Data Documentation: VEREKON Cost Parameters for 2050 in its Energy System Model

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ABSTRACT

In this data documentation, all relevant cost parameters for determination of levelized cost of electricity (LCOE) are reviewed for the current and future time frames. More than 100 studies, articles and past reviews have been reviewed, adjusted for inflation and statistically analysed. The cost parameters for a range of power generation and storage technologies have been reviewed. In terms of conventional power plants, lignite and hard coal power plants, both open cycle and combined cycle gas turbine plants in addition to biomass co-firing plants were studied. Energy storage technologies featured in the review comprised: lithium ion and redox flow batteries, pumped hydro storage units, adiabatic compressed air energy storage technologies, electrolysers, methanizers and gas storage caverns. The main renewable energy technologies covered were: biogas, concentrated solar power plants, photovoltaic and on-shore and off-shore wind parks.

Keywords:

Levelized cost of energy (LCOE); cost parameters; energy storages; renewable energy

1. Introduction

The EU has set ambitions for the sustainable transformation of energy systems across its member states, with "secure, clean and efficient energy" regarded as one of the "societal challenges" in the Horizon 2020 Programme [1]. Following from the UNFCCC conferences, focused on reducing emissions, the EU established targets for reducing CO_2 emissions, increasing the share of renewables in the power mix and enhancing energy efficiency in the Climate & Energy Package 2020 [2], launched in 2009 and later updated for 2030 in 2014 [3]. The Paris Agreement was the first global legally-binding commitment to limit global warming and reinforced cooperation and responsibility in taking action on climate change [4]. In a wider context of falling costs, the Paris Agreement gave a further boost to the expansion of wind and solar power technologies in the EU [5]. Germany has pledged to reduce its carbon emissions by 80 to 95% by 2050 compared to 1990 baseline levels [6] and, under its *Energiewende* policy, it strives for a minimum share of renewables in gross power consumption of 80% by 2050 [7]. For Germany, the *Energiewende* represents an overhaul of the power system from one which has been centred on fossil fuel generation to one in which intermittent renwable generation dominates. This leads to substantial opportunities and challenges for the German power system, in terms of the expansion of new technologies and how to adapt the system in response to them.

Security of supply, affordability and sustainability are the three core priorities which power systems in the EU must fulfil [8]. In a system characterised by an increasing share of intermittent renewable generation technologies, greater attention must be given to affordability and security of supply, in terms of generation, transmission, distribution and storage capacity [3]. These are the two priorities which present challenges in the context of the *Energiewende*.

To make predictions on how to fulfill the present and coming challenges, energy system simulations have to be made. These simulations need sensible parameters for the power unit's associated costs in order to check, whether a solution that fulfills supply and sustainability objectives is also feasible economically. To create these cost assumptions, one can apply one's own expertise [9], ask experts [10], use current cost and apply learning curves [11], or rely on other sources [12]. These methods all have their own advantages, but may lead to very different results for technologies, that are not well represented in the current market, such as e.g. energy storage technolgies.

In this paper, a comprehensive review of the economics of conventional, renewable and storage technologies is presented. Thereby we develop recommendations for cost assumptions based on suggestions obtained from as many studies as we could access in a reasonable amount of time. In taking an overall estimate for the parameters from these studies, we opted for the median, similar to the approach in [13], drawing on the wisdom of the crowd [14] as this is likely to minimise error[15]. In contrast to [13] we develop suggestions for a very large set of technologies, that are discussed in context of the Energy Transition

2. Methodology

As the cost data and the technical parameters are closely related it makes sense to give a short background for the technologies before presenting the data.

As the term capacity is used differently when referring to conventional power plants and renewable energy generators than when referring to energy storage devices, the following convention is proposed: capacity is used in its physical understanding of capacitance, so as a term of energy. For the conventional and renewable units' "capacity", the term power or rated power is used and it is also used for the energy storage devices. As the term capcity is used differently when referring to conventional power plants and renewable energy procuders than when referring to energy storages, the following convention is proposed: Capacity is used in its physical understanding of capacitance, so as a term of energy [16]. For the conventional and renewable unit's "capacity" the term power or rated power is used, as it is used for the energy storages.

Further all costs are based in €$_{2015}$ as 2015 constitutes a base year for the price index [17]. As the sources had their cost projections in US-$, €, and CHF, yearly average exchange rates according to [18–20] were used as they are depcited in Table 1. If a source did not specify its base year for cost parameters, it was assumed to be the year of publication, if the publication was published after June that year, other than that the prior year to publication was assumed.

Table 1: Factors for calculating source values to €$_{2015}$ according to [17–20]

Year	Inflation Index in %	€ in US-$	€ in £	€ in CHF
2005	1.6	1.24	0.68	1.55
2006	1.5	1.26	0.68	1.57
2007	2.3	1.37	0.68	1.64
2008	2.6	1.47	0.80	1.59
2009	0.3	1.39	0.89	1.51
2010	1.1	1.33	0.86	1.38
2011	2.1	1.39	0.87	1.23
2012	2.0	1.28	0.81	1.21
2013	1.4	1.33	0.85	1.23
2014	1.0	1.33	0.81	1.21
2015	0.5	1.11	0.73	1.07
2016	0.5	1.11	0.82	1.09
2017	1.5	1.13	0.88	1.11
2018	1.8	1.18	0.88	1.16

Operation and maintenance cost for conventional power generation units are given in two parts. The fixed O&M cost, which cover regular inspections, insurance, and recurring maintenance tasks, are thought of as a yearly expense, given either in €/kW or as a $\%_{\mathrm{Invest}}$/a. The variable O&M cost are thought as wear and tear related maintenance cost and are considered relative to the delivered energy of the plant, and are, therefore, given in €/MWh. The latter of O&M cost are mainly given for conventional power plants and sometimes for wind parks. As wind turbines can have a fixed tarif covering for all maintenance- related costs and since conventional power plant owners abolish the variable O&M cost component as part of their cost calculation due to lower full-load hours, we refrain from reviewing variable O&M costs. Instead, we suggest to only use fixed O&M cost for energy system projections. Nonetheless, for project planning, considering variable O&M cost might still be sensible.
Another important part in the cost calculation is the assumed lifetime of the deviceassumed, as it has a high influence on the annuity as can be seen from

$$A = I\,\frac{(1+i)^n \cdot i}{(1+\,i)^n - 1}. \tag{2.1}$$

where A is the annuity in €/a, I the investment in €, i the interest rate and n the lifetime or more accuratly the amortization period. For a private project planned by a private investor, the interest rate would be the $WACC$ (weight average cost of capital), representing the returns required on the mix of equity and debt used to finance the projectand n the repayment period. As this paper is more concenered with finding appropriate assumptions for energy system simulation than finding the levelised cost of electricty (LCOE), the technical lifetime seems the more appropriate parameter for the lifetime of the device.

3. RESULTS

3.1. Conventional power plants

Conventional power plants refer to various configurations of coal plants and gas plants which will deliver residual back-up power to renewables in the future power system [21]. Hard coal plants can burn coal or be adapted for biomass whereas gas plants come in the form of Open Cycle Gas Turbine (OCGT) plants or Combined Cycle Gas Turbine (CCGT) plants. Residual conventional power plants may be fitted with carbon capture and storage technology [22], in order to minimise their carbon output. Moreover, hard coal power plants adapted for co-firing biomass could represent a negative emissions technology, if fitted with a CCS device [23]. Energy crops would be grown to substitute fossil fuels, absorbing CO_2 in the growth process, and CO_2 would then be captured and stored following fuel combustion, removing CO_2 from the cycle [24]. Residual power plants may act as part of long-term storage systems, through converting hydrogen and synthetic natural gas, produced during times of surplus renewable power, back into electricity at times of renewable power shortfalls [25].

Since conventional power plant technologies are mature, the estimates for cost and key technical parameters do not show a systematic divergence between the current period, 2030 and 2050, as is shown in figures on pages 6-10. For coal, in relation to supercritical plants, [26] estimate learning rates for overall plant construction costs to be between 1.1% and 3.5%, assuming 100 GW of new capacity. With respect to advanced combined cycle gas turbines, a learning rate of 5% for the period 2013-2040 is estimated in [27] For CCGT plants with CCS technology, learning rates are estimated at between 2 and 7% [26]. These learning rates indicate that the potential for further cost reductions are relatively limited for conventional plants. The addition of CCS technology leads to a substantial increase in costs for conventional power plants, with the costs of gas plants doubling and coal plants with post-combustion CCS systems costing 70% more than conventional plants [28].

There is a certain difference among sources in terms of the efficiency of conventional power plants and this is significant to both the cost and environmental impact of these plants. The most efficient coal plants are plants which operate at high pressure, allowing higher efficiencies namely super-critical and ultra-supercritical plants [29], with efficiencies for 2050 of up to $\eta_{\mathrm{el,netto}} = 50\%$ deemed possible by [29]. Other estimates are slightly less optimistic about the possible efficiencies, with [30] citing a net electrical efficiency of 46% and [27] offering a range of possible efficiencies, from 47%, at the lower end, 48% as a baseline and 49% as a higher estimate. For 2050, the efficiency of OCGT plants is estimated at a maximum of 46%, with 63-64% efficiency considered the best case scenario for CCGT plants [29]. Equipping conventional plants with CCS technology incurs substantial efficiency losses. For both coal plants and gas plants, efficiency losses from post-combustion (the most mature technology currently available) result from the low CO_2 level in the flue gas, leading to difficulty in achieving a sufficient CO_2 concentration for transport and storage [31], with [32] estimating an efficiency loss of 10-12 %-pts. resulting from the use of post-combustion capture technology. For gas plants, implementing post-combustion technology results in estimated efficiency penalty of around 8%-pts. [31].

The net load of the German power system will exhibit greater variability, leading to changes in how the remaining residual plants are operated [33]. There will be a shift from coal to CCGT plants, with CCGT plants experiencing a far higher number of start-ups in 2030 compared to 2013, with the share of start-up costs as an overall share of variable costs increasing [33]. Start-up costs will, nevertheless, remain a small component of overall costs, unless assumptions change [33]. Power-to-gas technologies will play a crucial role in sector coupling, whereby renewable electricity will be converted to gas and heat allowing greater flexibility options [34]. Indeed, under a scenario of 85% cuts in carbon emissions, one third of power generated in Germany in 2050 should be used to produce hydrogen, synthetic methane and synthetic liquid fuels [21]. This implies that there will be still a substantial role for conventional gas turbines and turbines capable of burning hydrogen. Gas turbines have to be adapted to burn hydrogen, due to hydrogen's different properties which can make it less stable and there is a need to adapt the combustion process in order to minimise the emission of NO_x [35]. In terms of the technical feasibility, Kawasaki has developed turbines which can operate on 100% hydrogen and natural gas mix [35] and Siemens has developed turbines which can combust a fuel mix consisting of between 20 to 90% hydrogen, leaving at least the remaining 10% for steam recirculation to pass emission tests [36]. This demonstrates that the technology is available, although there is currently very little information relating to the economic parameters of hydrogen turbines.

Table 2: Values for Hard Coal

Type		Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value
Invest Cost in €$_{2015}$/kW	Current	1271	1434	1480	1593	1819	2025
	Sources			[12,28,29,37–45]			
	2030	1271	1406	1439	1544	1800	1839
	Sources			[12,28,29,37,39,40,42,45,46]			
	2050	1271	1406	1439	1544	1572	1839
	Sources			[12,28,29,37,39,40,42,45–47]			
O&M Cost in %$_{\mathrm{Invest}}$/a	Current	1.3	1.9	2.5	2.3	2.6	4.0
	Sources			[12,28,29,37–40,42–45]			
	2030	1.3	1.98	2.25	2.25	2.6	3.1
	Sources			[12,28,29,37,39,40,45,46]			
	2050	1.3	2.0	2.5	2.44	2.6	4.0
	Sources			[12,28,29,37,39,40,42,45–47]			
Fuel Cost in €$_{2015}$/MWh$_{th}$	Current	7	10	10	11	12	20
	Sources			[11,12,28–30,33,37–40,42–44,48]			
	2030	5	11	13	14	16	25

	Sources			[11,12,29,30,33,37–40,42,46,48]			
	2050	5	11	16	17	20	35
	Sources			[11,12,29,30,37–40,42,46–48]			
Lifetime in a	Current	25	36.25	40	39.64	43.75	50
	Sources			[12,28,29,37–43,45]			
	2030	35	37.5	40	40.91	43.75	50
	Sources			[12,28,29,37,39,40,42,45,46]			
	2050	25	35	40	39.58	45	50
	Sources			[12,28,29,37,39,40,42,45–47]			

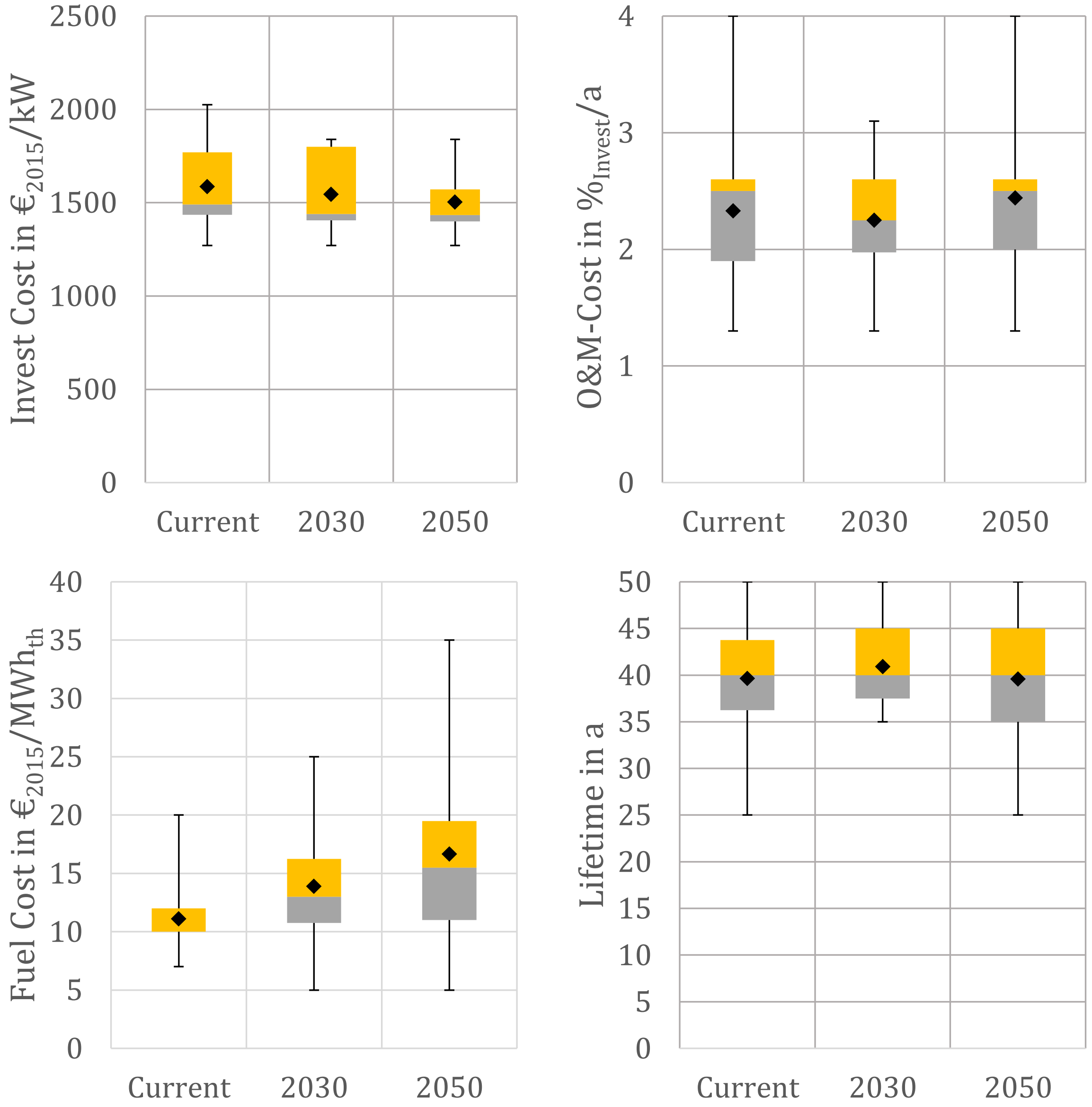

Figure 1 All Cost Parameters for Hard Coal

Table 3: Values for Lignite

Type		Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value
Invest Cost in €2015/kW	Current	1498	1582	1708	1833	2020	2568
	Sources			[28,29,37–42,44,45]			
	2030	1498	1563	1611	1748	2014	2100
	Sources			[28,29,37,39,40,42,45,46]			
	2050	1498	1564	1622	1720	1800	2033
	Sources			[28,29,37,39,40,42,45,46]			

O&M Cost in $\%_{Invest}$/a	Current	1.6	2.0	2.25	2.33	2.75	3.1
	Sources			[28,29,37–40,42,44,45]			
	2030	2.0	2.23	2.5	2.56	2.93	3.3
	Sources			[28,29,37,39,40,42,45,46]			
	2050	2.0	2.4	2.5	2.66	3.0	3.3
	Sources			[28,29,37,39,40,42,45,46]			
Fuel Cost in $€_{2015}/MWh_{th}$	Current	1.5	1.6	3.1	3.0	3.9	5.5
	Sources			[11,28–30,33,38,39,44]			
	2030	1.6	2.1	3.9	3.6	4.7	6.0
	Sources			[11,29,30,33,38,39,46]			
	2050	1.5	2.7	4.0	4.0	5.6	6.0
	Sources			[11,29,30,38,39,46]			
Lifetime in a	Current	35	38.75	40	40.8	45	50
	Sources			[28,29,37–42,45]			
	2030	35	40	40	41.6	45	50
	Sources			[28,29,37,39,40,42,45,46]			
	2050	35	40	40	41.6	45	50
	Sources			[28,29,37,39,40,42,45,46]			

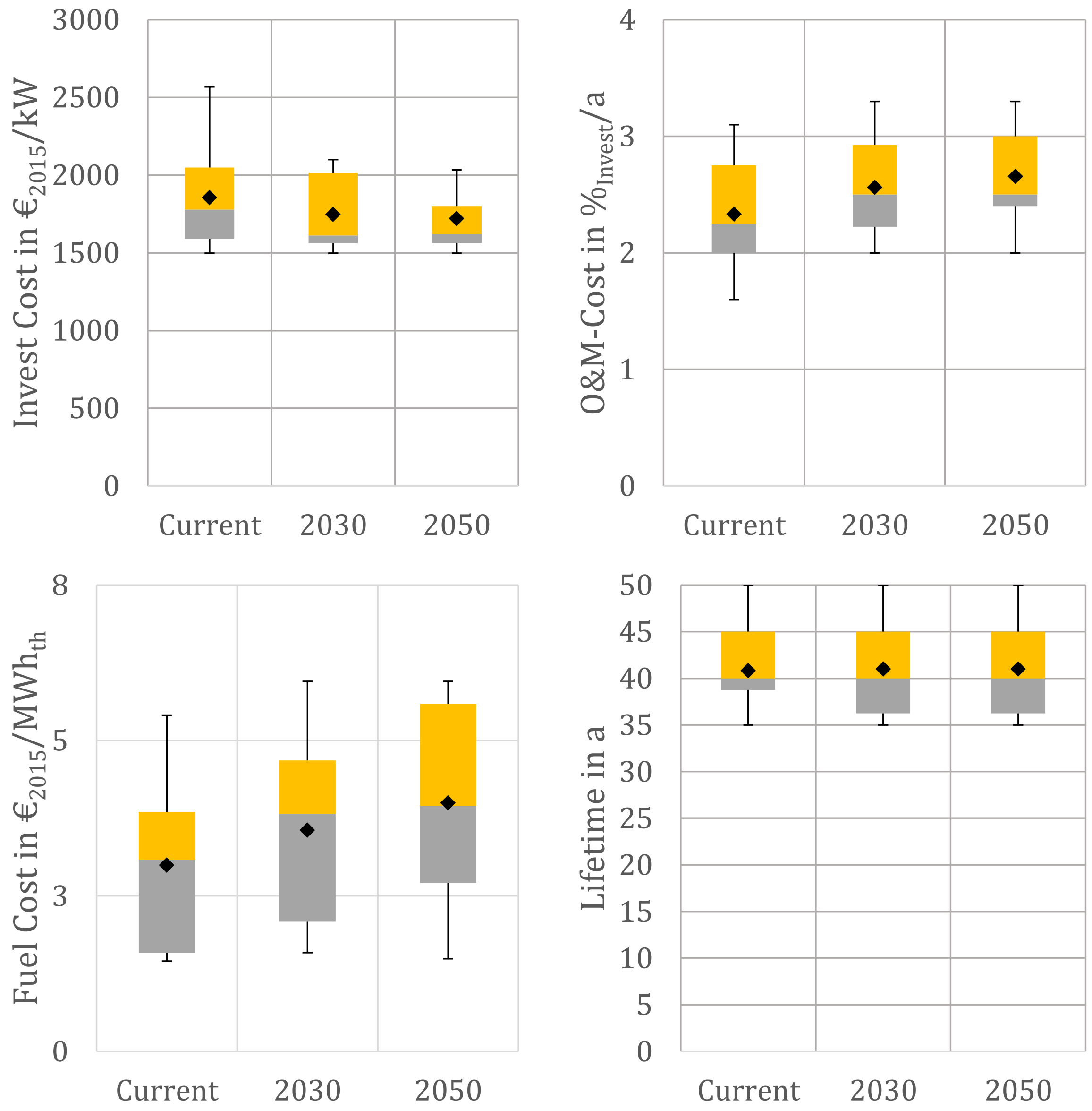

Figure 2 All Cost Parameters for Lignite

Table 4: Values for CCGT

Type		Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value
Invest Cost in €$_{2015}$/kW	Current	505	702	783	787	874	1075
	Sources	[11,12,28,29,37–45,49–51]					
	2030	505	692	779	757	833	973
	Sources	[12,28,29,39,40,42,45,46,49,52]					
	2050	600	700	743	773	865	963
	Sources	[11,12,28,29,37,39,40,42,45–47]					
O&M Cost in %$_{Invest}$/a	Current	0.5	2.4	2.75	2.62	3.0	4.0
	Sources	[11,12,28,29,37–40,42–45,49–51]					
	2030	1.2	2.5	3.0	2.86	3.2	3.9
	Sources	[12,28,29,37,39,40,42,45,49,52]					
	2050	1.25	2.5	3.0	2.93	3.4	4.0
	Sources	[11,12,28,29,37,39,40,42,45,47]					
Fuel Cost in €$_{2015}$/MWh$_{th}$	Current	14	23	26	26	31	37
	Sources	[11,12,28–30,33,37,38,40,42–44,48,53]					
	2030	15	30	33	33	37	44
	Sources	[11,12,29,30,33,37,38,40,42,46,48,53]					
	2050	15	33	40	39	47	59
	Sources	[11,12,29,30,37,38,40,42,46–48,53]					
Lifetime in a	Current	25	25	30	30.44	32.25	40
	Sources	[11,12,28,29,37–43,45,51]					
	2030	25	25	30	31	35	40
	Sources	[12,28,29,37,39,40,42,45]					
	2050	25	25	30	31.64	38.75	40
	Sources	[11,12,28,29,37,39,40,42,45,47]					

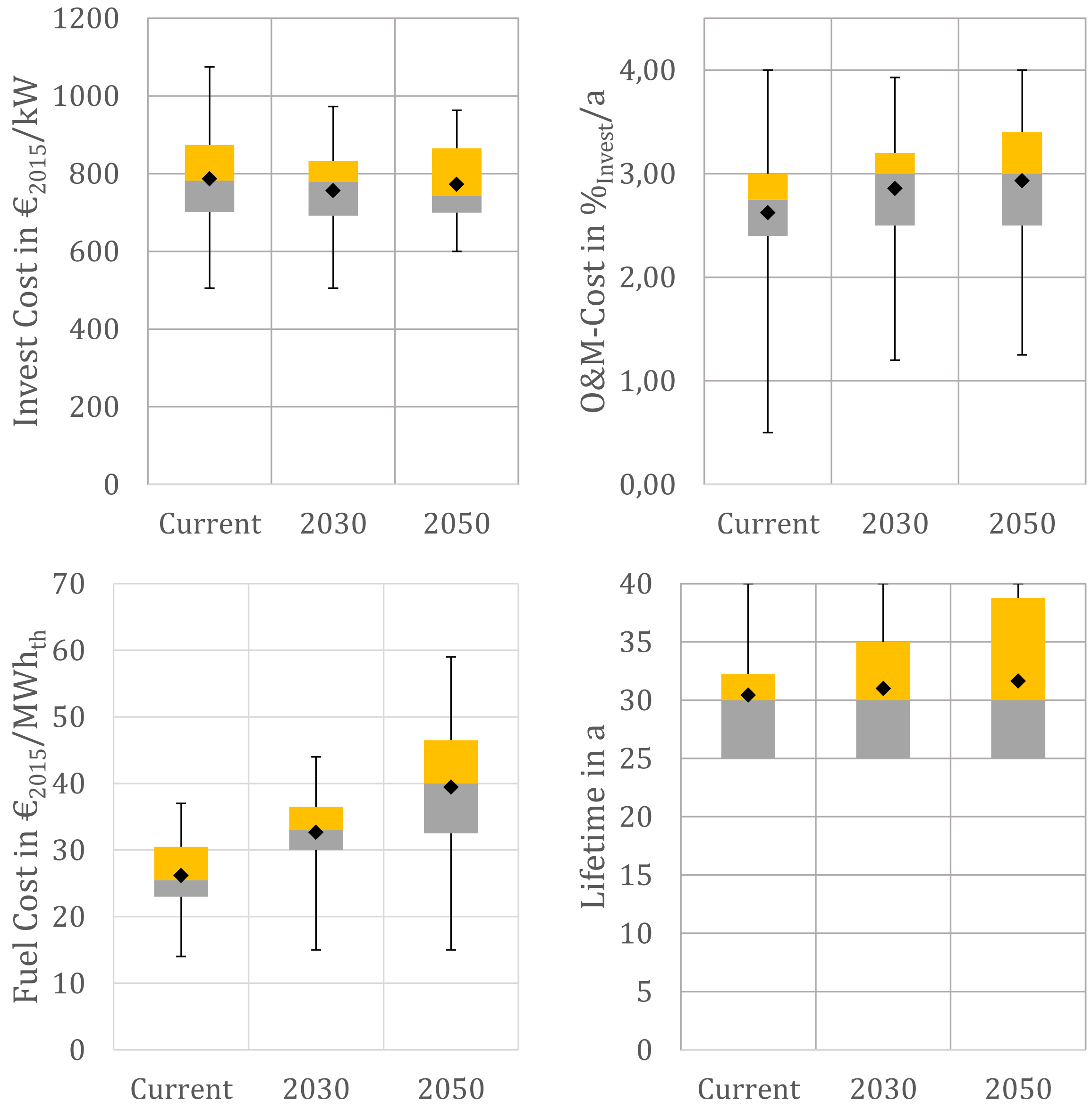

Figure 3 All Cost Parameters for CCGT

Table 5: Values for OCGT. Fuel Cost are equal to that of CCGT in Table 4.

Type		Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value
Invest Cost in €$_{2015}$/kW	Current	350	396	447	475	540	695
	Sources	[11,12,28,29,37–45,49]					
	2030	350	393	436	462	456	695
	Sources	[12,28,29,37,39,40,42,45,49]					
	2050	350	391	400	444	455	695
	Sources	[11,12,28,29,37,39,40,42,45,47]					
O&M Cost in %$_{Invest}$/a	Current	1.2	2.0	3.0	2.85	3.5	5.0
	Sources	[11,12,28,29,37–40,42–45,49]					
	2030	1.5	2.15	2.7	2.72	3.06	4.25
	Sources	[12,28,29,37,39,40,42,45,49]					
	2050	1.9	2.8	3.13	3.13	3.56	4.25
	Sources	[11,12,28,29,37,39,40,42,45,47]					
Lifetime in a	Current	15	25	27.5	31.64	34.5	50

Sources		[11,12,28,29,37–40,42,43,45,49]				
2030	15	25	25	29.83	33.5	50
Sources		[12,28,29,37,39,40,42,45,49]				
2050	15	25	25	31.38	35	50
Sources		[11,12,28,29,37,39,40,42,45,47]				

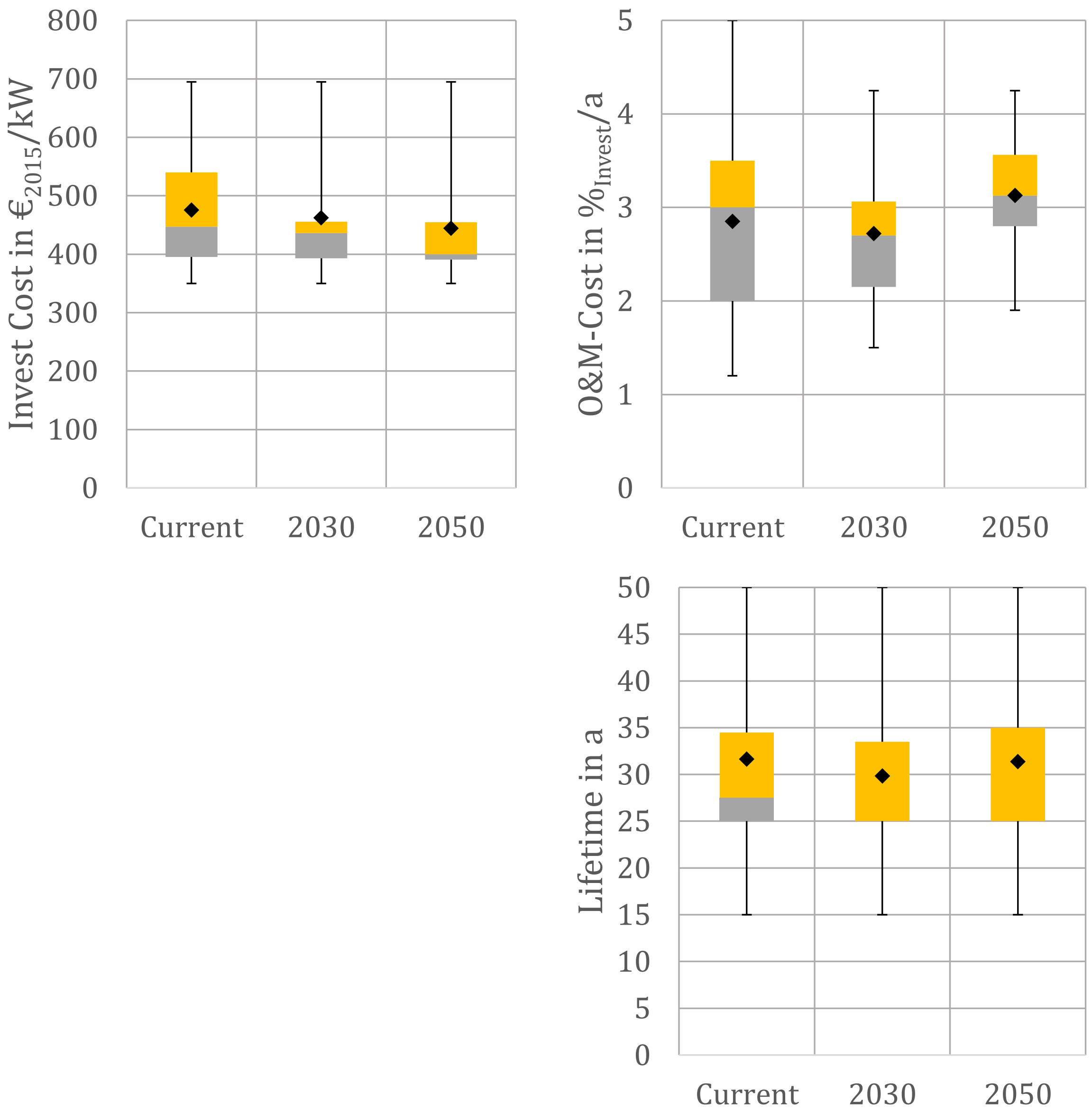

Figure 4 All Cost Parameters for OCGT

3.2. Energy storage technologies

Energy storages are a necessity to many energy system studies as they model energy systems without conventional power plants [12]. As there is currently no market for most of the energy storage types [54], most storage technologies' cost are high [10]. There is a wide variety of both energy storage technologies and examples of their use. [55] investigated different type of storages for different storage lengths, categorising them as short-, medium-, and long-term storages with one, seven and 200 hours of capacity respecitvely. These definitions are not set in stone as [13] uses a quarter of an hour for short-, up to two hours for medium-, and four to eight hours for long-term, respectively, and [16] only seperates into short- and long-term storages, where a short-term storage is defined as a storage unit abble to deliver five hours or less of rated power.

In terms of their cost parameters, energy storage technologies have different characteristics. More often than not, investment costs are given only with respect to one parameter, i.e. either the installed power or the installed

capacity and it is often unclear whether these refer to the net or gross values and if the power is rated in terms of the input or the output and so on. On the other hand, in [29], the investment costs are separated into power-related and capacity-related costs and, within the power-related cost, there is separation between charging and discharging units. For purposes of clarity, the following convention is set: The power specific cost is not separated into input and output power, it is always given as the power related cost only, assuming the grid rated powers of charging and discharging unit are the same. This is done because of the available data. As battery inverters are sold as a single unit [56] and some pumped hydro energy storage units use the same unit as pump and turbine [57] this seems sensible for most storage technologies. As the power-to-gas path might vary, essentially, we are giving seperate information for the charging units.
Furthermore, the investment cost is split into power-related and capacity related cost, assuming the terms are applied appropriately in the source. For example, the power specific cost of a battery energy storage unit only refers to the installed inverter, while the capacity cost refers to the actual lithium ion battery cells, both including their part of the BOS-cost (balance of system). This way we harmonize the data to a comparable measure.
If no information about the usage of net or gross values is given, the value is assumed to mean the net value. If no ratio for net/gross is given, a technology specific value is assumed.

3.2.1 Pumped hydro storage

Pumped hydro storage is the most prominent type of energy storage as it represents a sophisticated, large scale energy storage solution [58]. Pumped hydro storage technologies are considered fully developed, which is why most of the studies featured do not see a potential for cost reduction. it is agreed that the cost is heavily dependent on the local surroundings and environmental challenges which is why some studies [47] even consider the resorvoir to have no costs. Among lifetime assumptions, the data seem rather consistent(see Table 6), except for the minimum value, which is probably referring to the project lifetime rather than the reservoir lifetime.

Table 6: Values for Pumped Hydro Storage

Type		Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value
Invest Cost in €$_{2015}$/kW	Current	487	527	987	1028	1169	2567
	Sources	[11–13,28,37,40,43,55,58–64]					
	2030	450	524	1048	1461	2163	4100
	Sources	[12,28,37,41,55,58]					
	2050	588	667	963	1120	1157	2567
	Sources	[11,12,28,29,37,40,47,65]					
Invest Cost in €$_{2015}$/kWh	Current	5	5.5	20	39.23	65.25	115
	Sources	[12,13,40,55,58–60,63]					
	2030	5	14	27	58.86	86	180
	Sources	[12,41,55,58]					
	2050	0	8.75	17	27.53	24.5	98.2
	Sources	[12,40,47,65]					
O&M Cost in %$_{Invest}$/a	Current	0.3	0.42	0.8	0.92	1.0	3.0
	Sources	[11–13,28,37,40,43,55,59–61,63]					
	2030	0.3	0.65	1.0	0.9	1.0	1.7
	Sources	[12,28,37,41,55]					
	2050	0.3	0.88	1.0	1.21	1.33	3.0
	Sources	[11,12,28,29,37,40,47]					
Lifetime in a	Current	50	53.75	75	66.18	80	100
	Sources	[11–13,37,40,43,55,58–61,63,64]					
	2030	50	50	80	60.2	80	100
	Sources	[12,37,55,58]					
	2050	20	50	70	57.79	80	100
	Sources	[11,12,29,37,40,47,65]					

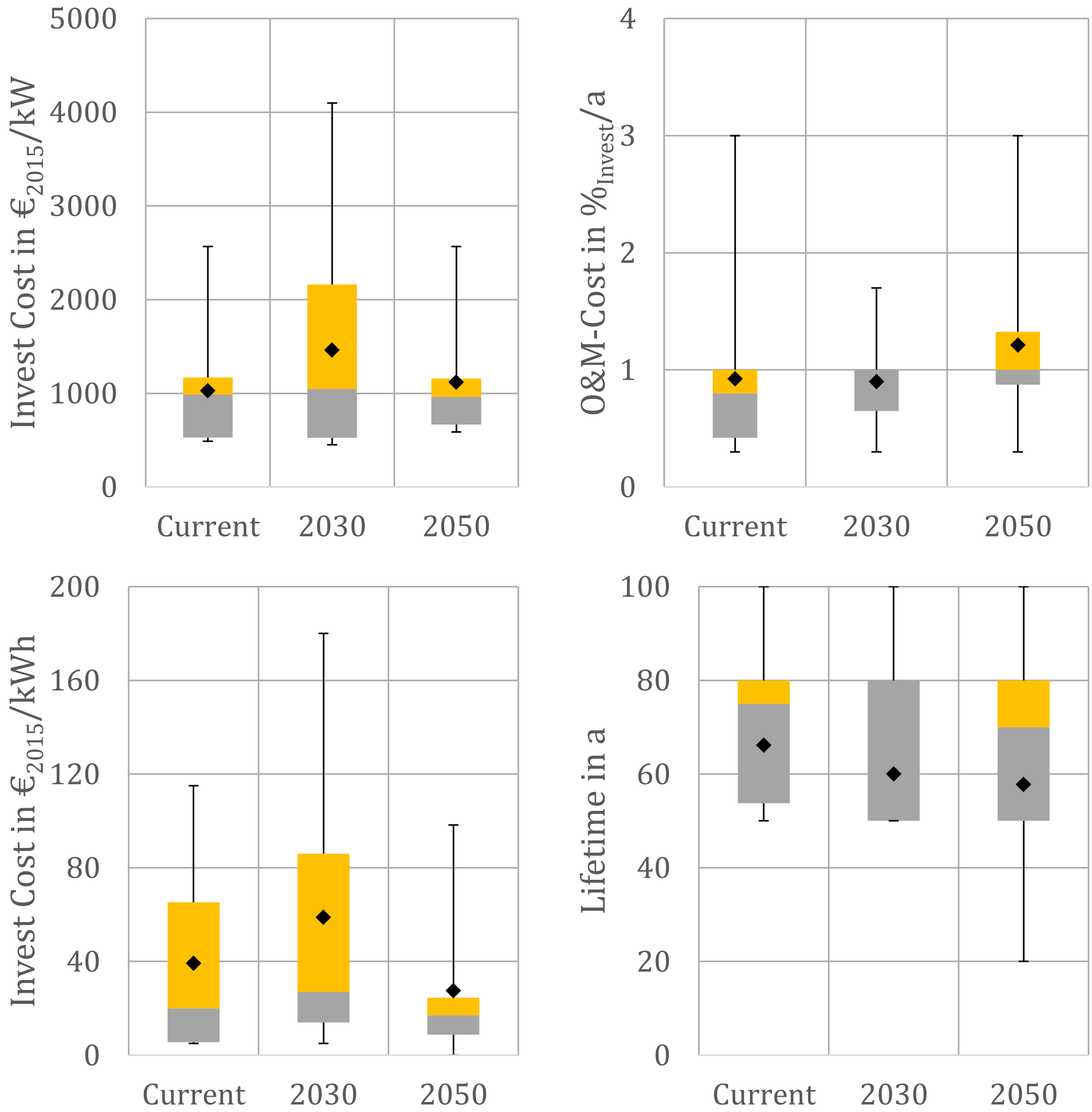

Figure 5 Cost parameters for Pumped Hydro

3.2.2 Lithium Ion Battery Storages

It is often assumed, that battery storages, and most other storages for that matter, have a fixed temporal capacity (e.g. 4 h at a 1000 MW installed power mean roughly a 4000 MWh capacity). Power and capacity are not fully independent, as the battery cells (i.e. smallest unit of capacity) themselevs have a fixed upper power rating [16], but for a battery storage plant these can be scaled somewhat independently as e.g. [66] shows. However, the installed power should not exceed the installed capacity as a dis-/charge rate of more than 1 C is discouraged [16]. A dis-/charge rate of 1 C means to discharge the storage in 1 h as the dis-/charge rate ξ of batteries at a constant power P and a storage capacity of C for a time frame Δt is defined as

$$\xi = \frac{C}{P\ \Delta t}. \qquad \textbf{(3.1)}$$

Furthermore, a parameter that needs consideration, when talking about battery cost, is whether the gross or net capacity is used. These derived from the maximum capcity of charge a battery can hold and the maximum advisable depth of discharge ($\boldsymbol{DoD}$) meaning the operating limits at which the integrity of the battery is not stressed too much [67]. Unless otherwise stated, costs were assumed to refer to net capacity with a $\boldsymbol{DoD}$ of 80%. All other values were calculated to fit that definition.

Table 7: Values for Lithium Ion Batteries

Type		Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value
Invest Cost in €$_{2015}$/kW	Current	0	150	186	385	399	2407
	Sources	[12,13,29,40,58,60,61,64,68–75]					
	2030	20	41	66	326	379	3100
	Sources	[12,29,37,41,58,62,64,70,71,73,74]					
	2050	0	28	68	141	222	503
	Sources	[12,29,37,40,62,65,70,71]					
Invest Cost in €$_{2015}$/kWh$_{net}$	Current	100	346	611	700.6	975	1705
	Sources	[11–13,29,38,40,58–61,64,68,69,71–74,76–78]					
	2030	76	163	232	322.68	305	2050
	Sources	[12,29,38,41,58,62,64,70,71,73,74,76–79]					
	2050	57	88	157	168.86	215	337
	Sources	[11,12,29,40,62,65,70,71,76,78]					
O&M Cost in %$_{Invest}$/a	Current	0.5	1.0	1.4	2.46	1.63	15.2
	Sources	[11–13,29,61,68–70,74,75,80]					
	2030	0.5	1.28	1.5	1.93	3.0	3.4
	Sources	[12,29,37,41,70,74]					
	2050	0.5	0.78	1.15	1.32	1.45	2.9
	Sources	[11,12,29,37,70]					
Lifetime in a	Current	5	10	13.75	13.85	20	28
	Sources	[11–13,29,38,40,58,60,61,64,68,69,74–76,80]					
	2030	10	13	15	17.04	20	30
	Sources	[12,29,37,38,58,62,64,74,76]					
	2050	10	15	20	19.33	25	30
	Sources	[11,12,29,37,40,62,65,76]					

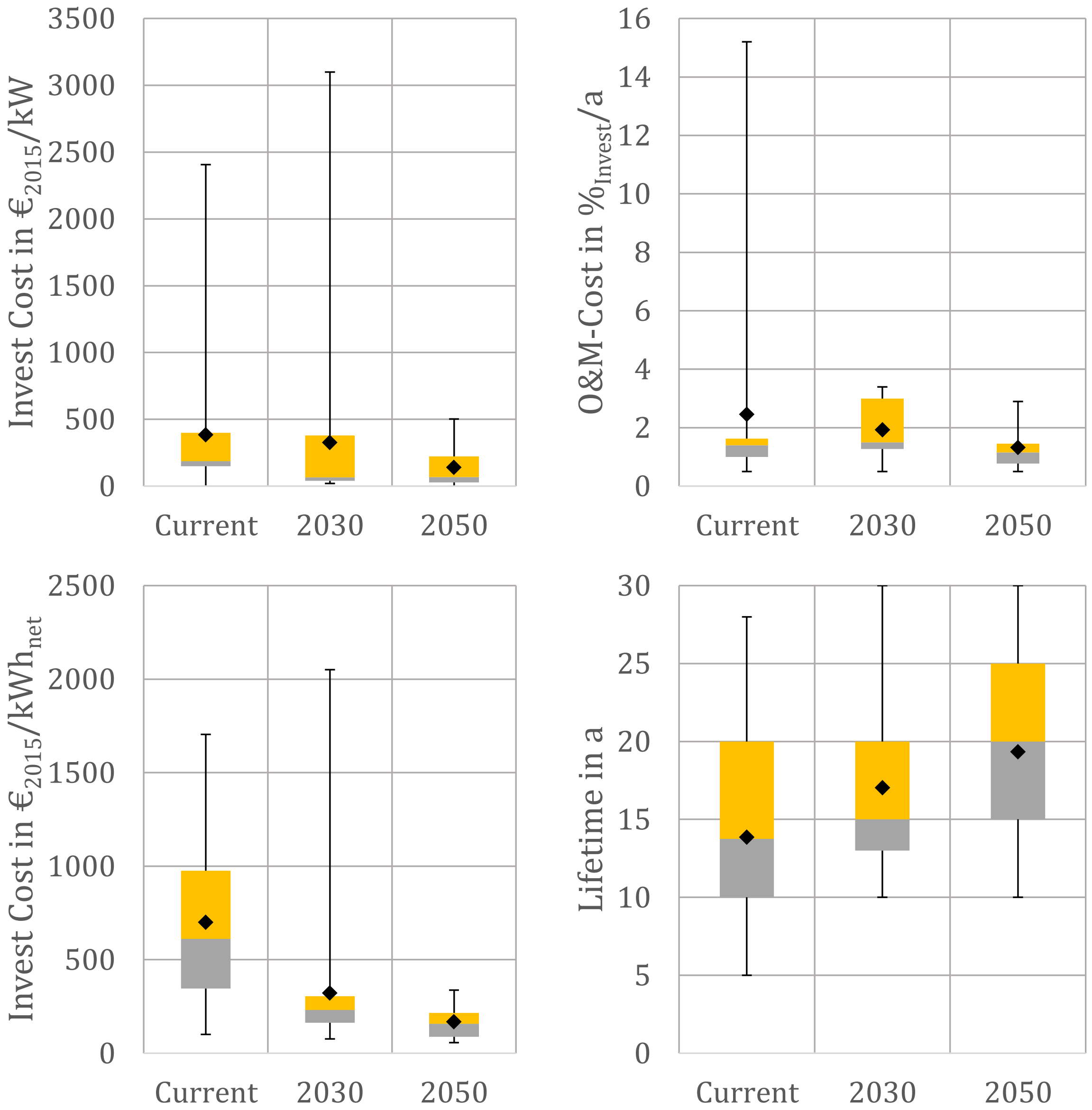

Figure 6 Cost parameters for Lithium Ion Batteries

Utitlity battery energy storages are currently on the market due to grid stability [66] or to enhance primary control reserve of conventional power plants [81] or renwable producers [82]. Most of the development however is currently done in the mobility sector [79], which might drive the cost down for utility scale battery energy storages as it is projected in [78] and [71]. With the exception of the operating and maintenance cost, many development suggestions were found and are ought to give some validity to the own recommendations in Table 16. For the current values it is hard to tell what a utility scale battery would actually cost as there is market noise understating their actual cost for various reasons [83], which [77] with their extrem low estimate is probbably an example of.

On the other hand, some studies only give either power-specific or capacity-specific values with a fixed C-rate for all installations. These then result in too high specific values for their respective type. However, this is thought to be cancelled out by the aforementioned market noise.

3.2.3 Power to Gas

Power to gas energy storage technologies have the particular feature that all their components can be scaled indepently from each other. For the power to hydrogen case, this means that regardless of the power rating of the electrolyser, the storage unit itself, in this case a cavern, and the fuel cell or CCGT for reconversion to electrical power can all be sized indepently. For the power to methane path, the methanizer is added as an independently-sized additional unit. These units are, therefore, listed individually.

One should note, that the storage unit is the only unit of these to have both the power and the capacity specific cost factors. The power rating here comes from the drillings and compressors needed to fill the storage unit and is used in e.g. [12]. This detailed look at the cavern however, is often neglected and therefore there was not enough data to generate values here, as well. As salt caverns are one of the most discussed storage option for power to gas, only these are further evaluated. It should be noted, that many studies however give there cost in €/kWh, which makes sense for discussing either hydrogen or synthetic natural gas storages. If both are part of the investigation, the absolute cost of the cavern should be the same. Therefore, all values were converted to specific invest cost of €/m^3_{Cavern}. For conversion from and to €/kWh we assume cavern operating pressures from 50 to 180 bar and a constant temperature of 50 °C, which results in roughly 300 kWh_{H2}/m^3_{Cavern} for hydrogen and 1500 kWh_{CH4}/m^3_{Cavern} for synthetic natural gas. These assumptions fit well with the data used in e.g. [84].

Commercial power to gas storages are currently in the project phase for sector coupling and are still part of research projects [85]. The individual parts are commercialy available at a small scale [86] and even hydrogen caverns exist commercially [19,87], but standalone electricity to electricity units are not yet commercially feasible.

A discussion of values for "re-electrification" is not given, as studies on cost development of fuel cells for utility scale reconversion are rare. Studies doing cost projections of fuel cells in vehicles predict remarkably low values [88]. Currently there are only a few demonstration plants, such as those in South Korea [89]. Competing alternatives for reconversion of hydrogen to electricity are combined cycle gas turbines (as discussed in section 3.1), which are at a comparable development state.

Where possible, only proton exchange membrane (PEM) electrolyser values were considered as these seem to be the most promising alternative to accompany volatile renewables [10]. Unless otherwise specified, it was assumed that PEM electrolysers were used. The power-specific cost for methanisation was calculated relative to the output, as it can be individually sized from the electrolyser. If the combined cost was given, the costs for the electrolyser were subtracted and, if it was given as relative to electric input, it was scaled according to the assumed efficiency.

Table 8: Values for Power to Gas - Electrolyser

Type		Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value
Invest Cost in $€_{2015}/kW_{el}$ for the Electrolyser	Current	732	1021	1369	1466	2002	2500
	Sources	[10,11,29,34,43,53,55,59,90–96]					
	2030	249	483	602	675	819	1571
	Sources	[10,29,34,37,53,55,91–93,95,97]					
	2050	140	263	345	426	499	1092
	Sources	[10,11,29,34,37,47,53,65]					
O&M Cost in $\%_{Invest}/a$	Current	2.0	2.5	3.0	3.0	3.5	4.0
	Sources	[10,11,29,34,43,55,91–93,95,96]					
	2030	1.5	1.81	2.5	2.57	3.23	4.0
	Sources	[10,29,34,37,53,55,91,92,95,97]					
	2050	1.7	3.0	3.25	3.18	3.8	4.0
	Sources	[10,11,29,34,37,47]					
$Lifetime_{Electrolyser}$ in a	Current	10	14	16.75	16.84	20	30
	Sources	[10,11,13,29,34,43,90–92,95,96,98]					
	2030	10	14	20	19.05	21.25	30
	Sources	[10,13,29,34,37,53,91,92,95]					
	2050	15	15.75	17.25	19.31	22.25	27
	Sources	[10,11,29,34,37,47,65]					

The less frequently considered option of methanisation only has a few sources for predicted values, so these should be taken with caution. As methanisers are somewhat simple reactors, the reduction in cost is mainly attributed to economy of scale effects. Please note, that the unit kW_{SNG} refers to the lower heating value of methane.

Table 9: Values for Power to Gas - Methanisation

Type	Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value

Invest Cost in $€_{2015}/kW_{SNG}$	Current	525	786	1419	2033	3388	4624
	Sources	[11,12,29,90,91,93,96]					
	2030	276	345	503	592	720	1158
	Sources	[12,29,34,37,53,91,93]					
	2050	127	200	551	555	923	970
	Sources	[11,12,29,37]					
O&M Cost in $\%_{Invest}/a$	Current	2.0	2.0	2.5	2.73	3.0	4.6
	Sources	[11,12,29,91,93,96]					
	2030	1.6	2.0	2.0	2.53	3.0	4.6
	Sources	[12,29,37,53,91,93]					
	2050	1.2	2.08	2.4	2.6	2.88	4.6
	Sources	[11,12,29,37]					
Lifetime in a	Current	10	15	20	18.89	20	30
	Sources	[11,12,29,90,91,96,98]					
	2030	15	15.25	18	20.17	23.75	30
	Sources	[12,29,37,53,91]					
	2050	20	25	25	26	30	30
	Sources	[11,12,29,37]					

Table 10 shows only a few sources for future cost associated with salt caverns.Given that caverns are well established as gas storage utilities, the values suggesting learning rates should be disregarded. Regarding the technical lifetime Patroni [99], although the maximum value in Table 10, seems the best assumption as it is based on experience of existing wells and the 75 years is the most common lifetime in that study.

Table 10: Values for Power to Gas - Cavern

Type		Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value
Invest Cost in $€_{2015}/m^3_{Cavern}$	Current	0.8	40	90	256	288	1800
	Sources	[11,13,29,34,40,43,55,60,87,88,95,100,101]					
	2030	0.24	12	65	92	158	241
	Sources	[29,40,41,88]					
	2050	0.15	63	90	109	138	300
	Sources	[11,29,40,47,65,88]					
O&M Cost in $\%_{Invest}/a$	Current	1.0	1.8	2.5	2.3	3.0	3.0
	Sources	[11,12,40,43,55,87]					
	2030	2.0	n/a	3.8	3.6	n/a	5.0
	Sources	[12,40,41]					
	2050	1.6	n/a	2.5	6.3	n/a	18.6
	Sources	[11,12,40,47]					
Lifetime in a	Current	20	32.5	40	40.14	41.05	75
	Sources	[11,12,29,40,43,95,99,100]					
	2030	20	n/a	40	35.35	n/a	41.05
	Sources	[12,29,40]					
	2050	20	35	40	35.91	40	40
	Sources	[11,12,29,40,47]					

3.2.4 (Advanced) Adiabatic Compressed Air Energy Storage (A-CAES)

A-CAES is not yet commercially available, it only exists as diabatic storage [54]. Previous research projectsnever got implemented [102], which explains the lack of data. As of now, first research projects are going to be installed and being tested [103]. Despite this, it is still often considered in future energy systems. As most components of an A-CAES are conventional, most of the development is attributed to two components: The compressor, which is still to reach desired temperatures [104], and the thermal energy storage, which might coincide with current developments [105].

Table 11: Values for A-CAES

Type		Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value
Invest Cost in €$_{2015}$/kW	Current	489	785	916	875	1000	1131
	Sources	[12,13,29,40,55,58–61,106]					
	2030	450	655	728	775	870	1350
	Sources	[12,29,37,41,55,58,64]					
	2050	432	489	555	584	684	760
	Sources	[12,29,37,40,55]					
Invest Cost in €$_{2015}$/kWh$_{th}$	Current	21	38	42	60.04	80	204
	Sources	[12,13,29,40,55,58–61]					
	2030	9	28	40	63.64	82	204
	Sources	[12,29,41,55,58,64]					
	2050	19	n/a	26.5	29.38	n/a	45.5
	Sources	[12,29,40]					
O&M Cost in %$_{Invest}$/a	Current	0.5	0.75	1.5	1.49	1.7	3.5
	Sources	[12,13,29,40,55,61]					
	2030	0.5	0.95	1.5	2.1	2.9	5.0
	Sources	[12,29,37,41,55]					
	2050	0.5	1.0	1.3	1.18	1.5	1.6
	Sources	[12,29,37,40]					
Lifetime in a	Current	20	25	32.5	33	40	50
	Sources	[12,13,29,40,55,58–61]					
	2030	25	25	40	35.71	40	55
	Sources	[12,29,37,55,58,64]					
	2050	30	n/a	41.25	40	n/a	55
	Sources	[12,29,37,40]					

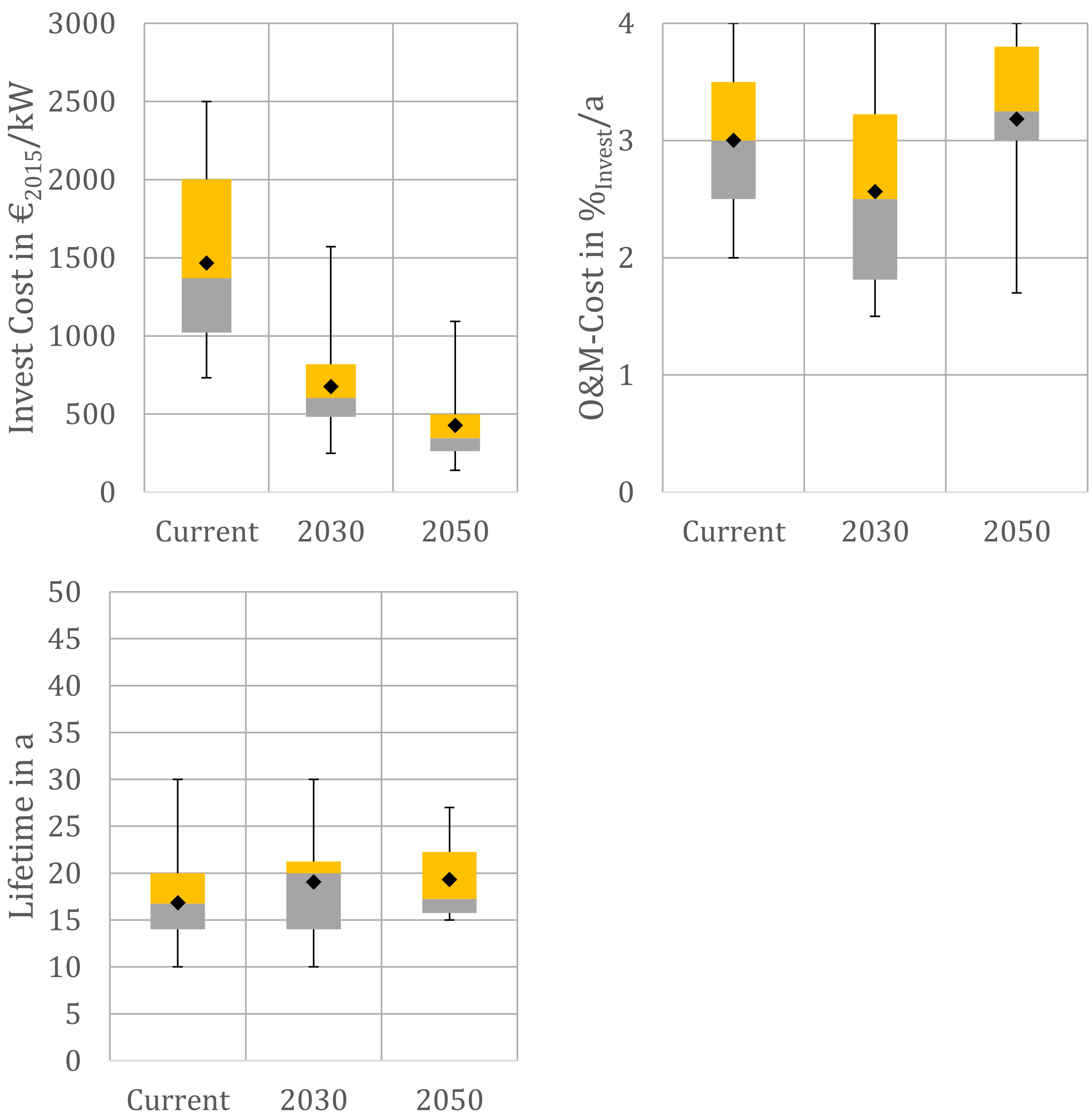

Figure 7 Cost Parameters Electrolyser

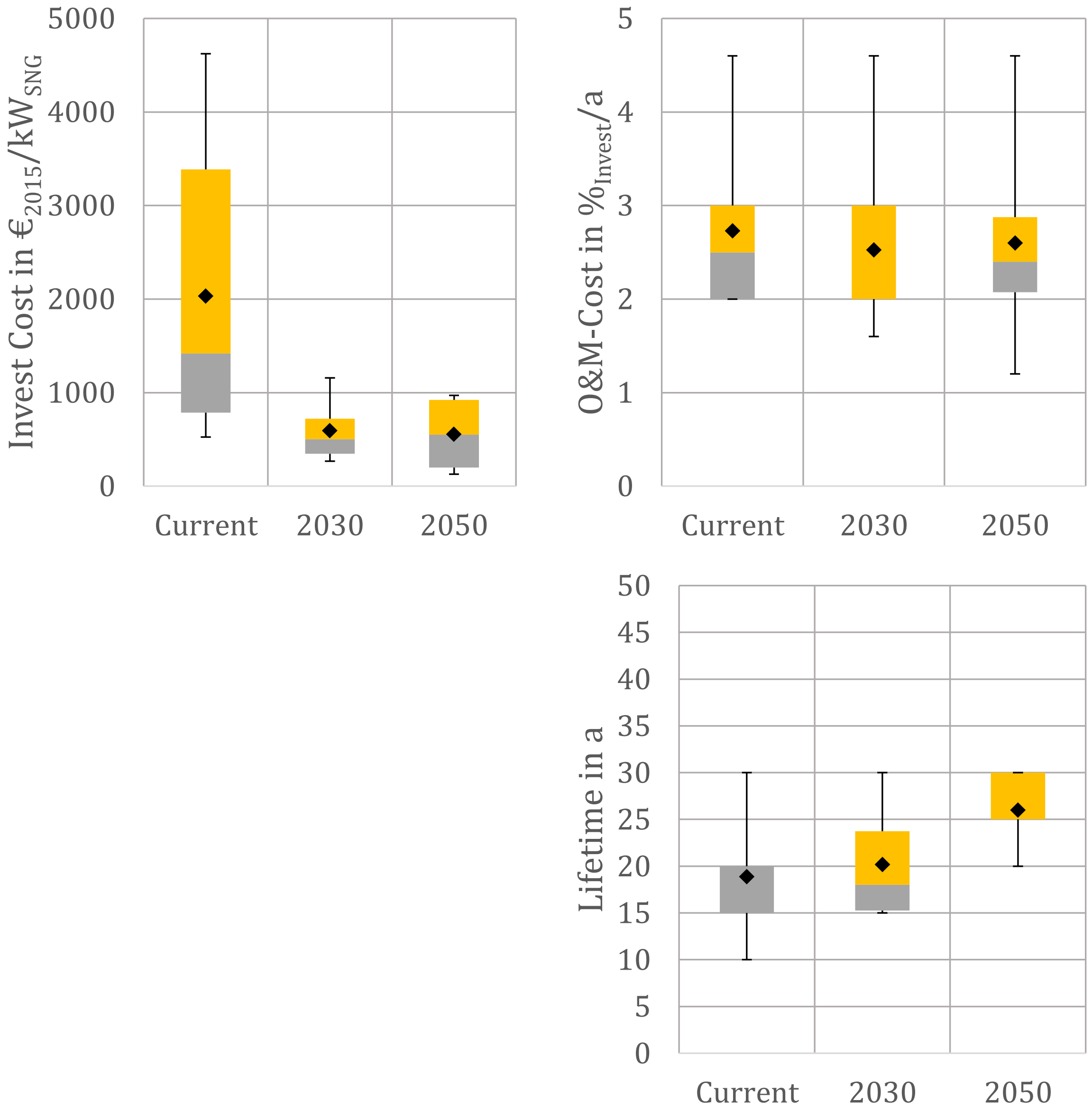

Figure 8 Cost Parameters Methanisation

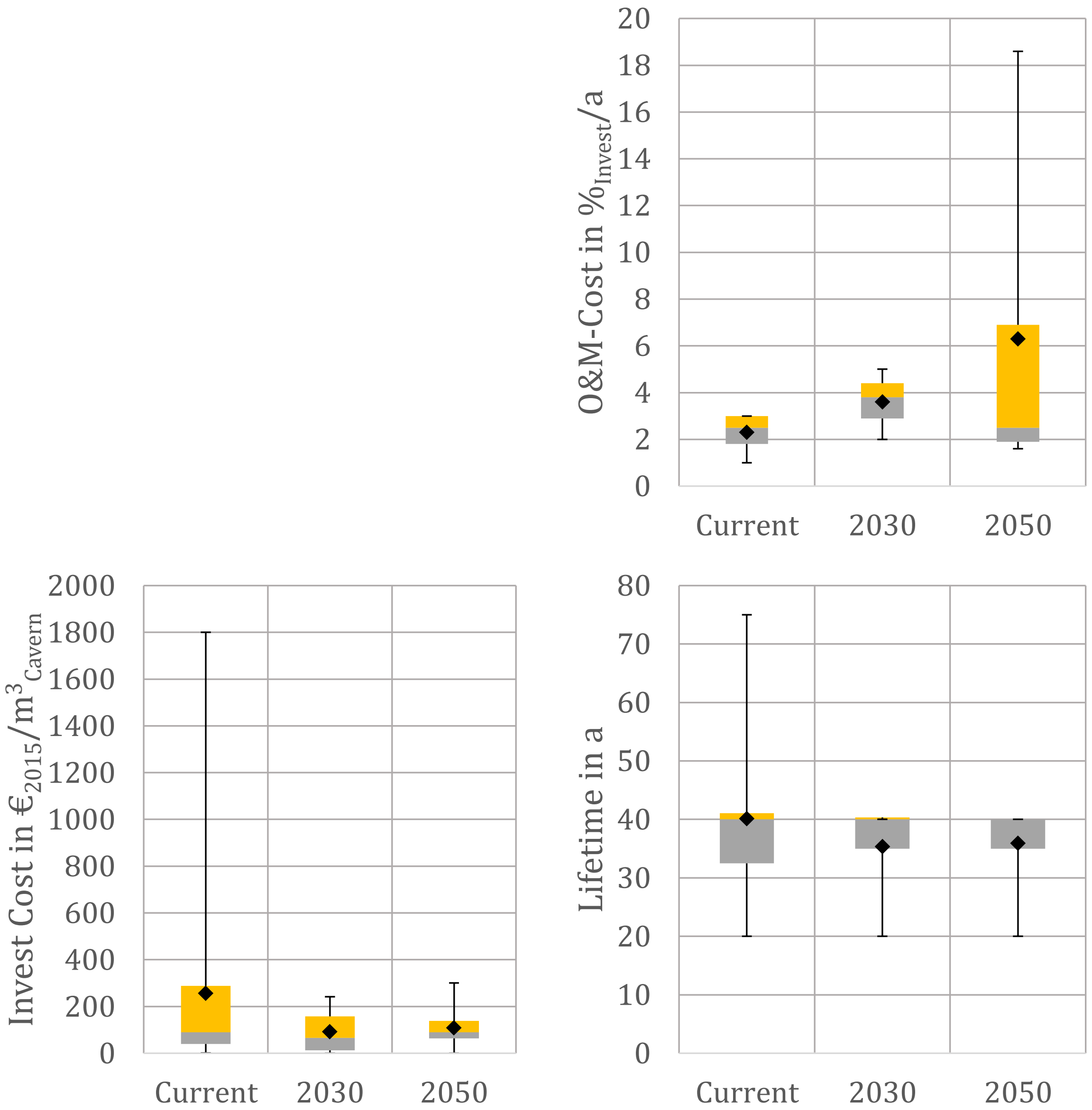

Figure 9 Cost parameters Gas Cavern

In contrast to power to gas underground storage units, where the values were given in €/m^3_{cavern}, it makes sense to use the €/kWh value as the A-CAES energy storage consists of two storage units, namely the underground air storage and above ground heat storage. This complicates the measurement in a way, as litte to no data is available. Furthermore, it can be obsereved, that there is little data on O&M cost, which is explicable with the low number of demonstration plants. With [103] released, there soon should be real data to compare to.
A-CAES is one of the storage technologies where a seperation between charging and discharging power might be desirable. In [29] slightly higher costs for the compressor than the turbine are suggested. This is why a 55-45 split between compressor and turbine, respectively, of the investment cost given in Table 11 could be done. Given the interquartile range (difference of Q3 to Q1 value) the uncertainty of the investment cost is probably higher than the uncertainty in that split-ratio.

3.3. Renewable energy generators

Renewable energy generators are the backbone of the energy transition, as they build the sustainable foundation of energy conversion. Their cost assumptions therefore are one of the major influences on LCOE calculation.

3.3.1 Bioenergy

Biomass is, in general, a less volatile source of renewable energy, but its potential is very limited [107]. Due to its limited potential, it is still a rather open debate in which sectors biomass should be used, and, therefore, biomass is omitted from many case studies. Due to its high carbon content, many consider it predestined for the mobility sector [46]. With only few studies to work with, a detailed analysis is not conducted. However, in the development of their own recommendations, the authors would like to give values for biomass conversion plants that use fermenters to produce biogas as a step in the process, and for biomass firing plants, that fire wood in a conventional thermal power plant as is done in e.g. DRAX power plant [108].

3.3.2 Concentrated Solar Power

As with energy storage technologies, CSP power plants' investment costs are often given with a specific plant layout in mind, e.g. whether it includes a thermal storage unit and how big that should be and where the plant is located. If the components are separated (mirrors, power block and storage), the investment cost data can be used. However, there are not many studies to work with and hence a further discussion is not undertaken.

3.3.3 Photovoltaic

PV has come a long way from being barely efficient enough to achieve an acceptable ROI over its lifetime to being one of the cheapest ways of producing electricity in a sustainable manner [109]. The rate of cost reduction has yet to slow down [9], which leads to a strong variation in projected cost. Usually, the cost projections are given for utility scale PV. The fast pace of cost reduction in PV means that current investment cost values are somewhat dependent on the source's year and, therefore, it is not advisable to use these values in project planning. Additionally, [9] noted, that the recent cost development outpaces common learning rate assumptions. Both methods of cost projections using learning curves based on current values and historical averages can be justified.

Table 12: Values for Utility Scale PV

Type		Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value
Invest Cost in €$_{2015}$/kW	Current	586	943	1070	1277	1269	3423
	Sources	[9,11,12,27,28,38–43,49,76,110]					
	2030	374	636	653	694	785	965
	Sources	[9,12,27,28,37,39,40,42,46,49,76]					
	2050	236	426	578	523	608	780
	Sources	[9,11,12,27,29,37,39,40,42,46,47,65,76]					
O&M Cost in %$_{Invest}$/a	Current	0.7	1.0	1.5	1.45	1.8	2.5
	Sources	[9,11,12,27,28,38–40,43,49,76]					
	2030	0.8	1.0	1.5	1.74	2.2	4.2
	Sources	[12,27,28,37,39,40,46,49,76]					
	2050	1.0	1.53	1.83	2.19	2.83	5.9
	Sources	[9,11,12,27–29,37,39,40,46,47,76]					
Lifetime in a	Current	20	25	25	25.94	30	30
	Sources	[9,11,12,27,28,38,40,41,43,49,76,110]					
	2030	20	25	25	26.82	30	30
	Sources	[12,27,28,37,40,46,49,76]					
	2050	20	25	27.5	27.5	30	30
	Sources	[9,11,12,27–29,37,40,46,47,65,76]					

As can be seen from Table 12 and Table 13, the utility scale PV plant is discussed more often. Of the studies, that take a look at both roof-top and utility scale, a factor of around 1.5 emerges, which fits the values of all considerations in the tables quite nicely. In relation to the the O&M costs, quite high values develop towards future scenarios. That is a result of studies with constant, absolute values for the O&M cost, which become a greater relative value, when assuming falling investment cost. That is also why rising relative O&M cost seem somewhat reasonable.

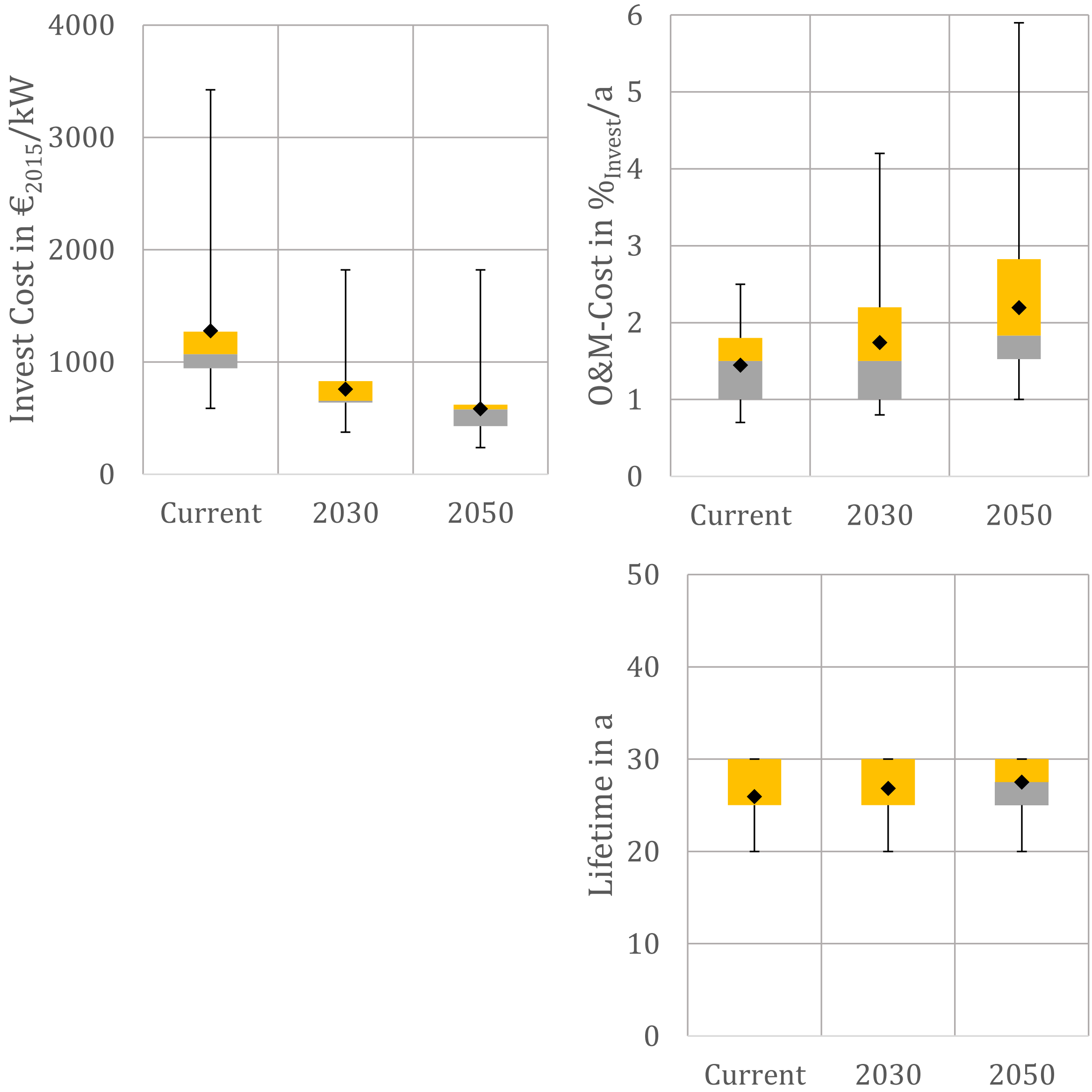

Figure 10 Cost parameters PV utility scale

The presented cost parameters assume the lifetime to cover the entire plant. Hence, it should be noted, that [9] suggests a lifetime for the module of 30 years, but only 15 years for the inverter, which leads to a necessary re-buy after those 15 years. As [9] splits the component cost, one could calculate the lifetime overnight cost, by assuming the interest rate and inverter cost to use the net present value (NPV) via

$$NPV = I \cdot \frac{1}{(1+i)^n} \tag{3.2}$$

using 15 years for n and the original investment cost for the inverter for I and adding that to the total system cost. Such correction was not undertaken in this research.

Table 13: Values for Residential Rooftop PV

Type		Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value
Invest Cost in €2015/kW	Current	782	1270	1412	1707	1815	3653
	Sources			[12,38–42,49,51,68,76,110]			
	2030	716	780	935	1101	1281	2063
	Sources			[12,37,39,40,42,46,49,76]			
	2050	440	496	633	661	739	1079

	Sources	[12,29,37,39,40,42,46,76]					
O&M Cost in $\%_{Invest}$/a	Current	0.6	1.0	1.5	1.41	1.6	2.5
	Sources	[12,38–40,49,51,68,76]					
	2030	0.7	1.43	1.7	1.63	1.98	2.3
	Sources	[12,37,39,40,46,49,76]					
	2050	0.8	1.4	1.8	1.79	2.0	3.1
	Sources	[12,29,37,39,40,46,76]					
Lifetime in a	Current	20	25	25	25.38	30	30
	Sources	[12,38,40,41,49,51,68,76,110]					
	2030	20	25	25	27.14	30	35
	Sources	[12,37,40,46,49,76]					
	2050	20	25	25	27.5	28.75	40
	Sources	[12,29,37,40,46,76]					

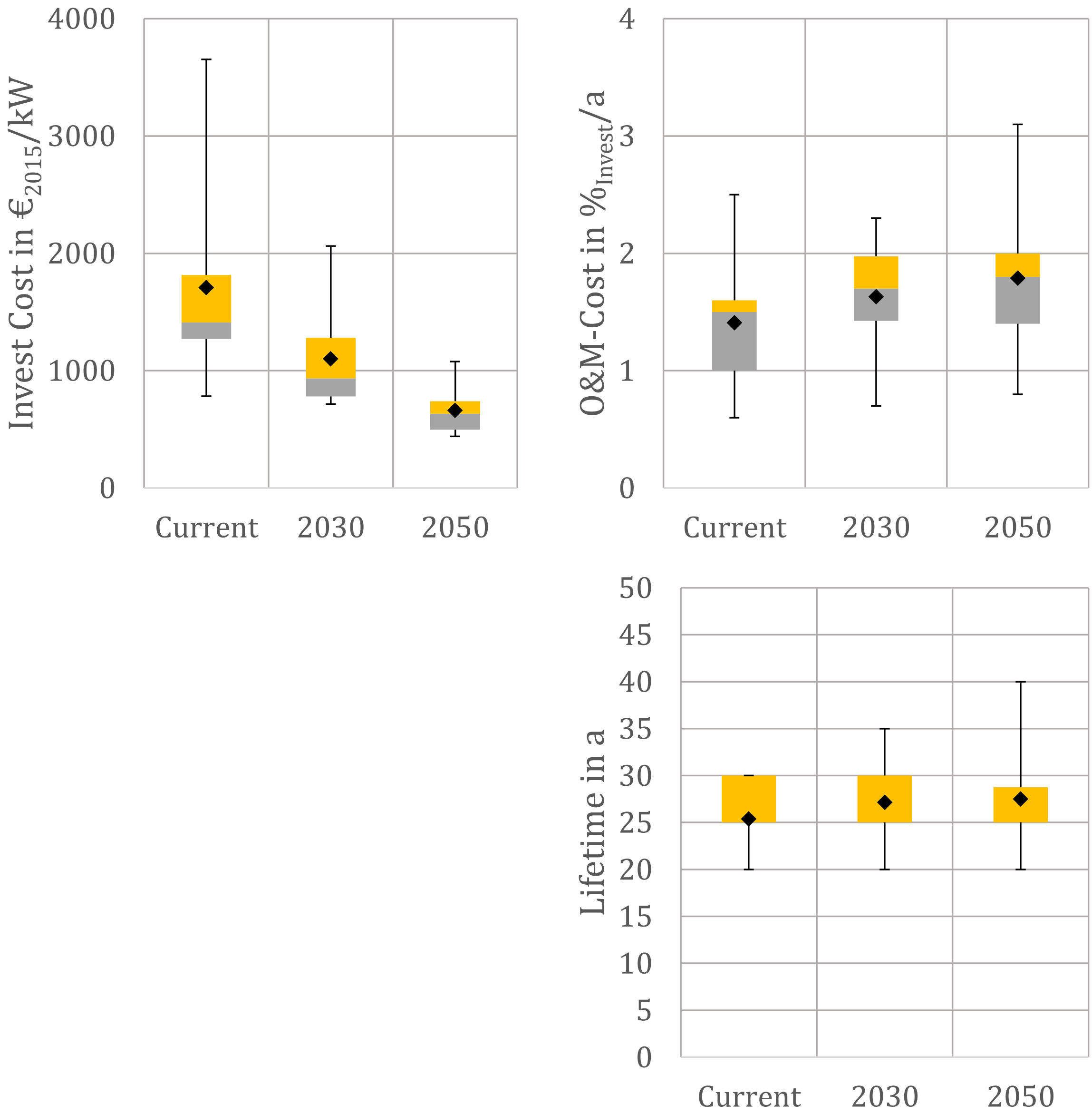

Figure 11 Cost parameters PV rooftop installations

3.3.4 Windenergy

The development in the power specific investment cost of onshore wind turbines is stagnant [111] and, therefore, the cost projections seem rather restrained. It should be noted, that the rotor area specific investment cost of wind turbines shows a significant decrease [111], which is not accounted for in this paper. For offshore development, a movement towards lower power specific investment cost is seen, but some studies [41] differentiate further by considering the water depth in which the wind farm will be placed or the distance it has to shore [112].

Table 14: Values for Wind Onshore

Type		Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value
Invest Cost in €2015/kW	Current	973	1267	1405	1479	1596	2251
	Sources	[11,12,28,38–43,45,49,51,110–114]					
	2030	935	1142	1184	1363	1402	2338
	Sources	[12,28,37,39,40,42,45,46,49,114]					
	2050	700	896	1073	1126	1220	2391
	Sources	[11,12,28,29,37,39,40,42,45–47,65]					
O&M Cost in %Invest/a	Current	1.1	1.95	2.6	2.92	3.73	5.7
	Sources	[11,12,28,38–40,43,45,49,51,110–114]					
	2030	1.3	1.93	2.2	2.54	3.08	5.0
	Sources	[12,28,37,39,40,45,46,49,114]					
	2050	1.4	2.04	2.73	2.87	3.38	5.0
	Sources	[11,12,28,37,39,40,45–47]					
Lifetime in a	Current	16	20	25	23.29	25	30
	Sources	[11,12,28,38,40,41,43,45,49,51,110,112–114]					
	2030	20	24	25	24.06	25	27.5
	Sources	[12,28,37,40,45,46,49,114]					
	2050	18	20	25	22.77	25	25
	Sources	[11,12,28,29,37,40,45–47,65]					

The future of wind power is rather hard to estimate, with the specific investment cost having appeared to be constant due to the rising hub heights bigger rotors. It is only in recent years that the cost for wind turbines started to go down [111][1]. For the latter [112] argues, that [111] excluded the project planning cost of around ~350€/kW. [112]'s value of 1567 €/kW is between this studies median and upper quartile in Table 14 and given [112]'s age and the recent development in turbine cost, this is viewed as a validation of this study's approach. It should be noted, however, that these are only average values as [111] shows a quite significant difference in pricing of various wind turbine classifications. The lifetime equivalence of onshore (Table 14) and offshore turbines (Table 15) is rather surprising and is rather to be interpreted as a project lifetime, which might be more relevant than their maximum possible lifetime as [112] states, that many turbines were repowered after 16 years, long before the end of their project life. The oldest wind turbine in the German market according to the MAStR [115] is currently 36 years old and should be treated as an exception rather than a rule.

[1] See https://about.bnef.com/blog/2h-2017-wind-turbine-price-index/ for the most recent developments. Unfortunately, the undelying study was not attainable by the authors.

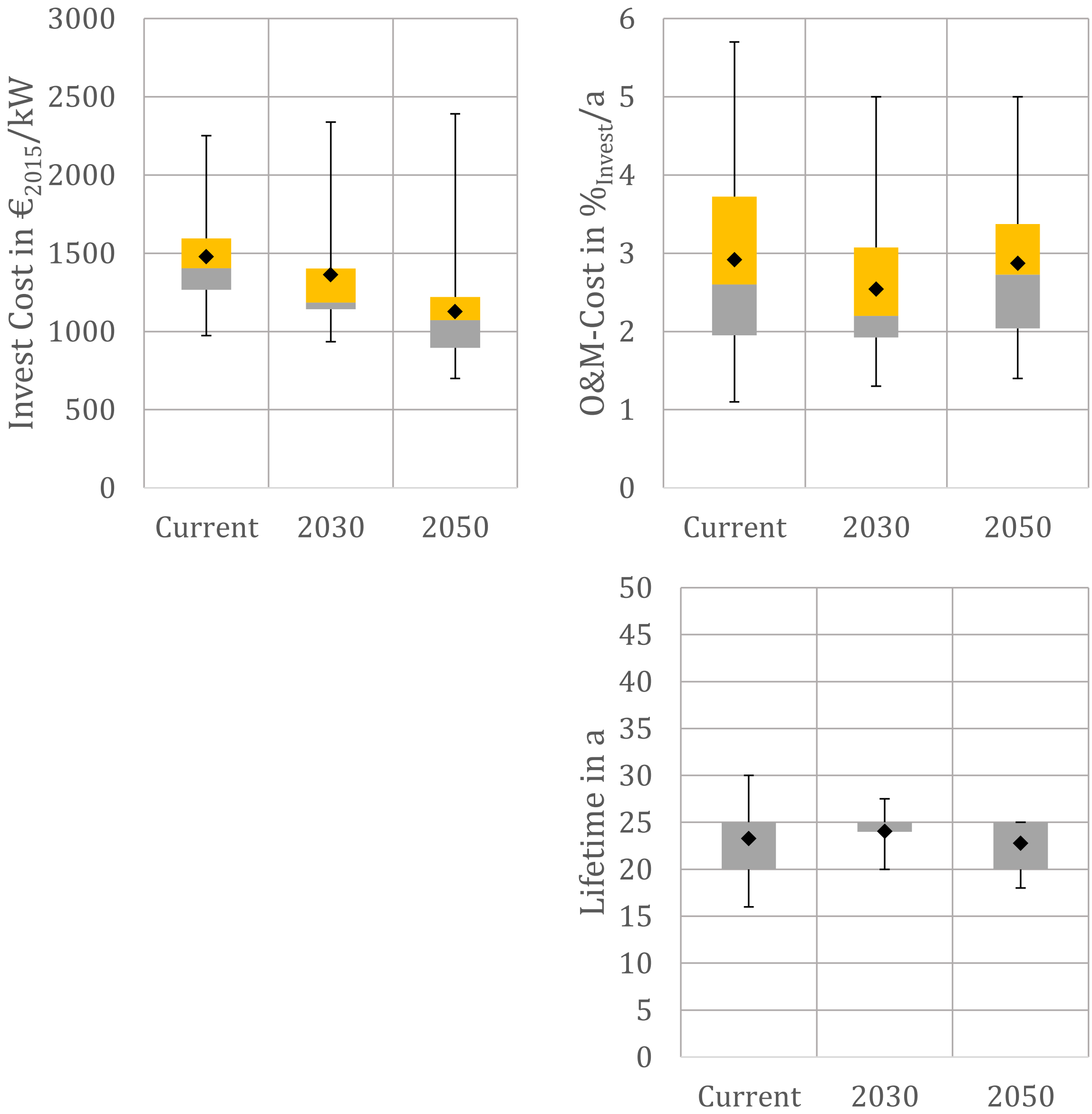

Figure 12 Cost parameters Wind Turbine Onshore

Table 15: Values for Wind Offshore

Type		Min Value	Q1 Value	Mean Value	Average Value	Q3 Value	Max Value
Invest Cost in $€_{2015}$/kW	Current	1947	2956	3209	3366	3915	5345
	Sources	[11,12,28,38–43,45,49,51,114]					
	2030	1877	2121	2525	2572	2693	3826
	Sources	[12,28,37,39,40,42,45,46,49,114]					
	2050	1256	1700	2103	2212	2334	4800
	Sources	[11,12,28,29,37,39,40,42,45–47]					
O&M Cost in $\%_{Invest}$/a	Current	1.8	2.7	3.3	3.35	3.7	5.5
	Sources	[11,12,28,38–40,42,43,45,49,51,114]					
	2030	1.9	2.69	3.1	3.27	3.63	5.0
	Sources	[12,28,37,39,40,42,45,46,49,114]					
	2050	2.0	2.84	3.7	3.92	4.75	7.2
	Sources	[11,12,28,29,37,39,40,42,45–47]					
Lifetime in a	Current	20	20	21.5	22.33	25	25

Sources	[11,12,28,38,40,41,43,45,49,114]					
2030	20	23	25	23.44	25	25
Sources	[12,28,37,40,45,46,49,114]					
2050	20	20	25	23	25	25
Sources	[11,12,28,29,37,40,45–47]					

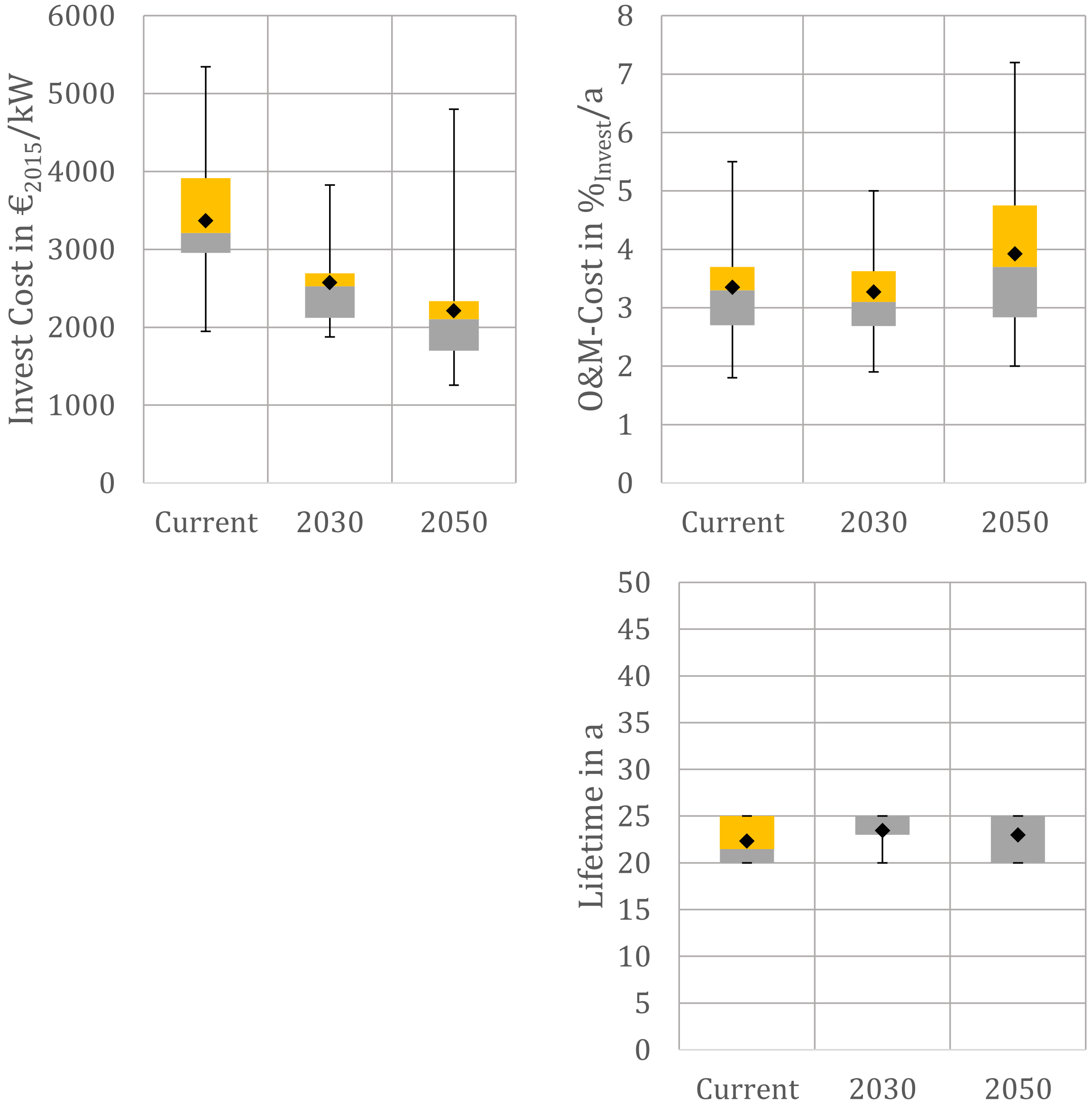

Figure 13 Cost parameters Wind Turbine Offshore

4. Conclusion – Own Recommendation

The authors' recommendation is to approximate the values, located between the mean and the median, to the nearest hundred. For wind power, the O&M costs are a notable exception, as most studies differentiate between fixed and variable O&M costs, which the authors think of as obsolete and, to compensate, they adjust the fixed O&M cost to the upper quartile. The lifetime of batteries is another case, where the selection was adjusted, which, in that case, is done to reflect the ongoing developments in durability. Methanisers and A-CAES energy storages consist mostly of well-known and proven technology that is configured in a new way, which is why current costs are relatively high. Supposing the demand for these technologies develops on the market, economies of scale will lead to lower values for 2030, at which point, they are assumed to plateau. Additionally,

the value for cavern lifetime is based on solely one study and relatively high, but the work of [99] is respected in terms of its methodology and, therefore, its value is taken.
Readers are invited to adjust these values, as needed. This is a way of justifying assumptions or placing them in relation to values presented in other studies.

Table 16: Own Recommendation for Cost Assumptions

Technology	Value	Current	2030	2050
Hard Coal	Invest Cost in €$_{2015}$/kW	1500	1500	1500
	O&M Cost in %$_{Invest}$/a	2.5	2.5	2.5
	Fuel Cost in €$_{2015}$/MWh$_{th}$	11	13	17
	Lifetime in a	40	40	40
Lignite	Invest Cost in €$_{2015}$/kW	1700	1700	1700
	O&M Cost in %$_{Invest}$/a	2.6	2.6	2.6
	Fuel Cost in €$_{2015}$/MWh$_{th}$	4	4	4
	Lifetime in a	40	40	40
CCGT	Invest Cost in €$_{2015}$/kW	750	750	750
	O&M Cost in %$_{Invest}$/a	3.0	3.0	3.0
	Fuel Cost in €$_{2015}$/MWh$_{th}$	26	33	40
	Lifetime in a	30	30	30
OCGT	Invest Cost in €$_{2015}$/kW	450	450	450
	O&M Cost in %$_{Invest}$/a	3.0	3.0	3.0
	Lifetime in a	30	30	30
Pump Hydro Energy Storage	Invest Cost in €$_{2015}$/kW	1100	1100	1100
	Invest Cost in €$_{2015}$/kWh	30	30	30
	O&M Cost in %$_{Invest}$/a	1.0	1.0	1.0
	Lifetime in a	60	60	60
Lithium Ion Battery	Invest Cost in €$_{2015}$/kW	200	150	100
	Invest Cost in €$_{2015}$/kWh$_{net}$	650	250	150
	O&M Cost in %$_{Invest}$/a	1.4	1.4	1.3
	Lifetime in a	12	15	20
Electrolyser	Invest Cost in €$_{2015}$/kW	1500	750	450
	O&M Cost in %$_{Invest}$/a	3.0	3.0	3.0
	Lifetime in a	15	20	20
Methanisation	Invest Cost in €$_{2015}$/kW$_{SNG}$	800	550	550
	O&M Cost in %$_{Invest}$/a	2.5	2.5	2.5
	Lifetime in a	20	20	20
Gas Storage (Salt Cavern)	Invest Cost in €$_{2015}$/m$^3_{Cavern}$	90	90	90
	O&M Cost in %$_{Invest}$/a	2.5	2.5	2.5
	Lifetime in a	75	75	75
A-CAES	Invest Cost in €$_{2015}$/kW	900	750	750
	Invest Cost in €$_{2015}$/kWh$_{th}$	40	40	40
	O&M Cost in %$_{Invest}$/a	1.5	1.5	1.5
	Lifetime in a	30	35	35
PV (utility scale)	Invest Cost in €$_{2015}$/kW	1000	675	500
	O&M Cost in %$_{Invest}$/a	1.5	1.75	2.0
	Lifetime in a	25	27.5	30
PV (roof top)	Invest Cost in €$_{2015}$/kW	1500	1000	750
	O&M Cost in %$_{Invest}$/a	1.5	1.75	2.0
	Lifetime in a	25	27.5	30
Wind Onshore	Invest Cost in €$_{2015}$/kW	1450	1200	1100
	O&M Cost in %$_{Invest}$/a	3.0	3.0	3.0

	Lifetime in a	25	25	25
Wind Offshore	Invest Cost in €$_{2015}$/kW	3300	2600	2150
	O&M Cost in %$_{Invest}$/a	3.5	3.5	4.0
	Lifetime in a	20	25	25

Table 17 gives values for technologies, where the data available was far from sufficient for an analysis with the given methodology. Estimates for the cost of CSP are to be taken with caution, as all sources have an underlying plant design. This is because the mirror area and receiver size are dependent on the technology and the so-called solar multiple, a parameter relating the maximum deliverable thermal power by the receiver to the maximum thermal power the conversion unit can process.

Table 17: Own Cost Assumptions for technologies with only little data available

Technology	Value	Current	2030	2050	Sources
Biomass (Wood) Firing (Thermal power plant)	Invest Cost in €$_{2015}$/kW	2800	2800	2800	[11,28–30,37,40–42,45,49,116]
	O&M Cost in %$_{Invest}$/a	3.5	3.5	3.5	
	Fuel Cost in €$_{2015}$/MWh$_{th}$	30	30	30	
	Lifetime in a	40	40	40	
Biogas plant (excluding engine)	Invest Cost in €$_{2015}$/kW$_{Biogas}$	3000	3000	2000	[11,12,28,28,29,37,38,40–43,45,47,49]
	O&M Cost in %$_{Invest}$/a	3.5	3.5	3.5	
	Fuel Cost in €$_{2015}$/MWh$_{th}$	35	35	35	
	Lifetime in a	25	25	25	
Engines	Invest Cost in €$_{2015}$/kW	700	550	550	[11,12,29,41,49,117]
	O&M Cost in %$_{Invest}$/a	3.0	3.0	3.0	
	Lifetime in a	15	20	20	
Concentrated Solar Power	Invest Cost in €$_{2015}$/kW	4500	2500	1500	[12,28,29,38–40,43,45,47]
	Invest Cost in €$_{2015}$/MWh$_{th}$	40	40	40	
	O&M Cost in %$_{Invest}$/a	2.0	2.0	2.0	
	Lifetime in a	30	30	30	
Redox-Flow Batteries	Invest Cost in €$_{2015}$/kW	1100	900	570	[13,16,29,41,43,47,58–60,62,64,69,72,75,118,119]
	Invest Cost in €$_{2015}$/kWh$_{net}$	410	190	105	
	O&M Cost in %$_{Invest}$/a	2.0	2.0	2.0	
	Lifetime in a	15	17.5	20	
Fuel Cells	Invest Cost in €$_{2015}$/kW	2000	1500	1000	[73,78,84,89,92,95,120–127]
	O&M Cost in %$_{Invest}$/a	2.0	2.0	2.0	
	Lifetime in a	10	12	15	
Thermal Energy Storages	Invest Cost in €$_{2015}$/kW	5	5	5	[11,16,29,62,128]
	Invest Cost in €$_{2015}$/kWh$_{th}$	40	40	40	
	O&M Cost in %$_{Invest}$/a	1.0	1.0	1.0	
	Lifetime in a	20	20	20	
Run-of-River Hydro	Invest Cost in €$_{2015}$/kW	3000	3000	3000	[11,12,27,28,30,37,41,45–47,49]
	O&M Cost in %$_{Invest}$/a	1.5	1.5	1.5	
	Lifetime in a	60	60	60	

4.1. CCS Technologies

Carbon capture and storage technologies are frequently discussed but rarely modelled technologies to reduce CO_2 emissions. With the given greenfield cost parameters for the conventional technologies hard coal, lignite and CCGT, the assumption of [28] of a factor of 1,3 to scale the investment cost for CCS seems not to be sensible given the few sources available. Given [28–30,39,40,43,45,47,49] the scaling factor for both hard coal and lignite should be ≈1.7, with lignite being a little higher if diversification is wanted. For CCGT [28–30,39,40,43,47,49,51] were analysed leading to a scaling factor estimate of ≈2.0. Lifetime and O&M cost parameters are believed not to change. For lifetime the argument lies in the MEA reactor to be of equal or greater lifetime, while the argument for the O&M cost parameter lies in the percentage of invest approach leading to higher absolute cost following the higher invest cost mentioned before. For CO_2-transport costs of ≈3 €/t_{CO2} [129] can be assumed. For the cavern a maximum pressure of 180 bar and 50 °C as for hydrogen is assumed. This leads to a density of CO_2 $\rho_{CO_2} \approx 750$ kg/m³., which then can be used to calculate the cost of the cavern per ton of CO_2 using the cost parameters of Table 10. Please note, that for storing CO_2 permanently porous rock formations such as sandstone are preferred and sometimes empty oil wells are considered, which both result in different cost assumptions. Caverns might be preferred in scenarios, where the CO_2 is used for methanisation later on.

4.2. CO_2 Certificates

CO_2 certificates are a tool to encourage the use and development of CO_2-free technologies as it puts a price on the emitted CO_2. Depending on the research question, the CO_2 certificate cost may be a parameter or a result of the calculation. Furthermore, the model year is not always defined and the CO_2 certificate costs are separated into a low, medium and high cost scenario, which were translated into Current, 2030 and 2050 cost respectively. Using [12,28–30,33,37–40,42,43,46–48,51,53] for this comparison 20, 50 and 100 €$_{2015}$/t_{CO2} are recommended for Current, 2030 and 2050 CO_2 certificate cost respectively. Figure 14 illustrates the distribution of the sources' assumptions and results.

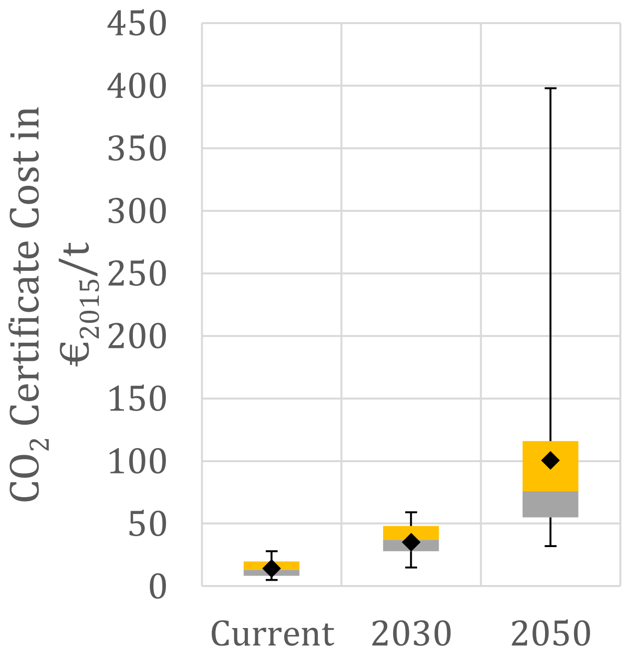

Figure 14 Distribution of CO_2 Certifcate Cost assumptions

5. Discussion

The most prominent critique of the paper at hand is the number and the details of sources chosen. Some assumptions are so rarely mentionend (e.g. 2050 lifetime of A-CAES in Table 11), that not even an interquartile

range could be given. The authors consider this review to be comprehensive, however there is always more that could have been done. Please note however, that any study found by and available to the authors was used.
In addition, the authors' recommend that different studies could be given different weights, with a detailed expert study with different scenarios like [9] having a bigger influence on the result than an assumption in a broader case study like [47]. Although this suggestion appears sensible, [10,114] stated that academic experts, especially, give rather optimistic answers about the cost development in their field. Additionally, the weighing factors would be subjective and therefore error prone.
The calculation of the $€_{2015}$ values might be error prone as well, as the consumer price index was used, which might not be applicable to the power unit production sector. As the consumer price index also reflects on the commodity price of electricity, this point is somewhat disregarded. Additionally, the use of the German price index might weaken the applicability of results to every geographical context.
Lastly, leaving out the variable O&M cost could viewed at as wrong, but as most studies consider the simulation of one year and assume this repeatedly for the lifetime of the plant, the variable O&M cost become a fixed recurring cost, making the methodology of choosing slightly higher fixed O&M cost seem reasonable.

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7. Nomenclature

Table 18: Nomenclature

Symbol	Unit	Description
a	-	Efficiency parameter
b	-	Efficiency parameter
C_{net}	-	Net capacity of storage
E	MWh	Storage level
e	kg/MWh_{th}	Specific CO_2 emissions
G	-	Set of conventional generation units

g	-	Index of conventional generion unit in set G
I	-	Set of points in efficiency curve
i	-	Index of points in set I
k	-	Index of optimisation period
K	-	Set of optimisation periods
P	MW	Power of unit on gridside
P_u	MW	Power of unit on unitside
p	-	Relative load
R	MW/min	Maximum power gradient of unit
S	-	Set of storage units
s	-	Index of storage unit in set S
T	-	Set of timesteps
T_k	-	Set of timesteps of interval for period k
$T_{k,0}$	-	First timestep of interval for period k
t	-	Timestep in Set T
t_{period}	-	Number of timesteps in a period
δ	-	Deviation in parameterisation problem
η	-	Efficiency
ξ	%/h	Self discharge rate of storage
τ	h	Length of timestep
ψ	-	Status variable for unit (0=off, 1=on)