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Abstract

Increasing flexibility in electricity systems with high-shares of volatile renewable generation is on top of the European policy making agenda. Large-scale pumped hydro storages are appropriate technology candidates to accomplish this. Therefore, they are one of the focus technologies of the European Commission in the Projects of Common Interest discussion. In order to get listed a thorough system benefit analysis has to be conducted.

This paper investigates a comprehensive socio-economic benefit analysis of storage technologies according to the indicators expected by the European Commission. The dispatch model EDistOn + Balancing is applied, which includes the functionalities depicting balancing mechanisms. Additionally, the profitability analysis tries to sort out the most convincing business cases where storage technologies contributing to more flexibility in the electricity system can sustain in the long-run. A simulation tool has been developed to model and quantify flexibility options, and to evaluate the profitability from the owner’s point-of-view.

The results show that in Central Europe with increasing storage capacities the necessity of reserve capacity and investments in peaking units decreases while maintaining a high security of supply level. In addition to electricity generation and balancing cost reductions, shedding of renewables and significant amounts of environmental damage costs of up to 1300 M€/a can be avoided. The profitability study shows that a reduction of minimum load or retrofitting hydro reservoir storages with pump mode increase the hours of participation in balancing markets and machine utilisation, e.g. operating hours and frequency of machine starts. With the latter also wear of machines increases. Therefore, it is important to find the optimum in terms of machine starts and market benefits.

Several benefits are presented per installed capacity to provide scalability and transferability of outcomes for other applications. Furthermore, the analyses make an important contribution to the European Projects of Common Interest discussion.

1. Introduction

In the last two decades energy systems have been facing a significant transition globally. Among others, one big step forward has been the implementation of liberalised electricity markets not only in Europe, but in many regions worldwide. Moreover, the electricity supply industry has been fundamentally changing from regulated utilities acting as monopolies with central power plant dispatch to competitive electricity markets with rapidly increasing variable renewable electricity generation (triggered by corresponding financial policy instruments), incentivising also new market players (e.g. distributed or local generators) to contest market shares of incumbents. Furthermore, besides decarbonising the energy systems in general, one of the key energy policy goals in Europe is to “democratisate” the energy system, notably the electricity system. Therefore, the consumer perspectives and aspects like the establishment of local energy communities and incentivisation of local-self consumption (“prosumers”) are on top of the agenda of energy policy making in Europe, [1].

Although there is no doubt about the environmental (and also other) benefits of variable renewable electricity generation, it is inevitable to realise that a forward-looking sustainable electricity system becomes much more complex than in the past. Thus, not only the development and implementation of emerging energy technologies (like different types of energy storages) needs to succeed, but also the interoperability of several of the existing and emerging energy technologies and technology components (incl. those enabling sector coupling to the gas, heat and transport sector) needs to be better understood. And finally, also methods and tools need to be developed to assess the added value and limits of different technology portfolios trying to manage the...
dynamics in electricity systems both from the socio-economic and the profitability perspective. This is important insofar as any kind of financial policy instrument supporting the market diffusion of different technology portfolio options has its time limitations. Moreover, those technology solutions can sustain in the long-term only where successful business models for several market players involved can be found.

Against this background, the objective of this paper is to conduct a comprehensive analysis of socio-economic benefits and profitability of further increasing energy storage technology capacities, notably Austrian hydro reservoir storage and pumped hydro storage power plants, for different 2030 scenarios (used by ENTSO-E) of future renewable electricity generation and transmission grid extension in Central Europe. In particular, in a first step the benefits of different expansion paths of Austrian pumped hydro and reservoir storage capacities are evaluated by determining a variety of different benefit indicators (similar to those used by ENTSO-E for transmission expansion projects), as there are e.g. changing market clearing prices and revenues gained in the Central European wholesale and balancing markets, social welfare increase in the corresponding market areas, changing power plant dispatch and corresponding changes of fuel mix and environmental benefits (e.g. CO₂ reductions), reduction of wind energy shedding, increase of flexibility and thus security of supply, and many others. For this socio-economic benefit analysis the existing fundamental market model EDisOn+ Balancing is applied, see Section 3. In a second step, different profitability analyses from a single hydro storage operator’s point of view are conducted for different possible technology measures to increase flexibility of a single unit (e.g. retrofitting reservoir storage plant with pumping mode) within a given market environment in Central Europe. Different use cases are conducted providing insight into the most beneficial operation modes of a single unit in terms of both flexibility provision and profitability. The major cornerstones and the syntax of the corresponding mixed-integer optimisation model are outlined in Section 3.

The added value and novelty of the analyses conducted in this paper is twofold: (i) On the one hand, there has not existed a quantitative socio-economic benefit analysis of energy storage technologies according to the benefit indicators expected by the European Commission in the policy process of the so-called Projects of Common Interest (PCIs)2 so far. The expectation to be listed as a PCI project (being also supported by the European Commission and treated with high priority) is that the project significantly contributes to the increase of flexibility of the European electricity system. (ii) On the other hand, the profitability analysis tries to sort out the most convincing business models/cases where energy storage technologies contributing to more flexibility in the electricity system can sustain in the long-run without any kind of financial support and/or subsidy. This is very important, because at present the discussion of energy storage integration into electricity systems, both in practise and in literature, mainly is argued with some kind of financial policy instrument, mostly in terms of small scale battery storage and in combination with photovoltaic systems [4,5].

Last but not least, the organisation of the paper is as follows: Section 2 presents the state-of-the-art of energy storage integration into electricity markets, notably pumped hydro storage, in literature. Section 3 outlines the major cornerstones, analytical approach and syntax of the two models used for the analyses. Section 4 presents the results of both socio-economic benefit and profitability analyses of pumped hydro storage extension and retrofitting in Austria. And finally, in Section 5 a synthesis of results is presented, followed by concluding remarks in terms of policy implications of the outcome of this paper.

2. State of the art

In literature there are several approaches for analysing pumped hydro and hydro reservoir storage power plants. On the one hand, there are contributions categorising and comparing several energy storage technologies. E.g., among others [6] provides an overview of the state-of-the-art and the expected future development of key technology and economic parameters (like typical rated power, energy intensity, charge/discharge time and frequency, capital and operation cost, etc.) of the two main bulk energy storage technologies pumped hydro storage (PHS) and compressed air energy storage (CAES). Whereas CAES has still to reach technology and market maturity. On the other hand, when addressing PHS technology specifically, contributions like [7–9] provide a techno-economic review of existing and proposed PHS plants and discuss improvements in terms of utilisation. Current trends of PHS investments generally show that developers operating in liberalised markets are tending to repower, enhance existing projects or retrofit hydro reservoir storages with pump mode rather than new pumped storage projects, see [10]. Also equipping existing PHS with variable speed technology can be observed, which offers a greater range of operational flexibility and efficiency over conventional PHS, e.g. two of the four Francis pump turbines of Goldisthal (Germany) have adjustable speed asynchronous motor/generators [11].

There are several scientific contributions focusing on a system-view of PHS in competitive electricity markets. A selection of the most important references (focusing on Europe) are listed in the following:

- The study in [12] analyses in a European context, if PHS utilisation increases at a similar rate as renewable energy sources (RES-E)
capacity in the ongoing energy transition. Datasets from 1991 to 2016 are analysed, revealing an uneven utilisation among European countries. While some countries increased the utilisation rates of PHS by a factor of three to four, PHS in others are heavily under-utilised.

- An assessment of further European PHS potential is conducted in [13] by linking two existing reservoirs to form a PHS system. The reservoirs are expected to have adequate difference in elevation and close enough to be reasonably linked. The results show that the theoretical energy storage potential is significant (comparing to existing PHS storage capacity reported for 14 countries by the factor of 3.5). The realisable potential still can be denoted twice the existing capacity.

- Paper [14] investigates the impact of pumped storage energy trading on social welfare in the electricity market. Based on a theoretical analysis it is concluded that in case of energy trading producers benefit more during storage operation whereas consumers’ surplus increases when releasing stored energy.

- The European Alps are well positioned to significantly contribute with their PHS capacities to renewable energy transition on national and European scale. Thus a significant amount of references exist focusing on PHS in the European Alps. E.g. the paper [15] provides a system view of hydropower production and energy storage in the Swiss and Austrian Alps. It discusses advantages and drawbacks of various assessment tools of PHS expansion and concludes that instruments evaluating the impacts and sustainability of PHS projects need to be improved and some of them newly developed. In [16] the joint Austrian and German electricity system is investigated with a focus of PHS energy storage contribution and needs to support significantly RES-E integration. The analysis and conclusion of this contribution provide evidence that the still unexploited Austrian PHS potentials together with the already existing capacities can significantly support the German electricity system with its fast growing wind and solar PV capacities.

- Scandinavia is also characterised by significant PHS potentials. In [17] an economic analysis of large-scale PHS in Norway is conducted, notably for a 2030 projection of the Northern European electricity system. The sensitivity of varying PHS capacity and transmission capacity expansion between Norway and Europe is studied. A substantial increase in transmission capacity from Norway to Europe is needed for profitable PHS operation and Scandinavian socio-economic surplus. In [18] the long-term profitability of a PHS project planned to be realised in an old mine in Pyhjrvi, Finland, is assessed in combination with increasing wind penetration in the region.

- Studies focusing on synergies between variable wind and PHS operation exist also in Southern European countries like Greece. However, despite high wind potential encountered in many Greek island regions, the wind energy contribution is significantly restricted due to imposed electrical grid limitations. In this context, the Refs. [19] and [20] examine the techno-economic viability of a wind-based PHS system (wind-hydro solution) for an Aegean Sea island. Another study [21] aims to investigate the performance of a pumped storage unit added to a conventional hydroelectric power plant. Various use cases in terms of different operation modes are examined and guidelines concerning optimum sizing and operation strategy of pumped storage are finally extracted.

In the literature, there exists a variety of studies beyond Europe focusing on several techno-economic, socio-economic and environmental aspects of hydro reservoir storage and/or PHS operation and expansion in electricity systems with increasing RES-E generation. Due to lack of space, a selection of most important regions and contributions is presented in the following only (focusing on those matching with the overall objectives of this paper):

- Many Latin American countries are well-known for operating significant amounts of hydro power plants in different operation modes. Moreover, lessons can be learned from this region also on how to comply with different constraints. E.g., in the Amazon region in Brazil the construction of storage reservoirs would have environmental and social impact and, thus, is frowned upon. Studies [22] and [23] present different options to increase hydro storage capacity and overall efficiency of a combination of a PHS plant combined with a series of hydropower dams in cascade on a watershed. Further contributions analysing Brazil’s techno-economic and/or environmental benefits with increasing shares of RES-E generation under different constraints can be found in [24,25] and [26].

- Asia, is denoted to be the fastest growing market in terms of energy storage technologies. Not least triggered by recent changes in China’s energy policy towards clean and sustainable energy technology development and implementation (incl. ambitious plans for electric vehicle roll-out), a variety of different energy storage studies exist. Exemplarily, in [27] a comparison of two technologies, battery storage and PHS, is examined for a microgrid with high shares of renewable generation on a remote island in Hong Kong. In [28], China’s current PHS developments are discussed and analysed in detail.

The global developments briefly outlined above show that there is a need to further implement new energy storage capacities and increase the utilisation of existing ones in electricity systems with high shares of RES-E. This is also concluded in a recent publication by the International Energy Agency (IEA), [7], focusing on (pumped) hydro storage.

Against this background, the European Commission also expects from the different energy infrastructure associations (and their members) that, on the one hand, the potentials and costs and, on the other hand, the system benefits of energy infrastructure investments are assessed. In this context, mainly transmission grid and large-scale (pumped-) hydro storage expansion are subject to ongoing investigations. ENTSO-E has taken a leading role in this process and develops a Cost/Benefit Analyses (CBA) not only for European transmission projects, but also storage projects and additional European infrastructure projects denoted to be so-called Projects of Common Interest (PCIs). The CBA methodology, subject to continuous improvements and its application on national projects with highest priority, is published biannually in the Ten-Year Network Development Plan (TYNDP).

So far there is no study available which analyses these new additional benefits for energy storage technologies, notably PHS, systematically and based on standardised and sophisticated modelling studies. Therefore, the novelty of this study is that most of the above mentioned benefit indicators are analysed and quantified for energy storage (Section 4.1). In addition, profitability analyses are conducted for different flexibility options of individual hydro storage units in Section 4.2.

3. Methodology

As mentioned in the introduction, the first part is about evaluating socio-economic benefits of additional pumped hydro and hydro reservoir storage capacity in Austria for the Central European electricity system. Therefore, a power plant dispatch model including balancing mechanisms is applied. For the second part a simulation tool has been developed to model and quantify different flexibility options of hydro power plants and to evaluate the profitability of a single hydro power plant on the spot and balancing market from the power plant owner’s point of view.

3.1. Benefit analysis with the EDisOn + balancing model

EDisOn (Electricity Dispatch Optimisation) is a fundamental market model, which computes the optimal (cost minimal) dispatch of power plants in the electricity system. A study using the basic functionality of EDisOn can be found in [29]. In order to enable the consideration of electricity balancing markets, a model extension has been developed called EDisOn + Balancing. Therefore, in an additional simulation step the procurement of balancing capacity is respected. Another study analysing the impacts of different balancing market designs by using
the EDiso+Balancing and modelled the detailed mathematical formulations can be found in [30].

The minimisation of total electricity generation cost is the objective function of the wholesale market model, see Eq. (1). Not only thermal generation is considered with its short run marginal costs (SRMC), but also minor costs of Renewable Energy Sources (for electricity - RE) generation (e.g. Run-of-River (RoR), photovoltaic (PV) and wind) are taken into account. The last term $\text{NSE}_{ji}$ in Eq. (1) is for demand, which cannot be covered by supply. In this analysis a value of lost load (VoLL) of 3000 EUR/MWh is assumed, which is the current peak-price on day-ahead auctions with delivery on German/Austrian control areas at EPEX SPOT.\(^3\)

\[
\begin{align*}
\text{min}_{\text{GSwhole}} &= \text{min} \sum_{\text{nomCA},\text{mca}} \sum_{\text{H,i}} \left( \text{thFRR}_{h,\text{th}} \cdot \text{SRMC}_{h,\text{th}} + \text{Stth}_{h,\text{th}} \cdot \text{CSt}_{h,\text{th}} \right) + \left( \text{FRR}_{h,\text{th}} - \text{Spill}_{h,\text{th}} \right) \cdot c_{\text{Spill},h} + \text{NSE}_{ji} \cdot \text{VoLL} \end{align*}
\]

with $\text{SRMC}_{h,\text{th}} = C_{\text{th},M} + C_{\text{th},M}^{\text{fuel}} / \eta_{\text{th}} + C_{\text{CO2}} \cdot \text{Em}_{\text{th}} / \eta_{\text{th}}$, where $h$ describes time (hour) and $\text{th} \in \text{T}_h$ thermal unit in node $i \in \text{I}_i$, corresponding to control area $ca \in \text{CA}$.

The capacity procurement is divided into automatically and manually activated Frequency Restoration Reserve (aFRR) and mFRR, which are equivalent to secondary and tertiary control reserve in Austria, Germany, Belgium and the Netherlands. It is assumed that the necessary up- and downward capacity per control area can be provided by thermal power plants, pumped hydro, hydro reservoir and other storages, like batteries.

Additionally, the objective function considers - compared to the power plant dispatch optimisation - the costs for reserving generation capacity to balance possible occurring imbalances of supply and demand in control areas, which can occur in real-time. This means that the costs of electricity dispatch and for procuring balancing capacity are minimised simultaneously. In the objective function (2) weighting factors $\omega_1 \in [0, 1]$ and $\omega_2 \in [0, 1]$ can be chosen, to determine, whether the costs of both markets are considered equally ($\omega_1 = \omega_2$) or the focus is on minimising the costs on one market only.

\[
\text{min}_{\omega_1, \omega_2} \text{OGSwhole} + \omega_2 \cdot \text{OGBalancing}
\]

with

\[
\begin{align*}
\text{OGBalancing} &= \sum_{\text{nomCA},\text{mca}} \sum_{\text{H,i}} \text{thFRR}_{h,\text{th}} \cdot \text{TC}_{h,\text{th}} \\
&+ \sum_{j \in \text{H,i}} \text{FRR}_{j,\text{th}} \cdot \text{TC}_{j,\text{th}} \\
&+ \sum_{j \in \text{H,i}} \text{FRR}_{j,\text{th}} \cdot \text{max}(V_{\text{th},j} - V_{\text{th},j}^{\text{NOM}}, C_{PS}) \\
&+ \sum_{j \in \text{H,i}} \text{FRR}_{j,\text{th}} \cdot \text{max}(V_{\text{th},j} - V_{\text{th},j}^{\text{NOM}}, C_{PS})
\end{align*}
\]

for $j = [m, a]$ aFRR and mFRR, $h \in H = [1, ..., 8760]$ hour, $\text{th} \in \text{T}_h$ thermal unit, $\text{ps} \in \text{PS}_i$ pumped hydro or hydro reservoir storage unit (PHS or HRS), $\text{st} \in \text{ST}_i$ other storage unit, $i \in \text{I}_i$ balancing group of control area $ca \in \text{CA} = \{\text{APG, Tennet, ...}\}$.

The following key performance indicators are decisive for the purpose of answering and evaluating the task:

- wholesale generation costs (in MEuro/a) = SRMC x thermal generation + Merit-Order RES-E x generation RES-E
- procurement costs of FRR (in MEuro/a) = capacity costs x reserved capacity
- $\text{CO2}$ emissions (in Mt CO2/a and in MEuro/a) and reductions of additional emissions like $\text{SO2}$, $\text{NOx}$, NMVOC and PM$_{10}$ in terms of environmental damage cost reductions (in MEuro/a)

- peak-price shaving (in MEuro/a)
- spillage of RES-E, like PV, wind and RoR (in GWh/a)
- $\text{RES}_{\text{share}} = (\text{PV + wind + RoR + biomass} + \text{HSP}^{\text{mod}} + \text{HSP}^{\text{sun}} + \text{FRes}^{\text{Pump}}) / \text{Demand}$ (in %)
- net imports to Austria (in TWh/a)

3.2. Profitability analysis of a single hydro storage plant

In this chapter the business implications of different technical measures for individual hydro power plants are discussed. The most important results targeted in this context are, on the one hand, the achievable profits in different markets and, on the other hand, the changes in operation mode. In geographical terms, the considered market places are the EPEX day-ahead spot market and the automatic Frequency Restoration Reserve market (aFRR) of Austria for the year 2015.

For the technical modelling of machine operation, linear mixed-integer optimisation problems are set-up, maximising the firms profit on the spot market, while reserving capacity for the balancing market. The pumps and turbines are implemented with very accurate, piecewise-linear efficiency curves. The economic simulation\(^4\) on day-ahead and balancing markets is carried out in the following steps:

1. Optimisation on the spot market: First, the operation on the spot market is optimised for each calendar week of the year using the following procedure.
   (a) Try to maintain storage volumes for up- and downward balancing for one week, and optimise the remaining flexibility on the day-ahead spot market. The time horizon for the optimisation is set two weeks to ensure that the initial storage level can be reached again. However, only the results for the first week will be saved. If (a) is successful, go to (c).
   (b) If the optimisation problem in (a) cannot be solved for an entire week, try to keep the storage contents and the balancing energy for one day. If this is not possible, act on the spot market only. Go to the next day of the calendar week.
   (c) Save the results of the current calendar week and start optimising the following week (a).

2. Simulation of the balancing market: Using 2015 historical data, weekly merit order curves are created for balancing energy bids. These data are used to obtain the activations of the investigated power plant from the historical retrievals and given bidding strategies. These activations, the reaction of the machines of the investigated power plant and the effects on the storage level are then simulated on a quarter-hourly basis throughout one year. The following assumptions are made for simulating the aFRR market:
   a. Daily peak, off-peak and weekend products are simulated.\(^5\)
   b. It is offered with a balancing capacity price of 0 Euro/MW.
   c. For the level of provision, the variants are considered: (i) no provision (spot market only), (ii) minimum provision (5 MW) and (iii) a provision of 10% of nominal capacity of the power plant.
   d. The following bidding strategies are examined for balancing energy prices: twice, five times and ten times the average price on day-ahead spot market.

4. Results

The first part of this section presents the socio-economic benefit analysis results of different future hydro storage expansion paths for

\(^3\)EPEX SPOT is the exchange for the power spot markets at the heart of Europe. It covers Germany, France, United Kingdom, the Netherlands, Belgium, Austria, Switzerland and Luxembourg; markets representing 50% of European electricity consumption, source: www.epexspot.com.

\(^4\)This approach is implemented in the programming language Julia [31] with the modelling package JuMP [32].

\(^5\)In 2015, up- and downward aFRR balancing capacity is procured in daily peak, off-peak and weekend products. A harmonisation process with the German aFRR balancing market started in 2017 and Austria introduced weekly peak and off-peak products due to the common activation of aFRR in Germany and Austria. In mid 2018, daily 4-h products are introduced in the aFRR market.
Austria in a Central European context, because the developments within Austria, which is highly interconnected to its neighbouring countries [33], also affects electricity exchanges and dispatches of surrounding electricity systems. In addition, three different future European electricity market scenarios are assumed for 2030 to evaluate the sensitivity of socio-economic benefits of Austrian hydro storages on the Central European electricity mix. The second part presents the results of profitability analyses conducted from a single hydro storage owner’s or dispatcher’s point of view. A selection of different operational strategies to further increase the flexibility of hydro storages are explained and evaluated and finally, the corresponding profitability within a given electricity market environment is assessed.

4.1. Socio-economic Benefit Analysis of PHS and HS

The Austrian pumped hydro storages (PHS: pump and turbine capacity, with/without natural inflow) and hydro reservoir storages (HS: turbine capacity, with/without natural inflow) with up to 6.4 GW installed turbine and 3.4 GW pumping capacity and their huge reservoir capacities of around 1730 GWh play an important role for the Central European electricity system. In addition, the interconnection with neighbouring countries is higher than the European average. Therefore, Austrian hydro storages are able to support the integration of RES-E in several regional markets. In order to provide a sensitivity on future hydro storage plant penetration in Austria, three different scenarios are assumed for 2030, based on ENTSO-E TYNDP 2018, [34]. They are called:

- Sustainable Transition (ST) which seeks a fast and economically sustainable CO₂ reduction by replacing coal and lignite by gas in the European electricity sector,
- Distributed Generation (DG) which places prosumers at the centre, and
- the external scenario (EC) which is a core policy scenario produced by the European Commission.

The assumed Austrian power plant park (including all planned PHS & HS expansions) is shown in Fig. 1 (left) and the respected Central European area is shown on the right based on ENTSO-E TYNDP 2018 scenarios [34].

For each of these three scenarios different expansion paths of hydro storages in Austria are analysed (detailed numbers can be found in Table A.1):

A. No further pumped hydro and hydro reservoir storage power plants (PHS & HS) are built in Austria after 2018.
B. PHS expansion cannot be realised as planned, around one third of turbine (1 GW) and pumping (400 MW) capacity is not realised.
C. PHS & HS expansion is proceeding as planned (see footnote 9).

4.1.1. Impacts on electricity generation mix and procured balancing capacities

Fig. 2 shows the results by applying the EDisoN + Balancing model in terms of electricity generation mix and resulting RES-E shares in relation to annual electricity consumption. It presents the optimisation results per ENTSO-E TYNDP 2018 scenario for both the Austrian (top) and the Central European (bottom) electricity system. In addition, the changes in generation due to varying installed PHS&HS capacities are shown on the right of Fig. 2. For each scenario the expansion paths B and C are compared with A used as the reference case.

In Austria, the RES-E generation share for 2030 is between 69.6% (ST) and 87.5% (EC) for Option A and the planned storage expansion allows additional RES-E share increases of 2.4% (A → C) in 2030-ST and 2030-DG, and 2.8% for scenario 2030-EC. The respected Central European area reaches RES-E shares of 47% (ST) and 51.1% (DG). Although the same installed capacities of pumped hydro and hydro reservoir storages are assumed in Option A, due to higher penetrations of PV and wind in scenario DG the consumption and generation of Austrian PHS&HS in scenario DG is higher than in ST (14%) and EC (7%). This is also true for the Central European electricity system (ST:10%, EC:8%). The pumped hydro storages largely compensate the occurrence of timing differences of generation, demand peaks and valleys, respectively. The additional PHS&HS capacities in Option B and C change mostly electricity imports to and exports from Austria. In general, Austria is a net importer in all scenarios, but by adding more installed PHS&HS capacities the import dependency decreases, cf. Fig. 2 (upper right) “net-Import” decreases.

The PHS&HS expansion in Austria also affects power plant dispatches in neighbouring countries. On the one hand, in all scenarios wholesale electricity generation of lignite, coal and gas power plants are replaced by PHS, HS, PV, wind, nuclear and other RES-E. On the other hand, the balancing procurement of other RES-E like biomass is replaced by gas, lignite and coal power plants, except for scenario 2030-ST. There can be observed a shift, but to a varying extent, e.g. in 2030-DG B wholesale generation of gas power plants is reduced by 1359 GWh/a (see Fig. 2), whereas balancing procurement of aFRR and mFRR increases by 280 GWh/a in 2030-DG B.

It is not possible to completely avoid curtailment of RES-E, but the Austrian PHS&HS expansion supports the more efficient use of renewable electricity generation, not only in Austria but also in neighbouring countries. In the Central European electricity system, RES-E curtailment is reduced by 1.6% in ST, 4.8% in DG and 4.2% in EC (A → C).

4.1.2. CO₂ emission reductions and environmental damage costs

The additional PHS&HS capacities enable CO₂ emission reductions of 2–9.1% in Austria and 0.1–0.5% in the Central European system per year. With assumed CO₂ certificate prices of 84.3 Euro/t in ST, 50 Euro/t in DG and 27 Euro/t in EC, [34], the emission reductions amount in monetary savings of 100 M€uro/a (ST), 24 M€uro/a (DG) and 48 M€uro/a (EC) (A → C).

Based on specific emission factors for SOₓ, NOₓ, non methane volatile organic compounds (NMVOC) and particulate matter (PM₁₀) (see Table A.3 based on [35]), the resulting emission reductions are calculated. They are assessed using environmental damage cost coefficients, see [36]. The differences in damage costs across the countries are remarkable, but reasonable. The highest damage costs are related to emissions released in the middle of Europe, i.e. France, Belgium, Germany and Austria. These emissions are mainly transported to densely populated areas, and consequently bring about high damage to human health. Moreover, the lowest damage costs are related to emissions in the Nordic countries, Greece and Ireland, which are located in the outskirts of Europe. In Fig. 3 the environmental damage cost reductions resulting from implementing hydro storage projects in Austria are

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6 Wholesale market dispatch is solved for AT, BE, CH, CZ, DE, FR, HU, IT, NL, PL, SI and SK. The procurement of balancing products is applied for AT, BE, DE and NL.

7 Source: values of “Hydro Water Reservoir” and “Hydro Pumped Storage” in 2018 from ENTSO-E Transparency Platform.

8 “Hydro-turbine” comprises turbine capacities of PHS and HS and “Hydro-pump” is the pumping capacity of PHS. “Hydro-run” are run-of-river (RoR) power plants. The category “Other RES” means all other RES-E which are not mentioned separately, e.g. geothermal.

9 Source: ENTSO-E, TYNDP 2018. In Austria, it is planned to build around 3.5 GW PHS and HS power plants by 2030.

10 For all TSOs of Austria, Germany, Belgium and The Netherlands it is assumed that aFRR is procured daily differentiated by off-peak and peak products and mFRR is procured daily in 4-h products. Cross-border balancing is not applied.

11 The damage cost coefficients are adjusted to 2018-Euro/t by using the European consumer price index (CPI), e.g. 2005 = 84.802, 2018 = 103.48, source: eurostat.
Concerning the assessment of climate damage induced by CO₂ a value of 145 Euro/t is assumed, based on [37]. The changes are split into wholesale (left) and up- and downward balancing (right: bal+, bal-). In all scenarios environmental damage costs of electricity wholesale generation are reduced. In contrast to the wholesale market, the emissions of balancing procurement are emitted upon activation only. Therefore, these emissions can be interpreted as an upper limit. The environmental damage costs for upward balancing (bal +) are in all scenarios negative, which is due; because the capacity is procured by lower-emission power plants if the pumped hydro storages

shown based on national values in Table A.4 for value of a life year. The value of a life year (VOLY) is an estimate of damage costs based upon the loss of life expectancy. This measure takes into account the age at which deaths occur by giving greater weight to deaths at younger age and lower weight to deaths at older age, see [36].
are added in Austria. In terms of downward balancing (bal-) an increase represents that even more emissions can be avoided if activated.

4.1.3. Residual load curve and relevant parameters for PHS and HS

The higher the penetration level of RES-E is, the more residual load curves (= load-(PV + wind + RoR + biomass)) shift downwards. In all scenarios residual load is to a certain extent negative, i.e. generation from RES-E is higher than demand, see Fig. 4. The remaining positive area below the curve has to be covered by thermal plants, HS, PHS and electricity imports. For each 2030 scenario and expansion Option A to C, the generation of HS and PHS (“HS+PHS turb”) and the consumption of PHS in Austria (“PHS pump”) are shown.

As mentioned previously, Austrian pumped hydro storage plants are the highest utilised in scenario 2030-DG, where solar PV and wind capacities are the highest followed by 2030-EC and 2030-ST, see also Table 1.

Another variables, which are shown in Fig. 4, are electricity imports to Austria and exports from Austria to neighbouring countries (X → AT), where positive values mean electricity flows to Austria, i.e. imports, and negative values represent exports. The hourly exchanges increase in all three scenarios, whereas, the number of hours when Austria is a net-importer decreases from 5559 (2030-ST A), 6544 (2030-DG A) and 5208 h (2030-EC A) by around 328 (ST), 473 (DG) and 321 h (EC).

Relevant parameters for determining revenues and costs of hydro power are generation and consumption quantities, the associated profits (assessed on the basis of shadow prices of the demand equation=wholesale price), the operating hours and the annual average price spreads. In Table 1, some of these values are listed separately for hydro reservoir storages (HS) and pumped hydro storages (PHS) for all three scenarios and each expansion path.

Significant changes in the quantities result for PHS, since the installed capacity increases from Option A to C. In terms of sales, it should be mentioned that not only the quantity influences sales, but also the endogenous spot prices are decisive for the amount. The average, annual spot price level for Option A in 2030-ST is 88.04 Euro/MWh, in 2030-DG 69.34 Euro/MWh and 45.36 Euro/MWh in 2030-EC. In this regard, a decline in the price spread can be observed and a decline of price spreads due to increased PHS capacity (g PHS spread for Option A to C in all scenarios), which confirms the theory of economic self-cannibalism of storages [38].

4.1.4. Electricity generation costs, procurement costs and peak-price shaving

Fig. 5 shows the cost reductions in terms of electricity generation and those of balancing capacity procurement. The reference is Option A for the corresponding scenarios, i.e. the assumed primary energy prices and the CO₂ certificate prices are identical for all options within the scenarios (see Table A.2 for details). Furthermore, the procurement costs of aFRR and mFRR are split. In Fig. 5 left, the percentage monetary savings for system operators (in general, all costs are passed on to consumers) are shown and on the right the corresponding absolute values in million Euro per ano.

The realisation of 2/3 of planned PHS expansions (Option B compared with A) amounts in cost savings between 100 MEuro/a (wholesale and FRR for scenario 2030-EC) and up to 200 MEuro/a (2030-DG). In terms of cost reductions per installed turbine capacity in Austria, values between 9,300 Euro/MW and 18,200 Euro/MW can be achieved.

If all planned PHS and HS in Austria are realised (Option C), savings between 148 MEuro/a (2030-EC) and 281 MEuro/a (2030-DG) are observed, which means savings of 12,400 Euro/MW (2030-EC) and 23,600 Euro/MW (2030-DG) respectively.

Reducing load during peak periods is called peak shaving or peak clipping. Peak shaving can realise a range of benefits when it coincides with peak demand, especially in terms of peak prices in the wholesale market, see Table 2.

Peak shaving can be achieved by shedding load, by shifting load into off-peak periods or by using onsite generation facilities during peak periods. Due to higher electricity demand during daytime, the electricity prices are higher in peak hours than in off-peak hours. Therefore, for PHS the most economical way of operating usually has been pumping during the night, while prices are low, and generating electricity during the day, when there can be earned enough money to compensate in addition efficiency losses. In recent years, however, a shift can be noticed. During the day several price drops are observed at power exchanges, e.g. on sunny summer days in Germany the electricity prices during midday are dropping, because of high priority in-feeds of solar PV generation or in case of significant additional wind generation, the prices can even get negative. As a consequence, for storage units new business cases are possible when responding to price fluctuations accordingly.

4.1.5. Reduction of necessary reserve power plant capacity

The evaluation starts by marking the hours where residual load (=load-(PV + wind + RoR + biomass)) is high (e.g. highest 10% of the year = 876 h). Fig. 6 shows for scenario 2030-ST Option C that the hours occur mainly during autumn and winter.

To get an indication how much capacity of thermal power plants (gas, coal, lignite and oil) can be substituted by pumped hydro and hydro reservoir storages, the hourly differences of thermal generation in these highest 876 h of residual load in Central Europe are calculated. Furthermore, several statistical measures like mean, median, quantiles are computed; see column “residual.” in Table 3. The duration of such peaks may not be neglected, because sufficient reservoir levels have to be available. An alternative approach is to compare the differences of the e.g. 876 h with maximum thermal generation (column “thermP”), which can result in comparing different hours with each other, whereas in the “residual” approach the same hours of the year are compared.
and, therefore, results in higher max/lower min values.

The median and mean values vary between −478 MW (2030-EC: thermP) and −1006 MW (2030-DG: residualL), so comparing these values with the additional installed turbine capacity around one quarter of thermal power plant capacity can be substituted on average in Central Europe. The detailed results of the second approach “thermP” are shown in Fig. 7. For all three scenarios the values centre around −500 to −750 MW.

Other important events for having sufficient reserve capacities are so-called “Dunkelflauten”\(^\text{13}\) (i.e. hourly electricity generation of PV and wind is smaller than a certain percentage of installed PV and wind capacities). Storage devices with respective reservoirs are appropriate generation technologies in relieving this kind of critical situation, but also the interconnections to neighbouring control areas support the electricity system in terms of security of supply.

\(^{13}\) The term has prevailed in German-speaking countries in recent years.

---

### Table 1

<table>
<thead>
<tr>
<th>Quantity (GWh/a)</th>
<th>2030-ST</th>
<th>2030-DG</th>
<th>2030-EC</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>B</td>
<td>C</td>
<td>A</td>
</tr>
<tr>
<td>HS turb</td>
<td>3508</td>
<td>3847</td>
<td>3841</td>
</tr>
<tr>
<td>PHS turb</td>
<td>7049</td>
<td>9107</td>
<td>9871</td>
</tr>
<tr>
<td>PHS pump</td>
<td>−3305</td>
<td>−5170</td>
<td>−5275</td>
</tr>
<tr>
<td>Profits (M€/a)</td>
<td>1025</td>
<td>1124</td>
<td>1187</td>
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<tr>
<td>HS turb</td>
<td>414</td>
<td>434</td>
<td>428</td>
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<tr>
<td>PHS turb</td>
<td>832</td>
<td>1041</td>
<td>1112</td>
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<td>PHS pump</td>
<td>−221</td>
<td>−351</td>
<td>−353</td>
</tr>
<tr>
<td>Operational hours (h/a)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HS turb</td>
<td>5194</td>
<td>5237</td>
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<tr>
<td>PHS turb</td>
<td>4465</td>
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<td>4559</td>
</tr>
<tr>
<td>PHS pump</td>
<td>2641</td>
<td>2613</td>
<td>2582</td>
</tr>
<tr>
<td>PHS Spread (Euro/MWh)</td>
<td>28.23</td>
<td>25.84</td>
<td>25.19</td>
</tr>
</tbody>
</table>
4.2. Profitability analysis of a single hydro storage plant

In reality, such assets are often managed in a portfolio and the storage levels can be in addition controlled by using intraday trades, but these facts have not been taken into account in these case studies and, therefore, have limitations.

4.2.1. Development of a hydro reservoir storage to a pumped hydro storage power plant

This case study examines how the retrofit of a single hydro reservoir storage power plant into pumped hydro storage mode (see Fig. 8 for a schematic overview) affects the achievable profits in different electricity markets (wholesale, balancing market) and the use of different machines.

In the reference use case storage, a storage power plant with two reservoirs and four turbines in the lower reservoir is considered. The efficiency curves[14] of these turbines used in the model are shown in Fig. 9 (left). The simultaneous operation of several turbines results in an efficiency curve for the entire power plant, which is shown in Fig. 10 (left).

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14 Personal information from technology provider.
the storage use case there are no pumps available. Hence, it is only possible to run turbines and, due to the minimum load of the individual turbines, the entire power plant also has a minimum load. This means that the power plant must run during the entire product time when operating on the balancing market. If negative balancing products are offered, the operation point of the power plant must be above the sum of the minimum load and the offered capacity during the product period.

In the retrofitting use case pumped storage, two pump turbines are added between the two reservoirs. The piecewise linearised efficiency curves for the pump and turbine operation of the new pump turbines can be seen in Fig. 9 (right). The (simultaneous) operation of turbines and pump turbines results firstly in a greater generation output of the entire power plant and secondly in more flexibility since both, consumption (pump) and production (turbine), are possible. The efficiency curve for the entire power plant is shown in Fig. 10 (right).

The additional pump turbines firstly allow more electricity generation to be marketed overall and secondly considerably simplify the procurement of balancing capacity. Due to the possibility of pumping, the pumped storage use case provides an operating range between approx. −70% and 100% of total installed turbine capacity. This means that in contrast to the storage use case, the storage unit needs not to generate electricity in order to be able to provide negative balancing energy. Therefore, for a pumped storage, the ability to provide enough capacity for a balancing product is independent of natural inflow. Crucial for this is the storage content at the beginning of the product time slice only.

To illustrate the difference between the two use cases, Fig. 11 shows the quarter-hourly operation on the day-ahead EPEX and aFRR balancing market for a selected day. In the middle is the quarter-hourly profit in the different markets in AT and below the relative storage levels. The three pictures on the left show the dispatch in the storage use case. Here it can be seen that the natural inflow on this day is not sufficient to provide balancing capacity for a whole product. Therefore, the available energy is marketed exclusively on the spot market - namely during the hours with the highest prices. Only small changes in terms of storage level are observed in the lower reservoir on this sample day.

In contrast, in the pumped storage use case on the right in Fig. 11, it can be seen that balancing capacity can be procured for the whole day due to several positive and negative activations. In addition, more flexibility is available for operation on the spot market, meaning that price arbitrage operation modes are attractive. Overall, the two graphs in the middle of Fig. 11 show that significantly more profits can be made that day in the pumped storage use case. Due to the additional pump turbines the storage level of the upper reservoir is also used and for example at 13:00 pumping mode is active and the level of the upper reservoir increases.

The influence of different bidding strategies (2 times the spot market price, 5 times and 10 times) can be summarised as follows: lower bidding leads to more frequent activations, both in the positive and in the negative balancing direction. A higher price per MWh, however, is achieved for higher bidding strategies.

The pumped storage generally has more operating hours than the storage. The two use cases are very similar to each other and differ mainly by the amount of balancing energy activations. If the pumped storage is only marketed on the spot market, it is more frequently in operation at optimum efficiency.

In the following, the most important economic and technical
indicators for the two use cases are compared. Fig. 12 shows the annual profits in EUR/MW achieved in the different markets for different reserve strategies, bidding strategies and use case. It can be seen that pumped storage generates higher profits than storage (both relative and absolute). With 10% provision, it is hardly possible to have sufficient reserve in the pumped storage use case and even worse results are achieved than exclusively in spot market.

However, higher profits in the pumped storage use case are also associated with greater machine utilisation. Both, the number of annual operating hours and the frequency of machine starts, are significantly higher than in the storage use case. In addition, the procurement of 10% of nominal generation capacity is practically never possible for the storage unit, because natural inflow (and storage volume) is not sufficient to provide enough reserve capacity for a whole balancing product. For pumped storage, however, it is always possible.

4.2.2. Reduction of the minimum load of a hydro reservoir storage power plant

This case study investigates the impact of a reduction of the minimum load of a hydro reservoir storage power plant on annual profits and machine operation.

In the reference use case, a storage power plant with a turbine and a minimum load of 33% of nominal capacity is considered. In a modified use case, this minimum load is reduced by 50%. Fig. 13 shows the efficiency curves of the turbine in the two use cases.

Although the turbine has a lower efficiency in the additionally available operating range, a reduction in the minimum load enables to bid balancing products with less continuous generation. This reduces the dependence of balancing market participation on natural inflows and increases the remaining available storage flexibility for spot market operations.
This can also be seen in Fig. 14, where the quarter-hourly operation and profit of the storage unit are shown for a sample day. 16.7% of the nominal capacity is reserved for the balancing market. To achieve this in the reference use case, the storage unit must be able to operate at least 50% of nominal capacity for the entire duration of the balancing product. In the modified use case, on the other hand, 33% of the nominal capacity is sufficient. Thus, less supply is needed and a larger operating range remains available for operation on the spot market.

Fig. 15 shows annual duration curves for the reference and modified use cases with a bidding strategy of 5 times the spot market price. Here it can be seen that a reduction of the minimum load leads to significantly more operating hours, since much more balancing energy can be provided. The time of turbine operation under the original minimum load of 33% of nominal capacity is approximately 1000 h.

From the annual profits in the different electricity market segments it can be concluded that a reduction in the minimum load for operation on the spot market does not add value. The reason for this is that with the optimisation for the spot market operation this partial load range with worse efficiency is not selected anyway. At low prices it will be turned off and operated at high prices in the high load range with optimal efficiency. However, for an operating strategy with balancing procurement, a reduction in the minimum load can enable a significant increase in annual profits.

Based on the results mentioned above it can be concluded that a reduction of the minimum load for a storage power plant increases the number of annual operating hours, but also reduces the number of machine starts. In this case study, a reduction of the minimum load by 50% increases the hours of participation in the balancing market from around 1600 to around 5400. The number of hours the turbine is operating below the original minimum load of 33% (this case only occurs in the modified use case) decreases with increasing bid prices.

5. Synthesis of results and conclusions

There are several limitations in terms of modelling, e.g. day-ahead wholesale and balancing markets are modelled for Central Europe only. However, several statements or estimates can be made. The socio-economic analysis shows that electricity generation and balancing procurement costs can be reduced in all three scenarios by expanding PHS &HS capacities in Austria. The necessity of conventional reserve power plant capacity, mostly defined as peaking unit, is lowered while maintaining a high security of supply level. Due to a shift from conventional power plants to renewable generation technologies, environmental damage costs of up to 1300 M€/a can be avoided in Central Europe when implementing the planned pumped hydro and hydro reservoir storage capacity in Austria in the upcoming years. The profitability studies show that by retrofitting hydro reservoir storages with pumping mode, a more flexible operation on the spot market and much more balancing capacity procurement is possible, since it can act more independently from natural inflows. A reduction of minimum load for a hydro reservoir storage power plant increases the number of annual operating hours. In the considered case study, a reduction of minimum load increases the hours of participation in the balancing
market. Both measures lead to significant increases in profits. With increased utilisation and more frequent machine starts also the wear of machines increases. Therefore, it is important to find the optimum in terms of machine starts and market benefits.

In general, the methodology of both analyses can be applied in any country with similar assumptions, which is mostly the case in the Central European Alps. It is not restricted to PHS and HS expansion in Austria only. The cost reductions and revenues are also presented in Euro per installed turbine capacity, hence, the study provides scalability and transferability for other storage projects as well.

Flexible technologies, especially storages, and interconnections are necessary to comply with the challenges of future electricity systems with high shares of variable RES-E generation. To speed up projects and attract private investors, the European Commission assesses PCIs based on their individual contributions for the European electricity system. In case of positive system benefits, these PCIs have access to funding. The EDisOn + Balancing model seeks the optimal power plant dispatch based on minimal generation costs, there are neither market distortions (e.g. in terms of financial renewable generation support) foreseen in the modelling approach, nor any benefit saving allocation to individual market participants or technologies. In practice, however, when raising the question on savings sharing among PCI projects, the total PCI funding (100% of savings or less) could be linked to the project specific benefit contribution pro rata by weighting factors. The methodology presented in this paper has been contributing to the ongoing European CBA 2018 assessment of PCI hydro storage projects. Future work shall develop a comprehensive analysis of transnational re-dispatch measures and consider a higher granularity, e.g. in terms of time resolution.

Fig. 14. Quarter-hourly operation, profit (in EUR/(MW installed turbine capacity)) and relative storage level of the storage unit without (left) and with (right) reduction of the minimum load on a sample day (May 13, 2015) in different markets, EPEX and aFRR in AT.

Fig. 15. Annual duration curves of the storage unit with and without reduced minimum load.
Acknowledgements

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Appendix A. Assumptions on Central European scenarios

In Table A.1 the assumed PHS and HS capacities, reservoir volumes and natural inflows for each path are shown.

<table>
<thead>
<tr>
<th>Path</th>
<th>Category</th>
<th>Installed capacity (GW)</th>
<th>Reservoir volumes (GWh)</th>
<th>Natural inflows (GWh/a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A.</td>
<td>PHS:</td>
<td>4.6</td>
<td>3.7</td>
<td>873</td>
</tr>
<tr>
<td></td>
<td>HS:</td>
<td>3.8</td>
<td>–</td>
<td>654</td>
</tr>
<tr>
<td>B.</td>
<td>PHS:</td>
<td>6.8 (+48%)</td>
<td>5.9 (+59%)</td>
<td>1025 (+17%)</td>
</tr>
<tr>
<td></td>
<td>HS:</td>
<td>4.1 (+8%)</td>
<td>–</td>
<td>714 (+9%)</td>
</tr>
<tr>
<td>C.</td>
<td>PHS:</td>
<td>7.8 (+70%)</td>
<td>6.3 (+70%)</td>
<td>1098 (+26%)</td>
</tr>
<tr>
<td></td>
<td>HS:</td>
<td>4.1 (+8%)</td>
<td>–</td>
<td>714 (+9%)</td>
</tr>
</tbody>
</table>

Table A.2 includes the assumed primary energy prices and CO2 certificate prices for the three different scenarios of 2030.

<table>
<thead>
<tr>
<th>IEA WEO 2016</th>
<th>Unit</th>
<th>2030-ST</th>
<th>2030-DG</th>
<th>2030-EC</th>
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<tbody>
<tr>
<td>Nuclear</td>
<td>Euro/MWh</td>
<td>1.69</td>
<td>1.69</td>
<td>1.69</td>
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<tr>
<td>Lignite</td>
<td>Euro/MWh</td>
<td>3.96</td>
<td>3.96</td>
<td>8.28</td>
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<tr>
<td>Hard coal</td>
<td>Euro/MWh</td>
<td>9.72</td>
<td>9.72</td>
<td>15.48</td>
</tr>
<tr>
<td>Gas</td>
<td>Euro/MWh</td>
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<td>31.68</td>
<td>24.84</td>
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<td>Lignite</td>
<td>Euro/MWh</td>
<td>4899.996</td>
<td>658.799</td>
<td>25872</td>
</tr>
<tr>
<td>Hard coal</td>
<td>Euro/MWh</td>
<td>8.28</td>
<td>8.28</td>
<td>27.00</td>
</tr>
<tr>
<td>CO2 prices</td>
<td>Euro/t</td>
<td>84.30</td>
<td>50.00</td>
<td>27.00</td>
</tr>
</tbody>
</table>

In Table A.3 the assumed emission factors per primary energy source are included and the national damage costs of emissions are shown in Table A.4.

<table>
<thead>
<tr>
<th>Unit</th>
<th>CO2 (t/MWh)</th>
<th>SO2 (g/MWh)</th>
<th>NOx (g/MWh)</th>
<th>NMVOC (g/MWh)</th>
<th>PM10 (g/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>0.202</td>
<td>2.448</td>
<td>355.880</td>
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<tr>
<td>Coal</td>
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<td>2753.998</td>
<td>1051.199</td>
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<tr>
<td>Lignite</td>
<td>0.364</td>
<td>4899.996</td>
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<td>Fuel oil</td>
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<td>701.999</td>
<td>13.320</td>
<td>57.600</td>
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<tr>
<td>Other oil</td>
<td>0.267</td>
<td>820.799</td>
<td>464.400</td>
<td>11.664</td>
<td>6.876</td>
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</table>

Table A.4 Assumed national damage costs of emissions for value of a life year (VOLY) and a (higher) value of statistical life (VSL), based on [36].

<table>
<thead>
<tr>
<th>2005-Euro/t</th>
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<th>NOx</th>
<th>NMVOC</th>
<th>PM10</th>
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<tr>
<td>VOLY</td>
<td>VSL</td>
<td>VOLY</td>
<td>VSL</td>
<td>VOLY</td>
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<td>NL</td>
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