OPTIMAL STORAGE AND TRANSMISSION INVESTMENTS IN A BILEVEL ELECTRICITY MARKET MODEL

MARTIN WEIBELZAHL* AND ALEXANDRA MÄRTZ**

Keywords: Bilevel Problem, Multistage Game, Congestion Management, Zonal Pricing, Storage Facilities, Long-Run Investments.

ABSTRACT. This paper analyzes the interplay of transmission and storage investments in a multistage game that we translate into a bilevel market model. In particular, on the first level we assume that a transmission system operator chooses an optimal line investment and a corresponding optimal network fee. On the second level we model competitive firms that trade energy on a zonal market with limited transmission capacities and decide on their optimal storage facility investments. To the best of our knowledge, we are the first to analyze interdependent transmission and storage facility investments in a zonal market environment that accounts for the described hierarchical decision structure. As a first best benchmark, we also present an integrated, single-level problem that may be interpreted as a long-run nodal pricing model. Our numerical results show that adequate storage facility investments of firms may in general have the potential to reduce the amount of line investments of the transmission system operator. However, our bilevel zonal pricing model may yield inefficient investments in storages, which may be accompanied by suboptimal network facility extensions as compared to the nodal pricing benchmark. In this context, the chosen zonal configuration of the network as well as the planning objective of the transmission system operator will highly influence the equilibrium investment outcomes including the size and location of the newly invested facilities. As zonal pricing is used for instance in Australia or Europe, our models may be seen as valuable tools for evaluating different regulatory policy options in the context of long-run investments in storage and network facilities.

1. INTRODUCTION

Modern electricity markets are typically characterized by a spatial or regional divergence of energy supply and demand. One example is the German electricity market with substantial wind production in the north and a high South-German consumption; see Bucksteeg et al. (2015). Given transmission capacity shortages, as a direct result of the regional divergence of demand and supply corresponding network congestion arises in many situations, where power flows between nodes are restricted by binding technical constraints; see also Dijk and Willems (2011) or Neuhoff et al. (2013). In this context, long-run transmission investments and the implementation of different short-run congestion management regimes are frequently discussed as possible solutions to network congestion; see for instance Jenabi et al. (2013), Grimm et al. (2016a), or Grimm et al. (2016b). Besides the described regional divergence of supply and demand, intermittent renewable energy supply yields additionally a temporal divergence of the produced and consumed energy. Obviously, both the regional and temporal dimension are highly interdependent, as for instance an extended inter-regional network may simultaneously contribute to a better adjustment of the inter-temporal divergence of demand and intermittent supply; see also Steinke et al. (2013). On the other side, storage facilities that typically smoothen inter-temporal demand spikes may also have the potential to lower the necessity for large network investments. To the best of our knowledge, we are the first to analyze such interdependencies of storage and network investments under different congestion management regimes in a multistage game that we translate into a bilevel market model. As we will demonstrate, in such a framework the chosen congestion management mechanism will highly influence long-run investments in both transmission lines and storage facilities.

In particular, this paper assumes a transmission system operator (TSO) that decides on optimal line investments as well as on a corresponding network fee on the first level. The TSO anticipates market outcomes of the second level, where competitive firms trade energy and invest in storage facilities given the realized network extensions of the TSO. Thus, energy trading on the second level directly accounts for possibly scare network capacities that may result in a regionally differentiated price structure. Within our model, we also study the effects of different zonal designs as well as the effects of different planning

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objectives of the TSO including welfare and profit maximization. In this context we will evaluate both absolute investment levels as well as the locations of the corresponding facility investments. Given that zonal pricing is applied in different European countries as well as in Australia (see for instance Bjørndal et al. (2003), Glachant and Pignon (2005), and Dijk and Willems (2011)), our analyses may directly contribute to the current policy discussion on the design of efficient market structures that account for adequate long-run investment incentives in both storage facilities and network lines. In addition, in times of growing importance of storage facilities the proposed models may also be seen as tools for a meaningful evaluation of the need for huge network extension plans that typically involve billions of euros like in Germany; for more details see German-Transmission-System-Operators (2017).

As our numerical results show, both under nodal and zonal pricing storage investments may in general have the potential to reduce network extensions as compared to the no-storage case. However, our bilevel, zonal-pricing-market model may yield inefficient storage facility investments that may be accompanied by suboptimal line investments as compared to a nodal pricing model. Moreover, invested storage facilities may affect inter-regional price and demand structures in a way that requires a complete reconfiguration of optimal zonal boundaries, i.e., in the case of storage facilities the welfare-maximizing zone configuration may change as compared to the no-storage case. Finally, if planning objectives of the TSO are not aligned with a maximization of welfare, the described investment inefficiencies may further be aggravated.

Our work directly contributes to various strands of the energy market literature. In particular, we elaborate on different congestion management regimes. In the context of congestion management, nodal prices are know to yield a first best outcome, as they simultaneously reflect all relevant economic and technical restrictions between the different nodes of the network; see Bohn et al. (1984), Hogan (1992), or Chao and Peck (1996). In contrast, zonal pricing assumes identical prices within given zonal boundaries, which directly yield a simplified price structure; see Bjørndal et al. (2014). Even though, zonal pricing may in general be accompained by a welfare loss as compared to a system of nodal prices, it is sometimes seen as being more attractive from an administratively and politically point of view. For this reason, various studies have focused on properties of zonal pricing systems that ensure a comparatively small welfare loss. Such properties relate for instance to the number of price zones and their respective boundaries; see Bjørndal and Jørnsten (2001), Ehrenmann and Smeers (2005), or Oggioni and Smeers (2013). In addition, we also contribute to the increasing literature on transmission investments. Traditionally, reference investment solutions were derived for integrated, single-level optimization problems as in Gallego et al. (1998), Hirst and Kirby (2001), or Alguacil et al. (2003). However, in recent years transmission investments were also analyzed in multistage games and corresponding multilevel optimization problems; see for instance Sauma and Oren (2006), Fan et al. (2009), Garcés et al. (2009), Baringo and Conejo (2012), or Jenabi et al. (2013). As pointed out by Grimm et al. (2016b), in such games the market environment and the chosen congestion management regime will highly influence optimal transmission expansions of the TSO. In particular, hierarchical market models may yield suboptimal line investments as compared to an integrated network expansion plan. Finally, we link the two above stands of congestion management and transmission investment literature to existing studies on price and welfare effects of storage facilities. Most of the latter studies including Sioshansi et al. (2009), Sioshansi (2010), Gast et al. (2013), and Sioshansi (2014) mainly abstract from transmission constraints and the network management regime. Only recently, Weibelzahl and Märtz (2017) study storage facilities and their effects in a zonal electricity market. However, the authors only consider the short-run perspective, where both the transmission network and storage facilities are given. It is the aim of the present paper to analyze the interplay of transmission and storage facility investments in a multilevel market environment from a long-run perspective.

This paper is organized as follows. Our model framework is introduced in Section 2. Then, Section 3 and Section 4 present the nodal pricing reference model and the bilevel zonal pricing model with storage, respectively. The main solution strategy for our multistage game and for the corresponding bilevel optimization model is then discussed in Section 5. Numerical results of our long-run investment analysis regarding storage facility investments and network extensions are presented in Section 6. Finally, Section 7 concludes and highlights main policy implications.

2. Notation and Economic Quantities

This section introduces the main model framework that is used in our paper. All sets, parameters, and variables are summarized in Tables 5, 6, and 7 in the appendix.

2.1. **Electricity Network and Time Horizon.**

In order to keep our analysis simple, we only consider an off-peak period t_1 and an on-peak period t_2, i.e, we assume that the time period set is given by $T = \{t_1, t_2\}$;

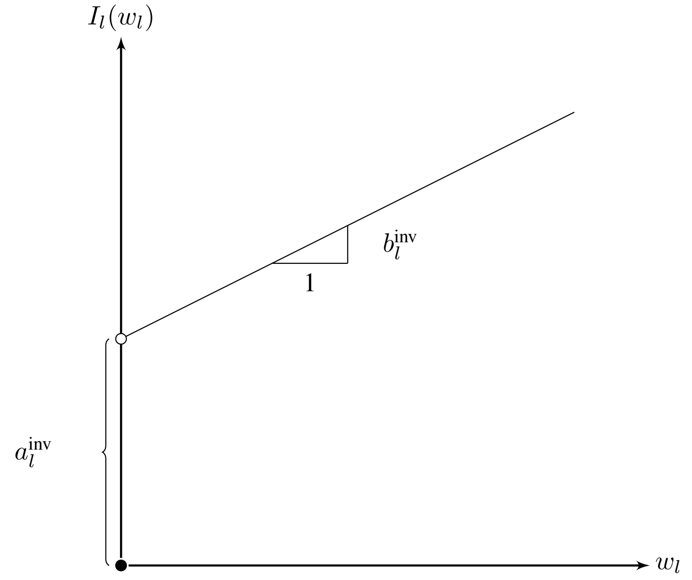


Figure 1: Stepwise Line Investment Cost Function $I_l(w_l)$

for similar two-period energy market models with storage see, e.g., Sioshansi (2010) or Sioshansi (2014).[1] In addition, we are given a connected and directed graph $G = (N, L)$, which is defined on a set of network nodes N and a set of transmission lines L. Each transmission line $l \in L$ is characterized by different technical properties such as the maximal transmission capacity $\bar{f}_l$ or the susceptance B_l. Corresponding lossless DC power flows on a line $l \in L$ will be denoted by $f_{l,t}$ for a given time period $t \in T$. In addition, we consider the case where specific transmission lines may be extended or strengthened by the TSO. Therefore, we assume a set of lines L^{inv} that may be extended by newly invested transmission capacity. In order to account for possibly high fixed line investment cost of a_l^{inv}, we assume a stepwise linear investment cost function

$$I_l(w_l) = \begin{cases} 0 & \text{if } w_l = 0. \\ a_l^{\text{inv}} + b_l^{\text{inv}} w_l & \text{if } w_l > 0. \end{cases} \tag{1}$$

which is depicted in Figure 1. In Equation 1, $w_l \in \mathbb{R}^+$ describes the line extension variable with b^{inv} giving the per unit construction cost of line $l \in L^{\text{inv}}$; such an investment cost function is used, e.g., in Arellano and Serra (2007).

Additionally, in this paper we assume that the node set N is partitioned into k connected price zones. We consider the case where a fixed zonal configuration $Z = \{Z_1, \ldots, Z_k\}$ is ex-ante specified:

$$\emptyset \notin Z, \tag{2}$$

$$\bigcup_{i \in \{1,\ldots,k\}} Z_i = N, \tag{3}$$

$$Z_i \in Z,\ Z_j \in Z \text{ with } i \neq j \Rightarrow Z_i \cap Z_j = \emptyset. \tag{4}$$

Note that in its two limit cases, the above definition comprises both a single zone as well as a nodal pricing configuration, i.e., $k = 1$ and $k = |N|$.

2.2. **Electricity Demand.** We further assume a set of demand nodes $D \subset N$ where consumers are located at. For each demand node $d \in D$ and time period $t \in T$ we are given a continuous and strictly decreasing demand function $p_{d,t} \in \mathbb{R}^+$, i.e., we assume fluctuating demand that is node- and time-dependent. Denoting by $x_{d,t}$ the consumption quantity of d in period t, the assumption of t_1 being the off-peak period directly implies $p_{d,t_1}(x) \leq p_{d,t_2}(x)$ for all demand nodes d and consumption quantities $x \geq 0$; see also Sioshansi (2014). Finally, we refer to

$$\sum_{t \in T} \sum_{d \in D} \int_0^{x_{d,t}} p_{d,t}(u) \, \mathrm{d}u$$

[1] As we do not expect additional insights into the topic of this paper from a multiperiod model with $|T| > 2$, for the sake of simplicity and improved clarity we decided to present the two-period energy market framework. However, the model can directly be extended to the more general case.

as the gross consumer surplus that is aggregated over all demand nodes and time periods. This gross consumer surplus measures the sum of all monetary consumer benefits.

2.3. **Electricity Generation.** Throughout this paper, we will denote by G the set of all ex-ante given generation facilities. $G_n \subset G$ describes the generators, which are located at a node n. In addition, we denote production of a generator g in a time period t by $y_{g,t}$. Production is further described by a continuous and strictly increasing marginal cost function $V_{g,t} \in \mathbb{R}^+$ that gives the respective variable production costs of a generator; see also Chao and Peck (1998), Bjørndal and Jørnsten (2001), Ehrenmann and Smeers (2005), or Oggioni and Smeers (2013).

We will assume that all firms act in a perfectly competitive environment as price takes. Such an assumption has been established as a standard in order to keep complex electricity market models computationally tractable, see, e.g., Boucher and Smeers (2001), Daxhelet and Smeers (2007), Grimm et al. (2016b), or Weibelzahl (2017). We further note that such models may also serve as a benchmark for evaluating deviations from perfect competition, i.e., market power.

2.4. **Storage Facilities.** Finally, we assume a set of storage facilities S that may be invested in. The non-storage scenario is captured by the limit case $S = \emptyset$. As above, by $S_n \subset S$ we denote the subset of storage facilities that are located at node n. Storage facilities are described by their (roundtrip) storage efficiency $\rho_s \in [0, 1]$; see for instance Sioshansi et al. (2014). Storage investment costs are given by a continuous and strictly increasing function $I_s(\bar{z}_s) \in \mathbb{R}^+$, with $\bar{z}_s$ denoting the invested storage capacity. An example is an affine investment function with a positive slope.[2] Further note that our framework allows to explicitly analyze both the size and location of storage facility investment within the electricity network G. For each storage facility we additionally introduce the variables $z^+_{s,1}$ and $z^-_{s,2}$ that describe the amount of electricity that is stored in or stored out in period 1 and 2, respectively. The latter two variables are obviously limited by the invested storage capacity $\bar{z}_s$.

2.5. **Network Fees.** In order to recover network investment cost, the TSO charges a network fee. In particular, we consider the case of a production-based fee that is paid for each unit of produced electricity. The corresponding fee is denoted by φ^{TSO}. Income I^{TSO} of the TSO is given by

$$I^{\text{TSO}} = \sum_{t \in T} \sum_{n \in N} \sum_{g \in G_n} \varphi^{\text{TSO}} y_{g,t}. \tag{5}$$

Analogously, expenses of the TSO in form of line investments can be written as

$$E^{\text{TSO}} = \sum_{l \in L^{\text{inv}}} I_l(w_l), \tag{6}$$

with the difference $P^{\text{TSO}} = I^{\text{TSO}} - E^{\text{TSO}}$ describing profits of the TSO.

3. Integrated Planning with Storage Facilities as an Overall Investment Optimum

As a first best benchmark, we present an integrated planning model, which may alternatively be interpreted as a nodal pricing model similar to Jenabi et al. (2013), Grimm et al. (2016a), Grimm et al. (2016b), or Weibelzahl and Märtz (2017). We add storage facility investments to these standard models in order to derive welfare-maximizing line and storage capacities that account for all relevant technical and economic restrictions in a single-level optimization problem. Therefore, this reference investment solution can be used to assess and evaluate inefficiencies of our zonal market model in Section 4, where investments are made in a complex hierarchical environment based on the expectations of the optimal decision response of market players.

In line with Section 2, we assume fully competitive firms that have no market power. This assumption directly implies that nodal pricing may be modeled as a welfare maximization problem:

$$W^{\text{i}} := \sum_{t \in T} \left(\sum_{d \in D} \int_0^{x_{d,t}} p_{d,t}(u) \, \mathrm{d}u - \sum_{n \in N} \sum_{g \in G_n} \int_0^{y_{g,t}} V_{g,t}(u) \, \mathrm{d}u \right) - \sum_{s \in S} \int_0^{\bar{z}_s} I_s(u) \, \mathrm{d}u - \sum_{l \in L^{\text{inv}}} I_l(w_l). \tag{7}$$

For each storage facility $s \in S$, the storage level in period 1 is described by the amount of stored in electricity less than the storage loss $(1 - \rho_s) z^+_{s,1}$. Assuming an adequate planning in terms of an optimal end of horizon inventory, we additionally require each storage facility to be empty in period 2, i.e.,

$$\rho_s z^+_{s,1} - z^-_{s,2} = 0 \qquad \forall\, s \in S. \tag{8}$$

[2] Observe that for an infinitely small slope such an affine investment cost function will converge to a constant investment cost function.

Denoting by $\delta_n^{\text{in}}(L)$ and $\delta_n^{\text{out}}(L)$ the set of in- and outgoing lines of node $n \in N$, Kirchhoff's First Law ensures power balance at every node and in each of the two time periods, i.e., demand, generation, charging and discharging activities as well as power flows in and out of a given node are balanced:

$$x_{n,1} = \sum_{g \in G_n} y_{g,1} + \sum_{l \in \delta_n^{\text{in}}(L)} f_{l,1} - \sum_{l \in \delta_n^{\text{out}}(L)} f_{l,1} - \sum_{s \in S_n} z_{s,1}^{+} \quad \forall\, n \in N. \tag{9}$$

$$x_{n,2} = \sum_{g \in G_n} y_{g,2} + \sum_{l \in \delta_n^{\text{in}}(L)} f_{l,2} - \sum_{l \in \delta_n^{\text{out}}(L)} f_{l,2} + \sum_{s \in S_n} z_{s,2}^{-} \quad \forall\, n \in N. \tag{10}$$

For all lines, the following set of constraints ensures that no transmission capacities are exceeded:

$$-\overline{f}_l \leq \quad f_{l,t} \leq \quad \overline{f}_l \qquad\qquad \forall\, l \in L \setminus L^{\text{inv}},\ t \in T. \tag{11}$$

$$-(\overline{f}_l + w_l) \leq \quad f_{l,t} \leq \quad (\overline{f}_l + w_l) \qquad \forall\, l \in L^{\text{inv}},\ t \in T. \tag{12}$$

Power flows $f_{l,t}$ on each line $l = (n, m)$ are further characterized by Kirchhoff's Second Law, which links line flows to the corresponding phase angles $\Theta_{n,t}$, and $\Theta_{m,t}$:

$$f_{l,t} = B_l\left(\Theta_{n,t} - \Theta_{m,t}\right) \qquad \forall\, l = (n, m) \in L,\ t \in T. \tag{13}$$

We additionally set the phase angle of the reference node 1 to zero, which will ensure unique phase angle values (see also Section 5):

$$\Theta_{1,t} = 0 \quad \forall\, t \in T. \tag{14}$$

Moreover, we assume that storage investment is nonnegative

$$\bar{z}_s \geq 0 \qquad \forall\, s \in S, \tag{15}$$

and that all charging and discharging variables will not violate their lower nonnegativity bounds as well as their upper storage capacity investment bounds, respectively:

$$0 \leq z_{s,1}^{+} \leq \bar{z}_s, \quad 0 \leq z_{s,2}^{-} \leq \bar{z}_s \qquad \forall\, s \in S. \tag{16}$$

In analogy, demand and generation are restricted by the following nonnegativity constraints:

$$0 \leq \quad x_{n,t} \quad \forall\, n \in N,\ t \in T. \tag{17}$$

$$0 \leq \quad y_{g,t} \quad \forall\, n \in N,\ g \in G_n,\ t \in T. \tag{18}$$

Finally, we use some simple variable bounds on the line investment quantities:

$$w_l \in \mathbb{R}^{+} \qquad \forall\, l \in L^{\text{inv}}. \tag{19}$$

Thus, the complete nodal-pricing problem can be stated as:

$$
\begin{aligned}
\max \quad & \text{Welfare}:\ (7), && \text{(20a)}\\
\text{s.t.} \quad & \text{Storage Level Constraints: } (8), && \text{(20b)}\\
& \text{Kirchoff's First Law: } (9), (10), && \text{(20c)}\\
& \text{Flow Restrictions: } (11), (12), && \text{(20d)}\\
& \text{Kirchhoff's Second Law: } (13), && \text{(20e)}\\
& \text{Reference Phase Angle: } (14), && \text{(20f)}\\
& \text{Variable Restrictions: } (15), (16), (17), (18), (19). && \text{(20g)}
\end{aligned}
$$

Let us conclude this section with an observation: The well-known concept of congestion cost measure the welfare loss of a network-constrained model (20) as compared to a non-network model, where transmission constraints and power flows do not play a relevant role. Obviously, we could relax all power flow restrictions in Problem (20) to derive the optimal welfare under such a non-network model. Given the optimal welfare level of such a non-network model, our network-based (nodal pricing) model (20) with its welfare maximization objective (7) can be equivalently rewritten as the minimization of the derived optimal objective function value of the model without network restrictions and the corresponding network-restricted objective. The difference of these two quantities measures congestion costs.

Observation 1. *The nodal pricing model* (20) *does not only maximize welfare, but also minimizes congestion cost.*

4. BILEVEL ZONAL PRICING MODEL WITH STORAGE

4.1. **Structure of the Hierarchical Game and the Corresponding Bilevel Optimization Problem.** Even though, an integrated, nodal pricing system ensures welfare maximizing investments, such a first best mechanism is not a realistic policy option for different countries and regions including for instance Europe; see Oggioni and Smeers (2013) or Bucksteeg et al. (2015). In contrast, in liberalized electricity markets decisions of independent market players are typically made in a highly complex market environment, which often uses a system of zonal prices. In such an interdependent market structure, the extent of optimal line investment of the TSO highly depends on optimal storage facility investments and vice versa. While transmission line extensions base on the respective regulatory structures, investments in storage facilities are driven by future profits of firms and corresponding structures of the (zonal) market. As we will see in our numerical results that are presented in Section 6, such a complex market environment will yield a quite different equilibrium investment solution as compared to our integrated benchmark model.

In this section we assume that the TSO decides on an optimal transmission expansion and on a corresponding network fee before firms invest in their storage facilities. In this hierarchical game the TSO is the leader that is the first to make an optimal investment decision with competitive firms reacting as followers in an optimal way to the leader's investment choice; see also the vast literature including Gil et al. (2002), Sauma and Oren (2006), Fan et al. (2009), Garcés et al. (2009), Baringo and Conejo (2012), Jenabi et al. (2013), and Grimm et al. (2016b) that also consider multistage games with the TSO acting as the leader. Our game directly relates to the classical problem of Von Stackelberg (2010), where a leader and different followers interact in an anticipative environment. Note that in our setting the sequential investment decisions of the TSO and of the firms are followed by trading on two zonal spot markets, which determine the profitability and efficiency of the respective investment decisions; see also Figure 2. As in Sauma and Oren (2006), we assume that at each stage all (investment) decisions of the previous stage(es) can be observed by the rational players, which allows a correct expectation formation. Therefore, our game can be translated into a bilevel programming problem with a network-extending TSO on the first level that anticipates storage investments and competitive market outcomes on the second level. Observe that storage investment and spot market trading may be analyzed jointly on the second level, as we assume a competitive market, where storage investments directly determine the stored amounts of energy in the two trading periods; for details see Section 5.1. The two problem levels will be described in more detail in the following two sections.

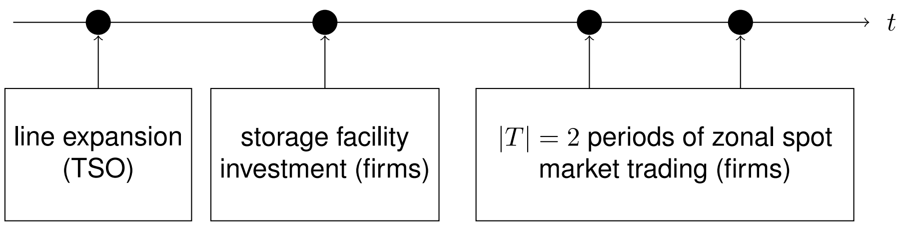


Figure 2: Timing of the Underlying Multistage Game

4.2. **First Level Problem: Network Extension.** On the first level, we assume that the TSO chooses a line expansion plan, i.e., the TSO decides, which line to extend by which amount. Such a long-term network development of the grid is a very challanging task, as in principle the TSO should eliminate all the transmission capacity shortages that are welfare diminishing; see also Hornnes et al. (2000), David and Wen (2001), or Rious et al. (2008). Despite this theoretical aim, in practice the TSO must both have an incentive and the responsibility to implement such a welfare maximizing extension plan. As a main drawback, the concept of welfare may not directly be measured and observed by the TSO, which will make it difficult for the TSO to decide on an efficient network expansion plan. As pointed out by Hirst and Kirby (2001), for this reason there may be quite different objectives that the TSO can pursue. A summary of objectives that are discussed in the literature can be found in Table 1. However, as some of the objectives presented in Table 1 will either be difficult to quantify or will be outside the scope of our model framework, in this paper we focus on the three extreme cases where the TSO maximizes (i) social welfare W, (ii) its own profits P^{TSO}, or (iii) tries to eliminate as much transmission obstacles O as possible, i.e., aims at a maximization of line extensions in order to reduce transmission limitations in the network. The corresponding objectives can be stated as:

TABLE 1. Different Transmission Expansion Objectives of the TSO

Objective	Reference
Welfare maximization	Sauma and Oren (2006), Torre et al. (2008), Garcés et al. (2009);
Network reliability	Hirst and Kirby (2001), Jenabi et al. (2013);
Elimination of transmission obstacles/ Robust network	Buygi et al. (2004);
Maximization of competition	Motamedi et al. (2010), Zhao et al. (2011);
Profit maximization of the TSO	Jenabi et al. (2013), Fan et al. (2009);
Investment cost minimization	Oliveira et al. (1995), Gallego et al. (1998), Gil et al. (2002);
Cheap electricity prices	Hirst and Kirby (2001), Zhao et al. (2011);
Facilitation of trade/ Maximization of consumption	Motamedi et al. (2010);

$$W^{\mathrm{f}} := \sum_{t\in T}\left(\sum_{d\in D}\int_0^{x_{d,t}} p_{d,t}(u)\,\mathrm{d}u - \sum_{n\in N}\sum_{g\in G_n}\int_0^{y_{g,t}} V_{g,t}(u)\,\mathrm{d}u\right) \tag{21}$$
$$- \sum_{s\in S}\int_0^{\bar{z}_s} I_s(u)\,\mathrm{d}u - \sum_{l\in L^{\mathrm{inv}}} I_l(w_l).$$
$$P^{\mathrm{TSO}} := \sum_{t\in T}\sum_{n\in N}\sum_{g\in G_n}\varphi^{\mathrm{TSO}} y_{g,t} - \sum_{l\in L^{\mathrm{inv}}} I_l(w_l). \tag{22}$$
$$O := \sum_{l\in L^{\mathrm{inv}}} w_l. \tag{23}$$

In all three model variants, we will assume that the TSO uses a production-based network fee in order to recover its network investment costs. The following budget constraint ensures that investment costs of the TSO are covered by its income in form of network fees:

$$\sum_{t\in T}\sum_{n\in N}\sum_{g\in G_n}\varphi^{\mathrm{TSO}} y_{g,t} \geq \sum_{l\in L^{\mathrm{inv}}} I_l(w_l). \tag{24}$$

Finally, we use some simply variable bounds on the line investment quantities:

$$w_l \in \mathbb{R}^+ \qquad \forall\, l \in L^{\mathrm{inv}}. \tag{25}$$

Altogether, the first-level problem can be written as:

$$\max \quad \text{Objective: (21), (22), or (23)} \tag{26a}$$
$$\text{s.t.} \quad \text{Budget Constraint: (24),} \tag{26b}$$
$$\text{Investment Variable Restrictions: (25).} \tag{26c}$$

4.3. **Second Level Problem: Storage Investment and Energy Trading.** On the second level firms invest in new storage technologies and trade energy on a competitive market. Note that the decision behaviour of the firms on the second level is part of the constraint set of the TSO on the first level.

As in Jenabi et al. (2013), the assumption of full competition allows to model profit maximization behaviour of firms as a welfare maximization problem, where costs in form of the transmission fee φ^{TSO} are directly taken into account:

$$W^{\mathrm{s}} := \sum_{t\in T}\left(\sum_{d\in D}\int_0^{x_{d,t}} p_{d,t}(u)\,\mathrm{d}u - \sum_{n\in N}\sum_{g\in G_n}\left(\varphi^{\mathrm{TSO}} y_{g,t} + \int_0^{y_{g,t}} V_{g,t}(u)\,\mathrm{d}u\right)\right) - \sum_{s\in S}\int_0^{\bar{z}_s} I_s(u)\,\mathrm{d}u. \tag{27}$$

As in Section 2, we consider a given zonal configuration Z, which satisfies the connectivity conditions (2) to (4). We will use the zonal pricing formulation introduced by Bjørndal and Jørnsten (2001), which requires that consumer and producer prices at network nodes that belong to a given zone $Z_i \in Z$ must be equal for every time period $t \in T$[3]:

$$p_{n,t} = p_{m,t}, \quad \forall\, i \in \{1,\dots,|Z|\}, \{(n,m) : n,m \in Z_i \cap D,\ n < m\}, \tag{28}$$
$$V_{g,t} + \varphi^{\mathrm{TSO}} = p_{m,t}, \quad \forall\, i \in \{1,\dots,|Z|\},$$
$$\left\{(n,m) : n \in Z_i \cap D^{\mathrm{C}},\ m \in Z_i \cap D,\ n < m\right\},\ g \in G_n, \tag{29}$$

[3]For applications of this zonal pricing formulation see Bjørndal et al. (2003), Ehrenmann and Smeers (2005), Bjørndal and Jørnsten (2007), Weibelzahl (2017), or Weibelzahl and Märtz (2017).

$$p_{n,t} = V_{g,t} + \varphi^{\text{TSO}}, \quad \forall\, i \in \{1, \ldots, |Z|\}, \quad \left\{(n,m) : n \in Z_i \cap D,\ m \in Z_i \cap D^{\text{C}},\ n \le m\right\},\ g \in G_m, \tag{30}$$

$$V_{g,t} + \varphi^{\text{TSO}} = V_{\tilde{g},t} + \varphi^{\text{TSO}}, \quad \forall\, i \in \{1, \ldots, |Z|\}, \quad \left\{(n,m) : n, m \in Z_i \cap D^{\text{C}},\ n \le m\right\},\ g \in G_n,\ \tilde{g} \in G_m, \tag{31}$$

where we explicitly distinguish between demand and production nodes and account for the transmission fee of the TSO.

As all equilibrium quantities must be both technically and economically feasible, on the second level all power flow, production, storage, and market clearing constraints discussed in Section 3 are taken into account. Therefore, the second level problem can be written as:

$$\begin{aligned}
\max \quad & \text{Welfare}: (27), && (32a)\\
\text{s.t.} \quad & \text{Zonal Pricing: } (28), (29), (30), (31), && (32b)\\
& \text{Storage Level Constraints: } (8), && (32c)\\
& \text{Kirchoff's First Law: } (9), (10), && (32d)\\
& \text{Flow Restrictions: } (11), (12), && (32e)\\
& \text{Kirchhoff's Second Law: } (13), && (32f)\\
& \text{Reference Phase Angle: } (14), && (32g)\\
& \text{Variable Restrictions: } (15), (16), (17), (18). && (32h)
\end{aligned}$$

Let us conclude this section with the following observation, which states that welfare under the integrated planning model (20) yields an upper bound for the bilevel model (26) and (32):

Observation 2. *For all variants of the bilevel model* (26) *and* (32)*, its optimal welfare level can not exceed welfare of the integrated planning model in* (20)*, i.e., welfare of the integrated model is at least as high as welfare of the bilevel model.*

5. Solution Strategy and Problem Reformulation

Our market model introduced in the previous section can be seen as a special instance of a general bilevel model. Being non-convex and non-differentiable, bilevel models are known to be NP hard, which implies that this class of optimization problem is in gereral very challenging and hard to solve; see for instance Jeroslow (1985). In this section we present a single-level problem reformulation and discuss our main solution strategy.

5.1. **Uniqueness of the Second Level Problem and KKT Reformulation.**

Given that the second level is a convex and continous optimization problem with only linear constraints, we can use a Karush-Kuhn-Tucker (KKT) reformulation in order to replace the bilevel problem by a single-level problem; see for instance Dempe (2002), Boyd and Vandenberghe (2004), or Colson et al. (2007). From a mathematical point of view, such a reformulation strategy yields a mathematical program under equilibrium constraints (MPEC); see Huppmann and Egerer (2015). However, a KKT reformulation is only valid, as the second-level problem has a unique optimal solution. In particular, in the case of nonuniqueness of lower-level optimal solutions, the TSO cannot anticipate the optimal storage investment choice of firms. On the other hand, the TSO can also not force the implementation of specific investments out of the set of multiple optimal storage facility extension plans. Ultimately, it will be impossible for the TSO to assess the value of an optimal transmission expansion on the first level; for details and further discussions see, e.g., Dempe (2003) or Zugno et al. (2013). From a policy persepctive, such ambiguities will also make it hard to compare different policy regulations and market designs, as it is unclear which equilibrium investments will be realized; see also Hu and Ralph (2007).

Being a prerequisite for meaningful bilevel policy analyses, we first prove uniqueness of the optimal solution of the second-level problem, before we present our KKT reformulation.

Theorem 1. *The second level problem* (32) *has a unique optimal solution.*

Proof. By assumption, all demand functions $p_{d,t}$ are continuous and strictly decreasing. In addition, both the variable cost functions $V_{g,t}$ and the storage investment functions I_s are continuous and strictly increasing. As a direct consequence, the second-stage objective is strictly concave in all demand, production, and storage investment variables, with

$$\frac{\partial^2 W^{\mathrm{s}}}{\partial x_{d,t}^2} = p'_{d,t} \quad \forall\, d \in D,\ t \in T, \qquad \frac{\partial^2 W^{\mathrm{s}}}{\partial y_{g,t}^2} = -V'_{g,t} \quad \forall\, n \in N,\ g \in G_n, t \in T,$$

$$\frac{\partial^2 W^{\mathrm{s}}}{\partial \bar{z}_s^2} = -I'_s \quad \forall\, n \in N,\ s \in S_n.$$

This strict concavity directly implies uniqueness of these variables; see Mangasarian (1988).

We next show that for each storage facility s, the amount of stored-in electricity $z_{s,1}^+$ in period 1 equals the uniquely determined storage capacity $\bar{z}_s$. To see this, assume the contrary, i.e., consider the case $z_{s,1}^+ < \bar{z}_s$. Obviously, $\bar{z}_s^* := z_{s,1}^+$ is also a feasible solution. However, as $\bar{z}_s^*$ yields a welfare increase as compared to $\bar{z}_s$, with $\triangle\ W = W(\cdot, \bar{z}_s^*) - W(\cdot, \bar{z}_s) = \int_{\bar{z}_s^*}^{\bar{z}_s} I_s(u) \mathrm{d}u > 0$, the original investment level $\bar{z}_s$ cannot be optimal. Obviously, this yields a contradiction. In addition, for each storage facility $s \in S$, the amount of stored out electricity is uniquely determined by Constraint (8), which readily implies $z_{s,2}^- = z_{s,1}^+$.

To show uniqueness of power flows, we finally consider Kirchhoff's First Laws (9) and (10). For all nodes $n \in N$ we set

$$F_{n,1} \quad := x_{n,1} - \textstyle\sum_{g \in G_n} y_{g,1} + \sum_{s \in S_n} z_{s,1}^+, \tag{33}$$

$$F_{n,2} \quad := x_{n,2} - \textstyle\sum_{g \in G_n} y_{g,2} - \sum_{s \in S_n} z_{s,2}^-, \tag{34}$$

and rewrite Constraints (9) and (10) for both periods $t \in \{t_1, t_2\}$ as:

$$F_{n,t} = \sum_{l \in \delta_n^{\mathrm{in}}(L)} B_l \left(\Theta_{n,t} - \Theta_{m,t}\right) - \sum_{l \in \delta_n^{\mathrm{out}}(L)} B_l \left(\Theta_{n,t} - \Theta_{m,t}\right). \tag{35}$$

Using (35), we see that for the unique optimal demand, production, and storage variable values captured by $F_{n,t}$, all phase angles are determined by a system of linear equations, which can equivalently be stated as the following matrix representation

$$F_t = B\Theta_t, \qquad \forall\, t \in T, \tag{36}$$

where Θ_t denotes the vector of phase angles in period t, F_t is the vector of optimal nodal net injections in period t, and B is the corresponding matrix of (aggregated) susceptances. As $\sum_{n \in N} F_{n,t} = 0$ holds for all time periods t, it directly follows that B is singular. However, in Constraint (14) we have set the phase angle value of the (arbitrarily chosen) reference node to zero, which yields non-singularity. Ultimately, optimal phase angles will be uniquely determined. By using the relation between phase angles and power flows given by Constraint (13), in each period and on each line optimal power flows will also be unique. $\square$

Given the above result, we equivalently describe the second-level problem by its KKT formulation, which comprises primal and dual feasibility as well as complementary slackness. We first state the corresponding primal-dual pairs of complementarity, where the symbol $\perp$ denotes orthogonality:

$$0 \le f_{l,t} + \overline{f}_l \perp \quad \delta_{l,t}^{\mathrm{low}} \ge 0 \quad \forall\, l \in L \setminus L^{\mathrm{inv}},\ t \in T, \tag{37}$$

$$0 \le -f_{l,t} + \overline{f}_l \perp \quad \delta_{l,t}^{\mathrm{up}} \ge 0 \quad \forall\, l \in L \setminus L^{\mathrm{inv}},\ t \in T, \tag{38}$$

$$0 \le f_{l,t} + (\overline{f}_l + w_l) \perp \quad \epsilon_{l,t}^{\mathrm{low}} \ge 0 \quad \forall\, l \in L^{\mathrm{inv}},\ t \in T, \tag{39}$$

$$0 \le -f_{l,t} + (\overline{f}_l + w_l) \perp \quad \epsilon_{l,t}^{\mathrm{up}} \ge 0 \quad \forall\, l \in L^{\mathrm{inv}},\ t \in T, \tag{40}$$

$$0 \le x_{d,t} \perp \quad \upsilon_{d,t} \ge 0 \quad \forall\, d \in D,\ t \in T, \tag{41}$$

$$0 \le y_{g,t} \perp \quad \nu_{g,t} \ge 0 \quad \forall\, n \in N,\ g \in G_n,\ t \in T, \tag{42}$$

$$0 \le z_{s,1}^+ \perp \quad \rho_{s,1} \ge 0 \quad \forall\, n \in N,\ s \in S_n, \tag{43}$$

$$0 \le z_{s,2}^- \perp \quad \varphi_{s,2} \ge 0 \quad \forall\, n \in N,\ s \in S_n, \tag{44}$$

$$0 \le \bar{z}_s \perp \quad \chi_s \ge 0 \quad \forall\, n \in N,\ s \in S_n, \tag{45}$$

$$0 \le -z_{s,1}^+ + \bar{z}_s \perp \quad \zeta_{s,1} \ge 0 \quad \forall\, n \in N,\ s \in S_n, \tag{46}$$

$$0 \le -z_{s,2}^- + \bar{z}_s \perp \quad \eta_{s,2} \ge 0 \quad \forall\, n \in N,\ s \in S_n. \tag{47}$$

Note that these complementarity pairs correspond exclusively to inequalities of the primal problem, while primal equality constraints are only equipped with unrestricted dual variables:

$$0 = \sum_{g \in G_n} y_{g,1} + \sum_{l \in \delta_n^{\text{in}}(L)} f_{l,1} - \sum_{l \in \delta_n^{\text{out}}(L)} f_{l,1} - \sum_{s \in S_n} z_{s,1}^{+} - x_{n,1} \quad \text{and} \quad \alpha_{n,1}^{1} \in \mathbb{R} \quad \forall\, n \in N, \tag{48}$$

$$0 = \sum_{g \in G_n} y_{g,2} + \sum_{l \in \delta_n^{\text{in}}(L)} f_{l,2} - \sum_{l \in \delta_n^{\text{out}}(L)} f_{l,2} + \sum_{s \in S_n} z_{s,2}^{-} - x_{n,2} \quad \text{and} \quad \alpha_{n,2}^{2} \in \mathbb{R} \quad \forall\, n \in N, \tag{49}$$

$$0 = B_l \left(\Theta_{n,t} - \Theta_{m,t}\right) - f_{l,t} \quad \text{and} \quad \beta_{l,t} \in \mathbb{R} \quad \forall\, l \in L,\ t \in T, \tag{50}$$

$$0 = \Theta_{1,t} \quad \text{and} \quad \gamma_t \in \mathbb{R} \quad \forall\, t \in T, \tag{51}$$

$$0 = \rho_s z_{s,1}^{+} - z_{s,2}^{-} \quad \text{and} \quad \iota_s^2 \in \mathbb{R} \quad \forall\, s \in S, \tag{52}$$

$$0 = p_{m,t} - p_{n,t} \quad \text{and} \quad \omega_{t,n,m}^{1} \in \mathbb{R} \quad \forall\, i \in \{1, \ldots, |Z|\}, t \in T, \{(n,m) : n, m \in Z_i \cap D,\ n < m\}, \tag{53}$$

$$0 = p_{m,t} - V_{g,t} - \varphi^{\text{TSO}} \quad \text{and} \quad \omega_{t,m,g}^{2} \in \mathbb{R} \quad \forall\, i \in \{1, \ldots, |Z|\}, t \in T, \{(n,m) : n \in Z_i \cap D^{\text{C}},\ m \in Z_i \cap D,\ n < m\},\ g \in G_n, \tag{54}$$

$$0 = V_{g,t} + \varphi^{\text{TSO}} - p_{n,t} \quad \text{and} \quad \omega_{t,n,g}^{3} \in \mathbb{R} \quad \forall\, i \in \{1, \ldots, |Z|\}, t \in T, \{(n,m) : n \in Z_i \cap D,\ m \in Z_i \cap D^{\text{C}},\ n \le m\},\ g \in G_m, \tag{55}$$

$$0 = V_{g,t} - V_{\tilde{g},t} \quad \text{and} \quad \omega_{t,g,\tilde{g}}^{4} \in \mathbb{R} \quad \forall\, i \in \{1, \ldots, |Z|\}, t \in T, \{(n,m) : n, m \in Z_i \cap D^{\text{C}},\ n \le m\},\ g \in G_n,\ \tilde{g} \in G_m. \tag{56}$$

We complement the KKT system with the set of dual feasibility requirements that correspond to the partial derivates with respect to the primal variables

$$-\delta_{l,1}^{\text{low}} + \delta_{l,1}^{\text{up}} + \sum_{n \in N : l \in \delta_n^{\text{in}}(L)} \alpha_{n,1}^{1} - \sum_{n \in N : l \in \delta_n^{\text{out}}(L)} \alpha_{n,1}^{1} - \beta_{l,1} = 0 \quad \forall\, l \in L \setminus L^{\text{inv}}, \tag{57}$$

$$-\delta_{l,2}^{\text{low}} + \delta_{l,2}^{\text{up}} + \sum_{n \in N : l \in \delta_n^{\text{in}}(L)} \alpha_{n,2}^{2} - \sum_{n \in N : l \in \delta_n^{\text{out}}(L)} \alpha_{n,2}^{2} - \beta_{l,2} = 0 \quad \forall\, l \in L \setminus L^{\text{inv}}, \tag{58}$$

$$-\epsilon_{l,1}^{\text{low}} + \epsilon_{l,1}^{\text{up}} + \sum_{n \in N : l \in \delta_n^{\text{in}}(L)} \alpha_{n,1}^{1} - \sum_{n \in N : l \in \delta_n^{\text{out}}(L)} \alpha_{n,1}^{1} - \beta_{l,1} = 0 \quad \forall\, l \in L^{\text{inv}}, \tag{59}$$

$$-\epsilon_{l,2}^{\text{low}} + \epsilon_{l,2}^{\text{up}} + \sum_{n \in N : l \in \delta_n^{\text{in}}(L)} \alpha_{n,2}^{2} - \sum_{n \in N : l \in \delta_n^{\text{out}}(L)} \alpha_{n,2}^{2} - \beta_{l,2} = 0 \quad \forall\, l \in L^{\text{inv}}, \tag{60}$$

$$\sum_{l \in \delta_n^{\text{out}}(L)} B_l \beta_{l,t} - \sum_{l \in \delta_n^{\text{in}}(L)} B_l \beta_{l,t} + \gamma_t = 0 \quad \forall\, n \in N : n = 1,\ t \in T, \tag{61}$$

$$\sum_{l \in \delta_n^{\text{out}}(L)} B_l \beta_{l,t} - \sum_{l \in \delta_n^{\text{in}}(L)} B_l \beta_{l,t} = 0 \quad \forall\, n \in N : n \ge 2,\ t \in T, \tag{62}$$

$$-\rho_{s,1} + \zeta_{s,1} + \rho_s \iota_s^2 - \sum_{n \in N : s \in S_n} \alpha_{n,1}^{1} = 0 \quad \forall\, s \in S, \tag{63}$$

$$-\varphi_{s,2} + \eta_{s,2} - \iota_s^2 + \sum_{n \in N : s \in S_n} \alpha_{n,2}^{2} = 0 \quad \forall\, s \in S, \tag{64}$$

$$I_s - \chi_s - \zeta_{s,1} - \eta_{s,2} = 0 \quad \forall\, s \in S, \tag{65}$$

in addition to the derivatives with respect to demand and generation quantities that we skip given their huge number of different cases.

5.2. **Linearization of Complementary Slackness Conditions and Final Single-Level Problem Reformulation.** In the above KKT reformulation, all constraints except the complementariy slackness conditions are linear. Exploiting the disjunctive structure of these complementary slackness conditions, in this section we use a Fortuny-Amat-like linearization to handle these nonconvexities in Equations (37) to (47); see Fortuny-Amat and McCarl (1981). For example, KKT condition (41) can be linearized as

$$0 \le x_{d,t} \le \quad \overline{\mathbf{M}}_{d,t} m_{d,t} \quad \forall\, d \in D,\ t \in T, \tag{66}$$

$$0 \le v_{d,t} \le \quad \underline{\mathbf{M}}_{d,t}(1 - m_{d,t}) \quad \forall\, d \in D,\ t \in T, \tag{67}$$

where $m_{d,t} \in \{0, 1\}$ is a binary auxiliary variable and $\underline{\mathbf{M}}_{d,t}, \overline{\mathbf{M}}_{d,t}$ are sufficiently large constants denoted as "big-M". Note that from a computational point of view it is important to choose adequate big-M parameters that are as large as necessary but as small as possible. For instance, in the above example we could set $\overline{\mathbf{M}}_{d,t} = p_{d,t}(0)$, which gives the maximum consumption possible at demand node d in period t.

In an analogous way we also linearize and reformulate all complementarity constraints in (37) to (47), which yields a more tractable problem formulation. Applying the results of the present and the previous section, the single-level reformulation of our bilevel model is given by the first-level objective that is subject to

(1) the original first-level constraints,
(2) the primal constraints of the second-level problem,
(3) the linearized complementary slackness conditions, and
(4) the dual feasibility constraints.

We implemented this single-level mixed-integer program in Zimpl (see Koch (2004)) and used SCIP (see Achterberg (2009)) as a solver.

6. On the Effects of Storage Facilities on Optimal Pricing: A Case Study Based on Chao and Peck (1996)

6.1. **Six-Node Network.** In this section we analyze the economic interdependencies of transmission and storage facility investments under different market environments including the integrated planning reference case as well as various variants of our bilevel market model. We consider the standard six-node example of Chao and Peck (1998) that has frequently been used for various policy-related analysis including Ehrenmann and Smeers (2005), Oggioni and Smeers (2013), or Grimm et al. (2016b). As can be seen in Figure 3, the network consists of three demand nodes (node 3, node 5, and node 6) and three production nodes (node 1, node 2, and node 4) that are interconnected by 8 transmission lines. Storage facilities with constant losses of 10% may be built at the three demand nodes, respectively. Only the two lines that interconnect the north with the south have a limited capacity of 200 MWh and 250 MWh, respectively. As the three nodes in the north (node 1 to node 3) are characterized by relatively low generation cost and a low demand with the south (node 4 to node 6) having the opposite characteristics, trade will naturally take place from the north to the south. In line with our theoretical framework introduced in the previous sections, we consider a two-period model with period 1 being the low demand period. All relevant demand and production input data that characterizes the respective market participants is given in Figure 3.

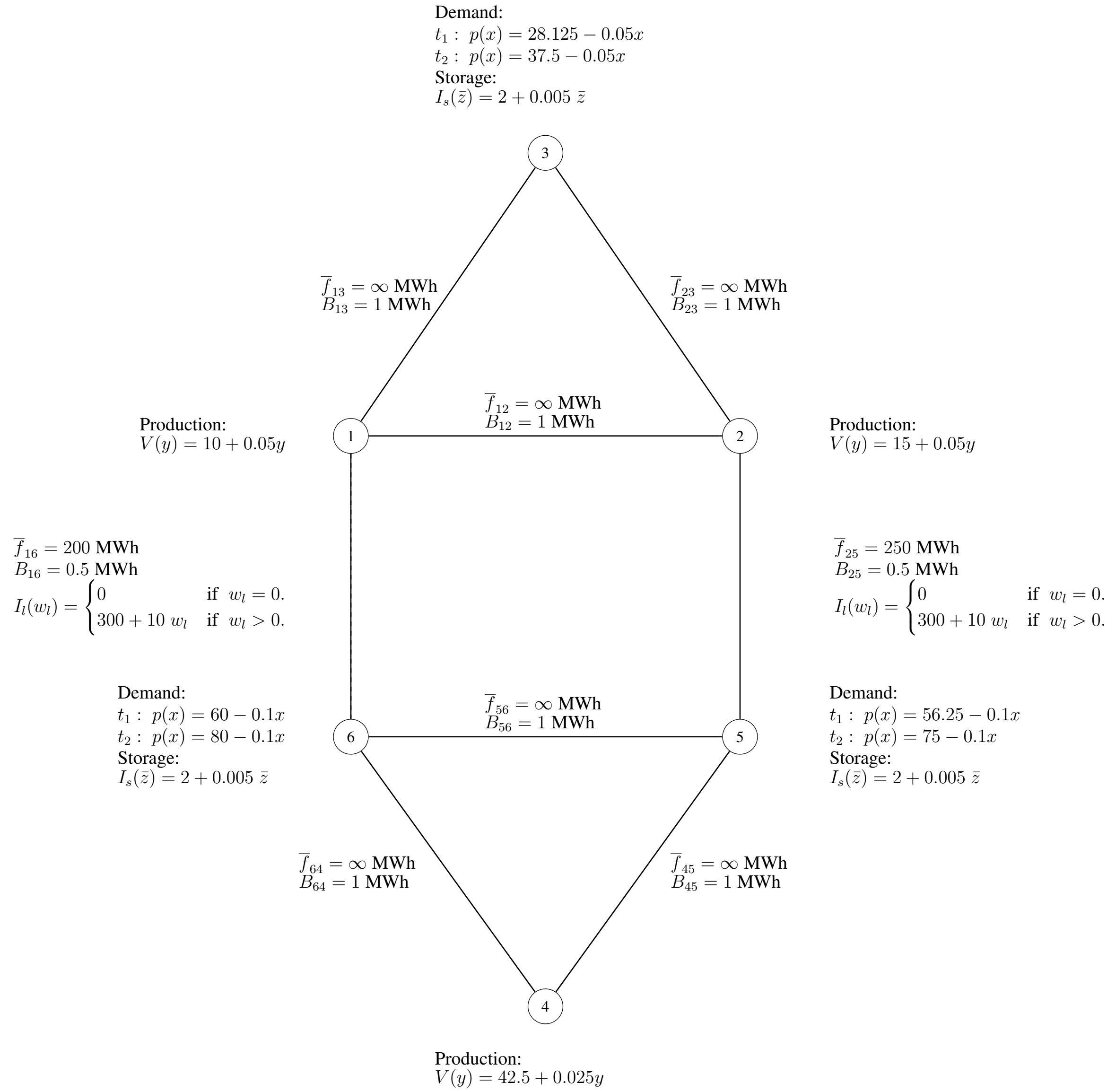


Figure 3: Six-Node Network of Chao and Peck (1998)

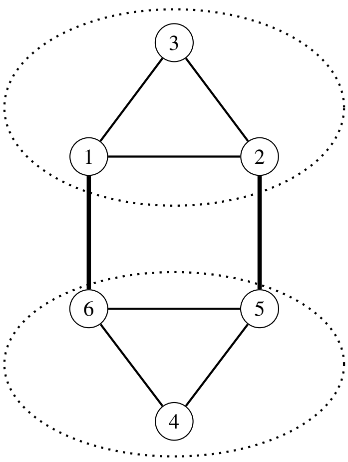
6.2. **Integrated Planning.** Let us first consider the nodal pricing, reference solution; see also Table 2. In the no-storage case, the TSO invests in both transmission lines in the amount of 159.38 MWh and 90.63 MWh, respectively. As expected, demand in the off-peak period is almost 200 MWh lower than in the on-peak period. Welfare amounts to 38626.56 \$. In the case where storage facility investments are possible, storages are built at the two southern demand nodes. Investment at node 5 amounts to 66.36 MWh, while at node 6 storage facility investment of 72.43 MWh takes place. However, given the relatively low northern zone demand, in the north no storage facility is invested in. Ultimately, the invested storage facilities in the south reduce line extensions of the TSO to 137.19 MWh and 69.18 MWh, respectively. As the invested storage facilities allow to significantly increase consumption in the on-peak period as compared to the no-storage case, welfare rises to 39370.85 \$.

TABLE 2. Nodal Pricing Solution

storages	no	yes
welfare	38626.56	39370.85
network fee	-	-
TSO revenues	-	-
TSO expenses	-	-
TSO profits	-	-
line investment (1,6)	159.38	137.19
line investment (2,5)	90.63	69.18
storage investment 3	-	0
storage investment 5	-	66.36
storage investment 6	-	72.43
aggr. demand t_1	612.5	517.59
aggr. demand t_2	800	895.82
aggr. production t_1	612.5	656.37
aggr. production t_2	800	770.91
aggr. stored-in energy t_1	-	138.78
aggr. stored-out energy t_2	-	124.90

6.3. **Bilevel Zonal Market Model.** In the case of our bilevel zonal market model, similar to Oggioni and Smeers (2013), we evaluate both a 3-3 and 4-2 configuration, i.e., we consider the two cases of $Z^{3-3} = \{\{1,2,3\},\{4,5,6\}\}$ and $Z^{4-2} = \{\{1,2,3,6\},\{4,5\}\}$. Note that under the two zonal designs at least one inter-zonal line has a limited transmission capacity, which directly yields a regional differentiated demand and generation structure; see also the thick lines in Figure 4. In this section we will further assume that the TSO exclusively aims at a welfare maximizing line extension, which may be interpreted as a situation where the TSO and the regulator constitute and act as a single public entity; see also Jenabi et al. (2013). The subsequent section will then compare these results to the case of profit maximization of the TSO and a minimization of transmission obstacles.

(i) Zonal Design Z^{3-3}



(ii) Zonal Design Z^{4-2}

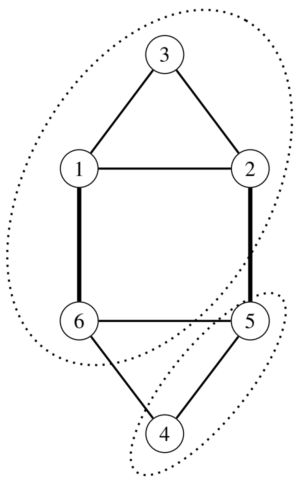


Figure 4: Zonal Designs Taken From Oggioni and Smeers (2013)

Again, under both zonal configurations storage facilities allow a welfare increase of 7.27 % and 3.05 % as compared to the no-storage case, respectively; see also Table 3. Similar to the nodal pricing reference case, in the north no storage facility is built. In addition, under the two zonal designs the storage facility investments in the southern zone reduce the need for line capacity extension of the TSO. As a direct consequence of these reduced line investments in the storage case, network fees decrease as compared to the no-storage model. However, given the strictly positive network fees, production (and consumption) decreases in all scenarios as compared to the (integrated) nodal pricing case.

As can further be seen from Table 3, under the 4-2 configuration storage investments are relatively low, with investment levels of only 56.08 MWh and 56.08 MWh, respectively. These low storage investments are accompanied by relatively high line extension of the TSO in the amount of 136.18 MWh and 51.85 MWh. In contrast, under the 3-3 configuration, investments in storage facilities increase to 57.08 MWh and 137.63 MWh, respectively. As a direct consequence of these increased storage investments, there is no need for large network extensions of the TSO as in the 4-2 configuration. Instead, only investment in the eastern line takes place in the amount of 59.69 MWh.

Let us finally note that in the no-storage case the 4-2 zonal configuration is welfare maximizing. In contrast, in the case of storage facility investments the 3-3 zonal design yields a higher welfare level as the 4-2 configuration. This underlies that markets with increased storage facility investments may require an adjustment and reconfiguration of the current zonal design in order to ensure and maintain efficient market structures.

TABLE 3. Solutions of the Zonal Pricing Model: Welfare Maximization of the TSO

zonal design	Z^{3-3}		Z^{4-2}	
storages	no	yes	no	yes
welfare	35148.97	37705.81	36438.60	37550.54
network fee	0.84	0.75	2.62	1.89
TSO revenues	987.5	896.88	3329.57	2480.32
TSO expenses	987.5	896.88	3329.57	2480.32
TSO profits	0	0	0	0
line investment (1,6)	68.75	59.69	177.78	136.18
line investment (2,5)	0	0	95.18	51.85
storage investment 3	-	0	-	0
storage investment 5	-	57.08	-	56.08
storage investment 6	-	137.63	-	56.08
aggr. demand t_1	394.19	331.66	468.78	437.39
aggr. demand t_2	777.53	838.30	804.13	866.42
aggr. production t_1	394.19	526.36	468.78	549.55
aggr. production t_2	777.53	663.07	804.13	765.47
aggr. stored-in energy t_1	-	194.70	-	112.17
aggr. stored-out energy t_2	-	175.23	-	100.95

6.4. **Regulatory Incentive Structures: Comparison of Different Planning Objectives of the TSO.** In this section we analyze and compare different objectives that the TSO may pursue in practice when deciding on a network development. As we will see below, regulatory incentive structures that relate to the planning objectives of the TSO will significantly influence the size and location of both transmission and storage investments. As a direct consequence, welfare will considerably vary under different regulatory environments. In particular, private interest like profit maximization may yield severe welfare losses. Note that similar conflicts of interests between public (welfare-driven) interests and private interests were previously reflected in Wu et al. (2006). Therefore, adequate regulations of the TSO are highly important for every well-designed and well-functioning electricity market.

In Section 6.3 we have seen that a welfare-maximizing TSO extends at least one of the two transmission lines that interconnect the northern zone with the southern zone. However, in the case where the TSO maximizes its own profits, in all four zonal model variants the TSO refrains from any network extension; see Table 4. This observation is in line with the results of Jenabi et al. (2013), where a profit maximization-oriented TSO does not have an adequate incentive to extent the network. As a direct consequence of the absence of line investments, demand decreases for all four zonal pricing model variants as compared to the welfare-maximization case. Further note that the TSO charges relatively high networks fees with values of more than 10 \$, which ultimately yield large profits for the TSO. These high network fees only allow a profitable storage facility investment of 86.10 MWh at node 6 in the 3-3 configuration, i.e., we observe a severe underinvestment in storage facilities. As compared to the welfare-maximization case, welfare losses between 27.85% and 32.15% can be observed. Obviously, these losses underline the importance of an adequate regulation of TSOs, as profit maximization of the TSO may be at the expense of welfare.

TABLE 4. Solutions of the Zonal Pricing Model: Profit Maximization of the TSO

zonal design	Z^{3-3}		Z^{4-2}	
storages	no	yes	no	yes
welfare	25165.19	27206.37	25479.88	25479.88
network fee	11.41	11.32	10.70	10.70
TSO revenues	6938.80	7003.38	10778.23	10778.23
TSO expenses	0	0	0	0
TSO profits	6938.80	7003.38	10778.23	10778.23
line investment (1,6)	0	0	0	0
line investment (2,5)	0	0	0	0
storage investment 3	-	0	-	0
storage investment 5	-	0	-	0
storage investment 6	-	86.10	-	0
aggr. demand t_1	112.50	86.13	318.75	318.75
aggr. demand t_2	495.83	524.01	688.27	688.27
aggr. production t_1	112.50	172.23	318.75	318.75
aggr. production t_2	495.83	446.49	688.27	688.27
aggr. stored-in energy t_1	-	86.10	-	0
aggr. stored-out energy t_2	-	77.52	-	0

We finally consider the case where the TSO aims at minimizing transmission obstacles in the network, i.e., we assume that the TSO focuses on maximizing its line extensions in order to reduce transmission restrictions of the network. Such an objective of the TSO may also be interpreted as some kind of a naive planning approach that aims at a more robust network with an increased system reliability. Interestingly, assuming a TSO that minimizes transmission obstacles gives identical production, consumption, network fee, storage investment, and storage operation results as compared to a profit maximizing TSO. This can be seen, as the TSO will try to maximize its income in order to being able to finance its huge network extensions. In particular, (aggregated) line investments in the amount of 663.88 MWh, 670.34 MWh, 1047.82 MWh, and 1047.82 MWh take place in the four model variants, respectively. As these additional transmission capacities cannot be used in a welfare-enhancing way, the increased line investment costs directly yield a further welfare reduction to 19957.78 $, 20203.03 $, 14700.68 $, and 14700.68 $ for the four considered scenarios. These results underline that a naive network planning in terms of constructing networks as large as possible may even yield a lower welfare as compared to a TSO that exclusively focuses on its own profits. As a main reason, not the pure amount of network investments but the interplay of grid extensions with consumption, production, and storage determines efficient investments. Obviously, this calls for a careful analysis of huge real-world grid development plans in order to avoid inefficiently large network extensions, which may also lower investment incentives in potentially efficient storage facilities.

7. CONCLUSIONS AND POLICY IMPLICATIONS

In this paper we are the first to analyze the interplay of network extensions and storage facility investments in a multistage game. We translate the investment game into a mathematical bilevel model. In particular, on the first level we assume a transmission system operator (TSO) that decides on optimal network extensions and on a corresponding optimal network fee. On the second level we consider competitive firms that trade energy on zonal spot markets and invest in new storage facilities.

As we show, adequate storage investments of firms may in general have the potential to reduce line investments of the TSO. However, investments in a (zonal) market environment may yield suboptimal results as compared to an integrated planning (nodal pricing) solution. In addition, we demonstrate that planning objectives of the TSO that are not aligned with a maximization of welfare as well as different zonal designs may aggravate these investment inefficiencies. As zonal pricing is currently applied in different regions and countries all around the world (see, e.g., Australia or Europe), these results call for a careful design of market structures that ensure efficient investments incentives of the different market players including the TSO as well as private firms. In addition, cost-intense network extension plans that are currently developed in various countries including Germany should account for the interdependencies of line and storage facility investments in order to avoid inefficiently large grid investment.

Appendix A. Sets, Parameters, and Variables

Tables 5, 6, and 7 summarize the main sets, parameters, and variables used in this paper.

Table 5. Sets

Symbol	Description
G	Electricity network
N	Set of network nodes
D	Set of demand nodes
L	Set of transmission lines
L^{inv}	Set of transmission lines that can be extended
T	Set of time periods
Z	Price zone configuration
G	Set of generators
$G_n \subset G$	Set of generators located at node n
S	Set of storage facilities
$S_n \subset S$	Set of storage facilities located at node n

Table 6. Parameters

Symbol	Description	Unit
a_l^{inv}	Intercept of line investment function l	\$/MWh
b_l^{inv}	Slope of line investment function l	\$ /MWh^2
ρ_s	Storage efficiency of facility s	%
$\overline{f}_l$	Transmission capacity of line l	MWh
B_l	Susceptance of line l	MWh
k	Number of price zones	1

Table 7. Variables and Derived Quantities

Symbol	Description	Unit
$x_{d,t}$	Electricity demand at d in period t	MWh
$p_{d,t}$	Electricity price at d in period t	\$/MWh
$y_{g,t}$	Electricity generation of g in period t	MWh
$z_{s,1}^{+}$	Amount of electricity stored in at s in period 1	MWh
$z_{s,2}^{-}$	Amount of electricity stored out of s in period 2	MWh
$\bar{z}_s$	Invested storage capacity of facility s	MWh
$f_{l,t}$	Power flow on line l	MWh
$\Theta_{n,t}$	Phase angle value at node n in period t	rad
w_l	Line extension variable for candidate line $l \in L^{\text{inv}}$	MWh
φ^{TSO}	Network fee	\$/MWh
I^{TSO}	Income of TSO	\$
E^{TSO}	Expenses of TSO	\$
P^{TSO}	Profits of TSO	\$
I_l	Line investment cost function	\$
I_s	Storage investment cost function	\$ /MW
$V_{g,t}$	Marginal generation cost function	\$ /MWh
W	Aggregated welfare	\$
O	Aggregated line investments	MWh

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* RWTH AACHEN UNIVERSITY, DISCRETE OPTIMIZATION & ADVANCED ANALYTICS, PONTDRIESCH 10-12, 52062 AACHEN, GERMANY, ** FRIEDRICH-ALEXANDER-UNIVERSITÄT ERLANGEN-NÜRNBERG, DISCRETE OPTIMIZATION, CAUERSTR. 11, 91058 ERLANGEN, GERMANY

E-mail address: *weibelzahl@math2.rwth-aachen.de

E-mail address: **alexandra.maertz@fau.de