topic not covered in the reports for is accounting for the physical power flow in the short-term markets. However, the ongoing discussion of flow-based market clearing in the DA might also have significant effects for the ID and the BM with regards to available transmission capacity.

5.1 Proposed model design

The starting point for the new model implementation within the PRIBAS project are the existing long-term models EMPS and FanSi, described in Section 1. Both existing models are implemented in a compiled language (Fortran) with complex model building facilities designed for computational speed.

Improved market modelling within the PRIBAS project will be performed in a high-level language (Python/Pyomo) to facilitate rapid prototyping and testing. The reader is referred to (A. Helseth, 2018) for a first version of such a model.

Based on the above description of the expectations for future market development a number of characteristics are identified, which should be taken into account in the modelling approach of the PRIBAS project. An overview of the main components of the new model design is shown in Figure 15.

Figure 15: PriMOD model requirements

To include all of these characteristics it is necessary to develop a modelling framework instead of one model containing all the steps. An additional important issue is the feedback of information to the calculation of water values and how results for the short-term markets will impact the long-term value of hydro.

6 Conclusions

We have reviewed scientific articles, technical reports, previous and ongoing research projects as well as existing power market models. We also review the current Nordic market design for short-term electricity markets. By doing so we identify the state-of-the-art on fundamental power market modelling, emphasizing on aspects that are relevant for the PRIBAS project.

The review shows, that there are significant challenges for the design, operation and optimisation of future power markets. This requires new tools to analyse the future power system operation and to support stakeholders in the planning and operation of the future power system in a socioeconomic optimal way. Many researchers and practitioners propose fundamental optimization models to assess the price formation and optimal system operation in future system representations. This indicates a preference for transparent models for which the underlying working principles can be easily explained. Furthermore, such bottom-up models have the ability to assess more fundamental changes in the future market environment, including possible changes in market design.

A number of the reviewed models have reached an advanced level with respect to market products, technical constraints and time-resolution. Furthermore, a few models combine the fine technical modelling with representation of uncertainties, giving possibilities for insightful studies. However, such models are challenged by high computation times, and are normally not backed with sufficient evidence that the added complexity "pays off" in the form of better results.

Many of the presented models are focused on the treatment of the rapid-growing new renewable technologies (wind and solar power) within an existing power system dominated by thermal power generation. Obviously, there is a significant need for flexible resources for balancing purposes in such systems. A few models also represent hydropower, but often at an aggregated level and using exogenous strategies, such as steering curves. Such models are not ideally suited to the characteristics of the Nordic power system, with hydropower as a dominating generation technology. Thus, we believe that results from the PRIBAS project have the potential to add to the research frontier by focusing on the characteristics of hydropower and its role as a flexibility provider in the future.

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