
economy
energy
FORUM ECONOGY

FORUM ECONOGY 2011

Programm am 9. November 2011 in den Stahlwelten der voestalpine Linz

10 Jahre Energieinstitut an der Johannes Kepler Universität Linz

9.00 – 10.15 Uhr	**Eröffnung & Plenum**
Priewasser	*Verkehr als energiewirtschaftliche Herausforderung der Zukunft*
10.15 - 10.45 Uhr	**Kaffeepause & Poster**

10.45 – 12.30:	**Energie und Recht**	**Schlüsseltechnologien der Energiezukunft**		**Regionale und nationale Strategien**	
Oberndorfer / Laimighofer	*Kritische Energieinfrastruktur – Sicherheit- und Krisenmanagement in der Energieversorgung*	**Lang**	*Kunststoffe als Innovationsmotor für Solarenergie-Technologien*	**Stöglehner**	*Regionale Energie-Netzwerke – ein Weg zu nachhaltigen Energiesystemen*
Poltschak	*Kooperation und Entflechtung von Übertragungsnetzbetreibern – ein Widerspruch?*	**Kiss**	*Gase – Energieträger der Zukunft*	**Robeischl**	*Entwicklung eines regional angepassten Ressourcenplanes für die Bezirke Freistadt, Perg, Rohrbach und Urfahr –Umgebung – MÜHLVIERTLER RESSOURCENPLAN*
Bieber	*Energiebesteuerung in der EU: Rechtsgrundlagen, Ökologisierungsdefizite und Weiterentwicklungstendenzen*	**Neubarth**	*Integration erneuerbarer Energien in das europäische Stromversorgungssystem*	**Luger**	*Der Beitrag von Klima- und Energiemodellregionen zur Schaffung einer nachhaltigen Ressourcen- und Energiewirtschaft*
Pflüglmayer	*Kyoto – Strafzahlungen für Österreich?*	**Wanek**	*Kraftwerke im Klimawandel – Auswirkungen auf die Erzeugung von Elektrizität*	**Bointner**	*Export- und Wachstumspotentiale erneuerbarer Energiesysteme in Österreich*

12.30 – 13.30 Uhr	**Mittagspause & Poster**

13.30 – 15.00	**Energie- und umweltpolitische Instrumente**	**Erneuerbare Energieträger I**		**Smart Metering**	
Bertenrath	*Effekte steigender Rohöl- und Co_2 Preise im Sektor der privaten Haushalte in Deutschland*	**Christian**	*Wasserkraft in Österreich und deren Rolle bei der Erreichung der EU Energieziele*	**Urban**	*Was nützt zusätzliches Feedback? Ergebnisse einer Pilotstudie zu Smart Metering*
Kettner	*The EU Emission Trading Scheme – Allocation patterns and trading flows*	**Felberbauer**	*Modellierung des Speicherbedarfs im Energiesystem Österreich unter Berücksichtigung eines zukünftig hohen Anteils an erneuerbarer Energie*	**Renner**	*Smart Metering und Privacy: Empfehlungen für die Einführung von intelligenten Messgeräten in Österreich*
Moser	*Vor- und Nachteile Weißer Zertifikate aus theoretischer und praktischer Sicht*	**Kloess**	*Techno-ökonomische Bewertung von Speichertechnologien zur Integration fluktuierender Stromerzeugung*	**Kollmann**	*Innovative Verbrauchsinformationen, Chancen und Herausforderungen – Ergebnisse aus E-Motivation*

15.00 – 15.30 Uhr	**Kaffeepause & Poster**

15.30 – 17.15	**Soziale und nachhaltige Perspektiven**	**Erneuerbare Energieträger II**		**Smart Grids**	
Götz	*Kommunaler Klimaschutz im Kontext steigender Klimaschutzanforderungen und demographischer Veränderungen*	**Kahr**	*Lignocellulosic Biorefineries – Research in Austria*	**Traxler**	*Smart Grids = „Marktorientierte Optimierungsplattform für Elektrizitätssysteme“*
Jungmeier	*Smart Citizens Living A Smart Life – Mögliche Lebensstile in einer nachhaltigen Ressourcen – und Energiewirtschaft*	**Kryvoruchko**	*Neue Geschäftsmodelle für alternative Formen der Biogasnutzung und Integration ins Gesamtenergiesystem*	**Prüggler**	*Grid Regulation in Austria: Smart Grids Incentives or Disincentives?*
Spitzer	*Leben unter Bedingungen von Energiearmut. Ein Beitrag zum Verständnis eines sozial- und umweltverträglichen Energiesystems*	**Balussou**	*Ökologische und energetische Analysen von Co – Vergärungs-anlagen*	**Kunit**	*Infrastrukturen für erneuerbare Energien – Wie „smart“ ist das Smart Grid?*
Hartner	*Input Output Analyse zur Bestimmung von Embedded Energy für aggregierte Produktgruppen in Österreich*	**Hummel**	*Solarthermische Energie in der österreichischen Lebensmittelindustrie*	**Hinterberger**	*Von Smart Grids zu Smart Cities – Die intelligenten Netze der Stadt von morgen am Beispiel Liesing Mitte*

17.15 – 17.30 Uhr	**Schlusswort**

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Vortragende am 9. November 2011 in den Stahlwelten der voestalpine Linz

Kontaktdaten:

Dipl.-Ing. David **Balussou**	Deutsch-französisches Institut für Umweltforschung (DFIU), Karlsruher Institut für Technologie (KIT)	david balussou@kit edu
RA Dr. Roman **Bertenrath**	Institut der deutschen Wirtschaft Köln, Consult GmbH	Bertenrath@iwconsult.de
Dipl.-Ing. Raphael **Bointner**	Institut für Energiesysteme und elektrische Antriebe, TU Wien	bointner@eeg.tuwien.ac.at
Dr. Thomas **Bieber**	Institut für Finanzrecht, Steuerrecht und Steuerpolitik an der JKU Linz	thomas.bieber@jku.at
Prof. Dr. Reinhold **Christian**	Forum Wissenschaft & Umwelt, Wien	office@fwu.at
Dipl.-Ing. (FH) Karl Peter **Felberbauer**	Institut RESOURCES – Institut für Wasser, Energie und Nachhaltigkeit in der Forschungsgruppe Energieforschung, JOANNEUM RESEARCH Graz	karl-peter.felberbauer@joanneum.at
Dipl.-Kfm. Mario **Götz**	Institut für Infrastruktur und Ressourcenmanagement, Wirtschaftswissenschaftliche Fakultät, Universität Leipzig	goetz@wifa.uni-leipzig.de
Mag. Michael **Hartner**	Institut für Energiesysteme und Elektrische Antriebe, TU Wien	michael.hartner@tuwien.ac.at
Dipl.-Ing. Robert **Hinterberger**	NEW ENERGY Capital Invest GmbH, Wien	Robert.Hinterberger@energyinvest.at
Dipl.-Ing. Marcus **Hummel**	TU Wien, Institut für Energiesysteme und Elektrische Antriebe	marcus.hummel@tuwien.ac.at
Mag.ª Dr.in Heike **Kahr**	Engineering and Environmental Sciences, FH Wels	Heike.kahr@fh-wels.at
Mag.ª Claudia **Kettner**	Österreichisches Institut für Wirtschaftsforschung (WIFO), Wien	claudia.kettner@wifo.at
Siegfried **Kiss**	RAG Rohöl-Aufsuchungs Aktiengesellschaft	siegfried.kiss@rag-austria.at
Dipl.-Ing. Dr. Maximilian **Kloess**	Institut für Energiesysteme und elektrische Antriebe, TU Wien	maximilian.kloess@tuwien.ac.at
Mag.ª Dr.in Andrea **Kollmann**	Energieinstitut an der JKU Linz	kollmann@energieinstitut-linz.at
Dipl.-Ing. Dr. Vitaliy **Kryvoruchko**	Leitung Energiesysteme an der HEI Eco Technology GmbH, Wien	vitaliy.kryvoruchko@hei.at
Ing. Mag. Gerhard **Kunit**	WIEN ENERGIE Gasnetz GmbH	gerhard.kunit@wienenergie-gasnetz.at
o.Univ.-Prof. Dipl.-Ing. Dr. Reinhold W. **Lang**	Institute of Polymeric Materials and Testing an der JKU Linz	reinhold.lang@jku.at
MMag. Martin **Luger**	Energieinstitut an der JKU Linz	luger@energieinstitut-linz.at
Mag. Simon **Moser**	Energieinstitut an der JKU Linz	moser@energieinstitut-linz.at
Dipl.-Ing. Dr. Jürgen **Neubarth**	e3 consult, Innsbruck	j.neubarth@e3-consult.at
Dr. Paul **Oberndorfer**/ Dr. Albert **Laimighofer**	Rechtsanwaltskanzlei Beurle-Oberndorfer-Mitterlehner, Linz	office@bom.at
MMag.ª Dr.in Barbara **Pflüglmayer**	Energieinstitut an der JKU Linz	pflueglmayer@energieinstitut-linz.at
Dr.in Elisabeth **Poltschak**	Institut für Verwaltungsrecht und -lehre an der JKU Linz	elisabeth.poltschak@jku.at
a. Univ.-Prof. Dr. Reinhold **Priewasser**	Institut für betriebliche und regionale Umweltwirtschaft an der JKU Linz	reinhold.priewasser@jku.at
Mag.ª (FH) Natalie **Prüggler**	Institut für Erneuerbare Energien, Fachhochschule Technikum Wien	prueggler@technikum-wien.at
Dr. Stephan **Renner**	Österreichischen Energieagentur, Wien	stephan.renner@energyagency.at
Mag. Michael **Robeischl**, PMP	Regionalmanagement für kommunale und wirtschaftliche Entwicklung in OÖ, Geschäftsstelle Mühlviertel	michael.robeischl@rmooe.at
Mag. Markus **Spitzer**	Österreichisches Institut für Nachhaltige Entwicklung , Wien	markus.spitzer@oin.at
Dipl.-Ing. Dr. Gernot **Stöglehner**	Institut für Raumplanung und Ländliche Neuordnung (IRUB), BOKU Wien	gernot.stoeglehner@boku.ac.at
Dipl.-Ing. Ewald **Traxler**	LINZ STROM NETZ GmbH	e.traxler@linzag.at
Dipl.-Ing. Maximilian **Urban**	EVN AG, Maria Enzersdorf	maximilian.urban@evn.at
Dipl.-Ing. (FH) Michael **Wanek**	FH JOANNEUM GmbH, Studiengang Energie- Verkehrs- und Umweltmanagement, Graz	michael.wanek@fh-joanneum.at

Economic assessment of electric storage technologies for the future energy system

DI Dr Maximilian Kloess*
Gusshausstraße 25-29/370-3,
1040 Wien
Telefon: +43 1 58801 370 371
Fax: +43 1 58801 370 397
kloess@eeg.tuwienl.ac.at
www.eeg.tuwien.ac.at

DI Mag Dr Wolfgang Prüggler
Gusshausstraße 25-29/370-3
1040 Wien
Telefon: +43 1 58801 370 369
Fax: +43 1 58801 370 397
prueggler@eeg.tuwien.ac.at
www.eeg.tuwien.ac.at

DI Rusbeh Rezania*
Gusshausstraße 25-29/370-3
1040 Wien
Telefon: +43 1 58801 370 375
Fax: +43 1 58801 370 397
rezania@eeg.tuwienl.ac.at
www.eeg.tuwien.ac.at

DI (FH) Karl-Peter Felberbauer
Leonhardstraße 59
8010 Graz
Telefon: +43 316 876 1332
Fax: +43 316 8769 1332
karl-peter.felberbauer@joanneum.at
http://www.joanneum.at/resources/eng.html

* Korrespondierender Autor

Inhaltsverzeichnis

1 Introduction

Reducing carbon emissions is one of the great challenges the electricity sector is facing today. In the European Union this problem is approached by increasing the share of renewables within the electricity mix [1]. However, integration of renewables brings about some substantial problems for the energy system. For example the discontinuous supply by some of these energy sources. While hydro power usually provides a continuous output, sources like wind and solar power, show a discontinuous supply profile. Their output depends on seasonal and meteorological conditions and often does not correspond with the actual electricity demand. That's why backup capacities are required to cover demand in times with low renewable supply, whereas in times of excessive renewable supply and low demand production has to be curtailed. This leads to less economic efficiency in the system and consequently to higher electricity costs.

This problem can be faced by extending electric storage capacities. With electric storage energy can be stored in times of excessive supply and used in times of supply shortage. This leads to better capacity utilization of renewables sources and a higher efficiency in the systems as a whole. However, the installation of an electric storage requires high investment that has to be economically justified. Like any other energy investment a storage plant will only be realized if it is expected to generate profit. In this paper we analyze different types of electricity storage systems and technologies from an economic perspective. In pursue of that we perform an economic assessment based on present and possible future market conditions.

The remaining paper is structured in the following manner:

Chapter 2 gives and overview on the storage technologies and storage types analyzed. Chapter 3 explains the method of the economic assessment. Chapter 4 discusses the results and chapter 1 will draw conclusions.

2 Electric storage systems

This chapter gives a brief overview on the analyzed storage types and storage technologies.

2.1 System definition

In order to compare technologies we chose different storage types like day-, week- and seasonal storage. For each of these types we define reference characteristics like power and capacity. Since the analysis has a country specific focus on Austria we assumed a plant power of 300 MW which is a typical size for power plant units in Austria. For each storage type different technologies are considered accounting for the properties of the technologies (see Table 1). Capacities of day and week storages are set according to typical pump storage operation schedules for these types. For the seasonal storage capacity is defined according to optimal storage operation of each technology.

Table 1: Specifications of storage systems (data sources: see text)

			day storage					week storage		
			pumped hydro	AA-CAES	NaS	Redox-Flow	Li-Ion	pumped hydro	hydrogen storage	methane storage
Power		[MW]	300	300	300	300	300	300	300	300
Capacity		[MWh]	2100	2100	2100	2100	2100	10500	10500	10500
Efficiency	charging	[%]	92	84	87	87	92	92	68	50
	discharging	[%]	92	84	87	87	92	92	55	55
Lifetime/Depreciation time		[years]	20	20	10	10	10	20	20	20
Investment costs										
ranges based on values found in		[€/kW]	500-1000	600-1200				1000-2500	1500-2200	1200-2800
literature & own estimations:		[€/kWh]			200-500	200-600	500-1500			
values used in the analysis:		[€/kW]	750	1000				1500	2000	2700
		[€/kWh]			400	400	600			
	total	[mio. €]	225	300	840	840	1260	450	600	810

2.2 Pumped hydro

In pumped hydro storages energy is stored by using electricity to drive pumps that lift water to a reservoir at higher altitudes. For discharging this process is reverted and the water from the reservoir drives turbines and generators that convert the energy into electricity. Modern pump hydro plants can reach efficiencies of up to 85% in the total cycle [2]. The technology is considered mature since it has been used for decades with considerable power installed on a global level [3]. The main problem of the technology is the fact that sites with sufficient altitude difference to build such a plant are limited and often far away from actual demand centers.

In the analysis we consider pumped hydro storage for all three defined storage types (see Table 1). Cycle efficiency and specific investment costs are set according to [2] respectively [3].

2.3 Adiabatic compressed air energy storage

Compressed air energy storage (CAES) plants use the potential energy of compressed air to store electricity. The electricity is used to drive compressors that compress the air at high pressure to store it in pressure vessels or in geological formations (e.g. salt caverns). When released the compressed air is used to drive turbines that generate electricity. There are two types of compressed air energy storage plants: diabatic and adiabatic plants. In diabatic plants natural gas has to be co-fired while discharging to keep temperature in the turbine high during expansion of the air. Adiabatic (AA-CAES) systems use the heat accumulated during compression to keep the temperature of the turbine high during expansion. Hence, an AA-CAES consists of a compressed air storage and a thermal energy storage system, making the technology more complex and costly. However, with up to 70% in the cycle it also shows much better efficiency than the diabatic system with up to 50% [2].

Globally there are currently only two diabatic CAES plants in operation [2]. The AA-CAES is still in a conceptual phase [4]. Large scale compressed air energy storage

relies on the availability of suitable geological formations (e.g. salt cavern) that are suitable in size and durability for storage operation. Potential sites where such a CAES can be installed are therefore limited.
As diabatic CAES require fossil fuels for discharge, they appears to be inappropriate for a renewable energy system. Therefore, we only consider AA-CAES in the analysis. Since no large scale projects have been realized so far, we had to estimate investment costs based on data found on diabatic CAES [2] [5] [6] (see Table 1).

2.4 Sodium Sulfur Batteries

Sodium sulfur batteries have been used for power system applications in japan for several years and can be considered a mature technology. They offer good cycle efficiency (≈75%) and high cycle life (≈2500 cycles). Their capacity related investment costs are between 200 and 500 €/kWh [7][8][9][10]. One major disadvantage of the technology is the high standby-losses due to the fact that the cells require high operation temperature (300-350°C) [11].

2.5 Redox Flow Batteries

The redox flow battery consists of two electrolyte reservoirs and a reactor unit. When charged or discharged the electrolyte is pumped to the reaction unit. The power of the systems therefore depends on the reaction unit, the electrochemical cell, whereas the capacity depends on the volume of the electrolyte reservoirs. This makes the systems very flexible for different applications.
The cycle efficiency of the redox flow batteries is around 75 % and the cycle life accounts for approximately 3000 cycles [7][9][12][2]. There seems to be some uncertainty concerning the specific investment costs, since figures found in literature range from 200 to 1000€/kWh [11][7][9].

2.6 Lithium Ion Batteries

Lithium Ion batteries are a relatively new technology in the field of power systems applications. They have excellent cycle efficiency above 90% [7] and high cycle life (≈3000 cycles). Their main disadvantage is their high costs, with specific investment costs ranging from 500 to 1500€/kWh [7][9][11][10].

2.7 Hydrogen storage

In hydrogen storage systems electricity is converted into hydrogen via electrolysis. The hydrogen is then stored either in pressure vessels or in suitable geological formations (e.g. salt caverns). To recover the stored energy hydrogen is fired in thermal power plants (e.g. a gas and steam plant). With 30-40 % the efficiency of the storage cycle is relatively low. So far no large scale plant has been realized. This is why we had to estimate investment costs based on the single components of the system (based on figures found in [9] & [13]) which implicates some uncertainty (see Table 1).

2.8 Renewable methane storage (RES-E-CH_4)

A relatively new approach to store electricity is the conversion into methane. In a frist step electricity is converted into hydrogen, which is then turned into methane by adding CO_2. The methane can be fed in the natural gas grid, respectively natural gas storage facilities can be used for storage. The reconversion to electric power is done by conventional gas and steam plants. There is still uncertainty concerning the reals cycle efficiency that can be achieved. We estimated cycle efficiency to be in the range of 25-30% based on data found in [14]. The main advantage of the concept is the fact that most components of the storage system (natural gas grid and storage, gas and steams plants) already exist and the technology fits well in the structure of the existing power system.

3 Method of approach

In the economic assessment we take a two-step approach. First we compare storage technologies based on defined input parameters. In a second step we simulate optimal storage operation based on electricity spot market prices.

3.1 Storage costs and efficiency

In order to get a brief overview on relevant economic parameter for storage systems we first calculated storage costs on predefined parameters. Basically, storage cost C_s is defined by its capital cost *CC* and operation cost *OC*, the operation time *OT*, the electricity price p_{in} for charging and the efficiency of the storage cycle η. Storage costs are defined by capital costs *CC* and operation costs *OC*. Yearly capital costs are calculated the capital recovery factor defined by the technology specific depreciation time (see table Table 1) and an interest rate of 8%.

$$C_s = \frac{CC+OC}{OT} + p_{in} \cdot (1-\eta) \tag{3-1}$$

$$CC = IC \cdot CRF \tag{3-2}$$

$$CRF = \frac{r \cdot (1+r)^{DT}}{(1+r)^{DT}-1} \tag{3-3}$$

C_s… storage costs [€/MWh]
CC … capital costs [€/MWh/year]
OC … operation costs [€/MWh/year]
OT … operation time [h/day; h/year]
p_{in} … electricity price for charging [€/MWh]
η … storage efficiency (cycle)
IC … investment costs [€/MWh]
CRF … capital recovery factor
r … interest rate [%]
DT … depreciation time [years]

The equations show that the relevant economic parameters for storage technologies are investment costs, efficiency and operation time. In a first step we exogenously define the operation time based on typical day- respectively week-storage operation (day storage: 2555h; week storage: 4275h). If the price of electricity is not considered (p_{in}=0 €/MWh) this leads to the storage costs displayed in Figure 1. The cost range arises from the uncertainties concerning the investment costs of the technology. As explained by equation (3-1), storage costs are also affected by the price of electricity for charging. The price dependent storage costs are depicted in Figure 3.

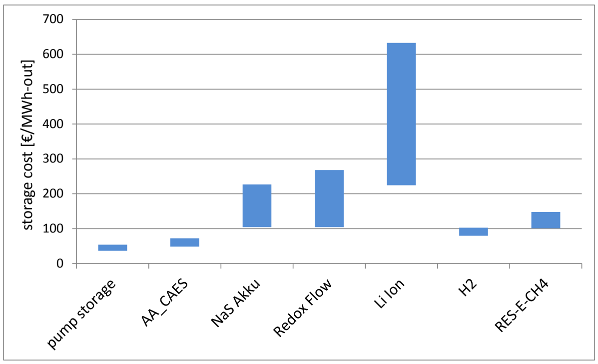

Figure 1: Storage cost of different technologies without considering electricity prices (p_{in} = 0€/MWh)

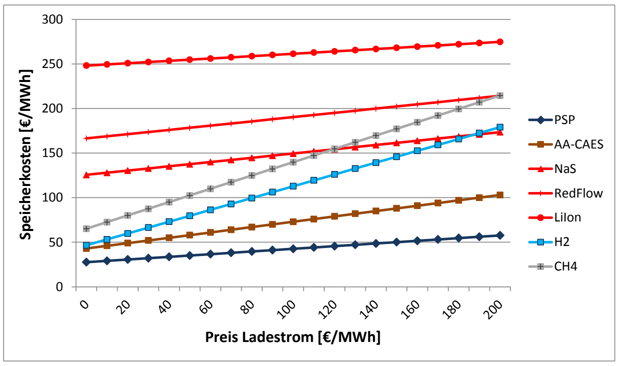

Figure 3: Storage costs of analyzed technologies over electricity price for charging

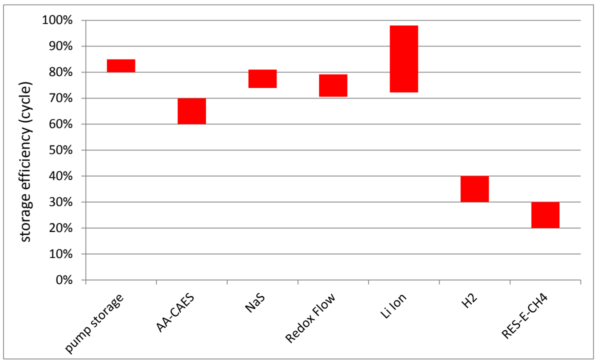

Figure 2: cycle efficiency of analyzed storage technologies

However, in practice defining storage cost is not that straight forward as defined. In real market based operation, time of operation depends on the electricity price as well as on the efficiency of the storage:

$$OT = f(p_{(t)}, \eta_s) \quad \text{(3-4)}$$

p_e … electricity price [€/MWh]

Hence, to gain a real insight in the economic performance of technologies we have to look into real economic storage operation as we will demonstrate in the following chapter.

3.2 Optimal storage operation

For the economic analysis we simulate optimal storage operation for each of the defined systems based on spot market electricity prices. For the simulation we use a linear optimization model implemented in General Algebraic Modeling System GAMS, determining optimal storage operation in order to maximize revenues from peak/off-peak arbitrage:

$$max[R_{p-o}] \quad \text{with} \quad R_{p-o} = p_{(t)} \cdot P \cdot \eta_{out} - \frac{p_{(t)} \cdot P}{\eta_{in}} \tag{3-5}$$

R_{p-o} … revenues from peak/off-peak spread [€/Jahr]
p … electricity price [€/MWh]
P … operation power of the storage

The profit of the storage plant *G* is defined by the revenues as derived from optimal peak-off peak arbitrage operation R_{p-o} and by storage costs *C.*

$$G = R_{p-o} - C \tag{3-6}$$

G … profit [€/year]
R_{p-o} … revenues from peak/off-peak spread [€/year]
C … storage costs [€/MWh]

3.3 Parameter assumptions

As described in the previous section the critical parameters for the economic performance of a storage system are investment costs, storage efficiency and the electricity price. In the following sections we will briefly discuss the assumption made for these parameters.

3.3.1. Investment costs and capital costs:

The assumed investment costs are based on values found in literature. However, it is evident that investment costs can differ considerably even when the same technology is applied. Most of these deviations in cost can be traced back to the site conditions for the specific storage project. Especially, for technologies that rely on specific natural conditions, e.g. pump storage, compressed air storage, on the site, there is a high sensitivity of investment costs with respect to the conditions found. This is why we find a broad range of investments for each technology in literature. A further problem is caused by technology-specific differences. Investment costs of most large scale technologies are given in cost per unit of power. This is appropriate for technologies like pumped hydro plants, where the cost strongly depends on the installed turbine and generator power and less on the capacity of the storage reservoir. However, for batteries this is different. Their investment costs depend solely on the installed capacity. Table 1 displays the ranges of investment costs found in literature as well as the values used in the analysis (see also section 2).

3.3.2. Storage efficiency

Figure 2 shows the ranges of storage efficiency for the analyzed technologies that were found in literature. We used values in the upper band of the ranges to represent the latest state of technology (see Table 1 and section 2).

3.3.3. Electricity prices

For the economic assessment we used 2009 EXAA prices [15]. For the day and week storage we selected typical days (work days and weekend days) for the relevant meteorological seasons (summer, winter, transition). Figure 4 illustrates the run of the prices for the three week-types.

The electricity price is the basis of storage operation and therewith strongly affects the revenues that can be achieved with the storage. In the future electricity prices are expected to increase in Austria as a consequence of higher renewable shares in the supply mix [16]. How this will affect the run of the price curve during the day, week and seasons remains uncertain. Hence, an important question with respect to future storage operation is: Will there by higher peak-/off-peak spreads or will the price curve level out with more renewables in the supply?

In order to test for effects of different price curves on the storage revenues we use a 2020 price scenario. The 2020 prices are based on [16] who estimated development of average electricity prices for different supply scenario. We selected a scenario with high renewable shares (*"CO_2 reduction scenario"*) and created the 2020 price curve by multiplying the 2009 curve with the corresponding factor of price increase. It is evident that this approach leads to higher amplitudes in the price curve and hence to a higher peak- to off-peak spread.

Figure 4: weekly electricity price for summer-, winter- and transition weeks

4 Results

In this section we will explain the results for the analyzed storage types: Day-, week- and year storage. We will present the optimal operation strategies for maximal revenues for the analyzed storage technologies. The revenues will be compared with the estimated yearly costs to derive the profit of the investment. Furthermore, we will perform a sensitivity analysis to test the robustness of the results with respect to changes in investment costs and the electricity price.

4.1 Day storage systems

Figure 5 to Figure 7 show the optimal day-storage operation for the analyzed technologies for the three seasons and the two day types (work day and weekend). Pumped hydro storage, with a cycle efficiency of 85%, is charged during the night starting around 12pm and discharged around midday between 11am and 3pm. In winter days there is a short recharging phase at late afternoon around 5pm, before storage gets completely discharged during evening peak hours (see Figure 5). Lower storage cycle efficiency, like the 75% of NaS and Redox Flow batteries or the 70% of the AA-CAES, leads to different optimal storage operation (see Figure 6). There is a lower maximum state of charge SOC during summer days and no afternoon recharge phase in winter days. The reduced operation time and the higher storage losses lead to lower revenues for less efficient storage systems (see Figure 8). This clearly shows the correlation between storage efficiency and storage operation time and confirms the objections concerning the simple storage cost calculation presented in section 3.1.

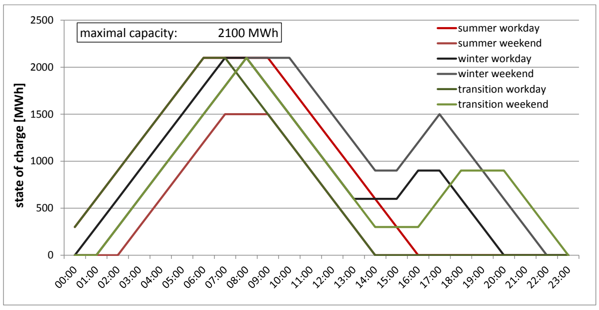

Figure 5 optimal day storage operation – pumped hydro (electricity prices 2009)

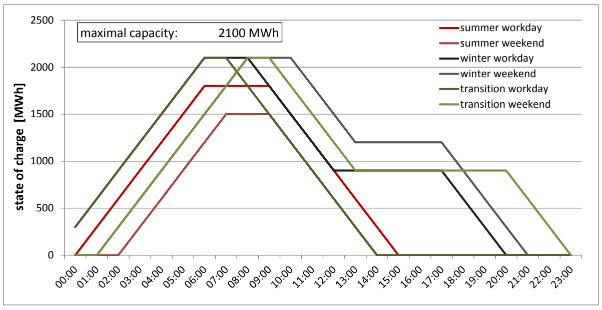

Figure 6: optimal day storage operation – NaS & Redox Flow (electricity prices 2009)

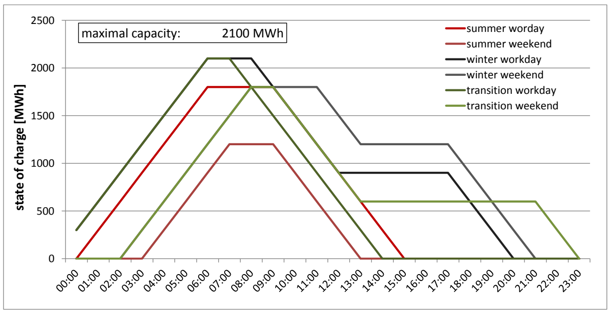

Figure 7 optimal day storage operation – AA-CAES (electricity prices 2009)

Figure 7 gives an overview on revenues and costs of the considered day storage technologies. It shows that with 2009 electricity prices no storage technology is profitable. None of the analyzed technologies can generate a profit under the given assumption. However, pumped hydro and AA-CAES can become cost effective either with higher spreads in the electricity price (see 2020 price scenario in Figure 8) or with lower investment costs, as shown by the sensitivity analysis in Figure 9. The results also indicate that batteries are far too costly for this field of application because of their high capacity-related investment costs.

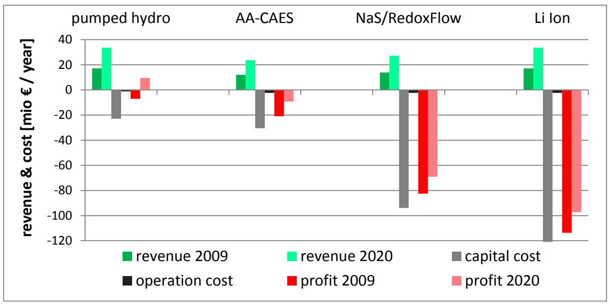

Figure 8 revenues, costs and profit of different technologies in day storage operation

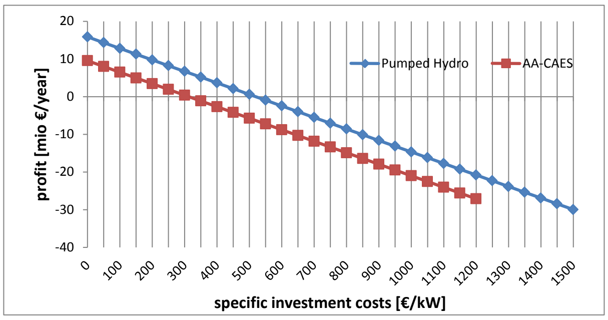

Figure 9: sensitiviy of profit with respect to specific investment costs (prices 2009)

4.2 *Week storage systems*

Figure 10 to Figure 12 show optimal operation of week storage systems for the three seasons. They illustrate how the differences in storage efficiency of the three analyzed technologies (pumped hydro: 85%; hydrogen: 40%; methane: 30%) affect storage operation and consequently revenues (Figure 13). The pumped hydro storage can use both, the weekend to week-day spread, as well as the intraday spread and fully exploits the defined storage capacity (10 500MWh) (see Figure 10). Whereas, the less efficient hydrogen and methane storage systems show much lower storage operation times and use only a fraction of the maximum capacity, leading to low yearly revenues (Figure 11 and Figure 12).

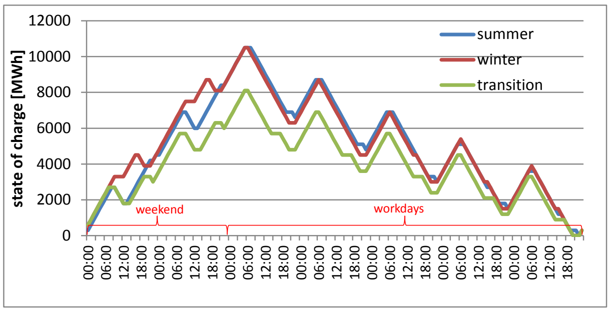

Figure 10: optimal week storage operation – pumped hydro storage

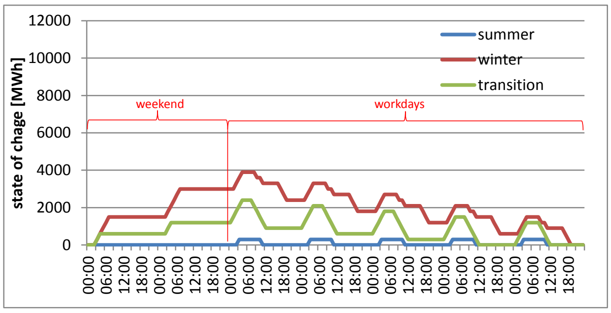

Figure 11: optimal week storage operation – hydrogen storage

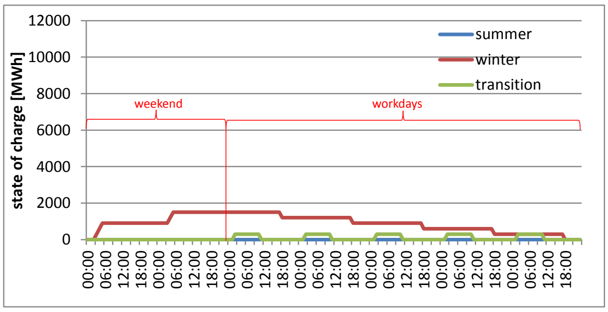

Figure 12: optimal week storage operation – methane storage

Figure 13 and Figure 14 show that, similar to the day storage, pumped hydro can become cost effective with higher spreads in future electricity prices or with lower investment costs. From an economic perspective hydrogen and methane storage systems are not applicable for week storage operation.

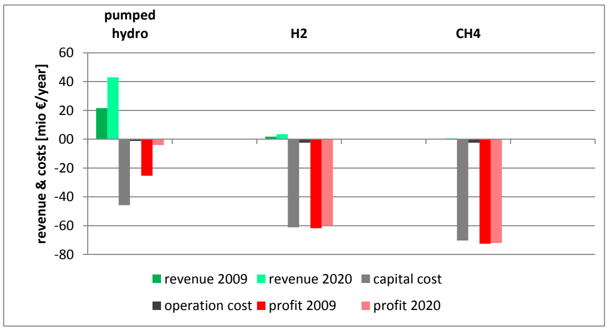

Figure 13: revenues, costs and profit of different technologies in week storage operation

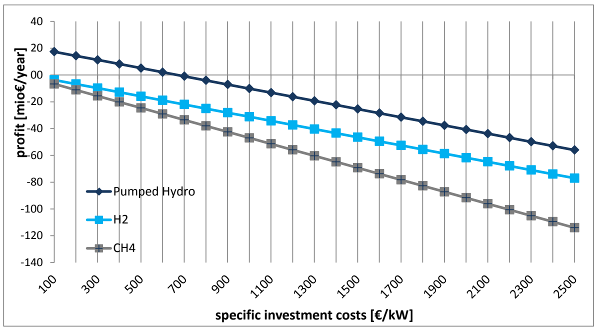

Figure 14: sensitivity of profit with respect to specific investment costs

4.3 Seasonal storage systems

Seasonal storage might become more relevant in the future, due to higher shares of renewable electricity and are therefore included in the economic analysis. We used the same three technologies as analyzed for the week storage, assuming the same system power of 300 MW, but without predefining the storage capacity. The latter is defined by the model in order to generate maximal revenues with each technology.

Figure 15 shows optimal storage operation of the three seasonal storages. They all show the same pattern in storage operation: charging from spring to late autumn and discharging during winter. Similar to the week storage, the storage efficiency does affect the maximum storage capacity. However, in this case the effect on the total storage capacity is much smaller in relative terms. Even low efficient hydrogen and methane storages are storing considerable amount of energy and generating revenues. In Table 2 these yearly revenues are translated into economically feasible specific investment costs. Accordingly investment costs should be below 800 €/kW for the pumped hydro storage, below 200 €/kW for the hydrogen storage and below 150 €/kW for the methane storage to be cost effective.

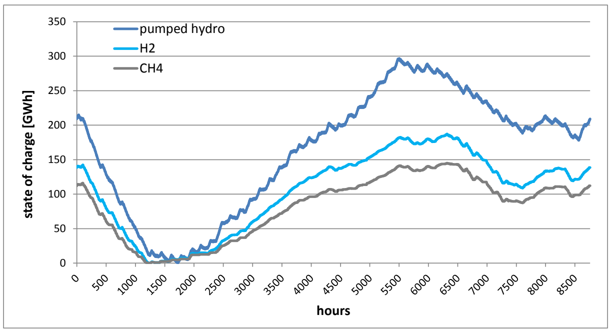

Figure 15: optimal seasonal storage operation of pumped hydro, H2 and methane storage

Table 2 specifications of seasonal storage systems

			seasonal storage		
			pumped hydro	hydrogen storage	methane storage
Power Capacity		[MW] [MWh]	300	300	300
Efficiency	charging	[%]	92	68	50
	discharging	[%]	92	55	55
Optimal storage capacity		[GWh]	297	187	145
Lifetime/Depreciation time		[years]	20	20	20
Storage Revenues		[mio.€/year]	24.4	6.3	4.7
econ. feasible investment costs		[€/kW]	797	206	156

5 Conclusion

The results show that economically pumped hydro storage is still the most attractive technology for all of the three analyzed cases. They have high cycle efficiency and relatively low capacity-related investment costs. For alpine countries like Austria, with potential sites available, pumped hydro will remain the first choice, even in the next years and decades. However, in other countries and regions potential sites for pumped hydro plants are rare (e.g. Germany) or in remote areas far away from demand centers, respectively from fluctuating renewable electricity production sources. In these countries alternative storage technologies will become increasingly important. For day storage operation the AA-CAES could be a promising option. As indicated by the results they are close to becoming cost effective with current technology costs and storage revenues. With decreasing investment cost due to better technological experience and growing production scale, the AA-CAES could be an option for the future. Electrochemical storage technologies in contrast are not likely to become costs effective for the analyzed storage cases, mainly because their capacity-related investment costs are too high to compete with the other large scale technologies. They will have other fields of application (e.g. providing power quality, grid support, small scale local storage etc.).

For storage systems with larger capacities such as week or seasonal storage systems pumped hydro is still the best option, but suitable sites for large capacity become even rarer, calling for alternative options. The analyzed alternative options, hydrogen and methane storage, perform very differently in the two application cases. They are inapplicable as week storage systems, since their efficiency is too low to create considerable revenues. However, they can create considerable revenues in seasonal storage operation. Whether these revenues will be sufficient for these systems to be cost effective, will depend on the development of their investment costs as well as on the future electricity price spread between seasons.

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