UNIVERSITY OF ŽILINA

Abstract
Doctoral Dissertation

Žilina, June 2022 Luca Lena Jansen, MSc.

University of Žilina
Faculty of Management Science and Informatics

Luca Lena Jansen, MSc.

Abstract of the Dissertation

Assessment of Innovative Solutions for the European Electricity Market

to obtain the academic title "**Philosophiae doctor**" (**PhD.**)
in the doctoral study program
Intelligent Information Systems
in the field of study
Informatics

Žilina, June 2022

The dissertation was prepared as a full-time doctoral study at the Department of Mathematical Methods and Operations Research, Faculty of Management Science and Informatics of the University of Žilina in Žilina.

Presenter: ***Luca Lena Jansen, MSc.***
Department of Mathematical Methods and Operations Research,
Faculty of Management Science and Informatics,
University of Žilina, Slovakia
Unit C.03 – Energy Security, Distribution and Markets,
Joint Research Centre, Ispra, Italy

Supervisors: *Prof.* ***Ľuboš Buzna****, Ph.D.*
Department of Mathematical Methods and Operations Research,
Faculty of Management Science and Informatics,
University of Žilina, Slovakia

Prof. ***Peter Braciník****, Ph.D.*
Department of Power Systems and Electric Drives
Faculty of Electrical Engineering and Information Technology
University of Žilina, Slovakia

Gianluca Fulli*, Ph.D.*
Unit C.03 – Energy Security, Distribution and Markets,
Joint Research Centre, Ispra, Italy

Reviewers: *Prof.* ***Ettore Bompard****, Ph.D.*
Department of Energy
Politecnico di Torino, Turin, Italy

Georgios Antonopoulos*, Ph.D.*
Unit C.03 – Energy Security, Distribution and Markets,
Joint Research Centre, Petten, The Netherlands

The abstract was sent out on: **........................**
The defense of the dissertation takes place on **.......................** at **..........** before the committee for the defense of the dissertation approved by the departmental committee in the field of study **Informatics**, in the study program **Intelligent Information Systems**, appointed by the dean of the Faculty of Management and Informatics of the University of Žilina
In Žiline on **..........................**

prof. Ing. ***Karol Matiaško****, PhD.*
Chair of the working group of the joint commission
in the field of study Informatics
study program Intelligent Information Systems
Faculty of Management Science and Informatics
Žilinská univerzita
Univerzitná 8215/1
010 26 Žilina

Abstract

This dissertation thesis assesses different design options for a model of the European electricity market to investigate nodal pricing. Concretely, technical aspects such as the choice of power flow model, network representation, intertemporal constraints and economic aspects such as demand elasticity were investigated. In a preliminary analysis, two formulations of the power flow model AC-OPF and DC-OPF were compared against each other in terms of obtaining nodal prices. While AC-OPF leads to a higher accuracy, which can be significant for operational purposes. For a model with a stronger focus on electricity markets and pricing mechanisms, DC-OPF is preferred, especially considering the computational benefits. A study that implements demand elasticity into the making of prices in a European context was conducted. It showed consumers' price elasticity impact on dispatching and the costs to generate power. The presented case study investigated these effects in the context of switching from a lower to a higher resolution of networks, which emphasizes the role demand elasticity could play in a system with a higher number of zones and ultimately under a nodal pricing regime. The main contribution of this Ph.D. thesis represents the development of a heuristic algorithm to model hydro storages in large-scale nodal pricing models. It allows overcoming the lack of data on hydro state of charge time series and issues with intertemporal constraints, when simulating large-scale models in sequences and displays the seasonality of hydro reservoir filling. Thereby, a nodal model of the European electricity market was developed that is capable of assessing nodal against the existing zonal pricing scheme through the incorporation of redispatching in the zonal modeling approach. A study of the costs of redispatching proves the applicability of the model and indicates the potential cost savings for congestion management that nodal pricing can signify.

Keywords: nodal pricing, electricity market model, internal European market, optimal power flow, optimization, heuristic

Abstrakt

Dizertačná práca analyzuje rôzne možnosti návrhu modelu európskeho trhu s elektrinou pre preskúmanie uzlových cien. Konkrétnejšie boli skúmané technické aspekty, ako voľba modelu pre tok výkonu, sieťová reprezentácia a podmienky zabezpečujúce časovú nadväznosť, ako aj ekonomické aspekty ako elasticita dopytu. V prvotnej analýze boli navzájom porovnané dve formulácie pre model toku výkonu, konkrétne AC-OPF a DC-OPF podľa uzlových cien. AC-OPF vedie k vyššej presnosti, ktorá môže byť signifikantná pre operačné dôvody. Pre model so väčším zameraním na elektrické trhy a cenové mechanizmy, sa preferuje DC-OPF, berúc do úvahy najmä menšiu výpočtovú náročnosť. Takisto bola vykonaná štúdia, ktorá implementuje elasticitu dopytu do tvorby cien v európskom kontexte. Výpočtové experimenty dokumentujú vplyv cenovej elasticity odberateľov na aktualizované objemy generovania energie jednotlivými zdrojmi a výrobné náklady. Prezentovaná prípadová štúdia skúmala tieto efekty v kontexte zmien z nižších na vyššie rozlíšenia sietí, ktoré zdôrazňujú úlohu dopytovej elasticity v systéme s vyšším počtom zón a v konečnom dôsledku pod režimom uzlových cien. Hlavný prínos tejto dizertačnej práce prezentuje vývoj heuristického algoritmu pre modelovanie vodných nádrží vo vysoko škálových modeloch uzlových cien. Práca napomáha prekonať nedostatok dát o časových radoch stavov vodných nádrží, problémy s podmienkami zabezpečujúcimi časovú nadväznosť pri rozsiahlych simulačných modeloch v sekvenciách a zobrazovaní sezónnosti naplnenia vodných nádrží. Z týchto dôvodov bol vyvinutý uzlový model európskeho trhu s elektrinou, ktorý aplikuje uzlový prístup oproti existujúcej zónovej cenovej schéme pomocou zahrnutia redispečovania zónového modelovacieho prístupu. Štúdia cien redispečovania dokazuje aplikovateľnosť modelu a indikuje potenciálne šetrenie nákladov pre manažment preťaženia spôsobeného uzlovými cenami.

Kľúčové slová: uzlová cenotvorba, model elektrického trhu, vnútorný európsky trh, optimálny tok výkonu, optimalizácia, heuristiky

1 Introduction & Research Question

Different strategies and regulations have been put forward to enable the transition of the energy system from a fossil fuel-based one to a system relying predominantly on renewable energies. As a part of the "Clean Energy for all Europeans", the European Commission aims to push for the so-called Energy Union, which among others, aims at redesigning and integrating the European electricity market [5]. This will allow electricity to flow freely across borders, not being held back by physical or regulatory constraints. Integrating the electricity market is expected to allow for a broader competition between energy utilities and ultimately reduce overall system costs [24]. Therefore, it is a task of high political interest to investigate possible future designs for the European electricity market that can facilitate the formation of the Energy Union and enable the integration of an increased amount of renewable generation into the electricity mix. Currently, the European market is based on zonal pricing. A uniform electricity price is determined for bidding zones, which predominantly follow country borders. Thereby, the physical limitations within the zones to the flow of electricity are disregarded. This calls for congestion management, as intra-zonal capacity limits of the electricity network are ignored in the price formation process, and flows that exceed these limitations represent a danger to the system's stability. One of the possible remedies to mitigate this problem that is increasingly gaining interest since its development is the concept of nodal pricing [27]. In the process of determining nodal prices, the physical capacity limits of the network are being taken into account, which can thus reduce the need for redispatching and sending correct price signals to market participants [12].

The electricity market is a complex and interconnected system with many stakeholders. Thus, alternations in its functioning and the making of prices need to be carefully assessed prior to implementation. Electricity market models are a key enabler to sound decision-making in such a complex environment.

There are different design options when building a model of the European electricity market. Their importance will be evaluated on case studies, which will allow a comparison of nodal and other market designs and ultimately assess the relevance of different modeling aspects in terms of such a comparative study. Concretely, the overall research goal of this thesis is:

The design of an extended electricity market model capable to investigate market designs based on alternative pricing mechanisms with a special focus on nodal pricing.

The particular modeling design aspects that shall be investigated with respect to their relevance when moving from a zonal to a nodal market design can be subdivided into two main groups:

- Technical aspects concerning the modeling of the physical grid, e.g. transmission capacity representation and utilization, the impact of AC-OPF and DC-OPF, or intertemporal dependencies.
- Economic aspects of modeling electricity markets, e.g. demand elasticity, or distribution of economic welfare.

The relevance of these modeling aspects will be quantified with regard to their impact on system performance, in particular under a nodal market design.

2 Electricity Markets: Theory and Background

This section will give an overview of relevant concepts from power flow modeling and economics that are essential to understanding electricity markets, which will be the focus of the second part of this section. The European electricity market and its functioning will be explained, and a short introduction to the US electricity system will be given as an example of a successful introduction of nodal pricing.

2.1 Optimal Power Flow & Market Clearing

Optimal Power Flow (OPF) is an optimization problem that seeks to minimize costs, with respect to constraints, which reflect physical limitations of the electricity grid as well as those of generators and loads. It is an essential tool that finds application in power system operation and planning. There are different formulations of OPF, while they can be very precise e.g. in taking into account various aspects of power plant operational constraints. Here, only the linearized approximation referred to as DC-OPF will be introduced. A power network is considered to consist of a set of nodes N, with $\mathcal{G} \subset N$ the set of power-generating nodes and $\mathcal{D} \subset N$ the set of power-consuming nodes. The objective function f of the minimization is usually considering costs to generate power P, while the choice of cost functions varies predominantly between linear, quadratic, and piece-wise linear. The DC-OPF formulation reads:

$$\underset{P,\theta}{\text{minimize}} \sum_{i \in \mathcal{G}} f(P_i) \tag{1}$$

subject to

$$P_i = \sum_{k \in N(i)} P_{ik} = \sum_{k \in N(i)} B_{ik}(\theta_i - \theta_k), \quad i \in N \tag{2}$$

$$-F_{ik} \leq P_{ik} \leq F_{ik}, \qquad i \in N, \quad k \in N(i) \tag{3}$$

$$\underline{P}_i \leq P_i \leq \bar{P}_i, \qquad i \in \mathcal{G} \cup \mathcal{D}. \tag{4}$$

where one seeks to minimize (1), subject to the following constraints: the power flow constraints for active power (2), which describes the relationship between P_i and voltage angles θ connected through the subsceptance B_{ik} of the power line connecting node i with adjacent nodes $j \in N(i)$; power flow limits F_{ik} of the lines (3), operational power limit for generation and load (lower $\underline{P}_i$ and upper $\bar{P}_i$ power limits) (4) [28].

In a zonal representation, which is currently in place in Europe, for every pricing zone, one power balance is enforced as well as flow limits between the zones. The dual variables associated with each power balance constraint will render the zonal market-clearing price.
Moving towards a more detailed representation of the electricity network, further energy balances can be introduced, in which case one would speak of a nodal representation and the dual variables of these constraints will render the nodal prices or locational marginal prices (LMP).
In the above formulation of the economic-dispatch problem, power could be drawn continuously. However, in reality, it will be delivered by a discrete number of power plants (units) that are committed to delivering. Therefore, the problem formulation needs to include binary variables, which leads to Unit Commitment (UC).

2.2 The European Electricity Market and Nodal Pricing

The EU initiated the process of liberalizing electricity markets in 1996 and with the Third Energy Package in 2009, ownership unbundling became mandatory [7]. However, the operation and maintenance of the power grid remain the task of regulated entities, as it represents a natural monopoly on distribution.

The European electricity market can be subdivided into three sequences.On the forward market, long-term agreements are made for months and years before the physical delivery of electricity. Moving closer to real time, the day-ahead market (DAM) plays a central role and can be viewed as the reference market. Within a bidding zone, electricity offers and demand bids are collected, and the market is cleared at a uniform market clearing price for an entire zone. A bidding zone is predominantly equal to a country within

Europe, while inter-zonal trading is possible. Between zones, a difference in prices can exist, as for inter-zonal trading the capacities of transmission lines are taken into consideration.A consideration of line capacities of the grid is not implemented within zones. This may lead to congestions of lines when their capacity is exceeded and calls for measures to be taken to ensure a secure operation of the grid. These measures are referred to as congestion management (including re-dispatching, counter trading) and are taken by the transmission system operators (TSO) responsible for the respective zone [13]. On the last sequence of the market the real-time or balancing market, balancing service providers can offer their services in terms of reserves (i.e. capacities to increase or decrease generation or demand) to TSOs, in order to allow them to perform congestion management as well as ensure the overall balance of supply and demand in the system.

While the current design of the European electricity market is based on zonal pricing, in the phase of the challenges that the electricity system is facing, several changes to the functioning of markets are being under consideration. The European Commission in their impact assessment have investigated four possibilities for improving local price signals to improve dispatch decisions and investments in the EU wholesale market [1, 6]. It is stated that a switch from zonal to nodal pricing would incorporate the value of available transmission capacity across market regions, which would utilize available resources more efficiently. The impact assessment further points out that for electricity markets and networks, nodal pricing is theoretically the most optimal pricing system and would render remedial actions by TSO to alleviate congestions unnecessarily. However, implementing nodal pricing in the European internal electricity market would imply a fundamental change to the structure of markets, the management of the grid, and trading mechanisms and was deemed disproportionate. Further, stakeholders expressed concerns about creating a single EU Independent System Operator, instead, a step-wise regional integration of system operation is preferred. Thus, currently, there are some regulatory barriers to implementing nodal pricing in the European electricity system, as well as some opposition by stakeholders, that would need to be overcome.

3 Electricity Market Modeling: State of the Art

3.1 Nodal Pricing in a Broader Context

A potential transformation of the European electricity market towards nodal pricing is subject of various discussions in research as well as in a policy context [1]. The market design currently in place in Europe is based on zonal pricing as mentioned above. In the following, some concrete advantages and challenges linked to the introduction of nodal pricing will be highlighted, as they are being discussed in literature. One of the main cases made in favor of nodal pricing is "getting the price right" [12]. This means that several prices are needed to sufficiently display the economic and physical reality of a transmission grid. Conversely, a single price i.e. a zonal price will not reflect the physical constraints within a zone appropriately. Capacity limits of the grid do not allow for a free flux within a zone, as a homogeneous price suggests. This fact is giving rise to readjustments as counter-trading and re-dispatching done by TSOs in order to ensure system stability. This is because the reality i.e. the bottlenecks of the grid are not displayed in electricity prices. These issues can be addressed through the introduction of nodal pricing, as it can render this step of re-dispatching obsolete or less important [11, 27].

A prominent argument made against nodal pricing is the increased presence of market power. Market power is exercised when a market participant is able to dominate the market due to its strong position in the same and abuse this power. A larger bidding zone does not only offer a higher liquidity, but as there is a large number of participants, their individual capabilities to gain and exercise market power is mitigated. Based on technical considerations and experiences gained from the implementation of several zones in the Californian market, Harvey and Hogan arrive at an opposite conclusions [10]. While a node represents a smaller area than a zone, the optimization and clearing of market prices is done considering a much larger area. Thus, at the same time, in the face of smaller bidding areas on a nodal level, market surveillance can become simpler.

In a technical report of the JRC, an analysis of the effects and possibility to implement nodal pricing in the European internal electricity market was conducted [1]. Among other aspects, it is pointed out that shift in the reference market would be required, i.e. balancing market would be the reference market while DAM and intra-day market would be considered forward markets. It is also stress the question of the roles of TSOs and DSOs and their interactions in the face of increased decarbonization and decentralization of the electricity system.

[30] survey nodal, zonal, and uniform pricing mechanisms in the context of congestion management. The main advantages of nodal pricing are identified to be welfare maximization and efficient pricing; and perfect integration of generation and transmission. Disadvantages, on the other hand, are a large number of prices, low liquidity, and a small number of traders and resulting low competition as well as the complex coordination of submarkets. The author concludes that nodal pricing yields the first best outcomes, as congestion is reflected in LMPs. While there may be some difficulties in the joint implementation of nodal pricing in Europe, it is worth investigating the feasibility given the advantages nodal prices could provide.

3.2 Models of Zonal and Nodal Markets

In the following various studies that rely on zonal, nodal or a combination of both are presented and applications of these models are discussed.

The Joint Research Centre (JRC) of the European Commission has developed a pan-European economic dispatch model [26, 31]. The optimization problem is formulated as a generation cost minimization problem. This economic dispatch model was applied to perform a techno-economic cost-benefit analysis of a submarine cable linking North America's and Europe's electricity systems. For this purpose consumer, producer, and merchant surplus were determined. Following basic economic theory, consumer surplus cannot be obtained when demand is a fixed input, which corresponds to a vertical demand function leading to infinite consumer surplus. Thus, linear demand functions were used, which were determined through a short-run demand elasticity value applied to all the nodes for the entire year of the simulation horizon. More detailed modeling of flexible demand has been identified as a shortcoming of the thus far conducted work and was picked up already as a starting point for improving the present model (see [17]).

The Aristotle University of Thessaloniki developed *PHOEBE* a European market model [2]. At the core of the bottom-up model lies the 3-level unit commitment optimization model that clears the different markets: day-ahead market, intra-day market, and balancing market. The model resolution features the hourly operation of the system for a yearly horizon. The main application of their model is the assessment of different demand response schemes and the impact of system adequacy and flexibility.

ELMOD a model of the European electricity market is formulated as a welfare maximization problem [21]. The cost of generation is represented by a step-wise supply function, while the demand is modeled through a linear function, and the model includes start-up costs and hydro storage. Simulations are conducted at increments of one hour and social welfare is maximized considering the entire time horizon, which in the foreseen application of this model is 24 hours. The European grid is modeled considering more than 4,000 nodes and more than 2,000 lines.

[3] develop an electricity pricing model, which investigates a hybrid pricing scheme consisting of areas with zonal and areas with nodal pricing in the Nordic electricity market and the impacts on congestion management. The model is applied to a 13-node system emulating the Norwegian and Swedish power systems. The authors pay special attention to a high-demand scenario, in which they conduct simulations for a single hour of peak demand. Results for the three pricing schemes are compared in terms of prices, line loading and utilization, social surplus, and total production and generation.

Felling at al. investigate the existing price zone configuration in central Western Europe and propose different configurations based on the results obtained from employing a large-scale modeling framework [8]. Their model is based on flow-based market coupling. A comparison of different zonal configurations is performed, which comprises technical and socio-economic impacts of the configurations. Their modeling efforts can be best described in a step-wise scheme. In the first step, an OPF model is employed to calculate LMPs for all nodes. Their OPF is based on the DC-lossless approximation. At the D-2 stage (two days before delivery), the allocation of capacity is determined, which is in reality a task of the TSOs. These capacities are the remaining available margins (RAM) resulting from the zonal power transfer distribution factors. At the D-1 stage (day-ahead stage), the WILMAR Joint Market Model (JMM) is employed to clear the market [29, 22]. This scheduling model depicts almost the complete European electricity market. In general, the JMM solves a cost minimization objective subject to inter-zonal capacity limits (RAMs), zonal power balance, and detailed generator operation constraints. At the D stage, the real-time stage, or redispatching stage, the TSO needs to adjust the dispatching of power. After the scheduling of plants is determined from the market-clearing stage, TSOs calculate the corresponding line loadings and in case of overloadings redispatch power plants. The redispatching model is formulated as an OPF with the objective of minimizing redispatching costs, i.e. those for ramping up or down generators. The constraints enforce nodal flow capacity limits, energy balance, and various limitations to redispatching capacities.

Mende et al. stress the need to combine market and grid models in order to perform studies that can assess the increased integration of RES into the electricity system [23]. When exploring future scenarios for the power system, the market perspective can only be a starting point, as especially grid extension and operational issues will play a key role in the future evolution of the system. Thus, they propose a soft-linked combined market and grid model. They apply their model to a case study on the German system and study the level of congestion due to a zonal dispatch of generators. They conclude that, especially given the spatial distribution of RES, a detailed representation of the grid and all power systems components is vital for a sound contingency analysis of future power systems.

Poplavskaya et al. develop a novel market design that integrated redispatching into a zonal market with flow-based market coupling [25]. They compare their outcomes against a full nodal model and a zonal model without integrated redispatching. They find that their approach can reduce the need for ex-post redispatching and increase cross-border capacity utilization.

Kunz et al. compare nodal to zonal pricing through two models [20]. The zonal model minimizes generation costs subject to zonal balance and generation constraints. In a subsequent step, congestion management is modeled through another cost minimization problem, where line capacity limits are enforced as constraints. The nodal model combines this two-step approach in a single optimization.

3.3 Overview and Summary

The previous section presented a literature review on different nodal and zonal models. An overview of modeling aspects that are present in the surveyed literature are summed up in Table 1. The market-clearing model is formulated as an optimization problem subject to a number of constraints. The modeling choices can be losely summed up in the following way: objective function (cost minimization / welfare maximization); supply and demand function type; power plant operational constraints (including e.g., start-up/-down, reserve provision, unit commitment constraints); power flow model (DC-OPF, AC-OPF, transport model).

From the overview in Table 1 one can see that both types of objectives cost minimization and welfare maximization are being employed in the literature. Regarding the formulation of the supply function, linear functions are common, while also piece-wise linear or step-wise functions are being used. For the models that do consider elastic demand, linear demand functions are used exclusively. When it comes to the detail of generation unit operation, economic dispatch is prevalent, while also unit commitment receives due attention. Also, the consideration of start-up and down, and on- and offline constraints, as well as reserves is sometimes included in the models, but not imperative in the surveyed studies. Lastly, the choice of power flow model is rather dominated by DC-OPF. Only dedicated studies explore more detailed formulations of the power flow equations. Transport models are sometimes used, which is predominantly the case in zonal models.

Table 1: Modeling choices for electricity market models; objective function formulation, supply and demand function, economic dispatch or unit commitment, intertemporal constraints or reserves, and power flow model. Shown are references that present electricity market models and the choices made for the respective models.

Reference	Objective Function	Supply function	Demand function	Economic Dispatch (ED) / Unit Commitment (UC)	Further operational constraints & reserves	Power Flow Model
Felling, et al., (2019)	min cost	piece-wise linear	none	ED	start-up & -down, on- & offline constraints	DC
Grimm, et al. (2018)	max welfare	linear	linear	ED	none	DC
Bakirtzis, et al. (2018)	min cost	linear	none	EDUC	start-up & -down, on- & offline constraints, reserves	DC
ENTSO-e. (2018)	min costs	N/A	N/A	ED	none	DC
Leuthold, et al. (2012)	max welfare	step-wise	linear	UC	on- & offline constraints	DC
Bjørndal, et al. (2014)	max welfare	piece-wise linear	linear	N/A	N/A	DC
Baghayipour, et al. (2012)	N/A	quadratic	none	ED	none	DC, improved DC and AC
Breuer, et al. (2013)	min cost	linear	none	ED	none	DC
Purvins, et al. (2018)	min cost	piece-wise linear	optional (linear)	ED (UC optional)	reserves	transport
Quelhas, et al. (2007)	min cost	piece-wise linear	none	ED	none	DC
Kunz et al. (2016)	min cost	linear	none	ED	none	DC

4 Towards a European Nodal Pricing Model: Results

This chapter presents the main outcomes of the work performed in the context of this Ph.D. studies. The scope of this condensed version of the thesis does not allow to present all results. Therefore, the interested reader is referred to the respective publications that detail these studies. Examine were the choice of power flow model and the role for nodal prices as well as the impact of different network representations [15, 16]. Further, a study on demand elasticity in a European context was conducted [17]. Incorporating consumers' elasticity to prices on a European scale represents a novelty.

The issue of modeling hydro storage state of charge evolution under myopic foresight is addressed in [18, 19] and is presented in a condensed fashion in Section 4.1. This is necessary due to a lack of data and the computational challenge of solving large-scale optimization problems of systems with very high spatial and hourly time resolution. Through the development of a heuristic algorithm, hydro state of charge profiles were obtained that allow for comparative nodal vs. zonal case studies. Lastly, to demonstrate the applicability of this heuristic, a case study on the costs of redispatching is performed. The methodology relies on a full nodal model and a zonal model coupled with a redispatching model.

4.1 Estimating State of Charge Profiles of Hydro Storage Units for a Large-Scale Nodal Pricing Model

4.1.1 Introduction

In order to assess nodal pricing as a market designs, one has to solve large optimal power flow (OPF) problems, which is a computationally challenging task. In order to be able to perform such simulations, it can be necessary to sequentialize the models. When doing so, one of the issues that arises is how to accurately model hydro storages. The challenges are due to the lack of data, the seasonality of hydro inflows and of storage capacity utilization, as well as the myopic foresight of sequenced OPFs.

Existing approaches are either tailored to zonal models, or they present a simplistic approach to displaying the seasonality of the usage of hydro storages. Therefore, a novel heuristic two-stage approach is proposed that firstly generates initial hydro SOC profiles from a zonal model and then adjusts these profiles for a nodal model. It allows overcoming the aforementioned shortcomings of methods proposed in literature. Furthermore, a comparability between nodal and zonal models is achieved. This methodology

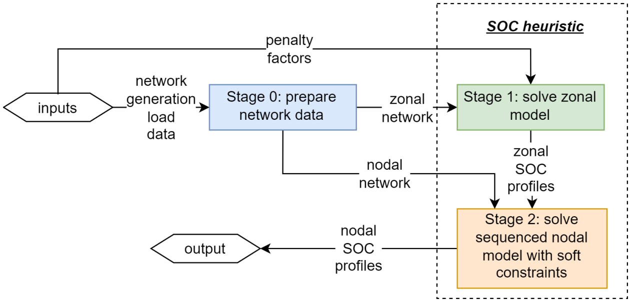

Figure 1: Stage-wise methodology to obtain nodal SOC profiles.

is introduced in Section 4.1.2. Results of computational experiments are presented in Section 4.1.3. It shows is the performance of the proposed solution against methods in literature as well as a case study on redispatch modeling, which relies on the obtained SOC input profiles.

4.1.2 Methodology

4.1.2.1 SOC Heuristic In this section, the methodology to obtain SOC profiles for large-scale nodal models is presented. A step-wise modeling framework is proposed, which is illustrated in Fig. 1. Initially in Stage 0 the data are collected and prepared, which serve as inputs to the nodal and zonal models. In Stage 1, the zonal model is run for the full time horizon. SOC profiles for individual storage units as well as aggregated SOC profiles for zones are the output. These are fed as inputs to Stage 2, where the nodal model is run in sequences, in order to produce adjusted profiles. The data preparation will be detailed in Section 4.1.2.3, while here the two stages to obtain the SOC profiles will be laid out.

In Stage 1, an aggregated version of the full nodal model is solved, referred to as zonal model, consisting of the set of zones Z. Connected to these zones are generators $\mathcal{G}$, storage units S and demands D. This model can be solved for the entire time horizon $T = \{1, 2, \ldots, 8760\}$ of one year with an hourly resolution. The problem is formulated as an economic dispatch problem:

$$\text{minimize} \quad \sum_{t\in T} \left(\sum_{g\in\mathcal{G}} P_{g,t} \cdot c_g + \sum_{s\in S} P^{dis}_{s,t} \cdot c_s \right) \tag{5}$$

subject to

$$\sum_{d\in\hat{D}(z)} P_{d,t} = \sum_{y\in Z(z)} F_{zy,t} + \sum_{g\in\hat{\mathcal{G}}(z)} P_{g,t} + \sum_{s\in\hat{S}(z)} (P^{dis}_{s,t} - P^{stor}_{s,t}), \ \forall\ z \in Z, t \in T \tag{6}$$

$$F_{zy,t} = - F_{yz,t}, \qquad \forall\ z \in Z, y \in Z(z), t \in T \tag{7}$$

$$NTC_{yz} \leq F_{zy,t} \leq NTC_{zy}, \forall\ z \in Z, y \in Z(z), t \in T \tag{8}$$

$$
\begin{aligned}
0 \leq & P_{g,t} \leq \bar{P}_g, && \forall\, g \in \mathcal{G}_{conv}, t \in T && (9)\\
0 \leq & P_{g,t} \leq \bar{P}_g \cdot p^{avail}_{g,t}, && \forall\, g \in \mathcal{G}_{res}, t \in T && (10)\\
0 \leq & P^{dis}_{s,t} \leq \bar{P}_s, && \forall\, s \in S, t \in T && (11)\\
0 \leq & P^{stor}_{s,t} \leq \bar{P}_s, && \forall\, s \in S, t \in T && (12)\\
0.3 \cdot \overline{SOC}_s \leq & soc_{s,t} \leq \overline{SOC}_s, && \forall\, s \in S, t \in T && (13)
\end{aligned}
$$

$$
\begin{aligned}
soc_{s,t} = & soc_{s,t-1} + \eta^{stor} \cdot P^{stor}_{s,t-1} - \frac{1}{\eta^{dis}} \cdot P^{dis}_{s,t-1} + \\
& + infl_{s,t-1} - spill_{s,t-1},\ \forall\, s \in S, t \in T.
\end{aligned} \tag{14}
$$

The objective function (5) minimizes the costs over all time steps t in the time horizon T. In the objective, included are the marginal costs $c_{g,t}$ to produce power $P_{g,t}$ from all generators $\mathcal{G}$ and the marginal costs $c_{s,t}$ to produce power $P^{dis}_{s,t}$ from all storage units S at time t. The zonal power balance is expressed in (6). It ensures that for all times t all power consumed by demands $\hat{D}(z)$ at zone z equals the sum of all power generated from generators, the net power output from storages $\hat{S}(z)$ as the difference between dispatched power $P^{dis}_{s,t}$ and stored power $P^{stor}_{s,t}$ and the sum of flows $F_{zy,t}$ going into zone z from adjacent zones $z \in Z(z)$. In order to maintain flow conservation at zones, (7) ensures that imports $F_{zy,t}$ to zone z from zone y equal exports $F_{yz,t}$ at all times. Cross-zonal line flows are limited by upper NTC_{zy} and lower NTC_{yz} capacity limits, the net-transfer capacities (8). Capacity limits are enforced for power generation from conventional generation units $\mathcal{G}_{conv}$ (9), renewable generators $\mathcal{G}_{res}$ (10) and storages' generation (11) and consumption (12). For fluctuating renewable generation units, the power output is further limited in (10) by a time varying reduction factor $p^{avail}_{g,t}$. The reservoir level or state of charge $soc_{s,t}$ of storages is constrained by the upper filling limit $\overline{SOC}$ and below by 30% of this capacity (13). In (14), the intertemporal continuity of the state of charge is preserved. It ensures that $soc_{s,t}$ equals the $soc_{s,t-1}$ at the previous time, plus the stored power $P^{stor}_{s,t-1}$ with efficiency η_s minus the dispatched power $P^{dis}_{s,t}$ with the efficiency η_s, plus natural inflows and minus the spillage $spill_{s,t}$.
From running this model, hourly SOC profiles for every storage unit s are obtained. These profiles for all individual units and aggregated for all storage units $\hat{S}(z)$ in each zone z are passed on as input to the next step.

In Stage 2 of the heuristic, the initial SOC profiles from the zonal model are adjusted for the nodal model. It features a higher spatial resolution. Given this difference between the two network representations, the initial profiles will not necessarily be feasible in the nodal model. Therefore, the input profiles are used as target values, which are implemented through soft-constraints. Thus, the inputs do not need to be met strictly. If the model deviates from them, this will contribute to the objective function value through penalty factors. The nodal model, as stated above, cannot be run for the full time horizon of one year and is thus solved in sequences. There is a sequence of I smaller optimization problems i, where each is solved for the set of times $T_i = \{t_{i,1}, t_{i,2}, \ldots, t_{i,end}\}$. The set of T_i make up the whole time horizon $T = \{T_1, T_2, \ldots, T_I\}$. Now, the implementation of the target values is done in a way that they are only passed to the problem at the end of each optimization sequence $t_{i,end}$. This will allow the freedom to deviate from the input profiles during the sequence on a short timescale. Only on a long timescale, following the profile is enforced. Between sequences, the SOC values at the end of each step are passed as input to the consecutive step. Therefore, it is necessary for the first step $i = 1$ in the sequence to have further inputs for the beginning of the sequence. Thus, SOC target values are also introduced for the first hour in the first sequence $t_{1,1}$. The formulation of the sequenced nodal model with soft-constraints for each problem i in the sequence reads:

$$\begin{aligned}
\text{minimize} \quad & \sum_{t\in T_i}\left(\sum_{g\in\mathcal{G}} P_{g,t}\cdot c_g + \sum_{s\in S} P^{dis}_{s,t}\cdot c_s\right)+ \\
&+\sum_{s\in S}(a_{s,t=t_{1,1}}\cdot\alpha_s + a_{s,t=t_{i,end}}\cdot\alpha_s)+ \\
&+\sum_{z\in Z}(a_{z,t=t_{1,1}}\cdot\alpha_z + a_{z,t=t_{i,end}}\cdot\alpha_z)
\end{aligned} \tag{15}$$

subject to

$$a_{s,t} \geq soc_{s,t} - SOC^{in}_{s,t}, \forall\ s\in S, t=\{t_{1,1}, t_{i,end}\} \tag{16}$$

$$-a_{s,t} \leq soc_{s,t} - SOC^{in}_{s,t}, \forall\ s\in S, t=\{t_{1,1}, t_{i,end}\} \tag{17}$$

$$a_{z,t} \geq \sum_{s\in\hat{S}(z)} soc_{s,t} - SOC^{in}_{z,t}, \forall\ z\in Z, t=\{t_{1,1}, t_{i,end}\} \tag{18}$$

$$-a_{z,t} \leq \sum_{s\in\hat{S}(z)} soc_{s,t} - SOC^{in}_{z,t}, \forall\ z\in Z, t=\{t_{1,1}, t_{i,end}\} \tag{19}$$

$$\sum_{d\in D(n)} P_{d,t} = \sum_{m\in N(n)} F_{mn,t} + \sum_{g\in\mathcal{G}(n)} P_{g,t} + \sum_{s\in S(n)}(P^{dis}_{s,t} - P^{stor}_{s,t}),\ \forall\ n\in N, t \tag{20}$$

$$F_{nm,t} = B_{nm}(\Theta_{n,t} - \Theta_{m,t}),\ \forall\ n\in N, m\in N(n), t \tag{21}$$

$$\beta\cdot\bar{F}_{nm} \leq F_{nm,t} \leq \beta\cdot\bar{F}_{nm},\ \forall\ n\in N, m\in N(n), t \tag{22}$$

$$NTC_{yz} \leq \sum_{\substack{n\in\hat{N}(z)\\ m\in N(n)\cap\hat{N}(y)}}\sum F_{nm,t} \leq NTC_{zy}, \forall\ z\in Z, y\in Z(z), t \tag{23}$$

$$SOC^{min}_{s,t} \leq soc_{s,t},\ \forall\ s\in S, t=t_{i,end}, i\neq 1 \tag{24}$$

(9) – (14).

In the objective function (15) the costs to generate power are minimized. There is an additional penalty contribution for deviations $a_{s,t}$ and $a_{z,t}$ from the target values for storage units $SOC^{in}_{s,t}$ and zones $SOC^{in}_{z,t}$. These deviations are weighted with the penalty factors α_s and α_z respectively. For $soc_{s,t}$ of individual storage units, soft constraints (16)&(17) are introduced, with slack variables $a_{s,t}$. For the sum of $soc_{s,t}$ of storage units $s \in \hat{S}(z)$ connected to zone z, slack variables $a_{z,t}$ for deviations from the input profiles $SOC^{in}_{z,t}$ are introduced, expressed in (18)&(19). In (20), the nodal power balance is defined for all nodes $n \in N$ the set of all nodes. At every time step t the sum of all demand $P_{d,t}$ of all loads $D(n)$ at node n equals the sum of incoming flows $F_{mn,t}$ from nodes $m \in N(n)$ the set of nodes adjacent to node n, the sum of (net) power generated at generators $\mathcal{G}(n)$ and storage units $S(n)$. The relationship between power flow $F_{nm,t}$ and voltage angles $\Theta_{n,t}$ of node n and $\Theta_{m,t}$ of node m is depicted in (21). B_{nm} is the susceptance of the transmission line connecting node n with node m. These power flows are limited by the thermal capacities of transmission lines $\bar{F}_{nm}$, which are reduced through the factor β. It is a common approach to approximate security constraints through a fixed reliability margin [21]. In (23), cross-zonal flows from zones $z \in Z$ to adjacent zones $y \in Z(y)$ are limited to the net-transfer capacities NTC_{zy} (compare constraint (8) of the zonal model). Constraints for power generation are the same as for the zonal model (9)-(14). Lastly, additional minimum target values $SOC^{min}_{s,t}$ for the state of charge of storage units s at the end of each sequence t_{end} are introduced. This is because the zonal model is required to meet the cyclic constraint for hydro storages (14). Thus also the nodal model needs to fulfill this requirement, but since it is run in sequences, it lacks the foresight to meet this requirement without constraint (24).

Through solving the nodal model for the set of sequences T_i, new nodal SOC profiles are obtained.

4.1.2.2 Redispatching Model The main difference between nodal and zonal models of the electricity system is the resolution of network data. In reality, this calls for remedial actions such as redispatching by TSOs, because a zonal dispatch of generators does not take the full network topology into account. Thus, a zonal model needs to consist of two parts. This difference between a nodal and zonal model is depicted in Figure 2.

Here, the formulation for the redispatching model is presented. As input it is using the outcomes of the zonal model in terms of power generation $P^z_{g,t}$. In general, redispatching can be formulated as cost or volume based redispatching [25]. The approach presented in [8] is followed and the optimization problem is formulated as redispatching cost minimization:

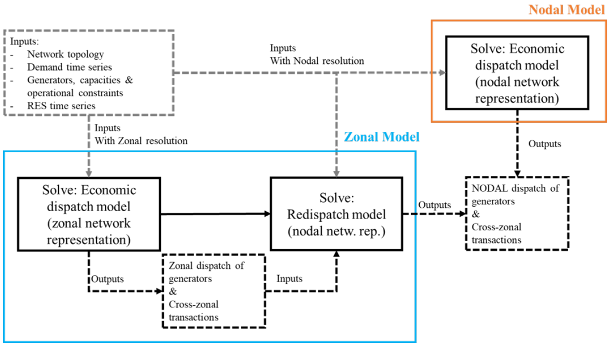

Figure 2: Flowchart of the zonal model, which consists of firstly an economic dispatch model with a zonal network resolution and secondly a redispatching model with nodal network representation; in comparison to the nodal model, which consists only of a single economic dispatch model with nodal network resolution.

$$\text{minimize} \quad \sum_{t \in T} \left(\sum_{g \in \mathcal{G}} u_{g,t} + \sum_{s \in S} v_{s,t} \right) \tag{25}$$

subject to

$$u_{g,t} \geq \left(-P^{z}_{g,t} + P_{g,t}\right) \cdot c_g, \ \forall \ g \in \mathcal{G}, t \tag{26}$$

$$u_{g,t} \geq \left(P^{z}_{g,t} - P_{g,t}\right) \cdot (c^{max} - c_g), \ \forall \ g \in \mathcal{G}, t \tag{27}$$

$$v_{g,t} \geq \Big(-(P^{dis,z}_{s,t} - P^{stor,z}_{s,t}) + (P^{dis}_{s,t} - P^{stor}_{s,t})\Big) \cdot c_s, \tag{28}$$

$$\forall \ s \in S, t \tag{29}$$

$$v_{g,t} \geq \Big((P^{dis,z}_{s,t} - P^{stor,z}_{s,t}) - (P^{dis}_{s,t} - P^{stor}_{s,t})\Big) \cdot (c^{max} - c_s), \ \forall \ s \in S, t. \tag{30}$$

$$(9)-(14)$$

$$(20)-(23)$$

Deviations of the power of generators $\mathcal{G}$ determined by the redispatching model $P_{g,t}$ from the input power of the zonal model $P^{z}_{g,t}$ is substituted with $u_{g,t}$. Analogously, deviations of the net power dispatch from storage units of the redispatching model $P^{dis}_{s,t} - P^{stor}_{s,t}$ from the input of the zonal model $P^{dis,z}_{s,t} - P^{stor,z}_{s,t}$ are substituted with $v_{s,t}$. In the objective function (25), the substitution variables are minimized. Constraints (26) and (29) ensure that upward redispatching is priced at the corresponding marginal costs c_g of generator g and c_s of storage unit s. Downward redispatching is priced through subtracting the marginal costs of corresponding generators and storage units from the marginal costs of the most expensive generator

c^{max}, expressed in (27) and (30). This is ensuring that more expensive generators are primarily used for downward redispatching. Equations (9)-(14) are the generation and storage units operational constraints. In (20) the nodal power balance is ensured. The relation between power flows and voltage angles is expressed in (21). Equations (22) and (23) are the limits for flows in transmission lines, from previously defined optimization problems.

4.1.2.3 Data Preparation and Experimental Setup The base dataset is obtained using PyPSA-Eur, an open-source tool to build and solve networks of the European transmission system from various open data sources [14]. 2018 is chosen as base year for the simulations, because of data availability. The nodal base network of 1010 nodes for Europe is build using the PyPSA-Eur workflow. Consecutively, the base network is aggregated to 45 zones emulating the reality of the European zonal market in 2018.

The models are implemented in Python and rely heavily on the PyPSA package [4]. The commercial solver Gurobi is used to solve the optimization problems. A cluster node with two ten core Intel Xeon processors and 750 GB RAM is used to run the simulations. The models are solved for one year with an hourly resolution. The proposed solution is tested on two benchmark cases of different transmission capacity reduction factor $\beta = 0.7$ and $\beta = 0.5$. The proposed heuristic requires setting the penalty factors α_s and α_z. A grid search is performed to explore these factors (in the following, this method is referred to as $SOC\_HEUR(\alpha_z, \alpha_s)$). Concretely, the investigated penalty factor combinations are: (1000,1000); (1000,10); (1000,0); (10,1000); (10,10); (10,0); (0,1000); (0,0). The method is compared against other approaches suggested in literature. These rely on introducing so-called bid prices for hydro storages. As constant bid prices 20, 40 and 60 EUR/MWh are chosen (referred to as $BIDS$(bid price)). Further, hydro shadow prices are derived as dual variables of constraint (14) of the zonal model and use these as time varying bid prices (referred to as SH_PRICES).

The results, i.e. the model runs with the obtained SOC profiles, are compared in terms of system costs, congestion, load shedding and computational times. To measure congestion, the average system congestion over the whole time horizon $\overline{sc}$ is used, which is the standard deviation of LMPs [9].

4.1.3 Results

An overview of results of the numerical experiments is presented in Table 2. The results obtained from the different methods are compared against the zonal model run in Stage 1 (referred to as $ZONAL$).

Table 2: Results overview for the two benchmarks with transmission capacity factors $\beta = 0.7$ and $\beta = 0.5$. Shown are the total system costs, which are made up of operational costs (i.e., power generation costs) and load shedding costs, the difference between *ZONAL* and the respective method relative to the total system costs of *ZONAL*; the average system congestion ($\overline{sc}$); the total amount of load shed and the share of this amount with respect to the total load; and the run times.

β	Method	Tot. costs [bn EUR]	Operational costs [bn EUR]	Load shedding costs [bn EUR]	Δ cost wrt ZONAL [%]	$\overline{sc}$	Load shedding [GWh] / [%]	Run time [h]
0.7	ZONAL	64.74	64.74	0.00	0.00	7.0	0 / 0.000	2.1
	SH_PRICES	216.65	68.47	148.17	234.6	957.0	14817 / 0.458	3.8
	BIDS(20)	242.92	68.37	174.56	275.2	985.9	17456 / 0.539	4.1
	BIDS(40)	230.50	68.75	161.74	256.0	977.6	16174 / 0.500	3.8
	BIDS(60)	224.95	68.51	156.44	247.5	977.4	15644 / 0.483	4.2
	SOC_HEUR(1000,1000)	68.46	66.87	1.59	5.8	664.5	159 / 0.005	22.9
	SOC_HEUR(1000,10)	68.42	66.84	1.59	5.7	663.8	159 / 0.005	13.0
	SOC_HEUR(1000,0)	72.98	67.35	5.63	12.7	696.0	563 / 0.017	34.1
	SOC_HEUR(10,1000)	68.45	66.86	1.59	5.7	664.2	159 / 0.005	25.7
	SOC_HEUR(10,10)	180.44	67.45	112.99	178.7	901.2	11299 /0.349	7.7
	SOC_HEUR(10,0)	220.17	67.94	152.23	240.1	973.9	15223 / 0.470	7.2
	SOC_HEUR(0,1000)	68.45	66.86	1.59	5.7	664.2	159 / 0.005	24.5
	SOC_HEUR(0,0)	279.17	68.96	210.22	331.2	1097.2	21022 / 0.650	5.8
0.5	ZONAL	64.74	64.74	0.00	0	7.0	0 / 0.000	2.1
	SH_PRICES	263.78	71.46	192.32	307.4	1122.0	19232 / 0.594	6.5
	BIDS(20)	265.82	71.51	194.32	310.6	1133.9	19432 / 0.600	6.6
	BIDS(40)	263.72	71.45	192.27	307.4	1121.8	19227 / 0.594	5.6
	BIDS(60)	260.11	71.48	188.63	301.8	1119.6	18863 / 0.583	5.4
	SOC_HEUR(1000,1000)	101.73	69.85	31.89	57.1	850.6	3189 / 0.099	34.8
	SOC_HEUR(1000,10)	102.01	69.56	32.45	57.6	847.2	3245 / 0.100	17.3
	SOC_HEUR(1000,0)	113.47	70.06	43.41	75.3	880.2	4341 / 0.134	38.3
	SOC_HEUR(10,1000)	101.90	69.76	32.14	57.4	847.6	3214 / 0.099	36.8
	SOC_HEUR(10,10)	198.37	70.06	128.31	206.4	1034.2	12831 / 0.396	27.8
	SOC_HEUR(10,0)	273.22	70.88	202.33	322.0	1159.4	20233/ 0.625	10.3
	SOC_HEUR(0,1000)	101.89	69.75	32.14	57.4	847.5	3214 / 0.099	38.1
	SOC_HEUR(0,0)	335.01	71.52	263.49	417.5	1254.4	26349 / 0.814	6.1

For the benchmark case with transmission capacity factor $\beta = 0.7$, one can see that SH_PRICES as well as the three $BIDS$ exhibit overall system costs that are around 250% higher than the $ZONAL$ system costs. The best performing combinations of penalty factors for the proposed heuristic on the other hand show system costs that are only 5.7-5.8% higher than the $ZONAL$ costs, these combinations are $SOC\_HEUR(1000, 1000)$, $SOC\_HEUR(10, 1000)$, $SOC\_HEUR(0, 1000)$ and $SOC\_HEUR(1000, 10)$. The highest system costs are obtained when no guidance for the hydro SOC profiles is provided ($SOC\_HEUR(0, 0)$). The lowest average system congestion is achieved with the methods that also exhibit the lowest costs. Accordingly, also the amount of load shedding is lowest for these methods. For the $BIDS$ and SH_PRICES methods, load shedding ranges around 0.5% of the overall load. Even though this amount seems small, due to the high value of lost load (VoLL) of 10,000 EUR/MWh used, the resulting costs for load shedding explain the poor performance in terms of overall system costs of these methods. This is also true for the case of myopic foresight ($SOC\_HEUR(0, 0)$), where the cost of load shedding make up around 75% of the overall costs. In terms of run times, one can observe that times are notably higher for the best performing methods, which indicated that lower costs come at a computational price.

To test the proposed solution in a scenario of higher congestion, the transmission capacity factor is reduced to $\beta = 0.5$. Expectedly, the overall costs are consistently higher as the system is more constrained. As in the $\beta = 0.7$ benchmark, the best performing methods in terms of costs and average system congestion are $SOC\_HEUR(1000, 1000)$, $SOC\_HEUR(10, 1000)$, $SOC\_HEUR(0, 1000)$ and $SOC\_HEUR(1000, 10)$. These methods also exhibit the lowest amounts of load shedding. The costs for the methods $BIDS$ and SH_PRICES are more than three times higher than for $ZONAL$. In comparison to the best performing methods, one can see that also the operational costs are higher, indicating that not only load shedding is responsible for this difference. Throughout the indicators, it is found that the method with myopic foresight ($SOC\_HEUR(0, 0)$) is performing poorest. Run times have consistently increased for all methods in comparison to the $\beta = 0.7$ benchmark, and again lower costs correspond to larger computational times. Considering the results from the two benchmarks, one can observe that the proposed solution renders better results than a model with myopic foresight. Furthermore, the methodologies relying on bid prices (fixed or derived from shadow prices) proposed in the literature are also outperformed by the proposed heuristic. However, it is interesting to investigate why in both benchmarks, the heuristic method with the highest penalty factors ($SOC\_HEUR(1000, 1000)$) performs well. The proposed heuristic introduces constraints only at the end of every sequence, which means that within every

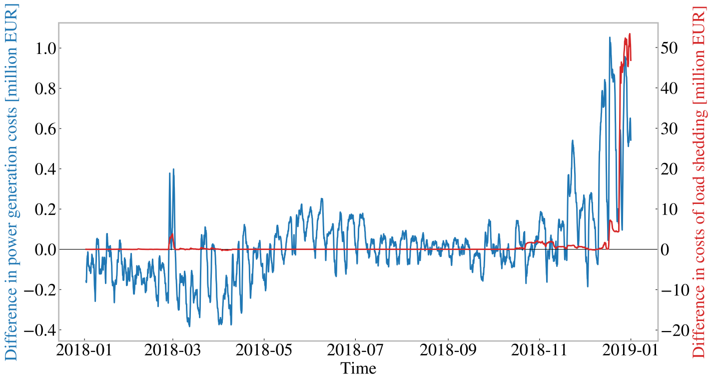

Figure 3: Difference in costs between $SOC\_HEUR(1000, 0)$ and $SOC\_HEUR(1000, 1000)$. Shown are differences in power generation costs in million EUR (blue) and difference in costs of load shedding in million EUR (red). (Displayed is the daily rolling average of the cost time series)

optimization step, deviations on a short scale from the input profiles are allowed regardless of the penalty factors. Thus, locally also high penalty factors allow reacting to congestions. Only on a longer timescale, the choices of penalty factors determine the deviation from input profiles. One could expect that especially in the case of higher congestion ($\beta = 0.5$), it could be beneficial to deviate from the zonal input profiles, at least within a zone. This would be the case for $SOC\_HEUR(1000, 0)$. Therefore, the evolution of differences in operational and load shedding costs for these two methods is compared and shown in Figure 3.

When considering the difference in operational costs (blue), one can observe that during the first third of the year (January-April), the costs for $SOC\_HEUR(1000, 0)$ are lower. In the next months, the costs fluctuate rather evenly, while towards the end of the year operational costs are a lot higher than those of the $SOC\_HEUR(1000, 1000)$ method. At the very end of the year also the difference in load shedding costs becomes very large. This can be explained with the enforced min target value, to reach (at least) the same SOC values at the end of the year as in the beginning. The freedom to deviate from the input profiles of $SOC\_HEUR(1000, 0)$ leads to lower costs at the beginning of the year, while this advantage is lost towards the end of the year, due to requirement to fulfill the annual water balance.

The best performing method obtained from the heuristic for the $\beta = 0.7$ benchmark ($SOC\_HEUR(1000, 10)$) is used for a redispatching case study. The results are analyzed in terms of generation by technology and system costs. Compared are the zonal model, the zonal model plus redispatching, broken down in positive and negative redispatching and the full nodal model.

Table 3: Results from the redispatching case study of one week for the zonal model, zonal + redispatching (zonal+RD), upward and downward redispatching with respect to the zonal model and the nodal model. Shown are the total system costs, which are broken down into operational and load shedding costs in bn EUR.

Model	Total costs	Operational costs	Load shedding costs
Nodal	1.783	1.575	0.208
Zonal	1.512	1.512	0
Zonal+RD	1.829	1.617	0.213

Table 4: Results from the redispatching case study of one week for the zonal model, zonal + redispatching (zonal+RD), upward and downward redispatching with respect to the zonal model and the nodal model. Shown is generation by technologies in GWh for gas, coal and lignite, oil, nuclear, wind (on- and off-shore), solar, other RES (biomass, geothermal and run-of-river), hydro storage (hydro dams and PHS) and load shedding.

Model	Gas	Coal & lignite	Oil	Nu-clear	Wind	Solar	Other RES	Hydro stor-age	Load shed-ding
Nodal	6682.6	20414.9	177.4	21460.1	11504.1	1774.2	3877.4	9556.9	20.8
Zonal	3835.6	22752.1	0.0	21911.8	11539.5	1774.3	4019.2	9635.8	0.0
Zonal+RD	6285.5	21198.1	416.9	21088.0	11337.7	1754.4	3846.8	9519.6	21.3
Upward RD	2449.9	16.6	416.9	0.0	0.0	0.0	0.0	25.7	21.3
Downward RD	0.0	-1570.6	0.0	-823.8	-201.8	-19.9	-172.4	-141.9	0.0

Simulations are performed for one week, in which high levels of congestion are detected. Considering the overall system costs (Table 3), the zonal model has the lowest costs. However, if the redispatching is included, the costs are 2.5% higher than the ones of the nodal model. This trend is also seen when only regarding the operational costs. The change in costs can be understood when examining the generation by technology (Table 4). One can observe that net positive redispatching occurs for gas and oil fired generators, and also load shedding is increasing in the redispatching model. These are the technologies with the highest marginal costs. Consequently, negative redispatching affects coal and lignite, nuclear, wind, solar, other RES and hydro storages. In comparison to the full nodal model, it is found that renewable resources are dispatched less in the redispatching model, which is not favorable, as they are the cleaner and cheaper alternative to conventional generation technologies.

4.1.4 Summary

The main outcomes and contributions of the work presented in this section are summed up in the following points:

- A heuristic to obtain state of charge profiles for large-scale nodal and zonal models of the European electricity market is proposed.
- The method helps to overcome the following issues related to modeling hydro storage SOC: data availability, myopic foresight of a sequenced model, maintaining seasonality pattern of SOC profiles, and respecting intertemporal constraints.
- From the results on system costs, system congestion, and load shedding, it is found that the introduced methodology renders better results than a model with myopic foresight, and the methodology also outperforms the shadow price and bid price approaches when penalty factor combinations are chosen beneficially.
- The method gives freedom to the optimization to adjust profiles on a short timescale, even for high penalty factors.
- In general, it seems reasonable to choose high penalty factors, which perform well under different scenarios of transmission capacity availability.
- A case study on redispatching is performed that demonstrates the applicability of the proposed heuristic framework.
- Results of the numerical experiments show that the nodal model renders lower overall system costs than the zonal model, which includes redispatching.
- More expensive generators are affected by upward redispatching, and predominantly renewable technologies are affected by downward redispatching. In comparison to the full nodal model, overall less renewable generators are dispatched.

Given that the need to develop the proposed method in the first place arose from a lack of data, in general, it would be ideal to pursue an open data policy that would allow for sound energy system modeling.

Improving the method in future work can be achieved by exploring dynamic penalty factors. Through this, more long-term deviations from the initial profiles of Stage 1 could be allowed in times of line overloadings, while in times of few congestions, following the zonal profiles more closely could be enforced. This would require predictions of congestions and would allow the methodology to behave in a more proactive way. Another indication for future research regards the application of the proposed methodology to perform comparative studies for nodal vs. zonal pricing through solving large-scale optimization problems.

5 Conclusions

This work has explored various modeling aspects relevant to assessing nodal pricing in large-scale European electricity market models. Concretely, technical aspects of optimization problem formulation as DC-OPF, AC-OPF, and unit commitment have been explored. Further, network capacity representation and intertemporal constraints of unit commitment and hydro storages have been assessed. As to the economic aspects, the role of demand elasticity in compensating costs of increased network resolution has been considered, as well as the welfare effects of myopic foresight in hydro storage modeling.

Further, a redispatching step was implemented as part of a zonal model that allows for a sound comparison between nodal and zonal pricing. This proved the applicability of the developed methodology to estimate hydro SOC profiles and showed the path to finalize the model. It should be further explored how to implement and conduct redispatching modeling by comparing different approaches in the literature. In the effort to combine the lessons learned from this Ph.D. thesis, a joint model that combines especially the elements of demand elasticity with sound hydro modeling and redispatching should be developed.

There are various modeling choices one has to make when designing electricity market models, and thus this work is by no means exhaustive in assessing all of them. Future work could focus on environmental aspects by including the costs of externalities or greenhouse gas emission reduction targets into the objective. This will surely become more relevant given the transformation of the power sector that lays ahead of us. In this context, the distribution of welfare is also an interesting topic to consider, as a switch from zonal to nodal pricing would entail distributional effects that need to be accounted for when assessing the benefits and drawbacks of a switch in pricing schemes.

Building up on the work already conducted, it will be interesting to explore nodal against zonal pricing in a pan-European context through exploring future scenarios of the evolution of the power system. While various country-specific studies have already been conducted, a broader perspective on the costs and benefits of nodal pricing is needed and should be explored in future applications of the developed model.

References

[1] Antonopoulos, G., Vitiello, S., et al.: 'Nodal pricing in the European internal electricity market', Tech. Rep. EUR 30155 EN, Publications Office of the European Union, Luxembourg, 2020, doi:10.2760/41018

[2] Bakirtzis, A., Biskas, P., et al.: 'DR Model for Adequacy Procedure: Final Report (D5)', Tech. rep., Aristotle University of Thessaloniki, Thessaloniki, 2018

[3] Bjørndal, E., Bjørndal, M., Cai, H.: 'Nodal pricing in a coupled electricity market', *11th International Conference on the European Energy Market (EEM14)*, Cracow, 2014, ISBN 9781479960958, doi:10.1109/EEM.2014.6861222

[4] Brown, T., Hörsch, J., Schlachtberger, D.: 'PyPSA: Python for power system analysis', *Journal of Open Research Software*, vol. 6, no. 1, 2018, ISSN 20499647, doi:10.5334/jors.188

[5] European Commission: 'Clean Energy For All Europeans COM/2016/0860 final', Tech. rep., Brussels, 2016

[6] European Commission: 'Impact Assessment of the Market Design Initiative SWD(2016) 410 final', Tech. rep., European Commission, Brussels, 2016

[7] European Union: 'Directive of 2009/72/EC: Common Rules for the Internal Market in Electricity', *Official Journal of the European Union*, vol. L211, no. August, pp. L 211/55 – L 211/93, 2009, ISSN 0036-8075, doi:10.1126/science.202.4366.409

[8] Felling, T., Felten, B., et al.: 'Flow-Based Market Coupling Revised - Part II: Assessing Improved Price Zones in Central Western Europe', *SSRN Electronic Journal*, , no. 07, 2019, doi:10.2139/ssrn.3404046

[9] Göransson, L., Goop, J., et al.: 'Linkages between demand-side management and congestion in the European electricity transmission system', *Energy*, vol. 69, pp. 860–872, 2014, ISSN 03605442, doi:10.1016/j.energy.2014.03.083

[10] Harvey, S.M., Hogan, W.W.: 'Nodal and Zonal Congestion Management and the Exercise of Market Power', Tech. rep., 2000

[11] Hogan, W.: 'Contract Networks for Electric Power Transmission', *Journal of Regulatory Economics*, vol. 4, no. 3, pp. 211–242, 1992

[12] Hogan, W.: 'Transmission Congestion: The Nodal-Zonal Debate Revisited', Tech. rep., Harvard University, Cambridge, 1999

[13] Holmberg, P., Lazarczyk, E.: 'Comparison of congestion management techniques: Nodal, zonal and discriminatory pricing.', *The Energy Journal*, vol. 36, no. 2, pp. 145–166, 2015, doi:10.5547/ 01956574.36.2.7.

[14] Hörsch, J., Hofmann, F., et al.: 'PyPSA-Eur: An open optimisation model of the European transmission system', *Energy Strategy Reviews*, vol. 22, no. September, pp. 207–215, 2018, ISSN 2211467X, doi:10.1016/j.esr.2018.08.012

[15] Jansen, L.L., Buzna, L.: 'Comparison of AC-OPF and DC-OPF in the Context of Nodal Pricing', *Proceedings of the 2020 Conference on Mathematics in Science and Technologies (MiST)*, University of Zilina, Rajecká Lesná, 2020

[16] Jansen, L.L., Buzna, L.: 'Evaluation of Modeling Differences of Nodal vs . Zonal Pricing Based Electricity Markets : Optimization Models and Network Representation', *18th International Conference on Emerging eLearning Technologies and Applications (ICETA) 2020*, IEEE, Kosice, 2021, doi:10.1109/ICETA51985.2020.9379255

[17] Jansen, L.L., Purvins, A., et al.: 'Modeling Methodology to Assess the Impact of Demand Elasticity on the Italian Electricity System in a European Context', *2020 17th International Conference on the European Energy Market (EEM)*, pp. 1–6, 2020, ISSN 2165-4093, doi:10.1109/EEM49802.2020.9221900

[18] Jansen, L.L., Thomaßen, G., et al.: 'An Efficient Framework to Estimate the State of Charge Profiles of Hydro Units for Large-Scale Zonal and Nodal Pricing Models', *Energies*, vol. 15, no. 12, pp. 1–23, 2022, doi:10.3390/en15124233

[19] Jansen, L.L., Thomaßen, G., et al.: 'Estimating hydro state of charge profiles for large-scale nodal and zonal pricing models using a heuristic approach', *International Conference on Electrical, Computer and Energy Technologies (ICECET 2022)*, July, pp. 1–7, 2022, doi:[Unpublished Manuscript]

[20] Kunz, F., Neuhoff, K., Rosellón, J.: 'FTR allocations to ease transition to nodal pricing: An application to the German power system', *Energy Economics*, vol. 60, pp. 176–185, 2016, ISSN 01409883, doi:10.1016/j.eneco.2016.09.018

[21] Leuthold, F.U., Weigt, H., von Hirschhausen, C.: 'A Large-Scale Spatial Optimization Model of the European Electricity Market', *Networks and Spatial Economics*, vol. 12, no. 1, pp. 75–107, 2012, ISSN 1566113X, doi:10.1007/s11067-010-9148-1

[22] Meibom, P., Barth, R., et al.: 'Stochastic optimization model to study the operational impacts of high wind penetrations in Ireland', *IEEE Transactions on Power Systems*, vol. 26, no. 3, pp. 1367–1379, 2011, ISSN 08858950, doi:10.1109/TPWRS.2010.2070848

[23] Mende, D., Böttger, D., et al.: 'About the Need of Combining Power Market and Power Grid Model Results for Future Energy System Scenarios', *Journal of Physics: Conference Series*, vol. 977, no. 1, 2018, ISSN 17426596, doi:10.1088/1742-6596/977/1/012009

[24] Newbery, D., Strbac, G., Viehoff, I.: 'The benefits of integrating European electricity markets', *Energy Policy*, vol. 94, pp. 253–263, 2016, ISSN 03014215, doi: 10.1016/j.enpol.2016.03.047

[25] Poplavskaya, K., Totschnig, G., et al.: 'Integration of day-ahead market and redispatch to increase cross-border exchanges in the European electricity market', *Applied Energy*, vol. 278, p. 115669, 2020, ISSN 03062619, doi:10.1016/j.apenergy.2020.115669

[26] Purvins, A., Sereno, L., et al.: 'Submarine power cable between Europe and North America: A techno-economic analysis', *Journal of Cleaner Production*, vol. 186, pp. 131–145, 2018, ISSN 09596526, doi:10.1016/j.jclepro.2018.03.095

[27] Schweppe, F.C., Caramanis, M.C., et al.: *Spot Pricing of Electricity*, Kluwer Academic Publisher, Boston, 4th ed., 1988, ISBN 9781461289500

[28] Taylor, J.A.: *Convex Optimization of Power Systems*, Cambridge University Press, Toronto, 2015, ISBN 978-1-107-07687-7

[29] Tuohy, A., Member, S., et al.: 'Unit Commitment for Systems With Significant Wind Penetration', vol. 24, no. 2, pp. 592–601, 2009

[30] Weibelzahl, M.: 'Nodal, zonal, or uniform electricity pricing: how to deal with network congestion', *Frontiers in Energy*, vol. 11, no. 2, pp. 210–232, 2017, ISSN 20951698, doi:10.1007/s11708-017-0460-z

[31] Zalzar, S., Bompard, E., et al.: 'The impacts of an integrated European adjustment market for electricity under high share of renewables', *Energy Policy*, vol. 136, no. May 2018, p. 111055, 2020, ISSN 03014215, doi:10.1016/j.enpol.2019.111055