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LCOE of renewables are not a good indicator of future electricity costs

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Summary

The falling levelized cost of electricity (LCOE) of renewable energies is repeatedly used to argue that electricity costs in Germany will decline. However, the LCOE is not a reliable basis for estimating future electricity costs. This is because comparing the production of wind or solar plants - which is the basis of an LCOE calculation - with the demand for electricity, there will be gaps in supply during many hours of the year which will have to be covered by complementary technologies such as battery storage or gas-fired power plants and, in future, hydrogen-fueled power plants. The investment costs of these plants and their operation must be included in the calculation of the costs of meeting demand. The "Levelized Cost of Load Coverage" (LCOLC) calculated in this way does not indicate that electricity costs will fall significantly in the coming decade.

Introduction

The levelized cost of electricity (LCOE) is the cost of constructing and operating a power plant in relation to the amount of electricity generated over its entire lifetime. This makes it possible to determine the average cost of generating one kilowatt hour (kWh) on a plant or technology basis. In recent years, the LCOE of renewable energies (RE) has fallen significantly and the LCOE of conventional power plants has risen due to rising CO2 prices (see e.g. Fraunhofer ISE (2021)).

In view of this development, it is repeatedly argued in the economic policy debate that electricity costs will not remain at the current level, but will fall with increasing RE expansion (cf. e.g. Bauermann (2023), Dullien et al. (2023)). Based on this expectation, various stakeholders are arguing in favor of establishing lower prices now by temporarily subsidizing the price of electricity in order to strengthen the competitiveness of energy-intensive industry in Germany ("transformation electricity price", BMWK (2023), SPD parliamentary group (2023)). Most recently, 5 ct/kWh (SPD parliamentary group (2023)) and 6 ct/kWh (BMWK (2023)) were called for. In the debate, it is often assumed that large companies could benefit directly from the low LCOE in future if they were supplied by a wind or solar farm. However, these LCOE can only be achieved for a consumer if the consumer's demand for electricity is precisely aligned with the electricity generation from wind or PV systems. On the other hand, the argument does not hold if the costs of supplying electricity to a consumer with a specific demand profile are to be determined.

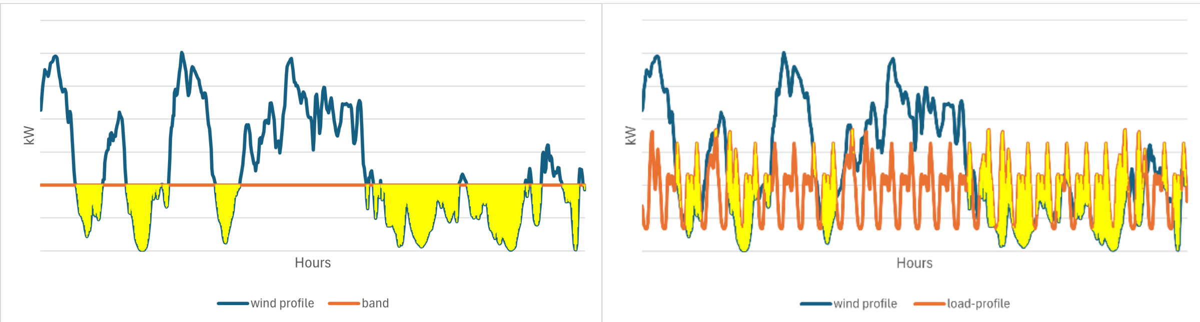

Figure 1: In order to meet demand, the supply gap (shown here in yellow), i.e. the difference between demand and the production of renewable energies, must be covered by complementary technologies. In the short term, gas-fired power plants and storage facilities can be considered, while also hydrogen power plants can be used in the long term.

This is easy to illustrate: If you want to ensure the supply of a company or satisfy the demand of a region (or a country), you need to meet the corresponding demand. This can be (in the case of a company that produces continuously) a largely continuous demand for electricity over time ("band"), or a load profile that reflects the demand of the corresponding consumers. If one compares the production of the wind or solar plants (which is the basis of an LCOE calculation) over time with the electricity demand, gaps in the supply arise which must be covered by the provision of other (complementary) technologies (see Fig. 1). The investment costs of these plants and their operation must be included in the calculation of the costs of meeting demand. Satisfying demand must therefore - correctly calculated - be accompanied by higher levelized costs, which we call Levelized Cost of Load Coverage (LCOLC) in the following.

In this policy brief, we show in various sample calculations which LCOLC result when the actual costs of supplying a large industrial customer or satisfying the demand of a region (or a country) are estimated. It turns out that the LCOE is not a good indicator of the costs of satisfying demand (LCOLC). The LCOE is therefore not suitable for estimating future electricity costs. As with the usual consideration of the LCOE, we calculate the LCOLC without taking other system costs into account.

The inadequacy of the LCOE for estimating electricity costs has been addressed in the literature on various occasions. Various authors propose alternative approaches to address the known deficits, see for example Joskow (2011), Ueckerdt et al. (2013), Hirth et al. (2014), Reichelstein and Sahoo (2015), Belderbos et al. (2017), Lai and McCulloch (2017), Simpson et al. (2020), Shen et al. (2020), Loth et al. (2022). Ueckerdt et al. (2013) and Hirth et al. (2014), for example, refer to the additional costs of renewable energies for the system, including balancing energy, backup capacities, additional grid capacities and a reduction in the full-load hours of conventional power plants. Taking these variables into account, they calculate the system LCOE, i.e. the costs of satisfying demand. Lai and McCulloch (2017) combine LCOE and "Levelized Cost of Delivery" (LCOD) for systems consisting of PV and battery storage. IEA and NEA (2020) calculate "Value Adjusted Levelized Cost" (VALCO), which corrects the LCOE of different technologies with their flexibility and capacity values. Joskow (2011) also points out that the economic value of electricity is determined by the revenue on the market, but that the concept of LCOE only covers the cost side and therefore possibly underestimates electricity prices.

The calculations in this paper are deliberately kept simple and therefore abstract from cost components arising from grid fees, necessary additional grid capacities, backup capacities required due to demand uncertainty or margins in electricity trading. The focus is on the costs of meeting a predictable demand in order to clarify the difference between the often-discussed LCOE of renewable energies and the LCOLC for meeting demand. By comparing different scenarios, the attractiveness and range of application of various complementary technologies such as electricity storage, gas and hydrogen power plants becomes particularly clear. The possible flexibilization of demand with the aim of adjusting the load profile of renewable energy production more closely is not considered here. However, due to the substantial flexibilization costs (see e.g. Ambrosius et al. (2018)), such flexibilization is not expected to fundamentally affect the results obtained here.

Calculation of LCOE and LCOLC

LCOE is calculated by dividing the net present value of the sum of the annuities of capital costs, fixed and variable operating costs and, if applicable, fuel costs and costs for emission rights by the electricity generated by the plant over the course of a year.

$$LCOE = \frac{Net\ present\ value\ of\ annual\ costs\ (X_{LCOE}, Q_{LCOE})}{Annual\ electricity\ generation\ (Q_{LCOE})} [€ct/kWh]$$

A fixed system size X_{LCOE} is assumed here (typically 1kWp for RE); when calculating LCOE for RE, the resulting electricity generation Q_{LCOE} is calculated as the amount that can be technically produced with the system over the course of the year (see Fraunhofer ISE (2021), p.14). For conventional power plants, on the other hand, a number of full-load hours is usually assumed that is considered plausible for the scenario to be calculated (see Fraunhofer ISE (2021), p.15). LCOE can be determined by directly adding up the costs incurred and the resulting production volumes over the course of the year. It is not necessary to solve an optimization problem.

In contrast, the calculation of the LCOLC is based on a demand that must be met (see "band" or "profile" in Fig. 1). For various available technology options, the capacities of the plants, X_{LCOLC} , and production quantities of the various plants, Q_{LCOLC} , are determined at minimum cost in such a way that the specified load profile is covered exactly. Optimal capacity and production quantities are thus determined by solving an optimization problem. The LCOLC is then calculated from the minimum-cost capacities and production quantities as follows:

$$LCOLC = \frac{Net\ present\ value\ of\ annual\ costs\ (X_{LCOLC}, Q_{LCOLC})}{Annual\ electricity\ generation\ (Q_{LCOLC})} [€ct/kWh]$$

Scenarios

We perform all LCOLC calculations for two demand scenarios: A constant electricity demand throughout (for example, of a large company) and a load profile that reflects the fluctuating electricity demand of consumers over time (for example, in a region or country).

We deliberately take a simple approach when analyzing different scenarios. As comparative scenarios, we calculate the LCOE of onshore wind and ground-mounted PV systems, $Wind_{LCOE}$ and PV_{LCOE}. In a further step, we then calculate the LCOLC for various available technology options for two demand scenarios, a constant electricity demand over time ("band") and a typical demand profile ("profile"). The technology options for meeting demand consist of renewable energies - wind only (W), photovoltaics only (PV), or both technologies (W&PV) - combined with either battery storage only (S) or battery storage and gas-fired power plants (S&G). In the scenarios for 2040, hydrogen (H2) is added as an option for covering the supply gaps. In all scenarios, we calculate the minimum-cost capacities and production volumes of the technology options permitted in each scenario. Deviating from the minimum-cost solution (e.g. due to specific expansion targets for individual technologies) would result in higher costs. The scenarios are summarized in Table 1.

		Load requirement		
		Without demand requirements	Load profile	Constant Demand (band)
LCOE	Wind	W_{LCOE}	Meeting demand exclusively through RE unrealistic	
	PV	PV_{LCOE}		
LCOLC from Wind (W), PV or W&PV with flexibility through...	Storage	Without demand requirements the result corresponds to the minimum of the LCOE values	$W\&PV^{S}_{Profil}$	W^{S}_{Band} PV^{S}_{Band} $W\&PV^{S}_{Band}$
	Storage & gas		$W^{S\&G}_{Profil}$ $PV^{S\&G}_{Profil}$ $W\&PV^{S\&G}_{Profil}$	$W^{S\&G}_{Band}$ $PV^{S\&G}_{Band}$ $W\&PV^{S\&G}_{Band}$
	Storage & H2		$W\&PV^{S\&H2}_{Profil}$	$W\&PV^{S\&H2}_{Band}$
	Storage & Gas & H2		$W\&PV^{S\&G\&H2}_{Profil}$	$W\&PV^{S\&G\&H2}_{Band}$

Table 1: Scenarios considered.

Assumptions

The calculations are based on assumptions regarding costs and technical parameters that were selected in various recent studies. In particular, we are guided by the assumptions made by Fraunhofer ISE (2021), as LCOE calculations were carried out in this study and it is helpful to compare them with our results. The interest rates used in 2021 are probably too low in light of current interest rate developments. However, an adjustment would only increase the levelized costs, but would not significantly change the relationship between the results in the different scenarios. We therefore adopt the assumptions on interest rates from previous studies in order to make it easier to gain insights from a comparison of the results.

We present calculations for two exemplary time periods, the year 2021 and the year 2040. In order to keep the complexity of the calculations low and to be able to present the results transparently, we consider a limited number of technologies: Onshore wind (W), ground-mounted PV systems (PV), combined cycle gas turbine power plants (CCGT) and battery storage (S). For the year 2040, we also include PEM electrolysis plants (PEM), hydrogen storage (H2 storage) and hydrogen-capable gas-fired power plants (H2 CCGT) in the analysis.

The parameters on which the calculations for 2021 are based are shown in Table 2. These are based on Fraunhofer ISE (2021) to facilitate comparability with their results. The parameters for the year 2040 are summarized in Table 3. The values for wind onshore, PV, storage and gas-fired power plants are also taken from Fraunhofer ISE (2021). Lifetimes, interest rates, OPEX (except fuel costs for gas-fired power plants, see Table 4) and capacities remain unchanged relative to the assumptions for 2021. Average CAPEX values are adopted for batteries in 2040. CAPEX values for wind onshore and PV in 2040 that are not directly stated are determined in such a way that they correspond to the average values of the corresponding LCOE for 2040 stated in Fraunhofer ISE (2021).

2021	Wind	PV	Battery Storage	Gas CCGT
CAPEX [€/kWp, €/kWh, €/kW]	1700	665	600	950
Lifetime of the system [years]	25	30	15	30
Interest rate [%]	2,96	2,50	2,50	5,80
OPEX ^{fix} [€/kWp, €/kWh, €/kW]	20	13.3	8	20
OPEX^{var} [€/kWh]	0,008	0	0	0,003
Efficiency storing out [%]			95	
Efficiency storing in [%]			95	

Table 2: Parameters for the year 2021 Source: Fraunhofer ISE (2021).

For the year 2040, we consider the use of electricity storage via hydrogen, going beyond Fraunhofer ISE (2021). Values for PEM electrolysers are taken from Osorio et al. (2023), the efficiency of electrolysers is taken from the database for electrolysers compiled at the Potsdam Institute for Climate Impact Research (PIK) (PIK, https://h2.pik-potsdam.de/H2Dash/). EWI (2024) is used for the hydrogen storage facilities, resulting in virtually identical values to ENTSOG and ENTSO-E (2022). In turn, values from Osorio et al. (2023) are used for the hydrogen-capable turbine power plants. Finally, Table 4 contains the fuel costs (natural gas) and the costs for emission certificates required for the operation of gas-fired power plants for both observation periods (Fraunhofer ISE 2021).

2040	Wind	PV	Battery storage	Gas CCGT	PEM	H2 Storage	H2 CCGT
CAPEX [€/kWp, €/kWh, €/kW]	1349	322	285	950	596	0.320	945
Lifetime [years]	25	30	15	30	20	30	40
Interest rate [%]	2,96	2,50	2,50	5,80	2,50	2,50	5,80
OPEX ^{fix} [€/kWp, €/kWh, €/kW]	20	13.3	8	20	11,92	0	28,35
OPEX^{var} [€/kWh]	0,008	0	0	0,003	0,003	0	0,004
Efficiency storing out [%]			95				57
Efficiency storing in [%]			95		65,5		

Table 3: Parameters for the year 2040. Parameters for wind, PV, battery storage and gas CCGT based on scenarios from Fraunhofer ISE (2021), PEM, H2 storage, H2 turbine: Osorio et al. (2023), https://h2.pik-potsdam.de/H2Dash/ and EWI (2024).

Gas	2021	2040
Fuel costs [€/kWh]	0.025	0.017
Efficiency [%]	60	62
Price of EU ETS certificates [€/tCO2]	34	225
Emission factor [tCO2/kWh]	0.00024	0.00024

Table 4: Costs for natural gas and CO2 emissions. Source: Fraunhofer ISE (2021).

The calculations are based on hourly profiles of the production of onshore wind and ground-mounted PV systems (from Pfenninger and Staffell (2016), Staffell and Pfenninger (2016), https://www.renewables.ninja/), which are scaled to obtain the average full-load hours used in Fraunhofer ISE (2021): Wind onshore 2500 full-load hours annually and PV ground-mounted systems 1107 hours annually. Alternatively, we use the wind and PV profiles from ENTSOG and ENTSO-E (2022) (https://2022.entsos-tyndp-scenarios.eu/download/) and report the results in the Appendix.

In our calculations, we consider a total demand of 8760 kWh within one year. For the continuous demand (band), this means an hourly demand of 1 kWh. In the load profile under consideration, the same annual demand is distributed differently over four seasons (winter, summer, two identical transitional periods), each with 3 different type days (weekdays, Saturday, Sunday). The resulting load profile corresponds to the assumptions in BDEW (2017). For calibration, the typical load curve for households provided in BDEW (2017) (spreadsheet "Statischer Jahresverlauf" in the document "Haushalt-Lastprofil.xls") is averaged to hourly values and scaled to a total consumption of 8760kWh.

In order to scale the results to the size of a specific electricity system, for example a country or a large consumer, the resulting capacities can be multiplied by an appropriate factor to obtain the total amount of energy under consideration.

Results

In the following, we present the LCOE for wind and PV as well as the LCOLC for the various technology scenarios. The scenarios W_{LCOE} and PV_{LCOE} where no specific consumption profile is required, allow the results of a traditional LCOE calculation for onshore wind and ground-mounted PV to be determined as a benchmark. In the other scenarios, the minimum average costs per kWh are determined that arise when covering the respective demand with different technology combinations. It is also determined which capacities of the respective available technologies must be installed at minimum cost. It should be noted that the actual costs of meeting demand may be higher than the LCOLC if the installed capacities deviate from the minimum cost solution due to certain requirements (e.g. minimum renewable energy capacities).

Table 5 shows the results for 2021. **For wind and PV, the LCOE are 5.49 ct/kWh and 4.07 ct/kWh respectively ($\boldsymbol{W_{LCOE}}$, $\boldsymbol{PV_{LCOE}}$).** Due to the similar parameterization, this is in line with the results from Fraunhofer ISE (2021) for large PV systems and onshore wind. The costs to cover a given demand (LCOLC) are (in some cases significantly) higher and also vary greatly depending on the available technology options.

Due to the still high costs of battery storage today and the need to install large capacities, LCOLC of over 32.76 ct/kWh result if only battery storage is available to cover the supply gaps ($\boldsymbol{W^S_{Band}}$, $\boldsymbol{PV^S_{Band}}$, $\boldsymbol{W\&PV^S_{Band}}$, $\boldsymbol{W\&PV^S_{Profil}}$). It is striking that, compared to the other scenarios, enormous RE and storage capacities are required to meet demand. Of course, these scenarios are not suitable for thinking about the energy system of an entire country. However, they show impressively that isolated solutions based solely on RE and battery storage can benefit enormously from a grid connection and access to other options. The comparison of our results with Fraunhofer ISE (2021) also shows that taking into account the flexibilization needs of RE by adding the investment costs of electricity storage of a fixed size in an otherwise classic calculation of the LCOE can lead to misunderstandings. Such calculations may suggest the provision of sufficiently flexible load coverage through battery storage at low additional costs. In the end, however, this is not the case, as our detailed calculation approach of the LCOLC shows.

If combined cycle gas turbine (CCGT) power plants are available as a technology option, they will be used to close the supply gap ($W^{S\&G}_{Band}$, $W^{S\&G}_{Profil}$, $PV^{S\&G}_{Profil}$, $PV^{S\&G}_{Band}$, $W\&PV^{S\&G}_{Profil}$, $W\&PV^{S\&G}_{Band}$). Battery storage plays no or only a very minor role when combined cycle power plants are available. The installed capacity of the gas-fired power plants is selected in the minimum-cost solution to cover demand in such a way that the peak load can be fully or almost fully covered. With a total annual demand of 8760 kWh, the latter is 1kW in the "band" scenarios and 1.84 kW in the "profile" scenarios.

Scenario	Capacities				Costs (LCOE or LCOLC)
	Wind [kWp]	PV [kWp]	Battery storage [kWh]	Gas CCGT [kW]	Ø-costs [€ct/kWh]
W_{LCOE}	**3,50**	-	-	-	**5,49**
$W^{S\&G}_{Profil}$	0,81	-	0,04	1,80	7,59
$W^{S\&G}_{Band}$	1,22	-	0,00	1,00	6,72
W^{S}_{Band}	13,14	-	30,04	-	37,75
PV_{LCOE}	-	**7,91**	-	-	**4,07**
$PV^{S\&G}_{Profil}$	-	2,16	0,01	1,83	7,25
$PV^{S\&G}_{Band}$	-	1,68	0,00	1,00	6,50
PV^{S}_{Band}	-	111,52	65,37	-	99,51
$W\&PV^{S\&G}_{Profil}$	0,49	1,98	0,02	1,81	7,23
$W\&PV^{S\&G}_{Band}$	0,33	1,55	0,00	1,00	6,49
$W\&PV^{S}_{Profil}$	10,92	9,84	20,03	-	32,76
$W\&PV^{S}_{Band}$	10,33	11,19	25,62	-	36,28

Table 5: Results for 2021, invested capacities and LCOE and LCOLC for different consumption requirements and different technology combinations.

Table 6 contains the calculations with parameterization for the year 2040. **The LCOE for wind and PV are lower, with the LCOE for PV falling particularly sharply between 2021 and 2040, to 2.59 ct/kWh** (PV_{LCOE} in Table 6). This is due to the fact that the expected cost degression for solar modules is significantly stronger for technological reasons (see e.g. Tsiropoulos et al. (2018) and Wirth (2024)). The costs of meeting a given demand (LCOLC) will still be (in some cases significantly) higher than the LCOE of RE in 2040 and will vary greatly depending on the available technology options.

Although the CAPEX of battery storage assumed for 2040 is significantly lower than for 2021, the costs remain high at over 21.70 ct/kWh if the supply gaps can be covered exclusively with battery storage (W^S_{Band}, PV^S_{Band}, $W\&PV^S_{Band}$, $W\&PV^S_{Profil}$ in Table 6). The costs do not fall more sharply compared to the LCOLC values for 2021, as enormous capacities of both RE and storage would still be required to cover a given demand (band or profile).

Scenario				**Capacities**				**Costs (LCOE / LCOLC)**
	Wind [kWp]	PV [kWp]	Battery storage [kWh]	Gas CCGT [kW]	PEM [kW]	H2 storage [kWh]	H_2 CCGT [kW]	Ø-costs [ct/kWh]
W_{LCOE}	**3,50**	**-**	**-**	**-**	**-**	**-**	**-**	**4,69**
$W^{S\&G}_{Profil}$	3,24	-	1,69	1,30	-	-	-	9,61
$W^{S\&G}_{Band}$	3,19	-	0,05	0,99	-	-	-	8,74
W^{S}_{Band}	10,70	-	37,43	-	-	-	-	25,93
PV_{LCOE}	**-**	**7,91**	**-**	**-**	**-**	**-**	**-**	**2,59**
$PV^{S\&G}_{Profil}$	-	4,71	2,34	1,26	-	-	-	10,35
$PV^{S\&G}_{Band}$	-	3,62	0,11	0,99	-	-	-	10,44
PV^{S}_{Band}	-	77,01	97,06	-	-	-	-	59,59
$W\&PV^{S\&G}_{Profil}$	2,33	3,07	2,54	1,01	-	-	-	8,11
$W\&PV^{S\&G}_{Band}$	2,74	2,04	0,41	0,94	-	-	-	7,97
$W\&PV^{S}_{Profil}$	4,95	17,89	28,94	-	-	-	-	21,70
$W\&PV^{S}_{Band}$	5,52	22,26	28,08	-	-	-	-	23,45
$W\&PV^{S\&G\&H2}_{Profil}$	2,61	3,77	2,26	0,34	0,73	206,91	0,69	7,80
$W\&PV^{S\&G\&H2}_{Band}$	3,07	3,08	0,39	0,33	0,99	191,21	0,61	7,63
$W\&PV^{S\&H2}_{Profil}$	2,84	4,23	2,51	-	0,99	637,29	1,00	7,85
$W\&PV^{S\&H2}_{Band}$	3,35	3,52	0,41	-	1,28	573,16	0,94	7,68

Table 6: Results for the year 2040, invested capacities and LCOE and LCOLC for different consumption requirements and different technology combinations.

Covering the supply gap with combined cycle gas turbine power plants would lead to relatively high LCOLC despite lower gas prices due to the high CO2 prices ($\boldsymbol{W^{S\&G}_{Profil}}$, $\boldsymbol{W^{S\&G}_{Band}}$, $\boldsymbol{PV^{S\&G}_{Profil}}$, $\boldsymbol{PV^{S\&G}_{Band}}$, $\boldsymbol{W\&PV^{S\&G}_{Profil}}$, $\boldsymbol{W\&PV^{S\&G}_{Band}}$ in Table 6). The LCOLC calculated for 2040 are even (in some cases significantly) higher than the values for 2021 due to the high CO2 prices. Natural gas-fired power plants would no longer be a realistic technology option in any case due to the climate targets in 2040. In this context, however, the calculations clearly show that enforcing the targets via CO2 prices does indeed make the use of natural gas-fired power plants unattractive from an economic perspective.

For comparison, we also consider hydrogen production, its storage and electricity generation as a technology option to cover the supply gaps. The parameterization is based on average values for the cost spectrum expected in 2040. Even a less favourable parameterization (multiplication of the OPEX values by 1.5) results in only 0.2 to 0.6 ct/kWh higher values. Despite the cautious calibration, it should of course be noted that the availability of this technology option is a prerequisite.

The lowest costs to cover a given demand in 2040 are achieved if the production of hydrogen, its storage and electricity generation are available as a technology option to cover the supply gap ($\boldsymbol{W\&PV^{S\&G\&H2}_{Profil}}$, $\boldsymbol{W\&PV^{S\&G\&H2}_{Band}}$, $\boldsymbol{W\&PV^{S\&H2}_{Profil}}$, $\boldsymbol{W\&PV^{S\&H2}_{Band}}$ in Table 6). **In the scenarios - unlike in 2021 - battery storage is also used to a significant extent.** This is likely due to the significantly lower costs of battery storage in 2040. **If conventional gas-fired power plants are available as a technology option, they are used to a certain extent. However, the LCOLC are only very slightly higher if natural gas-fired power plants are not available.** It should be noted in this context that considerable efforts are required to make the components necessary for the hydrogen technology option available. This involves hydrogen-capable gas-fired power plants on the one hand, but also electrolysis and storage capacities on the other. If we consider the energy system as a whole, it can be assumed that hydrogen will not only be produced, stored and converted back into electricity, as is simplistically assumed here. Rather, it is to be expected that the majority of the hydrogen will be imported, partially stored temporarily and converted into electricity (see Runge et al. (2023) or NWR (2024)). The costs of the grid capacities required for this - as well as the grid capacities (and grid fees) for electricity and gas - are not taken into account here. The reason for this is that we focus on the direct costs of satisfying electricity demand in line with the LCOE concept, which means that these costs are definitely greatly underestimated. If other cost components were taken into account, it would become even clearer that the conventional LCOE is unsuitable for estimating the costs of electricity supply.

In the scenarios, part of the RES production is curtailed in both years under consideration, 2021 and 2040, and is therefore not used. In the scenarios with all complementary technology options (storage and gas), curtailment is as low as 2.67% ($W\&PV^{S\&G}_{Band}$) in some cases, but mostly close to but below 10% of RE generation. If only storage is available to cover the supply gaps, over 72% of RE is curtailed in 2021 (2040: over 66%). This shows once again that a system based solely on RE and battery storage would not be expedient, not even in 2040. In principle, it is of course conceivable that surplus renewable electricity could be used by investing in demand-side flexibility. However, the flexibilization of demand is also associated with high costs in some cases (for the flexibilization of industrial electricity demand and the corresponding investment requirements, see e.g. Ambrosius et al. (2018)). At the level of the overall system, despite regional flexibilities on the demand side, the supply gaps to meet demand must also be closed by complementary technology options.

Conclusion

We have demonstrated that the LCOLC in all the scenarios presented here are significantly higher than the LCOE typically discussed for individual technologies. This is due to the fact that the usual LCOE calculations do not take into account the costs that must be incurred in addition to renewable energies in order to satisfy a given demand for electricity. The calculations reflect the fact that electricity costs (here: without grids) will not fall as significantly in the future as a consideration of the LCOE alone would suggest at first glance. Instead of 4.07 ct/kWh, which results from a pure calculation of the LCOE for PV, for example, the calculations for 2021 show average costs of over 6.49 ct/kWh to satisfy the demand for electricity. Calculations for the year 2040 result in LCOE for PV of only 2.59 ct/kWh. However, taking into account that demand must be met, a climate-neutral electricity generation system would incur costs of at least 7.68 ct/kWh. This does not take into account margins on the electricity market, grid and concession fees and taxes.

Electricity costs are therefore unlikely to fall significantly - as hoped - with the expansion of RE. The substantial costs that arise from covering the supply gaps can be concealed by political decisions - for example, if a large proportion of the necessary gas and hydrogen power plants are subsidized by the state, operated outside the market or grid fees are waived. However, this does not make the costs disappear; they must be borne by citizens either as electricity customers or (if they are not passed on to the electricity price) through current or future taxes.

It can be argued against our simplified approach that making demand more flexible opens up further opportunities to reduce LCOLC. However, making demand more flexible is also associated with costs, as storage facilities for intermediate products would have to be installed in industrial production, for example, and higher production costs would also arise due to longer downtimes and flexible plant running times. The flexibilization of demand is therefore only likely to take place to a limited extent and will not be able to fully adapt the load curve to the generation patterns (see, for example, Ambrosius et al. (2018)).

Our analysis therefore shows that estimating future electricity costs on the basis of LCOE gives a false picture. If one calculates the LCOLC that actually arise when demand is met, this results in significantly higher values than the LCOE of RE. We have deliberately not used a complex energy system model in this short paper in order to illustrate the danger of misinterpreting the conventionally calculated LCOE in a particularly clear and comprehensible way. The findings from our calculations, together with the insight that there is further potential for optimization (for example through the flexibilization of demand, sector coupling or European integration) but also further cost factors (for example through deviation from the minimum cost power plant mix, additional grid expansion costs and backup power plants), show that the LCOE of RE does not fully reflect the actual costs incurred for the electricity supply and is therefore not suitable for drawing conclusions about future electricity costs.

Finally, it should be noted that even if all electricity generation costs are taken into account, it is not possible to draw direct conclusions about the resulting electricity prices from the Levelized Cost of Load Coverage (LCOLC). Average electricity prices that arise on the market can be lower than the LCOLC, for example if the state subsidizes part of the electricity generation and thus finances part of the electricity costs through current or future tax revenues. However, they can also be higher than the LCOLC, for example in the case of an inefficient generation mix or due to margins that companies realize on the electricity market. In any case, the costs incurred to satisfy demand (LCOLC) must ultimately be borne by companies and consumers, either via the electricity price or via levies, surcharges or current or future taxes. The calculation of the LCOLC is therefore suitable for thinking about the (future) burdens and their distribution among the various stakeholders.

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Appendix

Table 7 shows the results of the calculations for the year 2040 if the wind and PV profiles from ENTSOG and ENTSO-E (2022) (https://2022.entsos-tyndp-scenarios.eu/download/) are used as an alternative.

Scenario	Capacities							Costs
	Wind [kWp]	PV [kWp]	Electri-city Storage [kWh]	Gas CCGT [kW]	PEM [kW]	H2 storage [kWh]	H_2 CCGT [kW]	Ø-costs [ct/kWh]
W_{LCOE}	**3,73**	**-**	**-**	**-**	**-**	**-**	**-**	**4,94**
$W^{S\&G}_{Profil}$	3,22	-	1,26	1,37	-	-	-	10,25
$W^{S\&G}_{Band}$	3,18	-	0,04	0,97	-	-	-	9,19
W^{S}_{Band}	17,88	-	23,70	-	-	-	-	29,02
PV_{LCOE}	**-**	**8,68**	**-**	**-**	**-**	**-**	**-**	**2,84**
$PV^{S\&G}_{Profil}$	-	5,98	2,53	1,19	-	-	-	10,16
$PV^{S\&G}_{Band}$	-	4,60	0,59	0,97	-	-	-	10,34
PV^{S}_{Band}	-	65,58	43,19	-	-	-	-	36,77
$W\&PV^{S\&G}_{Profil}$	1,97	4,36	3,31	0,87	-	-	-	8,16
$W\&PV^{S\&G}_{Band}$	2,48	2,65	0,33	0,95	-	-	-	8,10
$W\&PV^{S}_{Profil}$	3,55	23,87	17,65	-	-	-	-	18,07
$W\&PV^{S}_{Band}$	6,34	11,38	23,02	-	-	-	-	19,08
$W\&PV^{S\&G\&H2}_{Profil}$	2,36	5,28	2,60	0,40	0,77	209,26	0,56	7,91
$W\&PV^{S\&G\&H2}_{Band}$	2,95	3,89	0,29	0,40	0,91	203,48	0,55	7,80
$W\&PV^{S\&H2}_{Profil}$	2,58	5,68	2,83	-	0,94	518,99	0,92	7,96
$W\&PV^{S\&H2}_{Band}$	3,28	4,58	0,35	-	1,25	584,94	0,94	7,88

Table 7: Results for the year 2040, invested capacities and LCOE and LCOLC for different consumption requirements and different technology combinations. Full-load hours for ground-mounted PV systems and onshore wind according to TYNDP (lower full-load hours).

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