The Economics of the Global Energy Challenge

Online Appendix

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Contents

1 Introduction

This appendix describes the calculations used to compute the Private and Total Social levelized cost of energy (LCOE).

The Private LCOE is a standard metric used to determine a technology's economic viability. It is the price of energy that a source must charge so that the sum of present discounted annual revenue is equal to the sum of present discounted annual private costs.

To get the Total Social LCOE, we add the mortality cost of particulates and costs from greenhouse gas emissions to the Private LCOE. The Total Social LCOE incorporates externalities from energy generation and allows us to infer which technologies would be selected if energy was priced at its full social cost.

Our model for computing these LCOEs is based on that of Du and Parsons (2009) with modifications by Greenstone and Looney (2012) and subsequent changes in 2016 and 2024.

Section 2 describes the Private LCOE. Section 3 describes how we add social costs to the Private LCOE to get the Total Social LCOE. Section 4 explains the challenge of comparing conventional baseload energy sources with renewables and proposes a method of making such a comparison.

The report aligns with the code in the accompanying replication package.

2 Private LCOE

2.1 Inputs

Symbol	Variable	Unit	Source
C	Plant capacity	MW	EIA (2023b)
p	Plant capacity factor	(unitless)	EIA (2023c)
O	Overnight cost	\$/MW	EIA (2023b)
σ	Fixed O&M costs[1]	\$/(MW · yr)	EIA (2023b)
μ	Variable O&M costs	\$/MWh	EIA (2023b)
Ω	O&M escalation factor	(unitless)	Computed
H	Heat rate	mmBtu/MWh	EIA (2023b)
F	Initial fuel price	\$/mmBtu	EIA (2023a)
E	Initial grid-electricity purchase price[2]	\$/MWh	EIA (2023a)
Φ_t	Fuel escalation factor in year t[3]	(unitless)	Computed
w	Waste fee (nuclear only)	\$/MWh	Du and Parsons (2009)
D	Decommissioning cost factor (nuclear only)	(unitless)	Du and Parsons (2009)
κ_t	Construction schedule in year t	(unitless)	EIA correspondence[4]
δ_t	Depreciation schedule in year t[5]	(unitless)	IRS (2023)
R	Transmission cost	\$/MWh	EIA (2023c)
L	Plant life[6]	years	EIA (2023b)
T	Tax rate[7]	(unitless)	EIA (2023b)
COE_t	Cost of equity in year t[8]	(unitless)	EIA correspondence
COD_t	Cost of debt in year t	(unitless)	EIA correspondence
ES	Equity Share	(unitless)	EIA (2023b)
W	Nominal weighted average cost of capital (WACC)	(unitless)	Computed
δ_t	Discount factor in year t	(unitless)	Computed
Π_t	Inflation factor in year t[9]	(unitless)	EIA (2023a)

1. O&M stands for operations & maintenance.
2. Batteries purchase electricity from the grid at the EIA's electricity industrial end use rate.
3. Each fuel has a different Φ_t. We use the fuel escalation factor to scale up fuel prices paid by fossil fuel plants and electricity prices paid by batteries. The fuel escalation factor in year t, Φ_t, is computed directly from the EIA's fuel projections by dividing the fuel price in year t by F or E and adjusting for inflation.
4. We spoke to <laura.martin@eia.gov> and <manussawee.sukunta@eia.gov>.
5. Following IRS (2023) guidance, we use 15-year mid-quarter convention, Table A-2 in IRS (2023).
6. EIA (2023b) assumes a 30 year plant life for all plants.
7. EIA (2023b) uses a corporate income tax rate of 21%.
8. The cost of equity and cost of debt primarily use EIA projections. For 2022 and 2023, we compute our own cost of equity and cost of debt following the EIA's methodology in EIA (2022) Appendix 3.C.
9. We primarily use EIA (2023a)'s GDP Chain-type Price Index projections, but use actual inflation for 2022 and 2023 from the BLS.

Additional notes:

- For ease of exposition, we have made some unit conversions in the input table from our original sources. The full set of conversions is well-documented in the code.
- We will express the LCOEs in $/MWh. To convert to ¢/kWh, divide by 10.
- mm = million
- We define period $t = 1$ to correspond with the online year (2028). We let t_0 be the analysis start year (2022). The current year is t_c, 2023. Inflation and discounting is done relative to t_c. The final time period of operation is t_f.

2.2 Discount Rate

We assume that all sources are financed through a mixture of debt and equity and that all sources have the same equity share, ES. We compute the discount rate using the mean weighted average cost of capital (WACC) during the study period. Following EIA (2022) Appendix 3.C., the WACC in year t is equal to

$$W_t = ES \cdot \mathrm{COE}_t + (1 - ES) \cdot \mathrm{COD}_t \cdot (1 - T).$$

The mean WACC for the study period, W, is equal to

$$W = \sum_{\tau=t_0}^{t_f} W_\tau.$$

δ_t, the discount factor in year t is equal to[10]

$$\delta_t = \frac{1}{(1 + W)^{t-t_c}}.$$

2.3 Costs

First, we will examine the costs that generating sources face. All of these costs are expressed in discounted post-tax format.

10. The first plant begins construction in t_0, which corresponds with 2022 in our data. We want to discount to our current year, 2023, so t_c is equal to $t_0 + 1$.

2.3.1 Construction costs

The construction cost in year t is

$$\text{Cnstr}_t = \delta_t \cdot C \cdot O \cdot \kappa_t \cdot \Pi_t. \tag{1}$$

The overnight cost, O, is a measure of how construction costs scale with the capacity of the source. It is the source's construction cost per MW excluding interest costs. The construction schedule, κ_t, is the share of the project that is completed in year t. Thus, the undiscounted construction cost in year t is $C \cdot O \cdot \kappa_t$. Because all construction is completed prior to the online year, $\kappa_t = 0$ if $t \geq 1$.

2.3.2 Depreciation tax shields

The depreciation tax shield (expressed as a negative cost) in year t is a function of the *undiscounted* construction costs:

$$\text{Depr}_t = -\delta_t \cdot T \cdot d_t \cdot \sum_{\tau=t_0}^{t_f} \left(C \cdot O \cdot \kappa_\tau \cdot \Pi_\tau\right). \tag{2}$$

The depreciation calculation uses the sum of the nominal total construction costs as opposed to the overnight cost[11]. The IRS does not permit depreciation deductions until the property is placed into service. Therefore, the depreciation schedule d_t has the property $d_t = 0$ if $t < 1$.

Note: The following costs are related to operation. Thus, they are zero until the plant is placed into service, i.e. the costs are zero if $t < 1$.

2.3.3 Fixed O&M costs

The total fixed O&M cost in year t is

$$\text{FOM}_t = \delta_t \cdot (1 - T) \cdot C \cdot \sigma \cdot \Omega_t. \tag{3}$$

σ is the annual fixed O&M cost per MW of plant capacity. Ω_t allows for escalation in O&M costs over time[12]. The fixed O&M cost per MW in year t is $\sigma \cdot \Omega_t$. The total undiscounted pre-tax O&M cost in year t is therefore $C \cdot \sigma \cdot \Omega_t$.

2.3.4 Variable O&M costs

The total variable O&M cost in year t is

$$\text{VOM}_t = \delta_t \cdot (1 - T) \cdot 8766 \cdot C \cdot p \cdot \mu \cdot \Omega_t. \tag{4}$$

11. Since construction is spread over multiple years, nonzero inflation causes these two values to differ
12. In practice, we assume that fixed O&M costs are constant in real terms, so $\Omega_t = \Pi_t$.

The variable O&M cost, μ, is the O&M cost per MWh of electricity production. Ω_t allows for escalation in O&M costs over time[13]. The variable O&M cost per MWh in year t is $\mu \cdot \Omega_t$.

A plant with a capacity of C MW operating at full capacity produces C MWh of electricity per hour. Plants do not always operate at full capacity due to factors such as consumer demand, weather constraints (in the case of renewables), or routine maintenance. The capacity factor, p, captures the extent to which a plant operates at its full capacity. p is the ratio of expected annual generation to annual generation if the plant were to be continuously operating at full capacity[14]. Combining the facts above, the expected electricity production in any given hour is $C \cdot p$ MWh. Because there are 8766 hours in a year, a plant's expected annual generation is $8766 \cdot C \cdot p$ MWh. Therefore, the total undiscounted pre-tax variable O&M cost in year t is $8766 \cdot C \cdot p \cdot \mu \cdot \Omega_t$.

2.3.5 Fuel costs

For coal, gas, and nuclear sources, the total fuel cost in year t is

$$\text{Fuel}_t = \delta_t \cdot (1 - T) \cdot 8766 \cdot C \cdot p \cdot H \cdot F \cdot \Phi_t. \tag{5}$$

The fuel cost in year t is $F \cdot \Phi_t$ \$/mmBtu. The expected annual electricity production is $8766 \cdot C \cdot p$ MWh (see section 2.3.4 for intuition). The heat rate, H, is a measure of a source's efficiency in converting fuel (in mmBtu) to electricity (MWh)[15]. The expected annual fuel consumption is $8766 \cdot C \cdot p \cdot H$, which is priced at $8766 \cdot C \cdot p \cdot H \cdot F \cdot \Phi_t$.

We assume that batteries charge from the grid. Therefore, the fuel cost in year t for batteries is

$$\text{Fuel}_t = \delta_t \cdot (1 - T) \cdot 8766 \cdot C \cdot p \cdot E \cdot \Phi_t. \tag{6}$$

$8766 \cdot C \cdot p$ is the expected annual MWh of battery charge (and discharge). Their expected annual electricity requirement is therefore $8766 \cdot C \cdot p$, which is priced at $8766 \cdot C \cdot p \cdot E \cdot \Phi_t$.

Renewables do not require fuel, so $F \equiv 0$ and $\Phi_t \equiv 0$ for all t.

13. In practice, we assume that fixed O&M costs are constant in real terms, so $\Omega_t = \Pi_t$.

14. The capacity factor for conventional baseload technologies (e.g. coal) is usually greater than 0.8. Because renewables cannot always produce electricity, due to the weather and other factors, renewable capacity factors are typically less than 0.5. Natural gas combustion turbines (NGCTs) are used to produce electricity when there are spikes in consumer demand. They can produce electricity quickly, but are quite costly, so their capacity factor is 0.1. It is useful to have NGCT plants around in case of increases in electricity demand, but in practice they are not used as often as other sources.

15. A source with heat rate H requires H mmBtu of fuel to generate one MWh. For example, coal plants with carbon capture and sequestration (CCS) technology are typically less efficient in converting fuel to electricity because they have extra processes to capture carbon. Therefore, the heat rate for coal plants with CCS is typically larger in magnitude than the heat rate for conventional coal plants.

2.3.6 Decommissioning and waste costs (nuclear only)

The costs of dealing with spent nuclear fuel and shutting down a nuclear reactor are not trivial, so we include them here.

$$\text{Waste}_t = \delta_t \cdot (1 - T) \cdot 8766 \cdot C \cdot p \cdot w \cdot 1\{\text{Nuclear}\}. \tag{7}$$

The expected annual electricity production is $8766 \cdot C \cdot p$ (see section 2.3.4 for intuition).

$$\text{Decom}_t = \begin{cases} 0 & \text{if } t \neq t_f, \\ \delta_t \cdot (1 - T) \cdot \frac{350}{2000} \cdot O \cdot \Pi_t \cdot 1\{\text{Nuclear}\} & \text{if } t = t_f. \end{cases} \tag{8}$$

The decommissioning cost only applies in the final year of the plant's life. The $\frac{350}{2000}$ adjustment is the ratio of decomissioning costs to overnight costs computed in Deutch et al. (2003) and utilized in Du and Parsons (2009).

2.4 Total NPV of costs

The total net present value of costs is

$$\begin{aligned}
\text{Total NPV of Costs} = {} & C \cdot O \cdot \sum_{t=t_0}^{t_f} \delta_t \cdot \left[\kappa_t \cdot \Pi_t - T \cdot d_t \cdot \sum_{\tau=t_0}^{t_f} \kappa_\tau \cdot \Pi_\tau \right] && \text{(Capital)} \\
& + (1 - T) \cdot C \cdot (\sigma + 8766 \cdot p \cdot \mu) \cdot \sum_{t=1}^{t_f} \delta_t \cdot \Omega_t && \text{(O\&M)} \\
& + 1\{\text{Not battery}\} \cdot (1 - T) \cdot 8766 \cdot C \cdot p \cdot F \cdot H \cdot \sum_{t=1}^{t_f} \delta_t \cdot \Phi_t && \text{(Fuel)} \\
& + 1\{\text{Battery}\} \cdot (1 - T) \cdot 8766 \cdot C \cdot p \cdot E \cdot \sum_{t=1}^{t_f} \delta_t \cdot \Phi_t && \text{(Electricity)} \\
& + (1 - T) \cdot 8766 \cdot C \cdot p \cdot w \cdot \sum_{t=1}^{t_f} \delta_t && \text{(Waste)} \\
& + \delta_{t_f} \cdot (1 - T) \cdot \Pi_{t_f} \cdot \frac{350}{2000} \cdot O \cdot 1\{\text{Nuclear}\}. && \text{(Decom)}
\end{aligned}$$

Note that many of the summations iterate from 1 to t_f instead of t_0 to t_f. This is because many costs are not incurred until the power plant begins operation.

2.5 Price & Output

To obtain the Private LCOE, we first need to determine the break-even price of electricity for a given source. We will let Price_{t_0} be the Private LCOE in year t_0. The price in year t is

$$\text{Price}_t = \Pi_t \cdot \text{Price}_{t_0}. \tag{9}$$

The break-even price is chosen such that

$$\text{Total Revenues} = \text{Total Costs}.$$

By the definition of revenue and substituting the NPV of costs described in section 2.4,

$$\sum_{t=1}^{t_f} \text{Price}_t \cdot \text{Output}_t = \text{Total NPV of Costs}. \tag{10}$$

Note that Output_t will be zero if $t < 1$, i.e. if the plant has not started operation. Thus, we write the lower bound on the summation as $t = 1$ and not $t = t_0$. For $t \geq 1$, the discounted post-tax annual output is

$$\text{Output}_t = \delta_t \cdot (1 - T) \cdot 8766 \cdot C \cdot p. \tag{11}$$

Note that $8766 \cdot C \cdot p$ is expected annual electricity production in MWh (see section 2.3.4 for intuition).

We will now solve for Price_t. Starting from equation 10,

$$\begin{aligned}
&\sum_{t=1}^{t_f} \text{Price}_t \cdot \text{Output}_t = \text{Total NPV of Costs} \\
\iff &\sum_{t=1}^{t_f} \Pi_t \cdot \text{Price}_{t_0} \cdot \text{Output}_t = \text{Total NPV of Costs} \\
\iff &\text{Price}_{t_0} \sum_{t=1}^{t_f} \Pi_t \cdot \text{Output}_t = \text{Total NPV of Costs} \\
\iff &\text{Price}_{t_0} = \frac{\text{Total NPV of Costs}}{\sum_{t=1}^{t_f} \Pi_t \cdot \text{Output}_t} \\
\iff &\text{Price}_{t_0} = \frac{\text{Total NPV of Costs}}{(1 - T) \cdot 8766 \cdot C \cdot p \cdot \sum_{t=1}^{t_f} \Pi_t \cdot \delta_t} \\
\iff &\text{Price}_{t_0} = \frac{\text{Total NPV of Costs}}{\text{Total NPV of Output}} \\
\iff &\text{Price}_t = \frac{\text{Total NPV of Costs}}{\text{Total NPV of Output}} \cdot \Pi_t
\end{aligned}$$

Where the first line is equation 10. The second line follows from equation 9. The third and fourth lines follow from algebra. The fifth line follows from equation 11. The sixth line follows by definition of NPV. The seventh line follows from equation 9.

2.6 Private LCOE Formula

In particular, when $t = t_c$, 2023, the inflation factor is just 1, so the Base LCOE is

$$\text{Private LCOE} = \text{Price}_{t_c} = \frac{\text{Total NPV of Costs}}{\text{Total NPV of Output}}. \tag{12}$$

Note that if one wishes to express the Private LCOE in ¢/kWh as opposed to \$/MWh, one must divide by 10.

2.7 Transmission costs

CRS (2023) finds that transmission owners pass transmission costs to customers that benefit from transmission infrastructure according to the principle of *beneficiary pays*. Therefore, to each Private LCOE we add the source's transmission cost R (\$/MWh)[16][17].

16. Henceforth, when we refer to the Private LCOE, we are referring to the Private LCOE with the inclusion of transmission costs.

17. Adding transmission costs to the LCOE is standard. The EIA's Levelized Costs of New Generation Resources in the Annual Energy Outlook 2023, EIA (2023c), also includes transmission costs in their LCOE calculation.

3 Total Social LCOE

The Private LCOE only accounts for private costs. There are substantial social costs incurred from electricity production and in particular electricity production using fossil fuels. We consider two social costs: the mortality costs of particulate emissions and total greenhouse gas costs.

3.1 Inputs

Symbol	Variable	Unit	Source
Gen_t^k	Total electricity generation in year t from sources of type k	MWh	EIA (2023a)
$\text{PM}_{j,t}^k$	$PM_{2.5}$ concentration in census tract j in year t from sources of type k	$\mu g/m^3$	Hernandez-Cortes et al. (2023)[18]
$\text{Pop}_{j,t}$	Population in census tract j in year t	(unitless)	Manson et al. (2023)
SCC_t	Social cost of carbon in year t	\$/ton CO_2	EPA (2023)
E_{CO_2e}	Lifecycle CO_2e emissions intensity	ton CO_2e/MWh	Nicholson, Scott, and Garvin Heath (2021)

3.2 Particulate costs

Sources that burn fossil fuels release particulate emissions into the air. They also release NO_X and SO_2, which is converted to particulates through chemical processes[19]. Particulates are extremely detrimental to human health, see Greenstone and Hasenkopf (2023) and Ebenstein et al. (2017). We compute annual particulate costs by dividing annual particulate damages from plants of a particular type by annual electricity generation of plants of that type. We only consider mortality costs from particulate emissions[20]. We compute particulate damages following the analysis done in Greenstone et al. (2023) Table 7.

Annual mortality damages from particulates attributable to plants of type $k \in \{\text{Coal, Natural Gas}\}$ in census tract j in year t are

18. Data was obtained by visiting Hernandez-Cortes et al. (2023)'s GitHub repository.
19. Coal burning is particularly egregious in this respect, see Henneman et al. (2023).
20. There is a large literature on the impact of $PM_{2.5}$ on a wide range of other outcomes from productivity to visibility to wildlife welfare, so we are *underestimating* total particulate damages.

$$
\begin{aligned}
\text{Particulate damages}_{j,t}^{k} &= 0.098 && \text{Mortality impact } (years/(\mu g/m^3))^{a} \\
&\times \text{PM}_{j,t}^{k} && \Rightarrow \text{Loss of life expectancy } (years)^{b} \\
&\times 1/\text{US life expectancy} && \Rightarrow \text{Per year of operation } (years)^{c} \\
&\times \text{Pop}_{j,t} && \Rightarrow \text{Total loss of life years } (years)^{d} \\
&\times \text{VSLY} && \Rightarrow \text{Valuation of total loss of life years } (\$)^{e}.
\end{aligned}
$$

a. This is the change in life expectancy per $\mu g/m^3$ of $\text{PM}_{2.5}$ concentration that an individual is exposed to over their lifetime. Ebenstein et al. (2017) estimate that a 1 $\mu g/m^3$ increase in ambient PM_{10} reduces life expectancy by 0.064 years. We scale this by the 0.65 $\text{PM}_{2.5}$-to-PM_{10} ratio (Zhou et al. 2016) to arrive at 0.098.

b. $\text{PM}_{j,t}^{k}$ is the $\text{PM}_{2.5}$ concentration in census tract j in year t attributable to plants of type k.

c. The loss of life expectancy occurs after a lifetime of $\text{PM}_{2.5}$ exposure. US life expectancy comes from the CDC.

d. Each individual in the census tract experiences the loss of life expectancy.

e. Multiply the loss of life by the value of a statistical life year (VSLY). We compute the VSLY by dividing the EPA's value of a statistical life by US life expectancy.

The particulate cost in \$/MWh in year t from sources of type k are

$$
\begin{aligned}
\text{Particulate cost}_t^k &= \frac{\sum_j \text{Particulate damages}_{j,t}^k}{\text{Gen}_t^k} \\
&= \frac{\text{Total particulate damages}_t^k}{\text{Gen}_t^k}.
\end{aligned} \tag{13}
$$

We only have particulate concentrations, $\text{PM}_{j,t}^{k}$, for 2018, so we assume that the particulate cost is constant across years and equal to the particulate cost in 2018. That is,

$$
\text{Particulate cost}_t^k = \text{Particulate cost}^k \quad \text{for all } t. \tag{14}
$$

The assumption in equation 14 is that new plants will have the same ratio of particulate damages to total generation as plants had in 2018.

3.3 Greenhouse gas costs

Beyond particulate emissions, electricity generation releases greenhouse gases (GHGs). GHGs are emitted at multiple stages of the electricity generation process from construction of plants to fuel extraction to combustion to plant decomissioning (Nicholson, Scott, and Garvin Heath 2021). E_{CO_2e} is the lifecycle CO_2e emissions per MWh. The social cost of carbon in year t is SCC_t. The GHG damages in year t are

$$
\text{GHG damages}_t = \text{Output}_t \cdot E_{\text{CO}_2e} \cdot \text{SCC}_t. \tag{15}
$$

The product of the first two terms is the total GHG emissions in year t expressed in CO_2e. The product of the three terms are the GHG damages caused by total emissions in year t.

A source's GHG cost is

$$\begin{aligned}
\text{GHG cost (\$/MWh)} &= \frac{\text{Total NPV of GHG Costs(\$)}}{\text{Total NPV of Output (MWh)}} \\
&= \frac{\sum_{t=1}^{t_f} \Pi_t \cdot \delta_t \cdot 8766 \cdot C \cdot p \cdot E_{\mathrm{CO_2}e} \cdot \mathrm{SCC}_t}{\sum_{t=1}^{t_f} \Pi_t \cdot \delta_t \cdot 8766 \cdot C \cdot p} \\
&= E_{\mathrm{CO_2}e} \cdot \frac{\sum_{t=1}^{t_f} \Pi_t \cdot \delta_t \cdot \mathrm{SCC}_t}{\sum_{t=1}^{t_f} \Pi_t \cdot \delta_t}
\end{aligned}$$

The second line follows from equation 11 and equation 15. The third line follows from algebra.

Note that we have excluded costs due to natural gas methane leakage, so this will be an *underestimate* of the true social costs due to GHG emissions for natural gas plants.

3.4 Total Social LCOE

The Total Social LCOE takes into account both private costs and social costs and is equal to

$$\text{Total Social LCOE} = \text{Private LCOE} + \text{Particulate cost} + \text{GHG cost}. \tag{16}$$

4 LCOEs for Renewables with Backups

4.1 Background

Renewables such as wind or solar are not directly comparable to conventional baseload technologies such as coal or natural gas. Renewables face generation constraints that limit their flexibility in meeting demand. For example, after sunset, natural gas plants can increase production to meet spikes in electricity demand, but solar cannot. This lack of flexibility requires the grid to construct additional backup capacity to allow for the possibility that renewables will be unable to perform when they are needed.

Backups allow the grid to produce additional electricity at short notice when there are spikes in electricity demand that cannot otherwise be met. In order to adequately compare renewables to conventional baseload technologies, we need to consider the additional, often costly, backups that would need to be added to the grid along with the renewable to ensure reliable electricity supply. Natural gas combustion turbines (NGCTs) and batteries are common technologies used to provide backup electricity to the grid.

It is crucial to estimate exactly how much backup capacity needs to be added alongside renewables such that the addition of the renewable and the backup is comparable to adding a conventional electricity source. If we underestimate the backups required, then we cannot make an adequate comparison between the renewable and backup and a conventional source. If we overestimate the backups required, then we will also be overestimating the cost of the renewable and backup because backups are costly.

4.2 Effective Load Carrying Capability

We use the effective load carrying capability (ELCC) to quantify the amount of backup generation/storage that must come online simultaneously with a renewable source. The ELCC is an industry standard that captures the degree to which new sources contribute to overall reliable grid capacity[21]. It is the quantity of dispatchable[22] generation that a source can replace while holding constant the probability of grid failure[23]. The ELCC values differ across grids based on renewable saturation, demand patterns, and weather (Carron et al. 2021). For example, the ELCC for solar in the summer of 2019 in the SPP grid was 0.79, whereas in winter it was 0.37. This indicates that in the summer 100 MW of solar capacity is roughly equivalent to 79 MW of dispatchable capacity, but in the winter only 37 MW.

Lazard's LCOE publication, Bilicic and Scroggins (2023), uses the ELCC to determine how much backup capacity would need to be installed along with a renewable to make that system comparable to a dispatchable source. We likewise use the ELCC to determine how much backup capacity is necessary and then proceed with the calculation of the Private and Total Social LCOEs for renewables with backups.

To illustrate this calculation, consider the following example. Assume the solar ELCC is

21. California's grid operator, CAISO, recently prepared a report (Carden et al. 2023) for the California Public Utilities Commission (CPUC) using the ELCC to describe how they would be in compliance with CPUC's procurement requirement.

22. Generating sources can be categorized as dispatchable or intermittent. Dispatchable sources can produce electricity with few operating constraints (e.g. gas or coal) and intermittent sources have periods where generation is not possible (e.g. wind or solar).

23. Grid operators model the grid. They run simulations with random variables such as electricity load and weather and compute the probability of loss of load, when system load exceeds generation capacity, over a simulated year. This probability is stored as P. Grid operators run a series of simulations with the new generation source added to the existing grid. Each simulation removes more and more dispatchable capacity from the existing grid until the loss of load probability is equal to P. The ELCC is equal to the ratio of dispatchable capacity removed to the capacity of the renewable. See Carron et al. 2021 for a detailed discussion of the calculation.

constant across seasons and grids and is equal to 0.5. Assume we want to add a total of 100 MW of reliable system capacity and we have access to a 100 MW solar plant. We will need to add an additional 50 MW of NGCT capacity because the solar plant only contributes $100\text{MW} \cdot 0.5 = 50\text{MW}$ of reliable system capacity. In order to determine the Private (or Total Social) LCOE for the solar plant, we need to account for the fact that a 50 MW NGCT plant was also added to the grid. The LCOE for the solar plant is an expected electricity production weighted average of the LCOE of the solar plant and the NGCT that was added along with it.

4.3 Inputs

Symbol	Variable	Unit	Source
C_x	Plant capacity for sources of type x[24]	MW	EIA (2023b)
p_x	Plant capacity factor for sources of type x	(unitless)	EIA (2023c)
ELCC_x	ELCC for sources of type x	(unitless)	Various[25]

4.4 Renewables with NGCT backups

Assume we have access to a renewable source and a NGCT with capacity and ELCC equal to $C_{\text{renew}}, \text{ELCC}_{\text{renew}}$ and $C_{\text{NGCT}}, \text{ELCC}_{\text{NGCT}}$ respectively. The NGCT is perfectly dispatchable, so $\text{ELCC}_{\text{NGCT}} = 1$[26].

Step 1. Compute required NGCT capacity:

$$\begin{aligned} C_{\text{renew}} &= C^*_{\text{NGCT}} \cdot \text{ELCC}_{\text{NGCT}} + C_{\text{renew}} \cdot \text{ELCC}_{\text{renew}} \\ \iff C^*_{\text{NGCT}} &= C_{\text{renew}} \cdot (1 - \text{ELCC}_{\text{renew}}). \end{aligned}$$

24. We will need to consider capacities for renewables as well as for NGCTs and batteries. We will designate the capacity of the renewable as C_{renew}, the capacity of the NGCT as C_{NGCT}, and the capacity of the battery as C_{battery}. We will use this convention for capacity factors and ELCCs as well.

25. We use historical and projected ELCC values from the five largest US grids: ERCOT (Carden et al. 2022), CAISO (Carden et al. 2023), PJM (PJM 2023), MISO (MISO 2022) and MISO (MISO 2023), and SPP (SPP 2022) and (SPP 2023). We need to construct a single ELCC number for each source. Therefore, for each source we regress the ELCC on year weighting by each grid's annual generation in 2022. We then predict the ELCC in the online year, 2028, and set that to be the source's ELCC.

26. Assuming NGCTs are perfectly dispatchable, ELCC = 1, is consistent with procedure used in a report (Carden et al. 2023) on ELCC values in the CAISO system prepared for the California Public Utilities Commission.

Step 2. Compute the number of NGCT plants needed:[27]

$$N_{\text{NGCT}} = \frac{C^*_{\text{NGCT}}}{C_{\text{NGCT}}}$$

Step 3. Compute the renewable LCOE weight:[28]

$$w = \frac{C_{\text{renew}} \cdot p_{\text{renew}}}{C_{\text{renew}} \cdot p_{\text{renew}} + N_{\text{NGCT}} \cdot C_{\text{NGCT}} \cdot p_{\text{NGCT}}}$$

Step 4. Compute the LCOE:[29]

$$\text{LCOE} = w \cdot \text{LCOE}_{\text{renew}} + (1 - w) \cdot \text{LCOE}_{\text{NGCT}}$$

4.5 Renewables with battery backups

Assume we have access to a renewable source and a battery with capacity and ELCC equal to $C_{\text{renew}}, \text{ELCC}_{\text{renew}}$ and $C_{\text{battery}}, \text{ELCC}_{\text{battery}}$.

Step 1. Compute required battery capacity:

$$\begin{aligned} C_{\text{renew}} &= C^*_{\text{battery}} \cdot \text{ELCC}_{\text{battery}} + C_{\text{renew}} \cdot \text{ELCC}_{\text{renew}} \\ \iff C^*_{\text{battery}} &= C_{\text{renew}} \cdot (1 - \text{ELCC}_{\text{renew}})/\text{ELCC}_{\text{battery}} \end{aligned}$$

Step 2. Compute the number of batteries:

$$N_{\text{battery}} = \frac{C^*_{\text{battery}}}{C_{\text{battery}}}$$

Step 3. Compute the renewable LCOE weight as the proportion of total generation coming from the renewable:

$$w = \frac{C_{\text{renew}} \cdot p_{\text{renew}}}{C_{\text{renew}} \cdot p_{\text{renew}} + N_{\text{battery}} \cdot C_{\text{battery}} \cdot p_{\text{battery}}}$$

Step 4. Compute the LCOE:

$$\text{LCOE} = w \cdot \text{LCOE}_{\text{renew}} + (1 - w) \cdot \text{LCOE}_{\text{battery}}$$

27. The nameplate capacity of the NGCT plant is often larger than the nameplate capacity of the renewable source, so by construction, the number of NGCT plants will be less than 1. If for example, for a solar plant, the number of NGCT plants is 0.5, then, for every two solar plants, one NGCT plant must be added.

28. The intuition for the weight is that we have a single solar array and N_{NGCT} NGCT plants in operation. The expected hourly output from source x is $C_x \cdot p_x$, the product of the capacity and the capacity factor (see section 2.3.4 for intuition). Given a request for a unit of electricity from the new sources, the probability that the unit of electricity is served from the renewable is the fraction of total generation that comes from the renewable, w. The price of that unit of electricity is $\text{LCOE}_{\text{renew}}$.

29. This analysis can be done for the Private LCOE or the Total Social LCOE, so we will just write LCOE to indicate either may be used.

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