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Short Communication

Taking the long view on short-run marginal emissions: how much carbon does flexibility and energy storage save?

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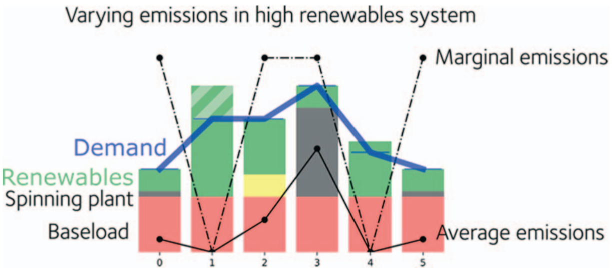
Abstract

Grid-scale electricity storage will play a crucial role in the transition of power systems towards zero carbon. During the transition, investments need to be channeled towards technologies and locations that enable zero carbon operation in the long term, while also delivering security of supply and value for money. We discuss metrics and market signals that are needed to guide this transition towards clean, secure and affordable solutions. Paradoxically, carbon metrics play an important role, but become less effective as a decision tool once the system approaches zero carbon. We critically assess the role of marginal and average emission and question the allocation of marginal emissions in systems where combinations of renewables and storage deliver flexibility. We conclude that, for strategic investments, short-term market signals may not always deliver sufficiently fast or far-sighted outcomes and operational decisions need to consider the merit order of demand as well as supply.

Graphical Abstract



Lay Summary: Energy storage can help to overcome the variability of solar and wind generation. If storage charges when renewable output is high and discharges at times when demand would otherwise require fossil-fuelled power stations, then storage unquestionably helps to reduce emissions. Once storage has successfully displaced those fossil-fuelled power stations, it becomes more difficult to show what the 'carbon benefit' of storage is. Is carbon even the right metric to focus on when trying to make long-term decisions on decarbonization? This paper comments on the surprisingly arbitrary nature of attributing carbon emissions to specific components within an energy system and points to the need to better understand optimal placement of storage on the network.

Keywords: energy storage, marginal emissions, zero carbon transitions, storage location

INTRODUCTION

Transitioning power systems to emit zero carbon dioxide requires major investment decisions in both conventional and disruptive assets and will fundamentally change the way the electricity system is operated. The transition is underway and accelerating as the price of solar, wind and storage decreases [1–3]. Clear metrics and market signals are needed to guide this transition and ensure that the end result is clean, secure and affordable. Vast sums of money need to be channeled into appropriate combinations of technologies in optimal locations, and in many cases at unprecedented speed, to deliver decarbonization that is consistent with a

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reasonable chance of maintaining acceptable climatic conditions [4].

Accounting for carbon emissions during electricity system planning and operational dispatch is an intuitive way to identify the appropriate solutions and to monitor progress towards decarbonization [5]. However, as carbon-emitting generators are gradually removed from the electricity system, carbon-based metrics lose their meaning. Taken to its extreme, no system component in a zero-carbon power system can claim to save or displace any carbon generation. Yet, many of the system components, such as storage, will be vital for such systems to function reliably, affordably and without the need for carbon-based backup generation. Savelli *et al.* [4] have shown that the carbon and cost benefits of storage depend on their location on the grid, but those markets do not necessarily send signals to locate them optimally today. How can the value of storage be recognized in such a way that both (1) investments are stimulated and channeled to the right places during the transition period to zero carbon generation; and (2) the resulting zero carbon system is and remains clean, secure and affordable?

Flexible assets, such as energy storage, can provide a range of services to the electricity system (Fig. 1). A vast range of nationally specific market arrangements and regulations stipulate which assets can provide particular services, often differentiated by the timescales over which energy is delivered.

The paper argues that the current market signals are insufficient to drive the transition to a low carbon system, and that carbon pricing alone will not drive the transition at the desired speed. Markets tend to span large geographic areas and signals can disguise local variations, especially is systems with network constraints. Nodal pricing and other granular markets can address this challenge [6]. It has been argued that nodal pricing can improve market power for some operators in constrained regions, but at the expense of revenue predictability, which can disadvantage renewables investors, for whom bankability matters particularly [7].

In this paper we wish to draw attention to the ability of storage and renewables to provide flexibility and highlight a research gap on the understanding of spatially and temporally resolved carbon attribution for storage and renewables when providing system balancing and stability on congested grids.

In any of these services the emissions associated with a storage asset can be taken as the sum of all emissions at the time of charging minus the sum of all emissions at the time of discharging. Round trip losses mean that energy for charging is always greater than discharging. A storage asset is carbon-beneficial when the difference in associated carbon emissions between charging and discharging is greater than the emissions caused by round trip losses.

$$C_{\mathrm{storage}} = \sum_{t} E_{\mathrm{charge},t} \times c_t - \sum_{t} E_{\mathrm{discharge},t} \times c_t + \sum_{t} \lambda_t$$

Where C_{storage} is total carbon dioxide emissions attributed to storage operation, c_t is emission factor at time t (determined in various ways, see below), and E is energy during charging or discharging. Importantly, we also include a factor λ_t to capture 'non-energy-related' carbon changes associated with the presence of storage, such as avoided emissions from part-loaded gas turbines providing spinning reserve/frequency response. This is discussed further below. Note also that $E_{\mathrm{discharge}} = \eta E_{\mathrm{charge}}$ where $\eta < 1$ represents round trip efficiency.

How to attribute system emissions at the time of charging and discharging is a non-trivial problem, since it is not obvious, which particular plant is being turned up or displaced. What might at first sound like an empirical engineering and economics question, with a simple numerical answer, is in fact far from clear-cut.

One school of thought is that the 'fairest' attribution is to take the combined emissions of all system assets at a given point in time, the so-called average emissions factor (AEF). However, for over 20 years scholars have argued that a better way to attribute emissions is the marginal emissions factor (MEF), which singles out the specific plant that would have respond to a change in demand at a given point in time [8]. Initially such models were based on emission factors and merit orders of dispatch. Hawkes [9] used empirical historical operational data from the UK to identify which power plant responded to changes in demand at different times of day and levels of demand. ElectricityMap [10] go further and trace the 'origin' of generation even across international borders. They state that the 'marginal plant is the cheapest plant that still has spare capacity to respond' and that it 'cannot be a wind turbine or solar cells, as you can't command them'.

If the merit order of dispatch aligns closely with the emissions of the dispatched plant, such that the highest emitting plant is only used as a last resort, use of marginal emissions as a control signal should favour storage. In practice, commercially operated energy storage has been found to sometimes increase overall emissions, especially in systems where coal is cheap and provides base-load [9, 11, 12]. An example of this is shown in Fig. 2. Consider two time points t_1 and t_2, with the same loads but different levels of renewable generation. Less renewable generation at t_2 implies a higher residual load. The price will be spread in the spot market and this incentivizes the load shifting from t_2 to t_1. So, the AEF is lower at t_1 than at t_2, and vice versa for the MEF.

In partially decarbonized electricity systems, periods of high demand can coincide with higher emission generators being active—such that storage discharging at these peak times reduces emissions, so long as the difference in emission factors compensates for the round trip losses. In some systems this does not hold true, as Gleue et al. [13] and Beuse et al. [14] have shown for Germany, where midday peak demand sees lower average emissions than mornings and evenings. This is an early sign of the effects of high penetration of PV on system emissions, but it is less obvious how to control storage for maximum carbon benefit in this situation.

A more accurate inclusion of the external costs of carbon dioxide emissions from generation might improve the environmental performance of storage and flexibility assets by improving the signals guiding commercial operation [15]. This could be achieved by, for example, carbon pricing associated with AEFs or MEFs. However, if this is to work then far more clarity is required on how to quantify and attribute carbon emissions associated with storage. The data-driven approach where MEFs are derived from historical data only allows for static analysis [14], that is to say, MEFs by definition only assume small changes and therefore cannot account for longer term system changes or large real-time changes to the generation mix. This could result in an under-appreciation of the broader and systemic impacts of storage. Storage and other flexible assets have the potential to change, at a fundamental level, how system assets are scheduled and what plant is considered 'marginal'.

Here we explore how the signals from average and marginal emissions may change over time during the transition to clean power systems, and ask what would happen if storage

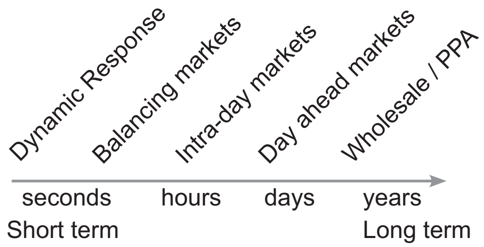

Figure 1. Markets serve a vast range of timescales, from short-term stability to long-term investment requirements

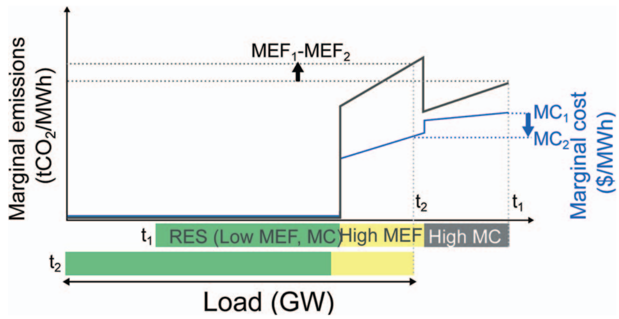

Figure 2. Dispatching high emission but cheap generators in-merit as a result of insufficient carbon pricing results in higher emissions. MC, marginal cost; MEF, marginal emissions factor

were to enable renewables to operate as the marginal plant directly.

Average and marginal emissions

Figure 3 gives a stylized example of the possible changes to average and marginal emissions as a system is decarbonized. In a fossil-fuelled dominated system (Fig. 3a) the average emissions (solid line) follow the same shape as overall demand. High demand results in the highest share of fossil-fuelled plant being used and therefore the highest average emissions. The difference between highest and lowest emissions is small, making it more difficult for storage to claim carbon reductions between these periods.

In a partially decarbonized system (Fig. 3b) the variability of *average emission factors* is greater. At times when renewable output dominates (such as time period 1) average emissions are lowest, such that storage can claim significant carbon reduction when charging during this time, and then discharging later (e.g. period 3) to offset higher emissions.

However, as the system is further decarbonized (Fig. 3c) and low carbon generators dominate for most of the time, average emission factors become permanently low. This mutes the signal indicating when and where flexibility is needed and makes storage appear to be 'less beneficial' for carbon, despite its potentially crucial role in enabling this system.

The transition from low to high, and back to apparent low-carbon benefit through these three phases is counter-intuitive, but this is because carbon as a metric becomes less meaningful for design and control decisions as we approach a zero-carbon system. However, during the transition period, carbon-based metrics remain useful (and perhaps essential) for choosing the optimal end system, i.e. the end-game zero carbon system may not be achieved without the best carbon-optimal decisions being made along the path to it.

A carbon price could be one way to address this; however, this is not a silver bullet – market failures have occurred with carbon pricing e.g. lack of innovation and lack of long-term investment [16]. Carbon prices alone do not send sufficiently strong signals for systems to transition at least at the desired speed. This is in part a result of the vast difference in timescales between operational decisions (minutes) and investment decision (decades). In deeply decarbonized system, network constraints and the location of storage assets become more challenging. Dealing with emissions directly can help to sharpen our focus on what really matters along the transition path.

An alternative means to attribute emissions from interventions in the power grid generation and demand mix is the *MEF*. While the average factor considers all emissions from all sources and divides these by the total output, the marginal factor is only concerned with the marginal plant—the source of the last unit of electricity that was required or avoided as a result of changes in supply or demand, including the charging or discharging of storage.

At present, the marginal plant may often be dictated by grid stability requirements. To ensure grid stability, a minimum share of highly responsive active plant is required, such as an open-cycle gas turbine. Such 'spinning reserve' is deliberately held at part-load, at or above its minimum stable generation limit, to respond to sudden increases or decreases in supply or demand. A side benefit of thermal plant is the inertia of its rotating mass. System operators also rely on this to stabilize the system. Alternative fast-response solutions may also have to make up for lost inertia. Being part-loaded carries an efficiency penalty for fossil-fuelled power generators [17]. High responsiveness also comes at an efficiency cost—open cycle gas turbines can ramp up faster than more efficient combined cycle gas turbines. Diesel generators can be faster still, but at even higher emission factors. Every time a less efficient but more responsive power station is kept in part load, the energy dispatched out-of-merit to maintain its minimum stable operation furthermore displaces other plant with potentially lower emission factors and lower short-run costs.

The consequence is that the emissions associated with the marginal plant are consistently high throughout the phases in Fig. 3a–c. In practice the responsive plant type changes depending on demand and availability, but for the illustrative purposes here it can be assumed to have permanently higher emissions than average. This leaves little opportunity for storage to claim carbon reduction from shifting energy between periods. This, too, seems counter-intuitive, leading ElectricityMap [18] to conclude that average emissions are a preferable metric for assessing the carbon impact of storage. In the end, it seems that MEFs are not very useful and could even encourage dirty investment decisions. What is required is proper modelling of the *entire* system change caused by a given design or operational decision. AEFs alone are deficient because they ignore overall generation and demand changes, and MEFs only account for small short-term changes and arbitrarily assume all demand is created equal. There might be a generation merit order, but as of today, there is no demand merit order.

Renewables and storage as a flexible resource

Modelling of entire grid operation requires us think in more depth about the link between renewable energy, grid stability and what we view as controllable and uncontrollable generation and demand. To ensure sufficient system flexibility, a certain minimum share of 'controllable' generators needs to be

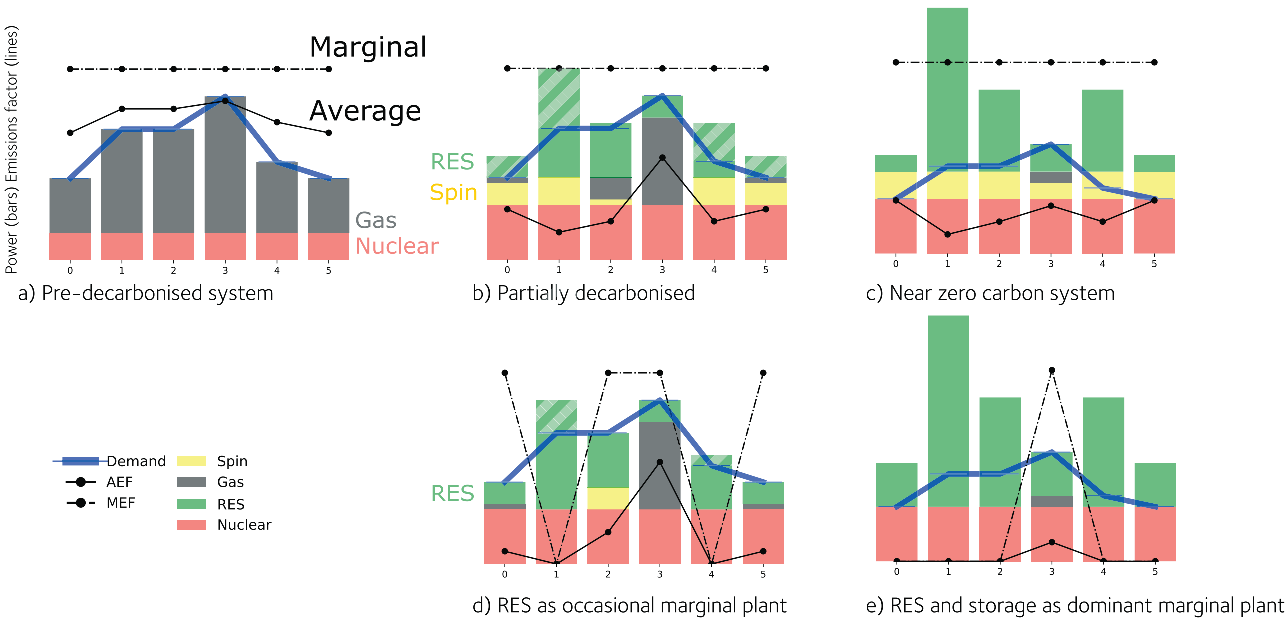

Figure 3. Carbon metrics are sensitive to operational choices. Illustrative example of the effect of decarbonized generation on emission factors. X-axes represent nominal 'time' e.g. settlement periods, y-axes represent emissions (gCO_2/kWh_e). (a–c) How average emissions (AEF) reduce as the system decarbonizes, while MEFs remain high, so long as spinning reserve (spin) with high emissions remain 'marginal'. (d,e) Part-loaded renewables (res), resulting greater variability in marginal emission.

maintained at all times. At times when renewable resources displace conventional thermal plant, some flexible spinning reserve is kept on the system (yellow regions in Fig. 3b,c), which enables ramping up and down between periods. For example, between periods 2 and 3 in Fig. 3b, the coinciding increase in demand and fall in renewable output necessitates a share of spinning reserve capacity that can ramp up fast enough for sudden or unexpected changes in net-demand in period 3 to be met.

This approach to spinning reserve is not generally compatible with a zero-carbon system, which eventually must operate without unabated fossil fuels being burnt. As the short-run marginal costs of abated fossil-fuelled plant are significantly higher than renewable electricity generators, load factors will decrease, resulting in a vicious cost cycle that could result in exceptionally high costs for the last few remaining periods of a year when they are required to maintain system resilience and stability. Storage and demand side measures will increasingly be able to take over the provision of this flexibility service.

Although the maximum power output of variable renewables such as solar and wind is weather-dependent, within this constraint these generators are not entirely 'uncontrollable' and in principle could reduce (and subsequently increase, assuming stable weather conditions) output power if required. Both wind and solar can be operated in 'part load' and (unlike thermal plant) turned on or off with little or no delay—with the flick of a switch or the twist of a blade. So long as there is any sun or wind available, even renewable sources can be responsive. Using renewables (and storage) in this way has profound implications for marginal emissions. Figure 3d and e illustrate the effect of using stored renewables as 'spinning reserve'. As Hedayati-Mehdiabadi [19] have shown, renewables can operate in ways that support system balancing. Renewables are technically and economically able to operate flexibly. Even wind and solar can contribute to the mix of flexible zero-carbon generators, such as hydropower or biogas. Deliberately throttling down the output of wind of solar below their instantaneous maximum output would reduce revenue under current market arrangements, but given renewables have the lowest short run marginal costs, the *overall system cost* would be reduced by doing this. Wind generators in Spain have been participating in this way since 2016 [20].

Part-loading variable renewables is unattractive in a market that rewards energy. Halving the load factor effectively doubles the levelized cost of energy for generators with (close to) zero short-run marginal costs. However, in a future where generators with low marginal costs dominate, power and flexibility/responsiveness may have greater importance than bulk energy per se. Efficient markets would therefore encourage an optimal level of part loading of generators with zero marginal cost by rewarding capacity and flexibility appropriately.

In period 1 of Fig. 3b renewables had to be curtailed, in part to enable sufficient thermal spinning reserve to remain on the system. In Fig. 3d the conventional spinning reserve has been replaced with 'part-loaded' renewables or storage. These can provide downward flexibility by turning a larger share off, but also upward flexibility thanks to the remaining headroom above the blue demand line. However, there are limits: insufficient renewables expected for period 3 still necessitate conventional spinning reserve to start up in period 3c.

The effect of using storage and part-loaded renewables on marginal and average emissions is significant. Average emissions are reduced, because less spinning reserve is dispatched. More importantly, the marginal emissions become more meaningful as a signal for the environmental impact of storage and other flexibility options. Load shifts towards periods 1 and 4 become appropriately recognized. These signals can encourage appropriate deployment of storage and the signals remain valid even in highly decarbonized systems that have a small amount of fossil-fuelled generation remaining, such as shown in Fig. 3e.

Short run marginal costs and short run marginal emissions are strongly linked, such that commercially operated flexibility measures are more likely to deliver environmentally beneficial outcomes. In the future system, some RES curtailment will become a necessity [21]. It's not economically efficient to avoid all curtailment in a system with high penetration of renewables. Storage has the ability to capture zero-carbon, zero-marginal cost output from renewables that would otherwise have to be curtailed, i.e. wasted. Despite round-trip losses, storage can therefore improve the overall system efficiency and reduce cost.

CONCLUSIONS

Locating and sizing storage assets on future grids correctly can reduce the overall system cost and speed up the transition towards a zero-carbon energy system.

A rethink is required regarding the role of renewables as responsive assets, especially when operated in combination with storage. Current market arrangements discourage curtailment of renewables and give the false impression that part-loading renewables is never economically justified. However, as systems decarbonize it will become more common and desirable to sometimes part-load renewables, i.e. not always use their full output for immediate consumption, but hold some generation capacity back to provide responsiveness.

For the resulting signals to guide major investment decisions, spatial as well as temporal imbalances need to be reflected. Hierarchical or fractal representations of the electricity grid with locational pricing could advance the visibility of such effects and support broader strategic considerations.

For strategic investments, short-term market signals may not always deliver sufficiently fast or far-sighted outcomes. This is especially true when one reflects on the rapid learning rates for solar, wind and energy storage systems. System models that can explore future tensions in system operation at longer timescales could provide a key complement to inform such decisions and to explore options with respect to counterfactual scenarios.

Carbon emissions factors, especially marginal factors, may mislead when it comes to investment and control decisions. A key reason is that we cannot easily prioritize demands in the same way as we can 'stack' generators by cost and emissions.

The DIGEST project is addressing these challenges by developing models to assess the system benefit of storage for different locations and configurations. Temporal and spatially resolved models will assess the system impact against counterfactual cases. Carbon impacts at asset and system level can be examined for short- and long-term effects. For example, the addition of a small amount of storage has a different effect on the system than significant large quantities of storage that would change planning and operational considerations.

Whole-system models can inform the short-term impact of storage, but more importantly, they can point towards the long-term role, which storage plays in enabling affordable and secure operation of zero-carbon systems.

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CONFLICT OF INTEREST

D.A.H. is a co-founder of Brill Power Ltd. No other conflicts declared.

AUTHOR CONTRIBUTIONS

All authors contributed to the manuscript with content and comments.

DATA AVAILABILITY

The data underlying this article is available on request from the corresponding author.

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