The Potential of using Power-to-Liquid Plants for Power Storage Purposes

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Abstract — **The Power-to-Liquid (PtL) concept offers the potential to interlink the power and fuel market by producing high quality fuels from electricity and CO_2. In addition, gaseous by-products from fuel synthesis can be used to generate electricity in peak load hours. In this work, a PtL concept comprising of a reversible solid oxide cell (SOC) is presented and evaluated in terms of 2014 fuel net production costs (NPC) and power storage potential. Results were compared with a reference system operating steady-state in electrolysis mode. A 100 % SOC run factor was realized, whereby the SOC unit runs primarily in co-electrolysis mode. Fuel net production costs (NPC) were slightly higher for the reversible SOC system, since increased capital costs exceed the revenue from lower average electricity costs. Though, fuel costs below 1 €/l are possible if every kWh of effectively stored electricity is credited with 3-9 €ct/kWh, which is the typical storage costs of state-of-the-art pump storage plants.**

Index Terms — Alternative fuels, energy storage, Power-to-Liquid, power supply management, techno-economic analysis

I. INTRODUCTION

Greenhouse gas (GHG) emissions reduction in the transportation sector is a major issue of the European agenda [1]. While electric driving may be an attractive option to decrease GHG emissions in light passenger transport, at least aviation and heavy load road transportation will continue to rely on liquid fuels with high gravimetric and volumetric energy density. The production of alternative fuels from power and CO_2 in the so-called Power-to-Liquid (PtL) concept can integrate the electricity and the fuel market. Thus, the large technical potential of renewable power in Europe can be utilized to reduce GHG emissions in the transport sector significantly. Additionally, future PtL plants might also be used for balancing highly fluctuating electricity generation of renewable power sources such like wind and solar power. Hydrogen can be produced in times of low electricity prices and be stored along with tail gas from Fischer-Tropsch (FT) synthesis. Stored gas can be reconverted to electricity in peak load hours. That concept requires a reversible electrolysis, notably a reversible solid oxide cell (SOC). Advantages and drawbacks of this concept shall be compared with the standard PtL concept. The technical and economic performance of PtL concepts has already been investigated in several techno-economic studies [2-5]. König et al. [6] reported that net production costs of PtL fuel highly depend on the electricity price. Though, a constant electricity price was used for the economic evaluation neglecting the additional potential of utilizing price fluctuations on the power market.

A process model with a nominal electrolysis capacity of 100 MW, corresponding to 18.05 kt/a FT product, together with appropriate gas storage equipment was developed and implemented in flow-sheeting software.

II. SYSTEM DESCRIPTION

A. Flexible SOC-PtL system

Fig. 1 shows the simplified process scheme of the reversible SOC-PtL system based on a SOC. It shall be noted that commercial SOCs are currently only available at small capacities, extensive research is underway to understand the technology, to increase its maturity and to bring large scale units into market [7-8].

In Fig. 1, all streams in electrolysis (SOEC) and fuel cell (SOFC) mode are marked with blue and red arrows, respectively. In SOEC mode, a mixture of steam and CO_2 is converted into syngas (H_2 and CO). By adjusting the CO_2 feed stream, a H_2/CO ratio of approximately 2 at the Fischer-Tropsch synthesis inlet can be achieved. With a SOEC conversion rate between 60-70 %, remaining CO_2 shall be removed by a selexol™ unit and reused as feed-gas. To allow steady Fischer-Tropsch production even in times of power shortage, a defined fraction (separation factor γ) of the syngas is separated after CO_2 removal, compressed to 80 bar and stored in a syngas salt cavern. For example, a SOEC run factor of 80 % corresponds to a separation factor of γ = 0.2 (20 % of the syngas is stored in the salt cavern). Consequently, the fuel output of the system reduces by 20 %. The remaining syngas is converted to fuel in the Fischer-Tropsch reactor [9]. The
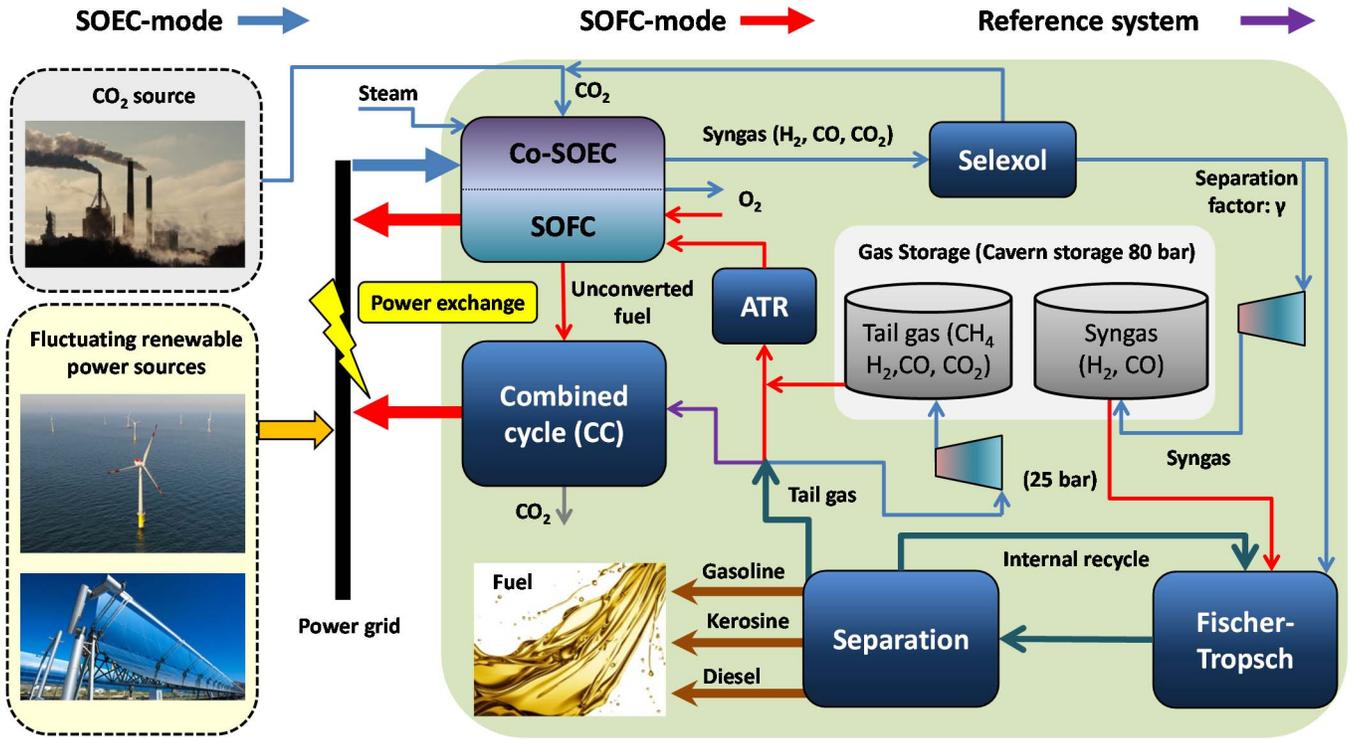
Fig. 1: Simplified process scheme of the proposed reversible SOC system

carbon number distribution of the product can be adequate described by the Anderson-Schulz-Flory (ASF) distribution as shown in equation (1).

$$x_n = (1 - \alpha) \cdot \alpha^{(n-1)} \tag{1}$$

Alpha is an empirically determined constant describing the probability of propagation and termination of the polymerization reaction. The FT-product mixture is separated in a waxen, liquid and gaseous fraction and further refined in the separation section. Wax is processed in a hydrocracker in order to maximize the liquid fuel yield (not shown in Fig 1). Unreacted syngas is partly recycled in the FT-reactor. Methane rich tail gas from FT-synthesis is compressed to 80 bar and stored in the tail gas salt cavern.

In SOFC mode, the syngas storage is discharged to enable steady-state operation of the FT fuel synthesis plant. Tail gas both from the product separation and the second storage system is first pretreated in an autothermal reformer (ATR) before the gas stream is used in the SOC unit in order to generate electricity. The ATR unit is required to reform methane and LPG gases to avoid coking within the SOC unit. Unreacted tail gas is burned in a subsequent combined cycle to maximize electricity output.

B. Reference system

A reference system in terms of a steady state PtL system is introduced to demonstrate the advantages and drawbacks from the power flexibility of the SOC-PtL approach. The reference system deviates only slightly from the SOEC/SOFC system. By definition, the SOC unit runs in SOEC mode at all times making any storage capacity redundant. Tail gas originating from product separation is directly utilized in the combined cycle plant (illustrated with the purple arrow in Fig. 1) and power consumption from the power grid is reduced.

III. MODELLING ASSUMPTIONS

A. Reverse SOC unit

As no data are available on performance characteristics of large scale reverse SOC systems, typical values for small scale (< 1 MW installed capacity) stand-alone SOEC and SOFC were used and adopted for the required plant size [2-8,15]. The main assumptions are summarized in Table 1.

TABLE I. CHARACTERISTICS OF REVERSIBLE SOC UNIT

Main characteristics of SOC unit		SOEC mode	SOFC mode
Electrical efficiency	(%)	0.77	0.70
Conversion rate	(%)	0.67	0.67
Operating temperature	(°C)	800	800
Operating pressure	(bar)	25	25
Operating potential	(V)	1.3	0.70
Current density	(A/cm²)	1	1
Total Current	(MA)	74.4	74.4

The current density shall be the same in both SOC modes and the reference case. Cell degeneration due to load changes was neglected in a first attempt, but shall be investigated experimentally in detail in future products.

B. Fischer-Tropsch synthesis

As it was intended to maximize the share of the liquid product, a cobalt-catalyzed low temperature fixed bed reactor operating at 200-250 °C and 20-30 bar [9] was investigated in this work. The product distribution was described by the ASF distribution with α = 0.85. Methane yield was adjusted to 12 %. A conversion efficiency of 40 % with regard to CO was assumed. An inert gas proportion of max 50 % in the feed-gas was postulated according to [10]. This was realized by adjusting the material flow of the recycle stream.

C. Determining the SOEC runfactor

One mayor objective of the reversible SOC system is to enable a steady-state operation of the FT fuel synthesis plant. In SOEC mode, both gas storage systems (tail gas and syngas)

are filled up. The storage loading rate of both systems is thereby a function of the separation factor γ. In other words, if SOEC run factor is decreased, a higher syngas portion has to be stored (γ is increased) to enable a steady-state FT-synthesis operation for a longer period with no syngas production. Smaller average syngas supply results in less fuel output together with less tail gas production. On the contrary, the longer the SOFC operation lasts, the more tail gas needs to be stored during SOEC mode. Fig. 2 shows, that exactly one operation point of equal tail gas production and consumption can be found. The equilibrium is indicated in Fig. 2 at an SOEC run factor of approximately 80 %.
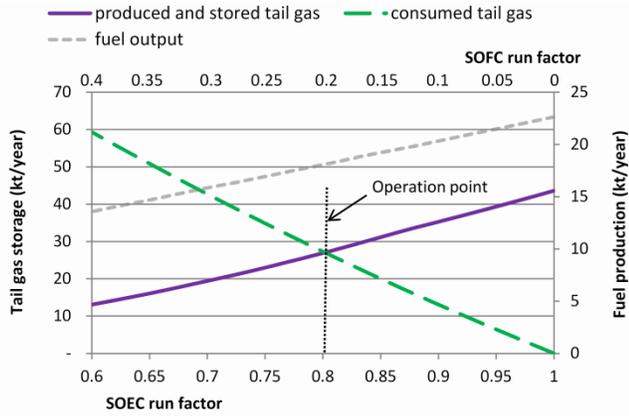

Fig. 2: Produced and consumed tail gas as a function of SOEC run factor

IV. METHODOLOGY OF TECHNO-ECONOMIC ANALYSIS

A standard approach adapted from the chemical process industry [11] was used to estimate key economic performance parameters such like capital expenditure (CAPEX), operational expenditure (OPEX) and fuel net production costs. The calculations were implemented in an in-house Tool TEPET (Techno Economic Process Evaluation Tool) to enable seamless interaction between process simulation and economic evaluation.

A. CAPEX

Equipment costs (EC) and total CAPEX were derived using the flow-sheeting simulation capacities (S) according to equation (2) and (3), respectively.

$$EC = EC_{ref} * \left(\frac{S}{S_{ref}}\right)^d * \frac{CEPCI_{2014}}{CEPCI_{ref}} * F_{pre} * F_{mat} \quad (2)$$

$$CAPEX = \sum(EC_i * \sum F_j) \quad (3)$$

Equipment costs (EC_{ref}) and capacities (S_{ref}) of reference equipment was scaled according to the calculated capacity from the process simulation (S) using a component specific digression factor (d). The reference data of the main equipment are summarized in Table II.

TABLE II. REFERENCE EQUIPMENT COSTS

[a]costs given in million € (2014)

Equipment	EC_{ref}[a]	S_{ref}	Unit	d	Ref.
ATR	33.2	400	MW (thermal capacity)	0.7	[12]
FT-reactor	17.6	1	m³ (reactor volume)	1	[13]
Gas turbine cycle	8.47	25	MW (power output)	0.7	[14]
Gas/liquid separator	0.09	10	m (unit length)	0.7	[11]
Hydrocracker	7.79	1.13	kg/s (feed mass flow)	0.7	[3]
Selexol unit	59.5	9909	kmol/h (CO2 in feed)	0.7	[14]
SOC unit	930	1	MW (installed capacity)	1	[15]
Steam turbine cycle	0.34	10.5	MW (power output)	0.44	[13]

Data were updated with the Chemical Engineering Plant Cost Index (CEPCI), higher costs due to operation pressure and/or material requirements were considered by the multipliers F_{pre} and F_{mat}. Additional factors (F_j) were multiplied with the unit equipment costs (EC) in order to account for the plant construction. The applied factors are summarized in Table III according to [11].

TABLE III. APPLIED FACTORS FOR ESTIMATING TOTAL CAPEX

Factor F_j	value	Factor F_j	value
Installation factor	0.47	Service facilities	0.55
Instrumentation and control	0.36	Engineering	0.33
Piping system	0.68	Construction expenses	0.41
Electrical systems	0.11	Legal expenses	0.04
Buildings	0.18	Contractor's fee	0.05
Yard improvements	0.1	Contingency	0.1

B. OPEX

Mass flows from the process simulation were multiplied with mean annual market prices (Table IV) to calculate raw material costs.

TABLE IV. MARKET PRICES FOR RAW MATERIALS AND UTILITIES

Raw material / utility	Market price		Ref.
Clean water	1.71	(€/m³)	[16]
CO2	37.75	(€/t)	[17]
Oxygen	50	(€/t)	[18]
Power price (reference case)	31.8	(€/MWh)	[19]
Selexol	4.75	(€/kg)	[20]
Waste water	0.56	(€/m3)	[11]

Hourly market prices from the European Energy Exchange (EEX) were used in the flexible SOC model in order to exploit price fluctuations (see next subsection). Labor costs and other operational expenses for e.g. maintenance, insurances and taxes were estimated based on the methodology presented in [11]. Operational expenditures were broken down in costs for raw materials and utilities (referred to as "direct OPEX") and other operational costs (referred to as "indirect OPEX").

C. Accounting for fluctuating power prices

In the flexible SOC system, electricity is only consumed during SOEC mode, whereas power is exported to the power grid in SOFC mode. Expenses for power can be reduced when hydrogen is only produced in hours with low electricity prices. On the other hand, switching to SOFC mode in hours of high power costs offers the potential of maximizing revenues from power export. It was assumed that the system imports and exports electricity at the hourly market prices defined at the European Energy Exchange (EEX) in terms of the Physical Electricity Index (Phelix). Phelix can be interpreted as pure power net production costs without accounting for taxes, grid fees and levies due to the German renewable energy act (EEG). Hourly EEX market prices from 2015 [19] were rearranged in ascending order as shown in Fig. 3 (left). As a second step, average electricity purchase costs were estimated as a function of SOEC run factor assuming that electricity is only consumed in hours with low electricity costs (Fig. 3, right). Based on the supposed SOEC run factor of 80 %, power prices vary in the range between -80 €/MWh and 40 €/MWh (Fig. 3, left). At the defined operation point, annual average power prices in SOEC mode and revenue in SOFC mode of approximately 27 €/MWh and 49 €/MWh, respectively, were identified. For the reference system with SOEC run factor of 1, the average electricity price was 31.8 €/MWh. In order to ensure economic feasibility of the SOC-PtL concept, the profit due to utilizing the market price
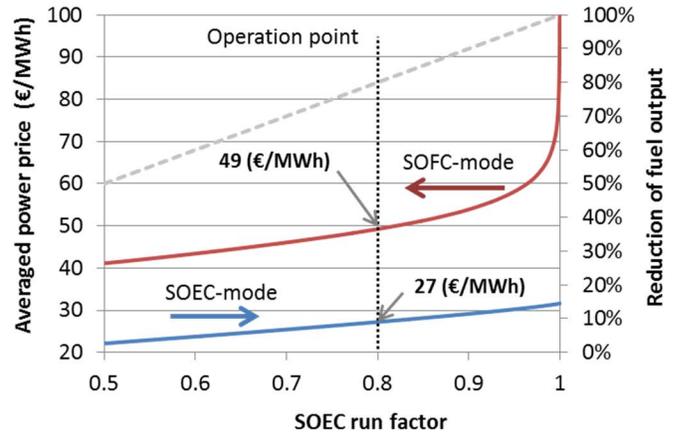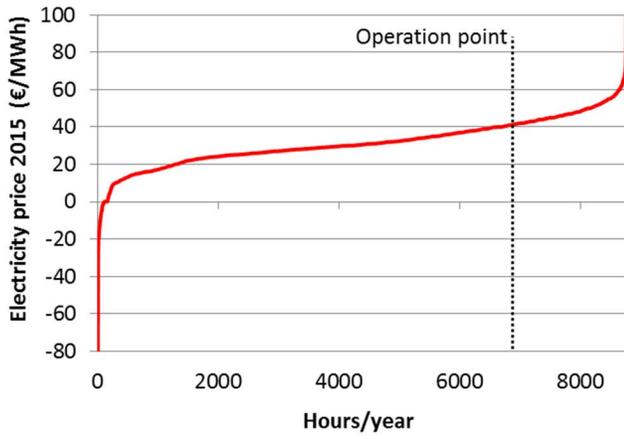
Fig.3: Listing of EEX electricity prices in ascending order according to [19] (left) and average EEX prices for importing/exporting electricity as a function of SOEC run factor (right)

difference of 22 €/MWh has to be larger than the increased investment costs, which arises due to additional equipment in terms of the larger combined cycle plant, compressors, gas storage and ATR. Furthermore, the total yearly product output is decreased by 20 % compared to the reference concept, since capacity of FT-synthesis is reduced linearly with the SOEC run factor. Hence, fuel specific investment costs (Investment costs/Product output) are even more increased.

D. NPC

NPC were estimated based on the total annual money flows in terms of annuity rate, OPEX and revenue from electricity export, divided by the yearly product output. An interest rate of 7 % and a plant operating time of 30 years was assumed. In order to simplify calculations, a PtL plant capacity factor of 100 % was assumed, corresponding to 8760 run hours per year.

V. RESULTS

A. Material flows and energy balance

Table V summarizes the energy and material flows in the reference (steady-state SOEC-PtL) and power flexible SOC-PtL system. Streams leaving the system have by convention a positive sign.

TABLE V.   MATERIAL AND ENERGY FLOWS

Material flows (t/h)	Concept		
	reference	*reversible SOC*	
		SOEC mode	*SOFC mode*
clean water	- 25.3	- 23.6	- 13.6
CO₂	-8.1	- 17	41.7
oxygen	7.8	19.9	- 10.1
liquid fuel	2.59	2.06	2.06
syngas to cavern	0	2.44	- 9.7
tail gas to cavern	0	3.9	-15.6
waste water	23	12.86	5.04
Energy balance (MW)			
power	-78.1	-100.2	137.5
to syngas cavern (LHV)	0	18.1	- 72.4
to tail gas cavern (LHV)	0	34.72	- 138.9
liquid fuel (LHV)	29.1	23.19	23.19
losses	49	24.19	50.6

The reference system is characterized by a constant electricity demand of 78.1 MW and a fuel output of approximately 29.1 MW resulting in a power-to-fuel efficiency of 37 %. In the reversible SOC case, power consumption in SOEC mode is higher (100.2 MW ≙ +33). During SOFC mode, around 137.5 MW is exported to the

power grid. Hence, a load change of 237 MW is realized indicating a large potential for balancing fluctuating power sources. However, the authors are aware of power grid stability issues arising by a sudden load change of that magnitude. Though, part load operation modes are possible allowing a smooth load change. Fuel output is reduced by 20 % in the reversible SOC plant due to the smaller FT-synthesis section. A considerable high Power-to-fuel efficiency of 44 % was estimated for the reversible SOC system according to equation (4) based on a SOEC run factor of 80 %.

$$\eta_{power-to-fuel} = \frac{23.19\ MW}{0.8*100.2\ MW - 0.2*137.5\ MW} \approx 44\ \% \quad (4)$$

The significant higher power-to-fuel efficiency can be explained by the better performance of the power generation system in the reversible SOC case consisting of SOFC in series with a combined cycle plant. Thus, a very high electrical efficiency was realized.

B. Economic evaluation

CAPEX, OPEX and NPC were calculated according to the methodology presented in Chapter IV. The results are summarized in Table VI.

TABLE VI.   ECONOMIC RESULTS

Monetary flows (mio.€/year)	Concept	
	reference	*flexible SOC*
CAPEX	20.95	24.61
direct OPEX	22.15	6.37
indirect OPEX	25.88	28.59
Total annual capital requirements (TCI)	**68.98**	**59.57**
NPC		
fuel output (kt/year) (m_fuel)	22.69	18.05
NPC (€/kg)	**3.04**	**3.30**
NPC (€/l)	**2.13**	**2.31**

Additional equipment such like salt caverns and ATR, requires significant higher capital investments for the flexible SOC concept. On the contrary, direct operational expenditures are reduced by more than 70 % as a result of utilizing power price fluctuations. Thus, total annual capital requirements (TCI) are reduced by approximately 10 % (Table VI). However, since fuel output is 20 % reduced as well, NPC is higher in the flexible SOC concept. Hence, the flexible SOC system is economic feasible only with economic incentives in

terms of support schemes for providing power storage capacity. Equal NPC of both the reference and reversible SOC system are achieved, if the exported electricity is financially supported with $c_{storage}$ = 1.95 €ct/kWh (required TCI reduction divided by annual SOC power production, see equation (5)), which can be interpreted as the "storage cost" for electricity in the flexible SOC-PtL system.

$$c_{storage} = \frac{TCI_{SOC} - NPC_{ref} * m_{fuel,SOC}}{SOFC\ run\ factor * 8760\ h * P_{SOFC}} =$$

$$= \frac{59.57\ mio.\frac{€}{year} - 3.04\frac{€}{kg} * 18.05\frac{kt}{year}}{0.2 * 8760\frac{h}{year} * 137.5\ MW} = 0.0195\ \frac{€}{kWh} \quad (5)$$

That figure shall be compared to other electricity storage costs like pump storage plants, compressed air storage systems and power-to-gas, which are given in [21] in the range of 3-9 €ct/kWh, 4-13 €ct/kWh and 15-29 €ct/kWh, respectively. Fig. 5 shows the impact of storage compensation on fuel production costs (3-9 €ct/kWh, see grey area in Fig. 4). When crediting power storage costs according to current storage market prices (upper range), fuel costs below 1 €/l are possible for SOC plants with electrolyzer capacities larger than 150 MW.
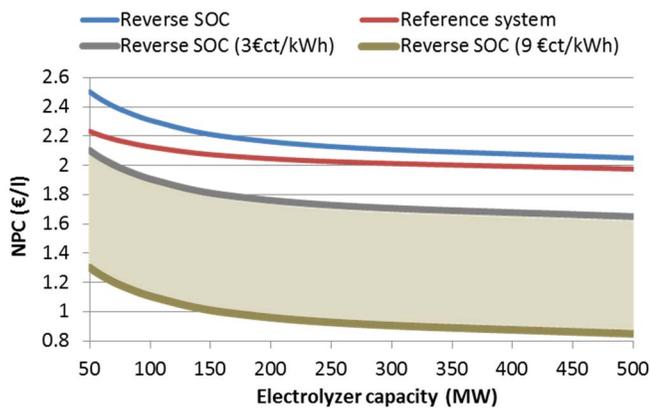

Fig. 4: NPC as a function of electrolyzer capacity and compensation for providing storage capacity

VI. CONCLUSION

A reversible SOC PtL system was investigated and compared to a reference single SOEC system in terms of power storage potential and net fuel production costs. It was shown that reversible PtL systems can efficiently be used for power supply and demand management at low specific power storage costs when a SOC runtime close to 100 % is achieved. Thereby, a load reduction of 237 MW was realized by switching from electrolysis to fuel cell mode. Though, NPC of liquid fuel are slightly higher compared to the reference case when no compensation is paid for providing storage capacity. On the contrary, net fuel production costs below 1 €/l can be achieved when a premium of 7-9 €ct/kWh is paid for stored electricity, which is in the range of specific storage costs of state-of-the-art pump storage power plants.

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