Strategic Storage and Fluctuating Wind Power in a Game-Theoretic Electricity Market Model with Imperfect Competition*

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Abstract

In this paper, we develop the game-theoretic electricity market model ElStorM that includes the possibility of strategic electricity storage. We apply the model to the German electricity market and analyze different realistic and counterfactual cases of strategic and non-strategic pumped hydro storage utilization by different players. We find that the utilization of storage capacities depends on the operator and its ability to exert market power both regarding storage and conventional generation capacities. The distribution of storage capacities among players also matters. A general finding is that strategic operators tend to under-utilize their storage capacities. This affects generation patterns of conventional technologies and market outcomes. Strategic under-utilization of storage capacities might also diminish their potential for renewable energy integration. Accordingly, economic regulation of existing and future storage capacities may be necessary, depending on policy objectives. We also find that the introduction of electricity storage generally increases overall welfare, while outcomes vary between different cases. Interestingly, if storage is distributed among several players, consumers may be better off if these players utilize their storage capacities strategically compared to non-strategic storage operation, since market prices in storage loading periods are lower.

JEL classifications: Q40, Q41, L13, D43

Keywords: Electricity market modeling, pumped hydro storage, strategic storage, oligopoly, market power, Germany

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1 Introduction

Electricity storage has recently received increasing attention in the light of renewable energy integration. Since wind and solar power have fluctuating and intermittent generation characteristics, electricity storage is an obvious strategy for integrating large amounts of such renewable technologies into electricity systems. Currently, the only large-scale storage technology available is pumped hydro storage. For decades, pumped storage has been used for balancing and back-up purposes. Possible future storage technologies include compressed air storage, advanced batteries, and plug-in electric vehicles. Most electricity market models, however, do not include storage. In particular, there is little research on the issue of strategic operation of storage capacities. In this paper, we analyze the impact of introducing storage on conventional electricity generation and on market results. We also examine the difference between stategic and non-strategic storage operation. Do strategic storage operators utilize their capacities differently than competitive ones, and what is the effect on market outcomes?

For this purpose, we have developed ElStorM, an oligopolistic, game-theoretic Cournot model of the German electricity market that includes pumped hydro storage. The model allows analyzing strategic and non-strategic operation of pumped storage capacities by various players which might also have market power regarding their conventional generation capacities. We examine counterfactual and realistic cases of pumped storage operation in Germany and compare the results regarding storage utilization, generation patterns of conventional technologies and welfare. Our main finding is that not only the existence of storage capacities matters, but also their operation and distribution among players. Strategic operatorators utilize storage differently than non-strategic ones. In particular, they tend to under-utilize their storage capacities. It should thus neither be taken for granted that storage capacities in electricity markets with imperfect competition will be fully utilized, nor that storage will be operated in a welfare-maximizing way. This finding not only has welfare implications, but might also have consequences for the potential of storage capacities to integrate renewable energy. Depending on policy objectives, economic regulation of storage facilities might thus be necessary.

The paper is structured as follows. In the remainder of this section, we discuss relevant literature. Section 2 introduces the general structure of ElStorM, the storage mechanism, and the model implementation. Section 3 provides data and defines different cases of strategic and non-strategic storage operation. Section 4.1 analyzes the effects of introducing electricity storage on conventional generation and market prices in the simplest, counterfactual storage case. Section 4.2 compares four different cases of strategic and non-strategic storage operation regarding storage utilization, ramping of conventional generators and welfare. The last section summarizes and concludes.

In recent years, electricity market modeling has received increasing interest among energy economists, mainly spurred by electricity market liberalization in many industrialized countries. Depending on the research focus, different modeling approaches are used. [Ventosa et al., 2005] provide a review of recent modeling activities. They classify models according to specific attributes like the degree of competition, time scope, uncertainty representation, interperiod links, transmission constraints and market representation. They identify three major trends: agent-based simulation models, optimization models, and (partial) equilibrium models. In the following, we focus on the the latter approach, since it is most suitable for analyzing market power issues.

Equilibrium models deal with simultaneous profit maximization problems of all players in the market. They have been widely applied for analyzing market power, hydrothermal coordination issues or network problems. They are either based on Cournot competition (quantity competition), or apply the supply function equilibrium approach (firms compete both in quantity and prices). [Klemperer and Meyer, 1989] show that, drawing on some assumptions, supply function equilibria are bounded by Cournot and Bertrand outcomes. [Borenstein and Bushnell, 1999] find that a Cournot approach fits electricity markets very well, and that Cournot oligopoly modeling is a useful tool for electricity market power analyses. Using the Californian market as an example, they find that the potential for market power is particularly high in peak load hours. Applying a game-theoretic model to the Northwestern European electricity market, [Lise et al., 2006] compare the implications of different market power scenarios and find that market power exertion by large producers harms consumers. The model features environmental externalities like green house gas emissions as well as two load periods in order to capture different operational characteristics of electricity generators. With a similar approach, [Lise et al., 2008] analyze the impacts of additional cross-border transmission capacities on European electricity markets with the game-theoretic COMPETES model. They find that the exertion of market power increases prices in countries where the number of firms is low and where cross-border transmission capacities are scarce. They also find that dry weather increases prices in hydro-rich northern European countries. Their model features 12 different load levels that represent a whole year. [Traber and Kemfert, 2009b] analyze the impact of German support for renewable electricity generation on prices, emissions and profits with the game-theoretic EMELIE model that includes emissions trading. They find a substitution effect (renewable energy displaces conventional sources) and a permit price effect (renewable energy decreases the demand for emission permits) of the German feed-in tariff on carbon emissions. While electricity-related emissions in Germany decrease significantly, they hardly change on the European level. [Lise and Krusemann, 2008] develop a dynamic version of the Cournot approach that includes long-term investment decisions. With a recursive dynamic model named dynLEM they simulate cost composition, investments and price paths for electricity markets between 2000 and 2050, drawing on a range of assumptions about demand, elasticities and the market structure.

The models mentioned above do neither feature an hourly time-representation, nor technical inter-period constraints. They rather draw on aggregated values. In contrast, a recent paper by [Traber and Kemfert, 2009a] introduces a game-theoretic model named ESYMMETRY wich includes an hourly time-resolution as well as some technical start-up constraints and related costs. The model is used for analyzing the impacts of wind power on incentives for investments in thermal power plants. The authors find that increasing wind supply decreases investment incentives for natural gas plants. Their results, however, depend on the fact that additional wind supply hardly substitutes conventional power generation.

Regarding electricity storage, there is a gap in the game-theoretic modeling literature. [Ventosa et al., 2005] show that most models omit storage altogether. In particular, the issue of strategic pump storage utilization has received little attention of modelers. In contrast, there is a considerable strand of literature dealing with 'hydro storage' in the sense of dispatchable hydro power. Hydro reservoirs allow generators to strategically shift production capacities from one period to another. The literature dealing with this kind of 'hydro storage', however, mostly assumes that hydro reservoirs are replenished by natural inflows. Firms may decide strategically on hydro generation and on remaining reservoir levels, but not on repleneshing their reservoirs. That is, players only decide on storage *outputs*, but not on *inputs*. [Rangel, 2008] provide the most recent literature review on strategic hydro scheduling in hydro-dominated electricity markets like New Zealand, Norway and some South American countries. While market power potentials are usually related to exploiting temporal and geographical market separation, demand fluctuations or transmission capacity constraints, players in hydro-dominated markets may also exploit the market power potentials of hydrological conditions, reservoir levels and inflow probabilities. [Rangel, 2008] propose market interventions by competition authorities and regulators in order to increase demand elasticity and decrease the concentration of hydro units.

In an early paper, [Borenstein and Bushnell, 1999] find that the availability level of hydro power is an important factor in determining the extent of market power. [Johnsen, 2001] explores this question in more detail in a stylized two-period model, where monopolists generate more electricity from hydro resources in the first period compared to the competitive solution. Thus, monopolists have less water left in the second period than competitive players. The author finds that this result fits well to Norwegian hydropower data. [Garcia et al., 2001] develop an oligopoly model with dynamic Bertrand competition of hydro generators. Their simplified model framework includes two players that hold equally sized, stochastically replenishing hydro reservoirs and apply Markov strategies based on the initial state of their reservoirs. The authors find that the introduction of price caps can play a significant role for disciplining oligopolists since they limit opportunity costs of selling hydro power. [Skaar, 2004] builds upon this stylized theoretical framework and analyzes additional policy measures like increasing transmission capacity and demand rationing. [Bushnell, 2003] develops a multiperiod Cournot model of hydrothermal coordination in the Western United States. The model includes both conventional generation and hydroelectric resources in a mixed complementarity framework. Firms strategically schedule their self-replenishing hydro resources in order to maximize profits. An important result is that strategic firms shift more hydro production towards off-peak periods than competitive ones. [Kauppi and Liski, 2008] apply a computational explicit dynamic model of imperfect competition to the Nordic power market. They estimate a market structure which explains the historical data of 2000-2005 and find that market power increases both reservoir levels and electricity prices. While social losses from imperfect competition in the Nordic power market are small, the potential for market power exertion increases substantially during events of extreme water shortage.

The game-theoretic Cournot model ElStorM developed in this paper increases the understanding of strategic hydro storage utilization, since it not only deals with the strategic allocation of hydro resources between periods, but also with firms' strategic decisions on storage *loading*[1]. By providing an analysis of strategic pump storage operation, this paper complements the body of literature that deals with the possibilities of exerting market power related to technical constraints of thermal generation, transmission capacity constraints, or locational disparities. ElStorM includes imperfect competition, an hourly time resolution, interperiod links like ramping constraints, and a representation of the whole electricity market. While the general formulation is related to [Bushnell, 2003] and to the more recent paper by [Traber and Kemfert, 2009a], ElStorM provides a substantial enlargement of the [Bushnell, 2003] hydro-thermal scheduling approach. Features like uncertainty, investment decicsions, and transmission constraints are excluded since they would significantly add to complexity without substantially contributing to the analysis of strategic storage[2]. Instead, we focus on market imperfections and strategic behaviour in a Cournot setting.

2 The model ElStorM

ElStorM is a game-theoretic Cournot model of the German electricity market. Firms maximize profits by deciding on hourly electricity generation of various technologies as well as hourly pumped hydro storage loading and discharging. In doing so, firms face several technical constraints. The virtue of this model type is the representation of strategic players that exert market power. The model solution represents a Cournot-Nash equilibrium. In contrast to several earlier applications of this model type, ElStorM includes electricity storage, inter-period constraints for both conventional generation technologies and pumped storage, and an hourly time-resolution. These features are

[1] We focus on pumped hydro storage in this model, because it is the only large-scale storage technology that is currently available. Nonetheless, the storage mechanism is also applicable to other storage technologies. Pumped hydro storage facilities do not directly store electricity, but potential energy of water. Pumps and turbines/generators are located in a valley and connected by a pipe to an uphill reservoir or storage lake. Electricity can be 'stored' by pumping water into the reservoir. Later on, the water in the reservoir is used to generate electricity by running downhill again and driving the turbine/generator.

[2] For an example of models with a network representation, see [Neuhoff et al., 2005], who compare three Cournot models that include transmission constraints and analyze the robustness of the results. They find that within this model family, results are highly sensitive to structural and behavioural assumptions on transmission and market design. A recent example of a model that includes a representation of the European high-voltage electricity transmission network is provided by [Leuthold et al., 2008].

essential for analyzing strategic storage operation.

Table 1 lists all model sets, indices, parameters and variables. In each time period $t \in T$, profit-maximizing firms $f \in F$ supply electricity by deciding on generation levels $x_{f,i,t}$ of different technologies $i \in I$: nuclear, lignite, hard coal, natural gas, oil, and (run-of-river) hydro power. In the following, these technologies are called 'conventional technologies'. Firms also decide on hourly loading $stin_{f,t}$ and discharging $stout_{f,t}$ of their pumped hydro storage capacities. In addition, exogenous electricity generation from wind power $wind_t$ is included, since wind is the major fluctuating renewable energy source in Germany. The exogeneity of wind reflects the German situation which gives priority to renewable electricity feed-in.

While making a combined decision on hourly generation levels of conventional technologies, storage loading and storage discharging, each firm faces the following constrained maximization problem:

$$\max_{\substack{x_{f,i,t}\\ stin_{f,t}\\ stout_{f,t}}} \left[\begin{array}{l} \sum_{t \in T} p_t \cdot \left(\sum_{i \in I} x_{f,i,t} + stout_{f,t} - stin_{f,t} \right) \\ - \sum_{t \in T} \sum_{i \in I} vgc_i \cdot x_{f,i,t} - \sum_{t \in T} vstc \cdot stout_{f,t} \end{array} \right] \tag{1}$$

$$\begin{aligned}
s.t. \qquad x_{f,i,t} - \overline{x}_{f,i}^{maxgen} &\leq 0 \quad \forall\, f,i,t && (\lambda_{gencap,f,i,t}) && (2)\\
x_{f,i,t} - x_{f,i,t-1} - \xi_{up,i} \cdot \overline{x}_{f,i}^{maxgen} &\leq 0 \quad \forall\, f,i,t && (\lambda_{rup,f,i,t}) && (3)\\
x_{f,i,t-1} - x_{f,i,t} - \xi_{down,i} \cdot \overline{x}_{f,i}^{maxgen} &\leq 0 \quad \forall\, f,i,t && (\lambda_{rdo,f,i,t}) && (4)\\
stout_{f,t} - \overline{st}_f^{maxout} &\leq 0 \quad \forall\, f,t && (\lambda_{stoutcap,f,t}) && (5)\\
stin_{f,t} - \overline{st}_f^{maxin} &\leq 0 \quad \forall\, f,t && (\lambda_{stincap,f,t}) && (6)\\
\sum_{\tau=1}^{t} stout_{f,\tau} - \sum_{\tau=1}^{t-1} stin_{f,\tau} \cdot \eta_{st} &\leq 0 \quad \forall\, f,t && (\lambda_{stlo,f,t}) && (7)\\
\sum_{\tau=1}^{t} stin_{f,\tau} \cdot \eta_{st} - \sum_{\tau=1}^{t-1} stout_{f,\tau} - \overline{st}_f^{cap} &\leq 0 \quad \forall\, f,t && (\lambda_{stup,f,t}) && (8)\\
X_t - d0_t \left(\frac{p_t}{p0_t} \right)^{-\sigma} &= 0 \quad \forall\, t && (p_t) && (9)\\
x_{f,i,t} &\geq 0 \quad \forall\, f,i,t && && (10)\\
stin_{f,t}, stout_{f,t} &\geq 0 \quad \forall\, f,t && && (11)
\end{aligned}$$

The objective function (1) represents player f's profit function. It includes revenues from selling electricity and costs of generation or storage in each period t. Revenues include sales of electricity from conventional generation technologies $p_t \cdot \sum_{i \in I} x_{f,i,t}$ and

Item	Description	Unit
Sets and indices		
F	Firms with $f \in F$	
I	Generation technologies with $i \in I$	
T	Time with time periods $t \in T$, $\tau \in T$	hours
Parameters		
σ	Elasticity of electricity demand	
$d0_t$	Hourly reference demand	MWh
$p0_t$	Hourly reference prices	MWh
$wind_t$	Exogenous wind feed-in	MWh
$\overline{x}_{f,i}^{maxgen}$	Installed conventional generation capacity	MW
$\overline{st}_f^{maxout}$	Installed pumped storage generation (discharging) capacity	MW
$\overline{st}_f^{maxin}$	Installed pumped storage loading capacity	MW
$\overline{st}_f^{cap}$	Installed pumped storage capacity	MWh
$\xi_{up,i}$	Ramping up parameter for conventional generation	
$\xi_{down,i}$	Ramping down parameter for conventional generation	
vgc_i	Variable generation costs	€/MWh
$vstc$	Variable pumped storage costs	€/MWh
ovc_i	Other variable cost	€/MWh
fp_i	Fuel price	€/MWh
ep	Carbon emission price	€/t
se_i	Specific carbon emission	t/MWh
η_i	Generation efficiency	
η_{st}	Storage efficiency	
$\theta_{gen,f,i,t}$	Market power parameter for generation	0 or 1
$\theta_{st,f,t}$	Market power parameter for pumped storage	0 or 1
Variables		
Π_f	Profit of firm f	€
p_t	Price of period t	€/MWh
$x_{f,i,t}$	Generation of firm f with technology i in period t	MWh
X_t	Total supply in period t	MWh
$stout_{f,t}$	Electricity generation in period t of firm f from pumped storage	MWh
$stin_{f,t}$	Pumped storage loading in period t of firm f	MWh
$\lambda_{gencap,f,i,t}$	Shadow price of conventional generation capacity constraint	€/MWh
$\lambda_{rup,f,i,t}$	Shadow price of ramping up constraint	€/MWh
$\lambda_{rdo,f,i,t}$	Shadow price of ramping down constraint	€/MWh
$\lambda_{stoutcap,f,t}$	Shadow price of storage generation capacity constraint	€/MWh
$\lambda_{stincap,f,t}$	Shadow price of storage loading capacity constraint	€/MWh
λ_{stup}	Shadow price of upper storage capacity constraint	€/MWh
λ_{stlo}	Shadow price of lower storage capacity constraint	€/MWh
$\vartheta_{f,i,t}$	Market share of firm f - conventional generation	
$\vartheta_{f,t}^{out}$	Storage market share of firm f - discharging	
$\vartheta_{f,t}^{in}$	Storage market share of firm f - loading	
$crent_t$	Consumer rent of period t	€
$prent_{f,t}$	Producer rent of firm f in period t	€

Table 1: Sets, indices, parameters and variables

from pumped storage $p_t \cdot stout_{f,t}$. As usual in electricity markets, there is one market price independent of the generation technology. Note that in the case of market power, the market price p_t not only depends on a firm's decisions on conventional output, but also on storage loading and discharging: $p_t = p_t(x_{f,i,t}, stout_{f,t}, stin_{f,t})$. On the cost side, equation (1) includes technology-specific variable generation costs vgc_i that depend on fuel prices fp_i, emission prices ep, specific emissions se_i, technology-specific generation efficiency η_i and other variable costs ovc_i as shown in equation (12)[3]. The profit function also includes variable costs of storage operation $vstc$, reflecting staff and maintenance costs. These costs are assumed to be constant for every unit of electricity generated and assigned to storage loading[4]. Equation (1) also includes opportunity costs of storage $\sum_{t \in T} p_t \cdot stin_{f,t}$, reflecting the fact that electricity stored at period t could have been sold on the market at the price p_t. Thus, firms face opportunity costs equal to the market price p_t for each unit of electricity stored at time t.

$$vgc_i = \frac{fp_i + ep \cdot se_i}{\eta_i} + ovc_i \qquad \forall i \tag{12}$$

Condition (2) represents the firm's maximum generation capacity restricitions. For each conventional technology i, a firm's actual power generation cannot exceed its installed capacity[5]. Conditions (3) and (4) represent inter-period constraints. (3) is a 'ramping up' restriction: between two hours, electricity generation of a particular technology can only be increased or 'ramped up' to a certain degree, depending on a technology-specific parameter $\xi_{up,i}$ and the total installed capacity. $\xi_{up,i}$ has values between 0 and 1. While $\xi_{up,i}$ is relatively small for inflexible nuclear power, it takes the value 1 for flexible gas plants (see Table 3). Likewise, condition (4) represents technology-specific 'ramping down' restrictions. In contrast to [Traber and Kemfert, 2009a], we include not only restrictions on ramping up, but also on ramping down.

Conditions (5) to (8) concern pumped hydro storage. Condition (5) resembles (2). It states that the amount of electricity generated from pumped storage cannot exceed the installed generating capacity in any period t. Likewise, condition (6) constrains the amount of electricity that can be loaded into the storage facility at any period t, i.e. considers limited pumping capacities. Conditions (7) and (8) represent restrictions on energy storage capacities, i.e. on available reservoirs. Condition (7) ensures that generation from storage stops once the reservoirs are empty. The amount of electricity generated from pumped hydro storage in any period t thus cannot exceed the net of previous inflows and outflows. Condition (8) represents the upper storage capacity constraint. For each period t, the amount that can be loaded into the

[3] The cost representation is related to [Traber and Kemfert, 2009a]

[4] It does not matter if variable storage costs are assigned to storage loading or discharging.

[5] We refrain from modeling indivdual power plants and rather focus on a firm's cumulative installed capacity of a given technology. This formulation avoids mixed-integer unit commitment problems, which would massively increase complexity, but would not substantially contribute to the analysis of strategic storage.

storage facility cannot exceed total reservoir capacities, given the history of inflows and outflows up to this period. This restriction makes sure that reservoirs never overflow. Conditions (7) and (8) include effciency losses: since pumped storage facilities are not perfectly efficient, only a share η_{st} of stored electricity can be recovered. There is no ramping constraint for pumped storage, since it is by design a very flexible technology.

The market clearing condition (9) is required to ensure that supply equals demand. X_t represents total electricity supply, consisting of the total amount of electricity generated by all firms and technologies, plus generation from pumped storage, minus storage loading, plus exogenous wind power feed-in, as shown in equation 13. In every period, total electricity supply has to equal demand. As in other models[6], demand is represented by an iso-elastic function, drawing on exogenous reference demands $d0_t$ and prices $p0_t$. σ represents price elastiticy of demand[7]. Conditions 10 and 11 ensure non-negativity of the variables $x_{f,i,t}$, $stin_{f,t}$ and $stout_{f,t}$.

$$X_t = \sum_{f \in F} \sum_{i \in I} x_{f,i,t} + \sum_{f \in F} \left[stout_{f,t} - stin_{f,t} \right] + wind_t \qquad \forall t \qquad (13)$$

We re-formulate the optimization problem (1 - 11) as a nonlinear mixed complementarity problem (MCP), which allows analyzing market power issues in a partial equlibrium setting. The definiton of a MCP, its application to economic analyses and its implementation in GAMS is described by [Rutherford, 1995] and [Ferris and Munson, 2000]. Consisting of a square system of equations, a MCP problem is a generalization of special cases like nonlinear equation systems or complementarity problems. Mixed complementarity problems incorporate both equalities and inequalities. Thus, MCPs can be used for modeling Karush-Kuhn-Tucker (KKT) optimality conditions. We solve the market clearing condition (9) for p_t, insert it into (1), and derive the KKT optimality conditions from the optimization problem. This results in equations (14-24), which form our mixed complementarity problem:

$$\begin{aligned} 0 \leq vgc_i + \lambda_{gencap,f,i,t} + \lambda_{rup,f,i,t} - \lambda_{rup,f,i,t+1} - \lambda_{rdo,f,i,t} + \lambda_{rdo,f,i,t+1} \\ - p_t \left(1 - \frac{\vartheta_{f,i,t} \cdot \theta_{gen,f,i,t} + \vartheta^{out}_{f,t} \cdot \theta_{st,f,t} - \vartheta^{in}_{f,t} \cdot \theta_{st,f,t}}{\sigma} \right) \\ \perp \quad x_{f,i,t} \geq 0 \quad \forall f,i,t \quad (14) \end{aligned}$$

[6]For example, [Borenstein and Bushnell, 1999] or [Traber and Kemfert, 2009b]

[7]It is assumed that elasticity neither depends on the time period nor on the demand level. Time-dependent or demand-dependent elasticities might be more realistic, but would complicate our analysis of strategic storage.

$$0 \leq vstc_{st} + \lambda_{stoutcap,f,t} + \sum_{\tau=t}^{T} \lambda_{stlo,f,\tau} - \sum_{\tau=t}^{T-1} \lambda_{stup,f,\tau+1} - p_t \left(1 - \frac{\sum_{i \in I} \vartheta_{f,i,t} \cdot \theta_{gen,f,i,t} + \vartheta^{out}_{f,t} \cdot \theta_{st,f,t} - \vartheta^{in}_{f,t} \cdot \theta_{st,f,t}}{\sigma}\right) \quad \perp \quad stout_{f,i,t} \geq 0 \quad \forall f,t \quad (15)$$

$$0 \leq -\lambda_{stincap,f,t} + \sum_{\tau=t}^{T-1} \lambda_{stlo,f,\tau+1} \cdot \eta_{st} - \sum_{\tau=t}^{T} \lambda_{stup,f,\tau} \cdot \eta_{st} - p_t \left(1 - \frac{\sum_{i \in I} \vartheta_{f,i,t} \cdot \theta_{gen,f,i,t} + \vartheta^{out}_{f,t} \cdot \theta_{st,f,t} - \vartheta^{in}_{f,t} \cdot \theta_{st,f,t}}{\sigma}\right) \quad \perp \quad stin_{f,i,t} \geq 0 \quad \forall f,t \quad (16)$$

$$\begin{aligned}
0 &\leq -x_{f,i,t} + \overline{x}^{maxgen}_{f,i} && \perp \quad \lambda_{gencap,f,i,t} \geq 0 \quad \forall f,i,t && (17)\\
0 &\leq -x_{f,i,t} + x_{f,i,t-1} + \xi_{up,i} \cdot \overline{x}^{maxgen}_{f,i} && \perp \quad \lambda_{rup,f,i,t} \geq 0 \quad \forall f,i,t && (18)\\
0 &\leq -x_{f,i,t-1} + x_{f,i,t} + \xi_{down,i} \cdot \overline{x}^{maxgen}_{f,i} && \perp \quad \lambda_{rdo,f,i,t} \geq 0 \quad \forall f,i,t && (19)\\
0 &\leq -stout_{f,t} + \overline{st}^{maxout}_{f} && \perp \quad \lambda_{stoutcap,f,t} \geq 0 \quad \forall f,t && (20)\\
0 &\leq -stin_{f,t} + \overline{st}^{maxin}_{f} && \perp \quad \lambda_{stincap,f,t} \geq 0 \quad \forall f,t && (21)\\
0 &\leq -\sum_{\tau=1}^{t} stout_{f,\tau} + \sum_{\tau=1}^{t-1} stin_{f,\tau} \cdot \eta_{st} && \perp \quad \lambda_{stlo,f,t} \geq 0 \quad \forall f,t && (22)\\
0 &\leq -\sum_{\tau=1}^{t} stin_{f,\tau} \cdot \eta_{st} + \sum_{\tau=1}^{t-1} stout_{f,\tau} + \overline{st}^{cap}_{f} && \perp \quad \lambda_{stup,f,t} \geq 0 \quad \forall f,t && (23)\\
0 &= X_t - d0_t \left(\frac{p_t}{p0_t}\right)^{-\sigma} && , \quad (p_t)\ free \quad \forall\ t && (24)
\end{aligned}$$

Equations (14-24) include market shares $\vartheta_{f,i,t}$, $\vartheta^{out}_{f,t}$ and $\vartheta_{f,t}$ as defined in (25-27). These market shares indicate a firm's market power regarding generation and storage. They also include market power parameters $\theta_{gen,f,i,t}$ and $\theta_{st,f,t}$. Exogenously assigning the values 0 or 1 allows 'switching' off and on market power for specific firms both regarding generation and storage operation.

$$\vartheta_{f,i,t} = \frac{x_{f,i,t}}{X_t} \qquad \forall f,i,t \tag{25}$$

$$\vartheta^{out}_{f,t} = \frac{stout_{f,t}}{X_t} \qquad \forall f,t \tag{26}$$

$$\vartheta^{in}_{f,t} = \frac{stin_{f,t}}{X_t} \qquad \forall f,i,t \tag{27}$$

Conditions (14-16) may be interpreted as follows. Equation (14) includes a standard Cournot result: In case of positive market shares $\vartheta_{f,i,t}$ for conventional generation technologies, market prices exceed the sum of marginal costs and shadow prices. The larger the market share of a firm, the larger its market power and its ability to raise prices beyond marginal costs. While this is a common result of Cournot models, the inclusion of storage-related market shares $\vartheta^{out}_{f,t}$ and $\vartheta^{in}_{f,t}$ is a new contribution to the literature. Positive market shares regarding storage output $\vartheta^{out}_{f,t}$ have the same effect as positive 'conventional' market shares: larger $\vartheta^{out}_{f,t}$ increase a firm's ability to raise prices beyond marginal costs. The market share of storage input $\vartheta^{in}_{f,t}$, however, enters with a negative sign. Keep in mind that a firm has opportunity costs for electricity that is stored and not sold at period t. Thus, higher prices imply higher storage loading costs. The higher the market share $\vartheta^{in}_{f,t}$ of a player, the larger its interest in low prices in periods of storage loading. Strategically operated storage capacities thus mitigate a player's incentives to raise prices by withholding conventional capacities during periods of storage loading. In contrast, in such periods strategic players with large storage-loading market shares $\vartheta^{in}_{f,t}$ may exert market power with their conventional capacities in order to drive *down* prices.

Condition (15) on storage outputs may be interpreted respectively. The market price exceeds storage-related marginal costs in the case of positive storage-related market power $\vartheta^{out}_{f,t}$. If a player also holds conventional generation capacities, its cumulative market shares $\sum_{i \in I} \vartheta_{f,i,t}$ of these technologies allow raising prices. Again, high storage loading market shares decrease a strategic player's incentives to raise prices, since $\vartheta^{in}_{f,t}$ enters with a negative sign. Looking at condition (16), the most obvious finding is that the shadow price of the storage loading constraint $\lambda_{stincap,f,t}$ enters with a negative sign. This implies that restricted storage loading capacities (i.e. the pumping capacities) dampen market prices. Relaxing this constraint, e.g. by installing higher pumping capacities, would drive prices up in the storage loading periods.

Equations (14-24) form an MCP equation system consisting of more than 60,000 variables and equations. It is implemented in the General Algebraic Modeling System (GAMS), including real data on generation capacities, costs and demand from the German electricity market. The problem is solved with the popular solver PATH, which represents a generalization of Newton's method, including a path search (cp. [Ferris and Munson, 2000]). Given convexity of the underlying optimization problem, the KKT approach leads to a globally optimal solution.

After solving the complementarity problem, consumer rent $crent_t$ and producer rent $prent_{f,t}$ are calculated. Consumer rent of period t is determined according to equation (28) by integrating the demand function from 0 up the the actual quantity[8] and substracting the amount actually paid. Producer rent for each player is calculated according to equation (29) by summing up revenues and substracting costs.

$$crent_t = \int_0^{X_t} p0_t \left(\frac{x}{d0_t}\right)^{-\frac{1}{\sigma}} dx - p_t X_t \qquad \forall t \qquad (28)$$

$$prent_{f,t} = \sum_{i \in I} x_{f,i,t} \cdot (p_t - vgc_i) + stout_{f,t} \cdot (p_t - vstc) - stin_{f,t} \cdot p_t \qquad \forall t \qquad (29)$$

3 Data and scenarios

The data used in the model represents the German electricity market. Regarding reference demand $d0$ and reference prices $p0$, hourly EEX data[9] is used for one characteristic week in October 2008 between Monday, 13 and Sunday, 19. Wind data is provided by German transmission network operators and has been converted from 15-minute values to hourly values[10]. We assume a short-term elasticity of demand of $\sigma = 0.4$. Calibrating the model with this value provides a reasonable replication of the reference data and is also in line with earlier models[11]. For reasons of simplicity and traceability, σ is assumed to be time-invariant.

Five players are included in the model: E.ON, RWE, Vattenfall and EnBW are the largest strategic market players. Together they hold around 81% of the German generation capacity (cp. Table 2). In addition, a competitive fringe player named 'Fringe' is included, which is assigned the remaining generation capacity. Table 2 shows installed capacities of conventional electricity generation technologies for these five players. 'Natural gas' includes natural gas combined cycle, steam and gas turbines. 'Hydro' includes run-of-river plants and other hydroelectric plants, but excludes pumped storage

[8] In the numerical application, $x = 1$ is used as the lower integration limit for reasons of solveability. The lower integration limit is irrelevant since we do not look at absolute levels of consumer rent, but only at rent changes between different scenarios.

[9] http://www.eex.com/en/Market Data/Trading Data/Power

[10] Sources include
http://www.transpower.de/pages/tso de/Transparenz/Veroeffentlichungen/Netzkennzahlen/Tatsaechliche und prognostizierte Windenergieeinspeisung/index.htm,
http://www.rwetransportnetzstrom.com/web/cms/de/101448/rwe-transportnetz-strom/netznutzung/marktplattform/netzkennzahlen/winddaten-nach-17-stromnzv/,
http://www.vattenfall.de/cps/rde/xchg/trm de/hs.xsl/153.htm and
http://www.enbw.com/content/de/netznutzer/strom/download center/windeinspeisung/index.jsp

[11] For example, compare [Borenstein and Bushnell, 1999] or [Traber and Kemfert, 2009b]

capacities. Data on generation capacities is derived from [Traber and Kemfert, 2009a].

Technology	**EnBW**	**E.ON**	**RWE**	**Vattenfall**	**Fringe**
Nuclear	4,019	7,639	3,536	1,418	957
Lignite	404	1,320	8,614	7,303	409
Hard coal	2,674	9,933	4,453	1,667	6,136
Natural gas	1,044	3,871	2,982	2,103	6,548
Oil	440	1,483	21	646	541
Hydro	427	1,507	638	0	893

Table 2: Installed conventional capacities in MW [Traber and Kemfert, 2009a]

Since not all plants are available at a given time due to maintenance and other outages, the installed capacities listed in Table 2 are not fully utilized in the numerical simulation. Table 3 lists availabilities which are calculated from EEX data[12]. The table also includes other technical parameters like ramping up and down parameters[13], costs, emission and efficiency parameters. Data sources include [Traber and Kemfert, 2009a], EEX, UCTE, International Energy Agency and own calculations. In addition, we assume a carbon emission price ep of €20/t.

	Nuclear	**Lignite**	**H. Coal**	**N. Gas**	**Oil**	**Hydro**
Availability	84%	92%	84%	88%	78%	83%
Ramping param. $\xi_{up,i} = \xi_{down,i}$	0.04	0.08	0.14	0.73	0.66	1.00
Fuel prices fp_i in €/MWh	2.1	4.5	7.2	21.7	17.2	0
Spec. carbon emission se_i in t/MWh	0	0.40	0.34	0.19	0.28	0
Generation efficiency η_i	0.33	0.37	0.38	0.45	0.35	1.00
Other var. costs ovc_i in €/MWh	0.7	2.6	2.0	1.4	1.5	2.6

Table 3: Parameters for conventional generation technologies

The total pumped hydro storage generation capacity currently installed in Germany amounts to around 6.4 GW. Table 4 shows how the total capacity is distributed among different players. Data sources include company reports and other publications[14]. The literature survey showed that most pumped storage plants have roughly the same capacities for loading and discharging. Thus, we assume $st_f^{maxout} = st_f^{maxin}$. Note that these values refer to the power of turbines and pumps, and are accordingly measured

[12] http://www.eex.com/en/Transparency/Power plant information/Data/Overview

[13] We assume equal parameters for ramping up and down, i.e. $\xi_{up,i} = \xi_{down,i}$.

[14] Sources include [Tiedemann et al., 2008] and company information provided by EnBW, E.ON, RWE, Vattenfall and Schluchseewerk. In addition to domestic capacities listed in Table 4, German grid operators also utilize pumped hydro storage plants in neighbouring countries to some extent. For reasons of traceability and consistency, only domestic capacities have been included. Note that 'Schluchseewerk' is a large German pumped hydro storage operator, which is owned by EnBW and RWE with 50% each. An interview with a company representative showed that 50% of the company's storage capacities are operated for EnBW and another 50% for RWE. Accordingly, the total 'Schluchseewerk' capacities have been assigned to EnBW and RWE with 50% each.

in MW. In contrast, the installed storage capacities st_f^{cap} refer to the volumes of the storage lakes and are thus measured in MWh. However, we assume that only 80% of the capacities shown in Table 4 are available at a given time. On the one hand, this is due to outages and maintenance, which leads to average pump storage availabilities of about 95%. On the other, it reflects the fact that around 15% of total capacities are reserved for backup and black start purposes[15]. Furthermore, we assume variable storage operation costs $vstc_{pumpstor}$ of € 1 per MWh generated from pumped storage and average storage efficiency of $\eta_{pumpstor} = 0.75$[16]. That is, for each MWh that is loaded into pumped storage facilities, 0.75 MWh can be retreived again.

	EnBW	**E.ON**	**RWE**	**Vattenfall**	**Fringe**
Storage generation capacity $\overline{st}_f^{maxout}$ in MW	1,006	1,017	1,023	2,893	456
Storage loading capacity $\overline{st}_f^{maxin}$ in MW	1,006	1,017	1,023	2,893	456
Installed storage capacity $\overline{st}_f^{cap}$ in MWh	7,200	6,790	6,959	17,141	2,202

Table 4: Storage capacities

Five different cases are analyzed. First, we exclude pumped storage altogether in the **nostor** case for reasons of comparison. Then, the total German pumped hydro storage capacity is either assigned to the Fringe player, or to the largest player E.ON. We assume that the Fringe operates pumps storage in a non-strategic way, just like its other generation assets ($\theta_{st,Fringe,t} = 0 \quad \forall t$ and $\theta_{gen,Fringe,i,t} = 0 \quad \forall i, t$). In contrast, we assume that E.ON operates its storage capacities as well as its conventional generation assets in a strategic way ($\theta_{st,E.ON,t} = 1 \quad \forall t$ and $\theta_{gen,E.ON,i,t} = 1 \quad \forall i, t$). These two simple, counterfactual cases provide an illustrative example for analyzing the basic properties of the storage mechanism and the general effects of strategic and non-strategic storage operation. We name them **counterstor-Fringecomp** and **counterstor-E.ONstrat**, repsctively. After that, we look at two cases in which the pumped storage capacities are assigned to the players according to real data from the German electricity market (compare Table 4). In the **realstor-allcomp** case, all players operate their storage capacities in a non-strategic way ($\theta_{st,i,t} = 0 \quad \forall i, t$). In contrast, in the **realstor-4strat** case, the four largest players operate their storage capacities strategically, just like their conventional generation capacities ($\theta_{st,EnBW,t} = \theta_{st,E.ON,t} = \theta_{st,RWE,t} = \theta_{st,Vattenfall,t} = 0 \quad \forall t$). Analyzing the latter two cases is more complex than analyzing the counterfactual ones, but leads to a better understanding of the situation on the German electricity market. In the following, the five cases are summed up:

1. **nostor**: The market result without storage capacities
2. **counterstor-Fringecomp**: Total storage capacity is counterfactually assigned to Fringe, which operates storage competitively

[15]Estimation based on interviews with industry representatives.
[16]Compare [Tiedemann et al., 2008]

3. **counterstor-E.ONstrat**: Total storage capacity is counterfactually assigned to E.ON, which operates storage strategically

4. **realstor-allcomp**: Realistic storage capacities, all players operate storage competitively

5. **realstor-4strat**: Realistic storage capacities, largest four players operate storage strategically

4 Results

4.1 General effects of introducing storage

First, we look at the simplest case **counterstor-Fringecomp** where the total German pumped storage capacity is assigned to the Fringe firm, which operates it in a non-strategic way, that is $\theta_{st,Fringe,t} = 0 \quad \forall t$. Figure 1 shows storage loading and discharging in the context of total electricity generation.

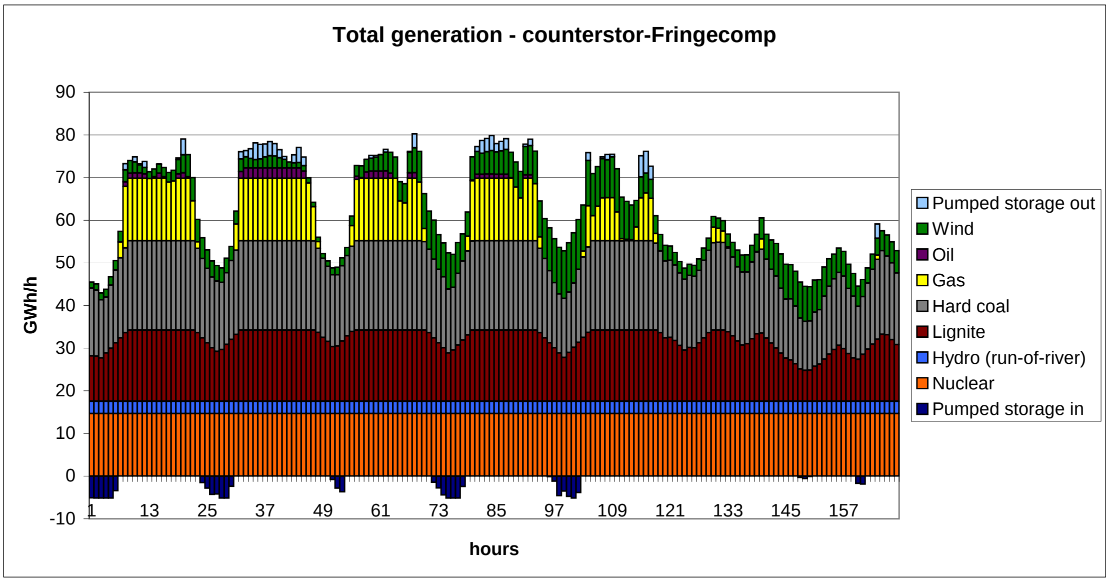

Figure 1: Total generation in the **counterstor-Fringecomp** case

Starting on a Monday, the different consumption levels of working days and the weekend are visible. A characteristic daily double peak - around noon and in the evening - is also observable for most days. Nuclear and run-of-river hydro plants (in contrast to hydro pumped storage) are providing base load due to technology-specific ramping restricitions (in the case of nuclear) and low marginal costs (both nuclear and hydro). Lignite and hard coal provide medium load. It is obvious that ramping restrictions are more tight for lignite than for hard coal. Gas and oil provide peak load. In the respective week, wind is blowing mainly in the second part of the week. Wind seems to substitute both gas and oil, as well as some amount of hard coal[17]. Overall, Figure 1 shows that the model provides a reasonable representation of the German electricity generation market.

As for storage, we observe a characteristic pattern of storage loading at nighttime (when prices are low) and discharging at the daily peak load hours (when prices are high). This result corresponds well with the operational characteristics expected from real pumped storage facilities. Comparing **counterstor-Fringecomp** to **nostor**, we find that pumped hydro output mainly substitutes peak load gas and oil generation. Figure 2 illustrates storage operation in the respective week in more detail. We can see that pumped storage facilities always need to be loaded before they can be discharged. The characteristic pattern of nighttime storage loading and peak-hour discharging is clearly visible. Some sensitivity analyses show that assuming lower storage efficiencies and higher storage costs both result in similar storage patterns, but in lower overall storage utilization.

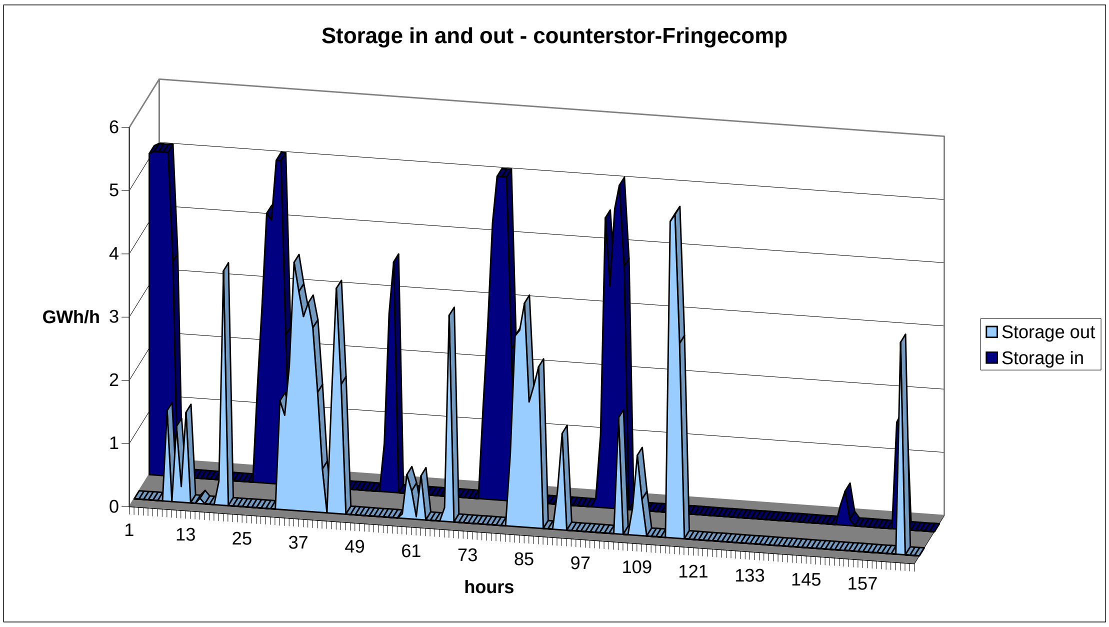

Figure 2: Storage loading and discharging in the **counterstor-Fringecomp** case

Comparing ramping restrictions between the cases without and with storage, we find that the introduction of pumped storage has a smoothing effect on conventional generation - in particular, regarding hard coal and lignite. Introducing storage decreases

[17]In the model, wind slightly increases total consumption since the additional costs of the feed-in tariff are not accounted for.

the number of binding ramping restrictions (i.e. positive shadow prices $\lambda_{rup,f,i,t}$ and $\lambda_{rdo,f,i,t}$) in the 168 periods from 401 in the **nostor** case to 298 in the **counterstor-Fringecomp** case. Thus, storage substabtially decreases the need for ramping[18]. This is an important storage characteristic in the context of renewable electricity integration, which in general increases ramping demand.

The introduction of pumped storage also has a smoothing effect on market prices. Storage allows increasing the generation of cheap base-load technologies and accordingly decreasing the generation of expensive peak load power. Since the market price is determined by the most expensive generation technology, storage utilization accordingly decreases peak prices and only moderately increases off-peak prices. Figure 3 illustrates this result by comparing prices of the **nostor** and **counterstor-Fringecomp** cases. In the respective week, the price smoothing effect of introducing storage leads to consumer benefits of about € 5 million and to producer losses of nearly € 4 million.

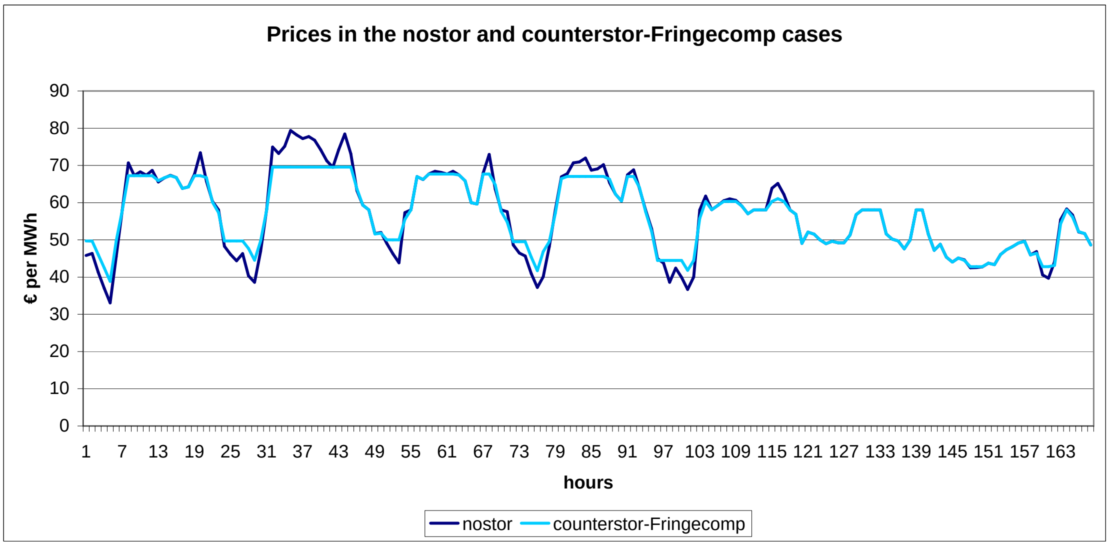

Figure 3: Comparison of prices in the **nostor** and **counterstor-Fringecomp** cases

4.2 Different cases of strategic and non-strategic storage operation

In this section we compare the model results for the cases **counterstor-Fringecomp**, **counterstor-E.ONstrat**, **realstor-allcomp**, and **realstor-4strat** to the **nostor** case without storage. The major finding is that storage utilization and market outcomes depend on the storage operator and on its ability for exerting market power both regarding storage and conventional generation capacities.

[18]Note that this results holds even though ramping-related costs are not included in the model.

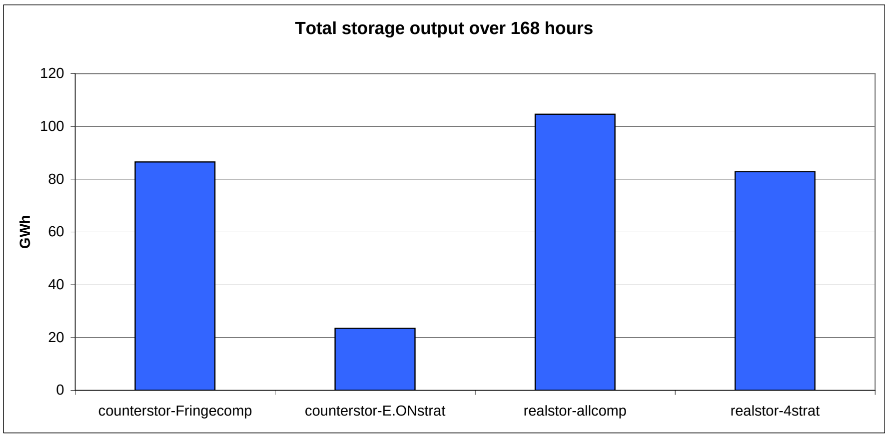

Figure 4: Comparison of storage output

Figure 4 shows that total storage output over the 168 periods varies substantially between the cases. Storage utilization is significantly higher in the two cases of non-strategic storage operation. In the counterfactual scenarios, we find a particularly large difference. In the **counterstor-Fringecomp** case, where the total storage capacity is counterfactually assigned to the Fringe, which operates it in a non-strategic way (just like its other generation capacities), total storage output is around 86 GWh. In contrast, in the **counterstor-E.ONstrat** case, where the total storage capacity is counterfactually assigned to E.ON, and E.ON operates storage strategically (just like its other generation capacities), total storage output amounts to only 23 GWh over the 168 hours. If storage is assigned to the players according to real data, non-strategic storage operation results in total storage output of about 105 GWh (**realstor-allcomp**), while strategic operation of the four largest players results in total storage output of only 83 GWh (**realstor-4strat**). These results show that storage utilization is highest if storage is operated in a non-strategic way. This is a relevant finding in the context of renewable electricity integration.

Regarding the impact of storage on conventional generation technologies, we find that storage generally decreases the number of binding ramping restrictions, i.e. smoothes conventional generation. Compared to **nostor**, which has 401 binding ramping restrictions, the number decreases in all cases that include storage. In the two counterfactual cases **counterstor-Fringecomp** and **counterstor-E.ONstrat**, we find 298 and 375 binding ramping restrictions, respectively. Conventional generation is thus much less smooth in the case of strategic storage operation: in the strategic **counterstor-E.ONstrat** case, storage utilization is much lower and ramping restrictions are accordingly higher than in the **counterstor-Fringecomp** case. Looking at the cases with realistic storage assignment, we find that the number of binding ramping restrictions decreases from 401 to 295 in the **realstor-allcomp** case, and to 286 in the **realstor-4strat** case, respectively. In this more complex setting, strategic and non-strategic storage operation seems to result in fairly similar ramping requirements[19]. Table 5 in the Appendix provides more details on storage utilization and ramping up and down restrictions in the different cases.

Regarding welfare, we find that the introduction of storage generally increases welfare, although there are significant differences between the cases. Figure 5 illustrates absolute changes in producer rent, consumer rent, and total welfare of the four scenarios compared to the **nostor** case. Table 6 in the Appendix provides more details on welfare results and on relative changes in producer rent.

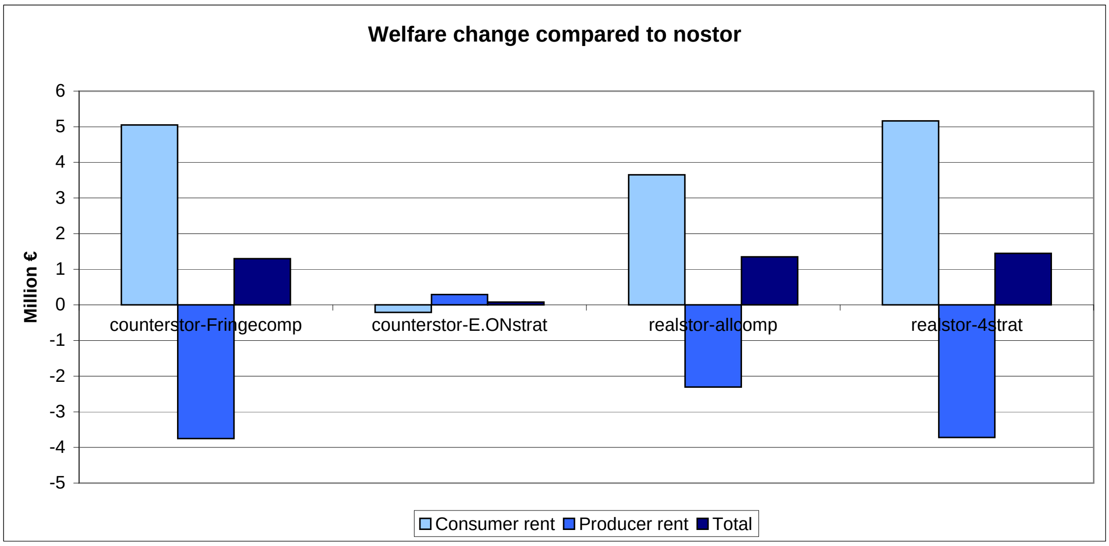

Figure 5: Welfare change compared to nostor

Comparing the cases with counterfactual storage assignment, we find that consumers are much better off in the **counterstor-Fringecomp** case, where storage utilization is high, compared to the **counterstor-E.ONstrat** case, where the storage capacity is under-utilized. The reason for this result is the price-smoothing effect of storage that was discussed in section 4.1. Pumped storage allows using a larger amount of cheap base-load technologies, which results in substantially lower peak prices. While consumers benefit from this effect, producers lose. Therefore, E.ON massively under-utilizes its storage capacity in the **counterstor-E.ONstrat** case in order not to smooth prices too much. E.ON's producer rent is accordingly much higher (about € 1.4 million) in the **counterstor-E.ONstrat** case compared to **counterstor-Fringecomp**. Other producers free-ride on E.ON's price-driving strategy, while consumers lose. Overall welfare is higher in **counterstor-Fringecomp** than in **counterstor-E.ONstrat** since higher producer rents in the strategic case do not compensate lower consumer rents.

[19]Note that ramping as such does not involve any costs in our model. Including a bottom-up representation of ramping-related costs, e.g. costs of thermal inefficiencies or additional fuel requirements, results might change.

In both cases with realistic assignment of storage capacities, **realstor-allcomp** and **realstor-4strat**, overall welfare increases compared to **nostor**. Consumers generally benefit from introducing storage, while producers lose. Above, we have shown that storage utilization is higher in the **realstor-allcomp** case compared to **realstor-4strat**. Drawing on the line of argument used above, one might expect that consumer rent was higher in the case of higher storage utilization, that is in the **realstor-allcomp** scenario. Model results however show that consumers are better off and producers are worse off in the case of strategic storage operation (**realstor-4strat**), although storage utilization is *lower* compared to **realstor-allcomp**.

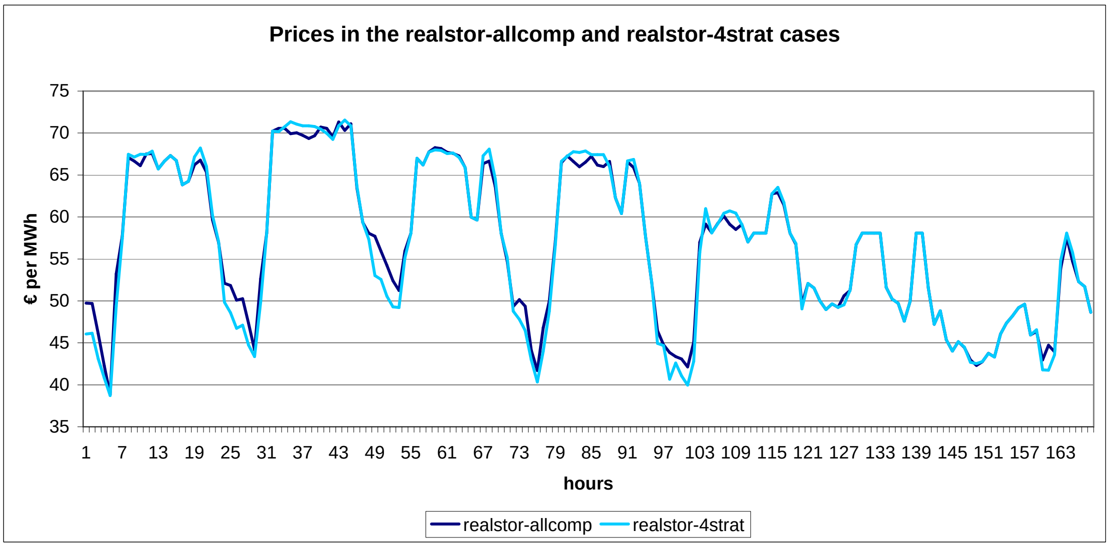

Figure 6: Comparison of prices in the **realstor-allcomp** and **realstor-4strat** cases

An explanation for this allegedly surprising result is the price-decreasing effect of strategic storage loading that outweighs the price-decreasing effect of higher storage utilization in this case. As outlined in section 2, strategic storage operators exert market power in order to drive down prices in off-peak periods where they load their storage capacities. Accordingly, off-peak prices are lower if several storage operators strategically load their capacities in these hours, compared to the non-strategic **realstor-allcomp** case. Figure 6 illustrates this result. Since price decreases in off-peak periods overcompensate price increases in peak-load periods, consumers are better off in the **realstor-4strat** case, while for producers the opposite is true. We find that all producers lose in the strategic **realstor-4strat** case compared to the non-strategic **realstor-allcomp** scenario. Additional model runs show that if only one firm operates its storage capacities in a strategic way, while all other players operate their storage capacities non-strategically, the respective firm will be better off compared to the **realstor-allcomp** case. However, if all four large players exert market power regarding storage, the **realstor-4strat** case materializes, and all producers would be better off with the non-strategic **realstor-allcomp** case. This situation resembles the classic prisoner's dilemma.

5 Summary and conclusion

We have developed ElStorM, a game-theoretic, computational Cournot model of the German electricity market that includes pumped hydro storage. Drawing on real data of the German electricity market, and using reference demand and price data of a characteristic week in October 2009, we have analyzed different cases of strategic and non-strategic pumped storage utilization by players that may also have market power regarding their conventional generation capacities.

First, we find that the storage mechanism developed in this paper results in realistic patterns of storage loading and discharging which are comparable to real pumped storage operation cycles. Introducing storage generally smoothes both conventional generation and market prices, and increases overall welfare. Our main finding, however, is that not only the amount of available storage capacities matters, but also storage operation. The utilization of storage capacities depends on a player's market power regarding both storage capacities and conventional generation, and also on the distribution of storage capacities among players. In turn, varying degrees of storage utilization have an impact on conventional electricity generation and welfare.

Analyzing the effects of strategic and non-strategic storage utilization, it is useful to look seperately at the results regarding storage utilization and welfare. We find that the utilization of a given storage capacity heavily depends on the ability of a player to operate it in a strategic or non-strategic way. A player's market power regarding its conventional generation capacities also matters. Moreover, storage utilization depends on the distribution of the total storage capacity among players. In the counterfactual cases, where the total storage capacity is assigned to only one player, we find a much higher storage utilization in the case of non-strategic storage operation by the Fringe Player (**counterstor-Fringecomp**) compared to strategic operation by the largest players E.ON (**counterstor-E.ONstrat**). With a realistic assignment of storage capacities to the players according to actual German data, we also find that storage utilization is higher in the case of non-strategic storage operation (**realstor-allcomp**) compared to the scenario where the largest four players operate their storage capacities in a strategic way (**realstor-4strat**). Since strategic storage operators under-utilize their capacities in all cases analyzed in this paper, our results indicate that non-strategic storage operation should be ensured if high storage utilization is a policy objective. Nonetheless, total storage utilization in the strategic case with realistic storage distribution is much higher than in the counterfacutal strategic case, where the whole capacity is assigned to a single strategic player.

Regarding welfare, we find that introducing storage increases overall welfare in all analyzed scenarios. Consumer rent and overall welfare in the counterfactual scenarios are much higher in the non-strategic **counterstor-Fringecomp** case compared to the strategic **counterstor-E.ONstrat** case. This implies that storage facilities should not be exclusively operated by a single strategic player for welfare reasons. In the cases where storage capacities are distributed realistically among players, the situation is more complex. The model shows that both regarding consumer rent and overall welfare, the strategic **realstor-4strat** case is superior to the non-strategic **realstor-allcomp** case. We have shown that lower prices in storage loading periods are the driving force for this result. The finding may be interpreted as a kind of self-enforcing market power mitigation mechanism: if storage capacities are distributed among several players that have market power regarding conventional generation capacities, strategic storage operation can improve consumer rents and overall welfare. Interestingly, if all four large players operate their storage capacities strategically (**realstor-4strat**), all producer rents are smaller than in the non-strategic case (**realstor-allcomp**). This situation bears a resemblance to the classic prisoner's dilemma. However, we have to concede that our welfare results might not perfectly reflect the real situation on the German electricity market, since prices in our model do not fluctuate as heavily as they do in reality. This is due to imperfect foresight in the real world, and maybe also due to missing ramping cost components. Our welfare results also show some sensitivity to demand elasticity σ. Nonetheless, it is conceivable that the welfare effects of introducing storage outlined above were even greater in the case of larger price fluctuations.

From our analysis, we draw the conclusion that not only the amount of installed storage capacities matters, but also their *operation*. In electricity markets with imperfect competition, it should not be taken for granted that exisitng storage capacities will always be fully utilized, or that they will be operated in a welfare-maximizing way. Moreover, pumped storage as such might provide previously unnoticed possibilities for exerting market power in electricity markets, since players may not only strategically decide on storage outputs - comparable to dispatchable hydro in the traditional literature on hydro-dominated markets - but also on storage *inputs*.

Under-utilization of storage capacities by strategic players may form an obstacle to large-scale renewable energy integration, which requires storage capacities to be utilized to the greatest extent. Although our model is not able to endogenously determine the amount of wind energy that can be integrated[20], our findings imply that there may be a need for economic regulation of storage operators in order to ensure a maximum level of storage utilization, if renewable energy integration is an energy policy objective. Given our findings, it may be beneficial to ensure that the total storage capacity is distributed between different players, and that they operate them in a non-strategic way. This might be particularly important for large future storage capacities that are currently

[20]Wind is exogenous in our model in order to reflect the German situation of priority feed-in.

being discussed, for example compressed air storage or advanced batteries[21].

Our findings are also relevant in the light of ongoing discussions about future electricity system designs. For example, electricity storage is an important part of the 'Smart Grid' concept[22]. Likewise, the idea of a pan-European 'Super Grid', which envisions wide-area transmission of renewable electricity, also includes large-scale electricity storage for balancing purposes, for example pumped hydro storage in the Alps or in Scandinavian countries. [Trieb et al., 2006] provide an example of such a concept. Last, but not least, the much-discussed idea of plug-in electric vehicles may result in large future grid storage capacities that could be prone to strategic operation and thus might require regulation. Nontheless, more research is required on the need for and the design of storage-related economic regulation.

As for future research, we recommend including storage into electricity market models. In particular, models that include imperfect competition should also feature strategic storage. Future applications of our model could analyze the market impacts of upcoming storage technolgies like plug-in electric vehicle fleets, and the question of who should operate them. Another possible field for research is expanding our storage mechanism towards a representation of demand-side measures like load shifting or interruptible load.

[21] For example, see
U.S. Department of Energy http://www.sandia.gov/ess/index.html or
Electricity Storage Association http://www.electricitystorage.org/site/technologies/

[22] Compare the European Technology Platform for the Electricity Networks of the Future, http://www.smartgrids.eu

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6 Appendix

	nostor	counterstor- Fringecomp	 E.ONstrat	realstor- allcomp	 4strat
Total storage output in GWh	0	86	23	105	83
Number of binding ramping restrictions:					
Ramping up	214	163	200	164	155
Ramping down	187	135	175	131	131
Total	401	298	375	295	286

Table 5: Comparison of storage utilization and binding ramping restrictions

	counterstor- Fringecomp	 E.ONstrat	realstor- allcomp	 4strat
Absolute change compared to **nostor** in €:				
Total welfare change	+1,297,547	+79,261	+1,346,586	+1,446,428
Consumer rent change	+5,050,524	-211,422	+3,653,109	+5,165,655
Total producer rent change	-3,752,978	+290,683	-2,306,523	-3,719,227
Relative change compared to **nostor** in %:				
Total producer rent change	-1.38%	+.11%	-0.85%	-1.37%
EnBW producer rent change	-0.77%	+0.11%	-0.20%	-0.78%
E.ON producer rent change	-1.39%	+0.10%	-0.87%	-1.49%
RWE producer rent change	-1.32%	+0.13%	-0.65%	-1.25%
Vattenfall producer rent change	-1.56%	+0.14%	-0.55%	-0.62%
Fringe producer rent change	-2.00%	+0.03%	-2.24%	-2.77%

Table 6: Comparison of welfare results