Levelized Full System Costs of Electricity

Robert Idel*

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Abstract

This paper introduces the Levelized Full System Costs of Electricity (LFSCOE), a novel cost evaluation metric that, unlike the Levelized Costs of Electricity (LCOE), includes the cost of intermittency by assuming that the entire market has to be supplied by one source plus storage. The LFSCOE condense the cost for each technology into one number per market, making them more straight-forward and catchy than other more sophisticated cost evaluation metrics that account for intermittency (like the System LCOE), which seems necessary to challenge the prevailing use of LCOE in public discussions. After introducing the concept of LFSCOE, this paper compares different power generation technologies for different markets, discusses some refinements and potential developments in the storage technologies. In the last part, the LFSCOE-95 are introduced which only require each technology to supply 95% of the total demand.

Keywords: Intermittent renewables, Levelized Costs of Electricity (LCOE), System LCOE, Power Generation Economics, Electricity

*PhD Candidate, Rice University, Houston, TX-77005-1827; Graduate Fellow at the Center for Energy Studies at the Baker Institute for Public Policy (www.bakerinstitute.org). Email: robert.m.idel@rice.edu.

1 Introduction

Lifetime costs of an investment are a key measures for decision making. This is true for investment decisions in electricity markets as well, where the most popular measure to compare different technologies for generating electricity are the Levelized Costs of Electricity (LCOE). To calculate the LCOE, the expected lifetime generation of an electricity generating plant and the expected costs to generate the lifetime electricity are calculated. After dividing total costs by total generation, the final number (usually in USD/MWh) is derived. Input assumptions like capacity costs, maintenance, marginal operating costs or average capacity factor, which is particularly relevant for renewables sources of electricity, are crucial for the calculation and vary by study.[1] For example, a continuously updated study by Lazard estimates the LCOE of coal between 66 and 152 USD/MWh and onshore wind in the range of 28-54 USD/MWh (see Lazard (2019)), whereas the U.S. Energy Information Administration calculated the LCOE for coal at 76 USD/MWh and wind at 40 USD/MW (see EIA LCOE (2020) and chapter 2). Many recent studies indicate that the Levelized Costs of Electricity are the lowest for onshore wind and utility scale solar using photovoltaic cells (hereafter referred to as "solar PV" or "solar"), findings that are cited frequently by proponents of a fast transition towards renewable electricity. But if it is the cheapest source while not emitting CO2, why are countries still investing heavily in new gas and coal power plants? Is it just because coal generation may employ more people in politically sensitive regions of the country, or are there financial reasons that are not reflected in the LCOE?

Critiques of LCOE are not scarce. Joskow (2011) is one of the first to point out that LCOE ignore the costs associated with intermittency. It is easy to see the fundamental misunderstanding in LCOE: The LCOE describe the costs of generating electricity. However, the function of supply in electricity markets is not to generate electricity, but to provide a specified amount of electricity to a certain place at a certain time. The locational aspect adds significant additional costs to renewables that are in general less flexible about where they can be sited than fossil fuel plants. As a result, a larger grid is required to transport the electricity from e.g. hydropower plants to the demand in urban areas. This is partly taken care of in some LCOE studies, when a transmission cost adder is included in the LCOE. But the timing aspect turns out to be even more

[1] I abbreviate the term "electricity plants that use renewable sources of energy" by "renewables".

crucial and the focus of this paper. Many renewables (like wind and solar) are intermittent and non-dispatchable (hereafter referred to just as "intermittent" unless further specified), and some that are not intermittent (like run-of-river-hydro) are often not fully dispatchable.[2] As long as the share of intermittent generation is low, sufficient dispatchable generation capacity will usually be available to step in and replace missing intermittent generation output. Economically, the fact that intermittent generation has no obligation to meet the demand can be seen as a hidden subsidy. One can even go one step further and argue that intermittent generation is of zero value if it cannot be made available to consumers that demand a steady flow of electricity. To do that, however, supply and demand on the network must always be in balance. In effect, the ability to schedule other generators to continuously maintain that balance is necessary to give value to renewable output. The dispatchable generators thus raise the value of renewable generation, but the subsidy is "hidden" because the latter does not have to pay for it. Once the share of intermittent generation increases to a certain level (and dispatchable capacity is shut down), efforts have to be taken to maintain system reliability. But who should be responsible for these costs? How can the cost of integrating renewables into the system (which increases significantly with their market share) be included in the evaluation of their cost?

Ueckerdt et al (2013) address the cost of integrating renewables into a network by introducing the "System LCOE". The System LCOE of an intermittent source are defined as the sum of the (marginal) generation costs (the LCOE) and the (marginal) integration costs, where integration costs can be split up into balancing costs, grid costs, and profile costs. Balancing costs include any cost incurred by the operator to overcome the uncertainty of the intermittent generation and ensure that supply and demand are always in balance, whereas grid costs are associated with the grid adjustments necessary to support the renewable system. Profile costs include all costs related to matching supply with demand if market conditions can be perfectly forecasted (and thus differ from balancing costs). Ueckerdt et al (2013) split up the profile costs into back-up costs, overproduction costs, and full-load hour reduction costs. Unlike conventional LCOE, the System LCOE of renewable sources of electricity depend highly on their market share. If the share

[2] Note that intermittency implies non-dispatchability, but not vice versa. Intermittency means that the capacity factor is subject to external influences and varies on a short time, whereas a source of electricity is non-dispatchable if its output cannot easily be controlled by the operator.

of wind (resp. solar) generation increases, the generation costs (i.e. the LCOE) remain constant, while the integration costs increase significantly. In their calculation, the System LCOE for wind in Germany increase from 60 EUR/MWh to almost 100 EUR/MWh if the share increases from 0% to 40%.

The System LCOE seem to be the state of the art and quite accurate (see Reichenberg (2017) for further refinement), but apparently seem to be too complicated and "not catchy" enough to be used by a non-academic audience.[3] However, there is high necessity of a cost measure that includes the costs of intermittency and is accessible to a broader audience. Since climate change and the accompanying transition of the electricity market became a key topic in public debates and in politics, the LCOE have become the most popular measure to evaluate investment decisions and market developments in electricity generation. As politicians and policy makers fail to understand the limitations and flaws of this measure and spread the idea that solar PV and wind are the cheapest sources of electricity, there is a need for a cost measure that addresses the limitations of LCOE yet remains accessible to a the broader audience by being simple and catchy.

This paper introduces a novel method to evaluate the costs of electricity that is catchy and includes the costs of intermittency: The Levelized Full System Costs of Electricity (LFSCOE). The LFSCOE are defined as the costs of providing electricity by a given generation technology assuming that a certain market has to be supplied solely by this source of electricity plus storage. While storage is necessary for intermittent sources of generation, storage can also allow conventional dispatchable technologies to meet system load at a lower costs, for example by smoothing demand fluctuations and allowing plants to operate at higher capacity factors. Assuming a full knowledge of the market conditions, the LFSCOE are calculated by first determining the cost optimal installed generation and storage capacity over the respective investment horizon and then averaging the total system costs over the supplied demand. Methodologically, the LFSCOE for intermittent or baseload technologies are the opposite extreme of the LCOE. While the latter implicitly assume that a respective source has no obligation to balance the market and meet the demand (and thus demand patterns and intermittency can be ignored), LFSCOE assume that this source has

[3]It is worth noting that the calculation of LCOEs is by no means simple. The appendix to the Annual Outlook of Energy requires more than 100 pages to introduce the terminology and describe the calculation process, see EIA Model Documentation (2020).

maximal balancing and supply obligations. This paper shows that in both Germany and in the region of the Electricity Reliability Council of Texas (ERCOT), the LFSCOE of wind and solar PV are higher than the most expensive dispatchable technology examined in this paper.[4] As a first counterfactual, the effects of a substantial decrease in storage costs are examined, which would heavily benefit intermittent generation and is used by proponents of renewables to economically justify a faster transition and a higher share of renewables.[5] However, even a storage cost reduction of 90% would not make wind or solar PV competitive on a LFSCOE basis. A very interesting observation occurs when losses in the storage cycle are added to the model. If the losses occur while charging the storage, the cost effects are significantly lower than if they occur while dispatching storage. This is not economically surprising since losses at the end effectively reduce the productivity of all inputs while those at the beginning only reduce the productivity of some inputs. Nevertheless, it is very interesting to see the small magnitude of economic effects of even significant storage losses in such a system. An extension of the LFSCOE are the LFSCOE-95, which assume that only 95% of the system has to be supplied by a certain technology plus storage. It is interesting to see that while the LFSCOE-95 are only slightly lower than the LFSCOE for dispatchable technologies, they are about 50% lower for intermittent sources, which really challenges the economic sanity of 100% intermittent renewable targets.

This paper is structured as follows: Section 2 introduces the method for calculating LFSCOE and concludes with the cost evaluations for the markets in ERCOT/Texas and Germany. Section 3 examines different changes in the model assumptions (such as storage losses), follows up with an analysis of significant decreases in storage costs, and concludes with an introduction of the LFSCOE-95. Section 4 discusses potential model extensions and concludes.

Literature To my knowledge, the cost measure and evaluation methodology introduced in this paper are new. However, studies that address the cost of intermittent renewables or baseload

[4]Though the ERCOT market does not span all of Texas, ERCOT and Texas are used interchangeably in this paper.

[5]Note that a decrease in storage costs is to some degree equivalent to an increase in the storage factor (i.e. the amount of MWh stored per MW installed). Some technologies (like solid state batteries) cannot really increase this factor, while others (like flow batteries) can. This matter is briefly discussed, but a thorough analysis of the economic consequences of an adjustable storage factor is not subject of this paper.

technologies when they are responsible to meet the market demand have been conducted. Hartley (2017) examines the requirements of a wind-only market in Texas. Denholm et al. (2012) combine renewables and nuclear with storage. For the market in Germany, Sinn (2017) discusses economic challenges by pointing out the large curtailment and storage requirements in a wind & solar market in Germany (using existing storage in Norway), while Zerrahn et al. (2018) conclude that electrical storage would rather not limit the transition to renewable energy. It is important to note that the main reason of this paper is to introduce a novel methodology of calculating costs and then use this methodology to examine some relevant counterfactuals. Given the simplifying assumptions, the numbers should not be seen as definitive.

2 Levelized Full System Costs of Electricity

This section first introduces the concept of the Levelized Full System Costs of Electricity and compares 5 dispatchable technologies with wind, utility scale solar PV (called "solar" from now on), and an optimal combination of wind and solar.

Assumptions A technology y has overnight capacity costs cc_y, fixed operation and maintenance costs (O&M) omc_y, and variable (or constant marginal) costs vc_y. Dispatchable technologies have ramping times of $rampup_y$ and $rampdown_y$, in percentage/hour relative to their current generation (as depict in table 1). Note that all modern technologies can technically ramp-up and ramp-down within an hour, making the ramping times redundant for the analysis which only considers deterministic hourly demand (see below). However, frequent fast ramp-ups and ramp-downs are not advisable and sometimes not permitted (for example for old nuclear plants - however, the costs in Table 1 are for new advanced plants). As a result of this, the ramping values are set to $rampup_y$ = 150% and $rampdown_y$ = 50%, meaning that the utility can change their output by ±50% per hour. This implicitly increases the costs for dispatchable generators, but not by much as the demand fluctuations of consecutive hours are almost always within ±50%. It is worth noting that the model only considers deterministic hourly demand and ignores any use of certain technologies outside the wholesale generation market (e.g. a natural gas combustion turbine, which, unlike nuclear power plants, can also be used in the short-term balancing market).

Table 1: Cost Assumptions

Technology	Overnight Capital Costs [USD/kW]	O&M Costs [USD/kW/year]	Variable Costs [USD/MWh]	ramp-up/down [% per hour]
Biomass	4,401	125.2	28	150%/50%
Coal (USC)	3,661	40	25	150%/50%
Natural Gas CC	1,079	14	18	150%/50%
Natural Gas CT	710	7	28	150%/50%
Nuclear	6,317	121	8.4	150%/50%
Solar	1,331	15.2	0	-
Wind	1,319	26.2	0	-
Storage	1,383	24.7	0	-

Table 1: Main data source is EIA Costs (2020). The fixed costs include overnight capacity costs and fixed O&M. Wind fixed costs are for on-shore wind. The variable costs include O& M and fuel costs, but do not include any carbon taxes or reserve payments for environmental purposes.

In period t, intermittent and non-dispatchable generators have an hourly generation intensity of $Ren_t \in [0, 1]$. This value is nothing else than the maximal capacity factor in hour t of the renewable plant - when the sun is shining or the wind is blowing, this value will be high (and close to 1), but during the night, the intensity Ren_t will be equal to 0 for solar PV. The hourly demand is denoted with D_t for $t = 1, ..., H$ (e.g. $H = 8760$ if the entire year is consider). Both intensity and demand are assumed to be perfectly forecasted and are deterministic, i.e. possible demand response is ignored. Following the calculations from EIA Assumptions (2020), the costs are averaged over an investment period of 30 years, where the investment occurs in the first two years (thus, the overnight capacity costs are split evenly between year 1 and year 2) and the generation goes from year 3 through year 30.[6] The cost of capital is fixed at 6.7% (and thus the annual discount factor is $\beta = 1/(1+0.067)$) and the model implicitly assumes the same demand and hourly wind and solar capacity factor profile in each of these years.[7] The variable costs for storage are zero and there are no losses in the storage process (the no-storage-losses assumption is relaxed in section 3). Storage

[6]Note that these investment periods seem to be quite generous for solar PV and wind, and too short for nuclear and coal. On the other side, the construction period is generous for nuclear and coal, and too long for solar.

[7]EIA Assumption (2020) calculates weighted average costs of capital for every year. As they are almost constant, using constant discount factor is a reasonable simplification.

can store $\rho_{sf} = 3$ MWh per installed MW of generating capacity, which is equivalent to current residential solid-state battery storage solutions. A moderate increase in the storage factor, which is discussed in section 3, is equivalent to decreasing the storage costs. For simplicity, no minimal storage level or security backup is required (i.e. $S_{security} = 0$ MWh), but demand has to be met at all times. In practice, if a market is supplied solely by an intermittent source, it will be very unlikely that no security storage is required as a backup. Furthermore, required security storage will also depend on the average hourly demand, its variability and price elasticity, installed storage as well as installed generation capacity, and will vary between markets. Ignoring the security backup in my model simplifies the analysis significantly and allows for maximal comparability.

Calculating the optimal installed capacity Let $x \in \mathbb{R}^{H+1}$ be the independent variable for the stored electricity in MWh (i.e. $x[t]$ is the storage level at the beginning of hour t), and $gen \in \mathbb{R}^{H}$ the independent variable for the dispatchable generation in each period (i.e. $gen[t]$ is the generation in period t).[8] In the optimization problem, denote the installed capacity by rp (for intermittent "renewable power") and dp (for "dispatchable power"), and the installed storage by sp (for "storage power"). Installed capacities, storage levels, and generation will be chosen to minimize total system costs conditional on meeting demand in every period. For any technology y, the net present value of all non-variable costs (i.e fixed costs) is

$$fc_y = (\frac{cc_y}{2} + \frac{cc_y}{2}\beta + \sum_{u=3}^{30} \beta^{u-1} omc_y).$$

[8]To enhance readability, the elements of vectors that are independent variables are denoted with brackets $[t]$ and the elements of vectors which are parameters are denoted with lower case t-s.
It is worth noting that electricity storage does not store electricity itself, but converts it do a different form of energy (e.g. pumped hydro plants convert electric energy into kinetic energy). However, to enhance readability, we will use the term "storing electricity".

With this notation (and further explanations of each line below), intermittent sources of generation with intensity Ren_t at period t solve the optimization problem

$$\min_{rp,sp,x} rp \cdot fc_{Ren} + sp \cdot fc_{Storage}$$

$$s.t. \quad 0 \leq x[t+1] \leq x[t] + Ren_t \cdot rp - D_t \quad for\ all\ t, \tag{D.1}$$

$$-sp \leq x[t+1] - x[t] \leq sp \quad for\ all\ t, \tag{S.1}$$

$$S_{security} \leq x[t] \leq sp \cdot \rho_{sf} \quad for\ all\ t, \tag{S.2}$$

$$x[1] \leq x[H+1], \tag{S.3}$$

whereas conventional sources y solve

$$\min_{dp,sp,gen,x} dp \cdot fc_y + sp \cdot fc_{storage} + \sum_{u=3}^{30} \beta^{u-1} \frac{8760}{H} \cdot \sum_{t=1}^{H} vc_y \cdot gen[t]$$

$$s.t. \quad 0 \leq x[t+1] \leq x[t] + gen[t] - D_t \quad for\ all\ t, \tag{D.2}$$

$$-sp \leq x[t+1] - x[t] \leq sp \quad for\ all\ t, \tag{S.1}$$

$$S_{security} \leq x[t] \leq sp \cdot \rho_{sf} \quad for\ all\ t, \tag{S.2}$$

$$x[1] \leq x[H+1], \tag{S.3}$$

$$gen[t] \leq dp \quad for\ all\ t, \tag{G.1}$$

$$-rampdown_y \leq \frac{gen[t+1] - gen[t]}{gen[t]} \leq rampup_y \quad for\ all\ t, \tag{G.2}$$

The objective function calculates the total costs to meet the demand. For intermittent renewables, this is just the costs of installing the capacity, for dispatchable sources, it also includes an additional term to account for the variable costs. Note that to calculate the net present value of these costs, dispatchable generators are implicitly assumed to have the same generation for every year. If H is smaller than 8760, the hourly costs are extrapolated accordingly to account for an entire year.[9]

[9] If $H = 8760$, there are 17523 independent variables. To reduce the computational burden in the counterfactual analysis, the optimization problem is only solved for half the year, i.e. H = 4380. To ensure that the solution is at least theoretically feasible for the entire year, the condition

$$maxcap_x \cdot dp + sp \geq max(D_t). \tag{X.1}$$

is added. This ensures that the maximal annual demand can be met with the proposed solution. For intermittent sources, the program can always be optimized over 8760 hours, which is particularly important as these costs are

Constraints (D.1) and (D.2) ensure that the demand is met at any period (and allows for free curtailment/disposal of electricity if necessary), while (S.1) ensures that the storage is charged and dispatched according to the technical maximum (which is the maximal installed power in GW). Constraint (S.2) ensures that the storage level is technically feasible and larger than the security storage. With a storage factor of $\rho_{sf} = 3$, we observe that the right hand side of (S.2) ensures that (S.1) is never binding for intermittent technologies. In these systems, bp will be so high to ensure that (S.2) is fulfilled so that (S.1) becomes redundant. Once the storage factor increases, however, (S.1) becomes binding at one point. Constraint (S.3) ensures that technologies are compared on a level playing field by always requiring energy in storage to return to the same starting level at the end of each simulation. Inequalities (G.1) and (G.2) restrict the generation to the maximal capacity and the hourly change in generation to the respective ramp-up and ramp-down rate.

A solution to the optimization problem above (i.e. the optimal rp (or dp), sp, gen, and x) for technology y is denoted by $(I^y, I^y_{storage}, GEN^y, X^y)$. This is then the optimal installed capacity for generation I^y and storage $I^y_{storage}$ along with the hourly generation GEN^y and hourly storage level X^y. Not that the generation vector GEN^y is an $H \times 1$ dimensional vector for dispatchable technologies (and equal to 0 for intermittent sources), whereas the storage level vector X is of size $H + 1 \times 1$ (and potentially equal to 0 if no storage is used).

Existence and uniqueness of solution Existence of a solution is easily proved as the set of constraints is clearly convex and non-empty. In fact, any capacity installation that is large enough can meet the constraints.

Uniqueness is more ambiguous: The solutions to both the intermittent and the dispatchable problem are not necessarily unique. In fact, without losses in the storage process, the optimization problems for both intermittent and dispatchable sources have an infinite number of solutions as the storage can be charged at any time (unless there is no storage capacity in the optimal system, as for natural gas CT). Adding a bonus of $\epsilon > 0$ for keeping electricity in storage, which can be justified as storage secures against unanticipated supply shortages, ensures the uniqueness of x for every investment tuple $(I^y, I^y_{storage})$ of renewable sources. While uniqueness of the independent

driven by periods with low hourly capacity factor and seasonal properties.

variables can still not be ensured, the value of the objective function is unique, which is sufficient for the purpose of this paper.

Definition LFSCOE After solving the optimal installed capacity, generation, and storage level $(I^y, I^y_{storage}, GEN^y, X^y)$, define the LFSCOE of a dispatchable source as

$$LFSCOE_y = \frac{I^y \cdot fc_y + I^y_{storage} \cdot fc_{storage} + \sum_{u=3}^{30} \beta^{u-1} \cdot vc_y \cdot \frac{8760}{H} \sum_{t=1}^{H} GEN^y_t}{\sum_{u=3}^{30} \beta^{u-1} \cdot \frac{8760}{H} \cdot \sum_{t=1}^{H} D_t}$$

and the LFSCOE of an intermittent source as

$$LFSCOE_{Ren} = \frac{I^{Ren} \cdot fc_{Ren} + I^{Ren}_{storage} \cdot fc_{storage}}{\sum_{u=3}^{30} \beta^{u-1} \sum_{t=1}^{8760} D_t}.$$

The numerator is nothing else than the total cost of the system (and thus equal to the objective function above). The denominator averages these total costs. The crucial element of the LFSCOE is the fact that costs are not averaged over the (discounted) lifetime generation but over the (discounted) lifetime demand that they and their associated storage support. For dispatchable sources, the lifetime generation is equal to (or at least close to) the lifetime demand as variable generation costs that are larger than 0 penalize producing excess output and as there are no storage losses. By contrast, the next section shows that for intermittent generators, lifetime generation is significantly higher than lifetime demand of the system, hereby causing a large amount of overproduction and curtailed electricity. The Levelized Costs of Electricity account for some, but not all, of the curtailment by adjusting the capacity factor and averaging over the total generation. Ueckerdt et al. (2013) solves this issue by including overproduction in their cost estimation, but as they limit their analysis to a 40% share of renewables, the overproduction is still relatively small (see below a comparison between the LFSCOE and the results of Ueckerdt et al. (2013)). Note that the LFSCOE are defined for one specific data set (e.g. one year for one region). If more data on hourly demand and hourly capacity factors for a certain region is available (e.g. data for different years, see below) and this data cannot be incorporated into a joint optimization process, the LFSCOE are calculated separately and (with slight abuse of notation) redefined as the mean of each year (see calculation below).

Calculating the LFSCOE Levelized Full System Costs of Electricity are derived with a Monte Carlo analysis. Starting with real market data for hourly demand, wind capacity factor, and solar capacity factor from 2010/2011-2017 for Germany and 2012/2013-2019 for Texas, the costs per MWh for each technology and year are calculated by solving the minimization problem as described above.[10] LFSCOE of a technology are then defined as the mean of the costs per MWh from each of the 8 years. Allowing also for a wind & solar mix, Table 2 and Figure 1 display the LFSCOE for each technology and market as well as the interval of the costs for each year (note the different scale of the x-axis).

Table 2: Levelized Full System Costs of Electricity

	Germany		Texas	
Technology	LFSCOE (Mean)	[Min,Max]	LFSCOE (Mean)	[Min,Max]
Biomass	104	[100,109]	117	[112,126]
Coal	78	[76,82]	90	[86,96]
Natural Gas CC	35	[34,36]	40	[38,41]
Natural Gas CT	39	[38,39]	42	[40,42]
Nuclear	106	[101,113]	122	[115,132]
Solar	1548	[1185,2058]	413	[341,579]
Wind	504	[438,552]	291	[229,369]
Wind&Solar	454	[319,498]	225	[178,358]

Table 2: Mean, Minimum, and Maximum in USD/MWh of the derived LFSCOE values. LFSCOE for Germany and Texas, using cost assumptions as in Table 1 and a discounting factor of $\beta = 1/(1 + 0.065)$.

Several interesting observations can be made. First, neither wind nor solar nor the wind & solar mix seem economically competitive to the dispatchable sources on a LFSCOE basis. Even the LFSCOE value of the wind & solar mix in Texas, which is the most competitive of the renewable technology installations considered, is almost twice as high as the LFSCOE value of the most expensive dispatchable technology. This is independent of the discount factor, which rather benefits technologies with higher upfront costs - see Appendix 5.2 for LFSCOE without

[10] As the installed capacity of solar was very low in 2010 in Germany and 2012 in Texas, the data does not seem trustworthy. Thus the year 2010 in Germany and 2012 in Texas are excluded in the analysis of solar and the wind & solar mix. For all other technologies, all 8 years are considered.

Figure 1: LFSCOE Mean and Max/Min intervals in the German (left) and ERCOT market

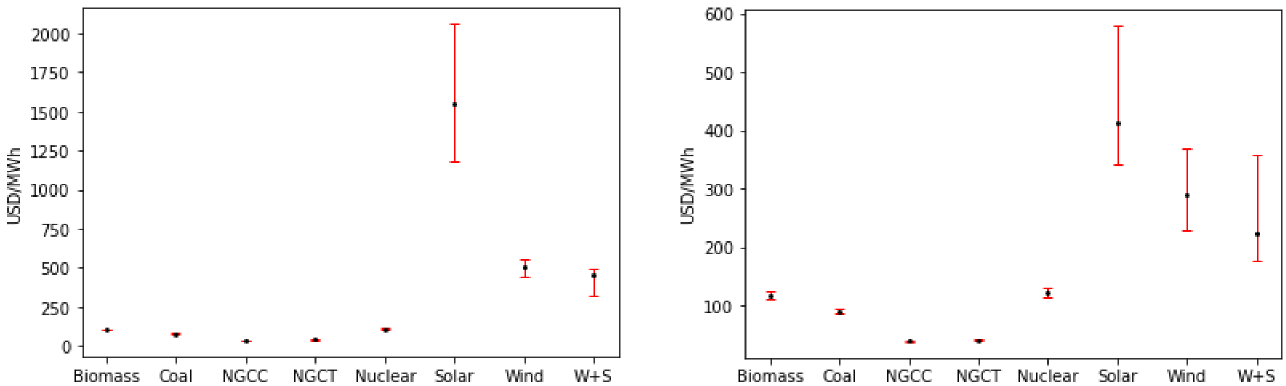


Figure 1 displays the mean and the max/min intervals for every technology (as in Table 2).

discounting. Second, while the LFSCOE for the conventional sources are slightly lower in Germany than in Texas, the LFSCOE for wind and especially solar are much higher in Germany (e.g. 1548 USD/MWh for solar in Germany vs. 413 USD/MWh for solar in Texas). The higher LFSCOE for dispatchable sources in the Texas market can be explained by the seasonal variance in demand. In Texas, the peak demand in the month with the highest demand is 67% higher than in the month with the lowest peak demand. This percentage is only 12% in Germany, which results in a higher overall capacity factor for dispatchable technologies in Germany than in Texas (see Appendix 5.1). The significantly higher LFSCOE for wind and solar in Germany compared to Texas stem from the higher overall capacity factor (0.35 vs. 0.20 for wind, and 0.23 vs. 0.11 for solar) and the fact that the high demand periods in Texas (during summer days) are correlated with the high capacity factors for solar, while the slightly higher demand in winter in Germany comes along with significantly lower solar generation. This correlation explains the fact that the effective capacity factor (i.e. the average dispatched electricity per hour) for solar is almost six times larger in Texas than in Germany - see Appendix 5.3. Third, the variation between years of LFSCOEs for dispatchable sources are much lower than for wind and solar. This does not come as a surprise as dispatchable sources depend only on one variable vector (demand) whereas wind and solar also depend on their own hourly capacity factor and are particularly impacted by periods with low hourly capacity factor. If consumers are risk averse, this higher variance can come with additional costs as they are willing to pay a premium for capacity that is only used in the worst case scenarios.

Storage Characteristics Table 3 displays characteristics of the storage in the system. It is not surprising that intermittent renewables require significantly more storage than the dispatchable technologies, out of which those with low capacity costs like natural gas CC and CT barely use storage at all. Furthermore, as the hourly capacity factor for solar is equal to 0 in almost half of the periods (at night), it is not surprising that almost half of the electricity in the market solely supplied by solar is dispatched from storage. The most surprising observation is probably the length of storage cycles, which are not longer than 334 hours (i.e. about 14 days) in Texas and 903 hours (i.e. about 38 days) in Germany. The main reason for the short storage cycles is the substantial overproduction, which is apparently cheaper than investing in more storage. Relaxing some model assumption like perfect forecastability would certainly increase the length of storage cycles, but it raises the question whether seasonal storage is required if it stays expensive (at least in Texas).

Table 3: Storage details on calculating the LFSCOE

Technology	Germany				Texas			
	Generation Capacity	Storage Capacity	Storage dispatch	Max storage cycle	Generation Capacity	Storage Capacity	Storage dispatch	Max storage cycle
	[GW]	[GW]	[%]	[hours]	[GW]	[GW]	[%]	[hours]
Biomass	76	14	0.1%	94	53	33	1.9%	94
Coal	79	5	0.05%	64	58	13	0.7%	64
Natural Gas CC	83	0.3	0%	15	69	0.3	0.0%	15
Natural Gas CT	84	0.2	0%	6	69	0	0.0%	6
Nuclear	73	31	0.5%	146	52	34	2.0%	146
Solar	3709	2078	48.3%	909	438	792	49.6%	332
Wind	1027	1030	9.2%	664	517	276	3.5%	128
Wind&Solar	916	948	6.2%	669	368	262	1.5%	117

Table 3 depicts the average storage capacity, generation capacity, storage dispatch (i.e. percentage of electricity coming from storage) and the longest storing cycle. In Germany, both NGCC and NGCT use storage in only one of the 8 years. Their average dispatched electricity is not equal to 0 (apart from NGCT in Texas), but on average lower than 0.1%. Note that the average hourly demand is 58 GWh in Germany and 40 GWh in Texas.

Comparison with Levelized Costs of Electricity Using similar assumptions on costs as in Table 1, EIA LCOE (2020) derives the Levelized Costs of Electricity. As mentioned above, this calculation is by no means simple, and is described in detail in EIA Model Documentation (2020). Table 3 summarizes their analysis and compares it with the LFSCOE derived above.

Table 4: Comparison of LCOE and LFSCOE

Technology	LCOE	LFSCOE	
		Germany	Texas
	[USD/MWh]	[USD/MWh]	[USD/MWh]
Biomass	95	104	117
Coal (USC)	76	78	90
Natural Gas CC	38	35	40
Natural Gas CT	67	39	42
Nuclear	82	106	122
Solar PV	36	1548	413
Wind	40	504	291

Table 4 displays the LCOE for onshore wind, while the LCOE for offshore wind are 122 USD/MWh. The data on the hourly wind capacity factor does not distinguish between on-shore and off-shore wind, thus the LFSCOE implicitly assume an on-shore/off-shore mix as currently deployed in the market in the given year. The highest share of off-shore capacity in the data was in Germany in 2018, which was ~ $5GW$ offshore of the total ~ $55GW$ installed capacity. The LCOE also include transmission costs (ranging between 1.1 USD/MWh for nuclear to 3.6 USD/MWh for solar), which are not part of the LFSCOEs (but can be added as a mark-up to the fixed costs).

LCOE and LFSCOE are relatively similar for all intermediate-load technologies (Biomass, Coal, and Natural Gas CC), which is a sign that the capacity factor assumed for the LCOE (and thus the lifetime generation) is similar to the average capacity factor if only one of those technology (plus storage) is responsible for meeting the market demand. Natural Gas CT, seen as a peak load generator under LCOE assumptions, has significantly lower LFSCOE as its capacity factor increases from 30% to almost 70% in Germany, while the capacity factor for nuclear, being the highest under LCOE assumptions (90%), drops to just under 80%.

The most striking difference can be seen for the intermittent technologies solar and wind. While the LCOE assume no responsibility in meeting the demand and focus solely on the costs of generation, the LFSCOE assume full responsibility of meeting the demand. This responsibility comes at a very high price, making the LFSCOE for intermittent renewables up to 40 times higher than the LCOE.

Comparison with System Levelized Costs of Electricity Ueckerdt et al. (2013) developed the System LCOE to address the inability of LCOE to reflect the cost of intermittency. System LCOE are the sum of generation costs and integration costs for a renewable source. Integration costs are split up into overproduction costs, full-load-hour reduction costs, and backup costs (plus grid costs and balancing costs, but they are ignored in parts of the paper and in my analysis as well).[11] The System LCOE are a very accurate way of calculating the cost of renewables, but their precision makes them less "catchy", as they depend on the share of the renewable generation. Figure 3 shows the System LCOE for wind and solar in Germany, taken from Ueckerdt et al. (2013).

Figure 2: System LCOE for Wind (left) and Solar (right) in Germany.

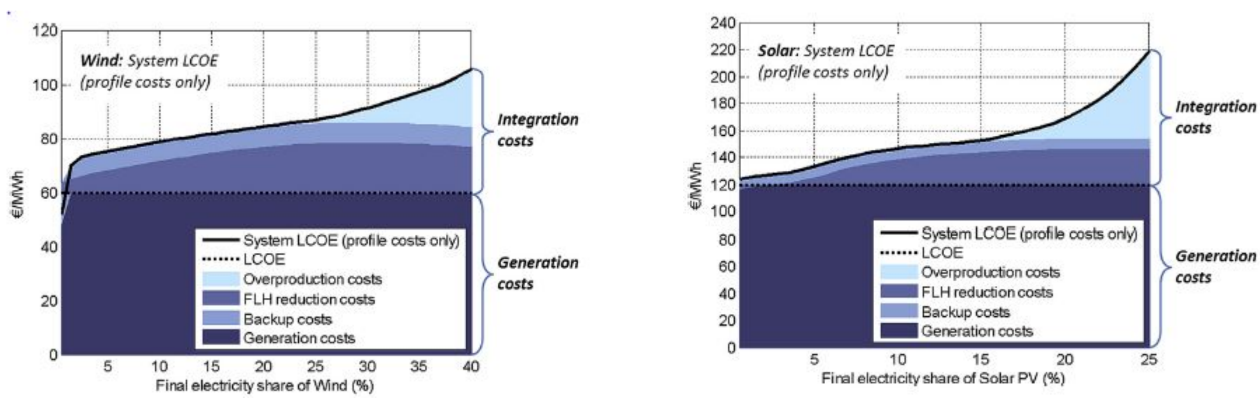


Figure 2: Graphs are taken from Ueckerdt et al. (2013), page 72, Figure 10.

It is important to note that as the paper was published in 2013, the LCOEs (60 EUR/MWh for wind and 120 EUR/MWh for solar) are outdated as they dropped significantly since. It is interesting to see that both LCOE and LFSCOE can be found in a complete System LCOE study: LCOE

[11]Ueckerdt. et al (2013) define balancing costs of VRE (i.e. renewables) as follows: "Balancing costs occur because VRE supply is uncertain. Day-ahead forecast errors and short-term variability of VRE cause intra-day adjustments of dispatchable power plants and require operating reserves that respond within minutes to seconds." (page 65). The LFSCOE model assumes deterministic demand and capacity factors while the shortest time interval is one hour. Thus, although storage is required to balance supply and demand, "balancing costs" as defined by Ueckerdt et al. (2013) are ignored in the LFSCOE model.

are similar to System LCOE with renewables supplying a 0% share of final electricity, whereas LFSCOE are conceptually equivalent to System LCOE with renewables supplying a 100% share of electricity. Indeed, if the LCOE values are adjusted to current LCOE estimations (which are 40 USD/MWh for wind and 34 USD/MWh for solar) and integration costs are extrapolated, the System LCOE ought to approach the direction of the LFSCOE as calculated in this paper. If the integration costs are extrapolated in Figure 2 in a linear fashion, the System LCOE will end up substantially below the LFSCOE for Germany presented in Table 4 - but if an exponential growth of integration costs is assumed, the System LFSCOE actually reach the magnitude of LFSCOE values as calculated above.

A key observation from the System LCOE analysis in Figure 2 is the increasing cost of overproduction as the share of renewables increases. The analysis of the effective capacity factors in Appendix 5.3 shows that LFSCOE supports this observation: In a system with solely intermittent generation, overproduction occurs on a large scale. However, the analysis of the effect of storage losses in the next section shows an advantage of overproduction. It turns out that even significant losses in the storage process do not increase the LFSCOE by much, as the additional demand in some periods (due to storage losses) is more than compensated by the overproduction in other periods without having to invest more in expensive storage.

3 Counterfactuals and Model Extensions

Counterfactual: Impact of falling storage costs Using the initial model as described above, LFSCOE can be determined if the costs for storage decrease significantly.

Figure 3 supports the intuition: Technologies that require large storage facilities (like wind and solar) benefit from a significant decrease in storage costs, whereas the effect on the LFSCOE for dispatchable technologies (like nuclear and natural gas) is barely noticeable. A reduction in costs of storage capacity by even 95% would still not make the LFSCOE of wind, solar, or wind & solar competitive to the dispatchable generation in Germany, but would at least in Texas move them below the LFSCOE of nuclear and biomass.

It is important to note that the dispatch constraint (B.1) is never binding for the renewables, meaning that a drop in storage costs can also be achieved by an increase in the storage factor.

Figure 3: LFSCOE with decreasing capacity costs for storage.

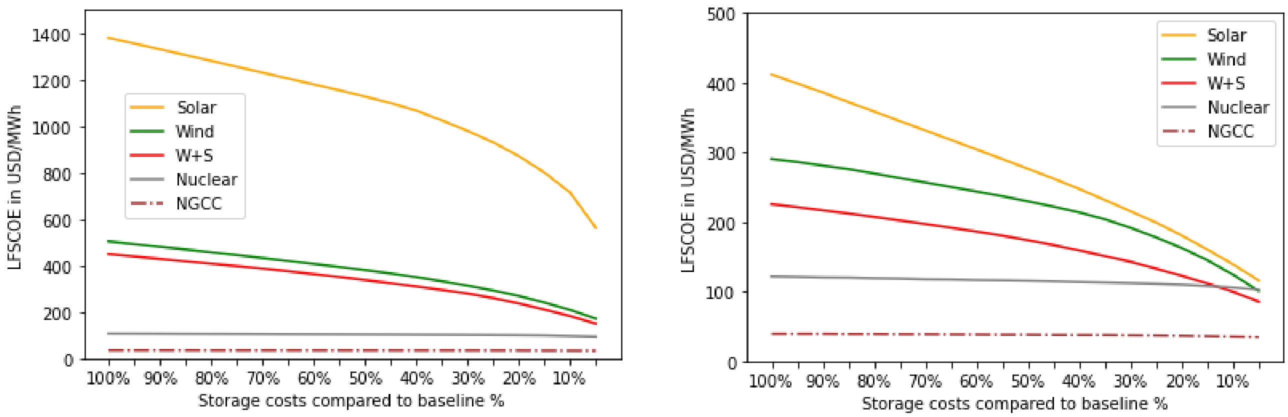


Figure 3: Development of LFSCOE if storage costs decrease significantly for the market in Germany (left) and Texas (right).

While a decrease of costs per MW installed capacity by 75% seems unrealistic any time soon (see Schmidt et al. (2019)), an increase in capacity factor by a factor of 4 (to 12 MW/MWh) can be achieved more easily with storage technologies like flow batteries (which, however, have higher capacity costs at the moment).

Model Adjustment: Including storage losses and depreciation Next, the no-storage-losses assumption is relaxed. To simplify, there are three fundamentally different losses that occur during a storage process (see Ibrahim et al. (2008) for a detailed description of storage technologies, and Schmidt et al. (2019) for current round-trip efficiency estimations). First, losses can occur when the storage is charged with the generated electricity. Let $\alpha_1 \in (0,1]$ be the share of electricity that reaches the storage facility in a charging process (and thus $1-\alpha_1$ the share that is lost in the process), meaning that $\alpha_1 = 1$ would be equivalent to no losses in the charging process. For many storage technologies, this is the main location for losses. Especially, turning water into hydrogen (so called Power-to-Gas) requires a significant amount of energy that cannot be fully recaptured, which is structurally nothing else than charging losses. Second, stored electricity can depreciate over time - this loss is denoted with $\gamma \in (0,1]$. Storage depreciation (or self-discharge) can have many different reasons: For hydrogen, it can occur due to leaks, for pumped hydro, it occurs due to evaporation (but might be offset in part through rainfall and runoff), and for solid state batteries, it occurs due to an unwanted chemical reaction. Third, losses can occur when the stored electricity is dispatched back to the grid - denote the share of electricity that reaches the grid by $\alpha_2 \in (0,1]$, i.e. the share of losses is $1-\alpha_2$. It is easy to see that "round-trip efficiency", the most common term to describe the efficiency of storage, is nothing else than $\alpha_1 \cdot \alpha_2$, and varies between 0.4 for Power-to-Gas and 0.88 for the flywheel as depict in Table 5. Unfortunately, the technologies with the highest round-trip efficiency sometimes come along with the highest depreciation (i.e. the lowest γ). In a context where it is desirable to store the energy for different length of time, it will be optimal to have a diversified storage portfolio.

Table 5: Storage losses by technology

Technology	Round-trip efficiency [%]	Self-discharge [%/day]
Pumped Hydro	78%	0%
Flywheel	88%	480%
Lithium-Ion	86%	0%
Vanadium redox-flow	73%	0%
Hydrogen	40%	1%

Table 5 displays round-trip efficiency and self-discharge of selected storage technologies, taken from the accompanying documents of Schmidt et al. (2019) (Table S4). The technology input parameters are from 2015 and the self-discharge is at an optimal charging level. A self-discharge level of 480%/day could be reinterpreted to 20%/hour which can then be interpreted at $\gamma = 0.8$ if discharging occurs at a fixed non-linear rate (which is, however, not the case for the flywheel).

Given the notations above, the system of equations for intermittent technologies changes to

$$\min_{rp,sp} rp \cdot fc_{Ren} + sp \cdot fc_{storage}$$

$$s.t. \quad x[t+1] - \gamma x[t] \leq (Ren_t \cdot rp - D_t)\alpha_1, \tag{D.1+}$$

$$x[t+1] - \gamma x[t] \leq (Ren_t \cdot rp - D_t)\frac{1}{\alpha_2}, \tag{D.1-}$$

$$-sp \leq x[t+1] - \gamma \cdot x[t] \leq sp, \tag{B.1}$$

$$S_{security} \leq x[t+1] \leq sp \cdot \rho_{sf}, \tag{B.2}$$

$$x[1] \leq x[H+1]. \tag{B.3}$$

Constraints $(D.1+)$ and $(D.1-)$ ensure that demand is met at any time: $(D.1+)$ has to hold in periods where storage is charged (i.e. with an abundance of electricity), whereas $(D.1-)$ corresponds to periods where electricity is generated by discharging storage.[12] Note that the system above only captures exponential storage depreciation γ. However, technologies like lithium-ion batteries self-discharge at other than an exponential rate over time. In that case, the percentage loss depends on both the time and the battery state/charging level, where 5% of the load depreciates within a day (if the battery was fully charged) and then just up to another 5% within the next month - see Battery University (2018). Given that storage cycles tend to be short, the long-term depreciation can be ignored in the analysis, while the short-term storage depreciation can be interpreted as a charging and discharging loss. As a result, γ will be fixed at 1 and the focus will lay on charging and discharging losses.

Figure 4 illustrates the effect of charging losses (left) and discharging losses (right) for the LFSCOE with German market data, assuming that there are no other storage losses.

Figure 4: LFSCOE with decreasing capacity costs for storage.

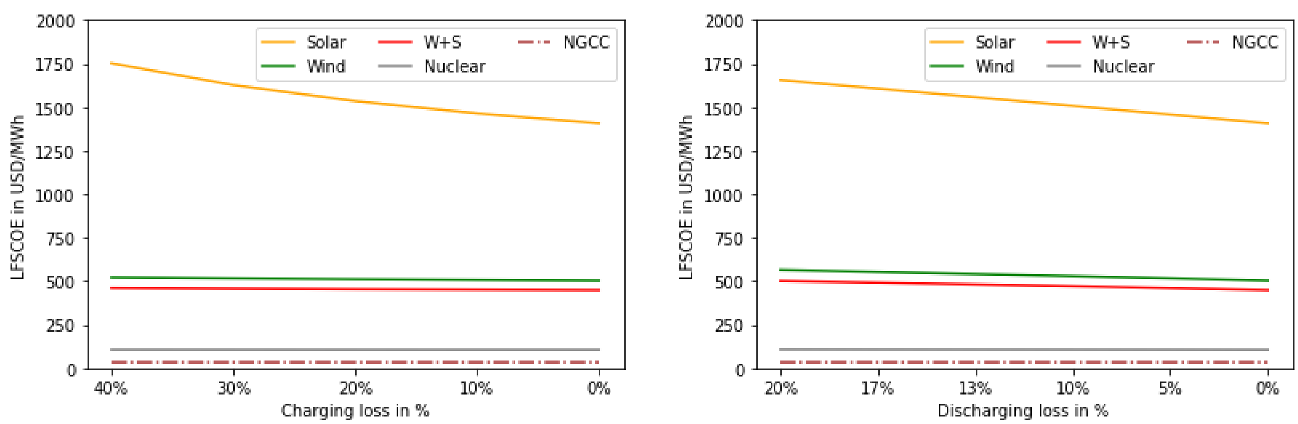


Figure 4: Note that the LFSCOE with charging losses of 40% are lower for wind and wind & solar than those with discharging losses of 20% (522 vs. 565 for wind and 461 vs. 501 for wind & solar). For solar, LFSCOE with charging losses of 40% are higher than for LFSCOE with discharging losses of 20% (1752 vs. 1656), but those with charging losses of 30% are lower (1627 USD/MWh).

The most striking observation is the low cost impact of storage losses, especially charging losses, in the wind and the wind & solar system. This stems from the substantial overproduction under the optimal capacity installation. Without storage losses, the abundant electricity is curtailed;

[12] Note that by replacing the left hand side of (S.1) with $max(D_t - Ren_t \cdot rp) \leq sp$, which can be replaced by $\alpha_2(D_z - R_z) \cdot rp \leq sp$ at $z = argmax_t\, D_t/Ren_t$, $H - 1$ conditions can be removed from the optimization problem.

with losses, it is just lost in the storage process. Given the different scale of the x-axis, one can say that discharging losses, though very small for wind and wind & solar, are roughly twice as costly as charging losses. Results for Texas (displayed in Appendix 5.4) support these observations.

Model Adjustment: LFSCOE-95 Immediate critiques of LFSCOE address the unrealistic assumption that an electricity market will rely on only one source of electricity (unless it is hydro, which is basically the only source of domestic power generation for some countries with very favorable geography like Paraguay or Albania). In addition, research on a complete reliance on intermittent renewables points out the significant cost reduction that could be achieved if the system would allow dispatchable technologies to back up renewables by supplying a small share of demand (see for example Jenkins et al. (2018)). This thought experiment is included by introducing the LFSCOE-95, the Levelized Full System Costs of Electricity if only 95% of the market has to be supplied by this respective source of electricity. To calculate the LFSCOE-95, assume that a generator is available that can generate electricity at the lowest costs available for intermediate-load generation (i.e. $mc_{95} = 18 USD/MWh$) but is restricted to only 5% of the demand. After calculating the total costs associated to each considered technology (plus storage), the LFSCOE-95 are then calculated by averaging not over the total system demand (which is jointly supplied by the respective technology and the low-cost supply) but only over the total demand that is supplied by the respective source of electricity (which is at least 95% of the total electricity). This means that the low-cost generation is basically treated as an adjustment of the demand curve (i.e. it reduces up to 5% of total demand at a price of $mc_{95} = 18 USD/MWh$, but can choose in which period it reduced the demand).

Table 6 displays the mean LFSCOE-95 for the data on Germany and Texas and compares it with the LFSCOE-100, while Figure 5 displays mean and intervals for the LFSCOE-95.

There are a few things worth mentioning: First, for dispatchable generation, the LFSCOE-95 are lower than LFSCOE as the residual demand curve for the generator is flattened by the free generation, which increases the average capacity factor. The flattened seasonal demand curve also reduces the difference in LFSCOEs between Texas and Germany. An additional consequence of the flattened demand curve is that the variance between years almost diminishes. For intermittent sources, all effects observed for the dispatchable technologies are more extreme. Going from

Table 6: Levelized Full System Costs of Electricity

Technology	Germany LFSCOE-100 [USD/MWh]	Germany LFSCOE-95 [USD/MWh]	Texas LFSCOE-100 [USD/MWh]	Texas LFSCOE-95 [USD/MWh]
Biomass	104	90	117	95
Coal (USC)	78	67	90	72
Natural Gas CC	35	31	40	32
Natural Gas CT	39	36	42	37
Nuclear	106	90	122	96
Solar	1548	849	413	177
Wind	504	279	291	131
Wind & Solar	454	220	225	97

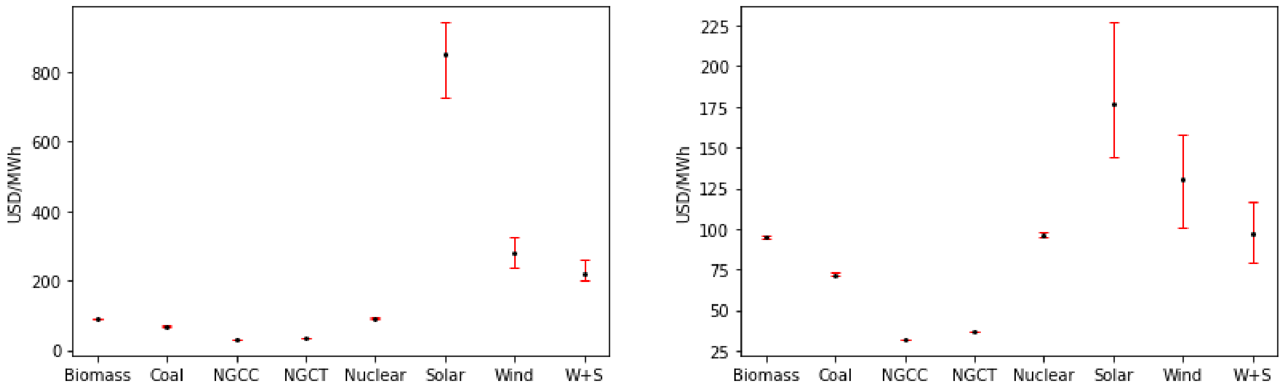
Table 6 - LFSCOE-95: For computational reasons, storage is not an option for dispatchable technologies anymore. Given that only at most 2% of electricity was dispatched from storage (see Table 3), this restriction does not distort the results.

LFSCOE-100 to LFSCOE-95, i.e. reducing the load responsibility of wind or solar from 100% to 95%, reduces the costs by roughly 50%. However, the LFSCOE-95 for wind and solar in Germany are still significantly higher than the LFSCOE-100 for all dispatchable sources, but especially the wind & solar mix in Texas appears to be as competitive as all non-natural-gas thermal generation on a LFSCOE-95 basis. In any case, the LFSCOE-95 show that having dispatchable generation to support the intermittent renewables reduces the total system costs significantly and should be considered when planning the energy transition.

4 Conclusion

Intermittency of generation makes the cost comparison between different generation technologies much more difficult. While being a good measure to evaluate the cost to generate electricity, the most popular cost measure, the Levelized Costs of Electricity, fails to include the costs associated with meeting the demand and providing usable electricity. On the other hand, the System Levelized Costs of Electricity by Ueckerdt et al. (2013) include the cost of integration and balancing, but do not seem to be simple enough to make it to a broader audience. Using the simple but

Figure 5: LFSCOE95 Mean and Variance in the German (left) and ERCOT market



radical assumption that each source of generation has to meet the demand over a given year (with the help of storage), the Levelized Full System Costs of Electricity introduced in this paper are the first cost measure to condense the cost of providing electricity to one number per market and technology. With LFSCOE being much higher than the LCOE for wind and solar, it becomes evident that LCOE are far from being an accurate measure to include the cost of intermittency.

Introducing storage losses to the model leads to a very interesting observation: In systems dominated by intermittent renewables, storage losses (especially while charging the storage) of up to 40% do not have a large effect on overall costs. In fact, the counterfactual analysis in this paper reveals that to enable affordable electricity with renewables, the focus should be more on reducing storage costs (or increasing the storage factor) than reducing storage losses.

This paper also introduces the LFSCOE-95, a cost measure that addresses the critique of LFSCOE being too extreme. By assuming that up to 5% of the annual demand can be supplied by a very inexpensive dispatchable source of electricity, this paper shows that reducing the responsibility of intermittent renewables to supply only 95% of the demand will cut the system costs in half. This observation is supported by existing literature criticizing any 100% emission-free approaches by pointing out the large costs associated with supplying the last 5%. For dispatchable sources of generation, LFSCOE95 flattens the demand curve and reduces the difference in costs between markets significantly, as seen in the example in Texas and Germany.

The cost evaluation concept in this paper can be the refined in different ways. First, the evaluation of LFSCOE can be refined by including transmission costs, capacity limits, or locational differences in capacity factors. Second, using data from other parts of the world, LFSCOE for other markets can be evaluated. Third, LFSCOE-95 can be relaxed even further to LFSCOE-90 or any reasonable demand reduction. Any extension, however, should find a balance between increasing accuracy while staying simple to address a broader audience.

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5 Appendix

5.1 Comparison of demand patterns in Germany and Texas Figure 6 displays the average daily peak and minimal demand for Germany and ERCOT/Texas, where years are normalized so that each year starts with a Monday. The comparison shows that the seasonal demand variation in Germany is relatively small compared to Texas. This does not come as a surprise as air conditioning accounts for a large share of residential electricity consumption in Texas, whereas it is rarely utilized in Germany. However, heating is more important in Germany than in Texas, but while around 60% of the housing units in Texas use electricity for heating (see United States Census Bureau (2019)), the main source of heating in Germany is natural gas (48.2% of households) and oil (25.6% of households).[13] Once heating gets electrified on a large scale, there should be a larger difference between the electricity demand in summer and in winter in Germany (unless air conditioning becomes popular in Germany as well).

Figure 6: Average Minimal and Peak Demand in Germany (left) and the ERCOT market.

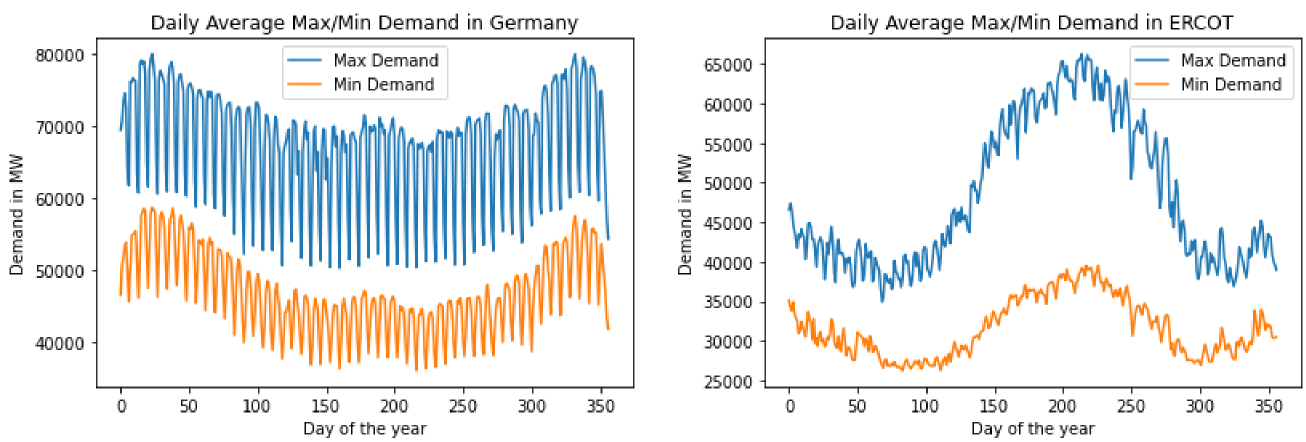

Figure 6 displays the average daily minimal and maximal demand in Germany and Texas over 8 years. The days are adjusted for weekdays, thus the first day of a year is always a Monday.

[13] For Germany, see Cleanenergywire (2020); for Texas, see EIA Texas (2009). In 2009, households in Texas use 18% of their total energy for cooling, almost exclusively by electric air conditioning units - which is very high compared to the U.S. average of 6%. While the data shows that households in Texas use 22% of the energy for space heating (compared to 41% in the U.S.).

5.2 Counterfactual: No discounting Generation technologies with low capital costs but higher variable costs benefit from a lower discounting factor (i.e. a higher cost of capital) compared to those with higher capital costs and lower variable costs. As a thought experiment, Table 7 displays the LFSCOE (mean and min-max interval) without discounting of the future (i.e. a cost of capital of 0 %).

Table 7: Levelized Full System Costs of Electricity without discounting

	Germany		Texas	
Technology	LFSCOE [USD/MWh]	[min,max] Conf.Int.	LFSCOE [USD/MWh]	[min,max] Conf.Int.
Biomass	71	[69,74]	78	[75,82]
Coal	52	[50,53]	57	[55,60]
NGCC	26	[26,27]	29	[28,29]
NGCT	33	[33,34]	35	[34,35]
Nuclear	60	[58,64]	68	[65,73]
Solar	734	[564,965]	188	[155,266]
Wind	247	[214,276]	146	[117,174]
W+S	221	[160,240]	111	[88,169]

Table 7: Levelized Full System Costs of Electricity without discounting (i.e. with a cost of capital of 0%).

5.3 Effective Capacity Factor Define the "effective" capacity factor as the average dispatched electricity per hour. This capacity factor is capped by the "technical" capacity factor, which is the (maximal) generation of a source of electricity. The average technical capacity factor in the data for wind (solar) is 35% (23%) in Texas and 18% (11%) in Germany. Table 8 displays the average effective capacity factor for each technology and the interval ranging from the minimal to the maximal capacity factor for each year. As net dispatch from storage is not permitted and there are no losses in the storage process, this can be calculated by dividing the average hourly demand by the installed capacity. Some observations can be made: First, the capacity factors for dispatchable sources in Texas are lower than in Germany, which stems from the higher seasonal variance of the demand. This means that capacity needs to be provided in Texas which only becomes relevant for a few month in the summer. A direct implication of the lower capacity factors are the higher LFSCOE values of dispatchable generation technologies in Texas compared to Germany. Second, the effective capacity factors for wind and solar are significantly lower than the technical capacity factor, implying that a large share of electricity gets curtailed. An interesting observation is that though the technical capacity factors for solar are just twice as high in Texas than in Germany (23% vs. 11 %), the effective capacity factor is almost six times higher in Texas than in Germany. This means that not only solar do generators generate less in Germany, they also sell significantly less electricity in a single-source market, making the investment even less profitable.

Table 8: Average Annual Effective Capacity factor

Technology	LCOE	Germany		Texas	
		LFSCOE	[min,max]	LFSCOE	[min,max]
Biomass	83%	76.0%	[72.0%,81.2%]	76.0%	[70.9%,80.6%]
Coal	85%	73.7%	[68.8%,81.2%]	68.9%	[61.0%,73.5%]
NGCC	87%	69.9%	[65.5%,73.8%]	58.2%	[55.9%,64.8%]
NGCT	30%	69.6%	[65.5%,73.5%]	58.1%	[55.6%,64.4%]
Nuclear	90%	79.9%	[74.6%,84.8%]	76.9%	[70.9%,81.8%]
Solar	29%	1.5%	[1.2%,2.0%]	10.4%	[5.0%,12.9%]
Wind	40%	5.9%	[3.7%,7.5%]	7.8%	[6.5%,9.6%]
Wind & Solar	–	6.5%	[4.5%,7.7%]	10.9%	[9.0%,12.4%]

Table 8: Capacity factors for LCOE taken from EIA LCOE (2020), where the table displays the capacity factors for onshore wind. The capacity factor for Wind & Solar is derived by dividing the the sum of the demand by the sum of the installed capacity.

5.4 Storage losses in Texas: Figure 8 depicts the effect of the LFSCOE values in Texas if charging and discharging costs are introduced. The observations of the LFSCOE in Germany hold here as well.

Figure 7: LFSCOE with charging and discharging losses in Texas.

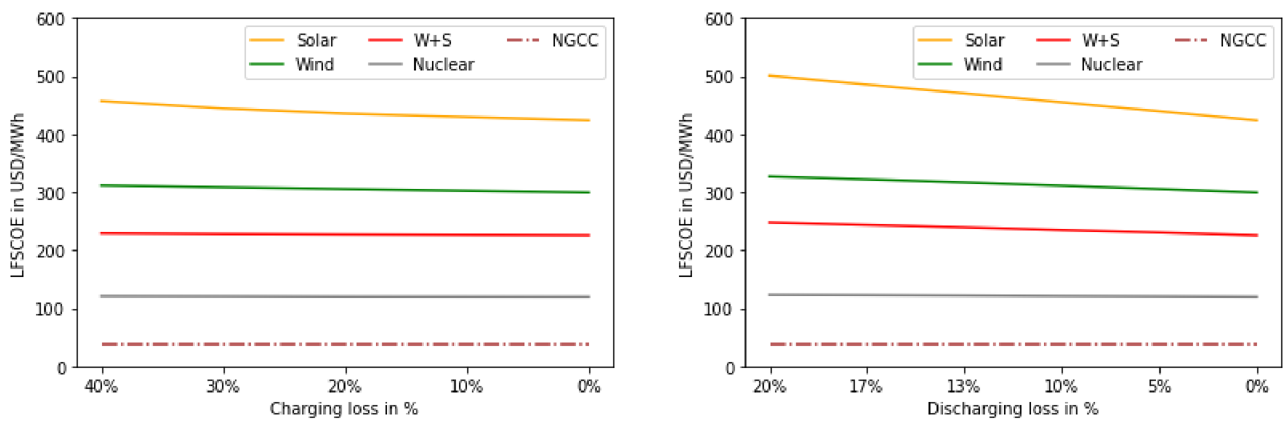

Figure 8 displays the LFSCOE in Texas with charging losses and discharging losses. Note that for every technology, the LFSCOE with charging losses of 40% are always lower than those with 20% discharging losses.