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How much wind and solar are needed to realize emissions benefits from storage?

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Abstract Environmental outcomes from energy storage depend on its usage patterns, the existing generation fleet, and fossil fuel prices. This work models the deployment of large, non-marginal quantities of energy storage and wind and solar power to determine their combined effects on grid system emissions. Two different grid environments are analyzed: a coal-heavy grid (Midcontinent ISO) and non-coal grid (New York ISO). An iterative dispatch model is used that operates storage to maximize income, considering that this operation can influence wholesale energy prices. With current low natural gas prices (\$2.6 per MMBtu), adding storage slightly reduces carbon emissions in New York, while increasing them in the Midcontinent ISO (MISO). Storage increases carbon emissions when it enables a high emissions generator, such as a coal plant, to substitute for a cleaner plant, such as natural gas. We estimate that adding storage operated to maximize revenue in the MISO region will not be carbon neutral until wind or solar power reach around 18% of the generation capacity. Different operation patterns for storage could realize higher carbon reductions. For example, a carbon price on emissions from generators would shift operation to make energy storage carbon neutral even with current wind and solar capacities. Sensitivity analysis shows that a higher natural gas price (\$5 per MMBtu) yields much higher storage-induced carbon emissions in both NYISO and MISO and storage in MISO will not be carbon neutral

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unless 35% of total generation capacity is from wind/solar. This illustrates that low cost, efficient natural gas generation is important to realize emissions reductions with storage under economic arbitrage.

Keywords Energy storage · Electricity grid · Emissions · Energy policy · Renewable energy · De-carbonize · Wind · Solar

1 Introduction

As of 2015, emissions from electricity generation in the United States contribute 27% of total US energy-related greenhouse gas emissions [1]. Renewable electricity technologies are a widely-discussed solution to reduce electricity system emissions of all kinds. However, given the intermittent nature of renewable technologies (wind and solar), large-scale integration is challenging [2,3]. Energy storage is a potential solution to the intermittency of renewables. However, the discourse on storage often presumes it to be inherently neutral or beneficial with regards to greenhouse gas emissions.

Policymakers in some jurisdictions have been promoting storage, e.g. through tax incentives or regulatory mandates, partly on the assumption that storage is an obvious or necessary complement to renewables. In 2017, Maryland passed a bill to provide tax credits for up to 30% of the cost of residential and commercial storage systems [4], becoming the first US state to provide exclusive tax credits for energy storage systems. In 2013, the California Public Utilities Commission required the state's three largest utilities to add 1.3 GW of energy storage through 2020 [5], arguing that storage "...stores [energy] when consumption is low and puts it back onto the grid when needed at peak demand times ...it is beginning to revolutionize the electric system by enabling increased renewables integration, increasing grid optimization, and reducing greenhouse gas emissions" [6].

Electricity grids are complex techno-economic systems, and it is important to explore whether the above assumptions about storage are correct. While storage systems certainly can solve the intermittency issues of renewable energy, storage in the US is rarely used to prevent curtailment of renewable energy. 88% of the total storage capacity in the US operates for profit maximization in an arbitrage scenario [7]. Deregulated grids feature generators (and consequently storage) as profit-maximizing agents. A profit-maximizing bulk energy storage system charges during low price/low demand periods and discharges during high price/high demand periods, regardless of the type of generation being used. The effect that this economic dispatch of storage has on grid emissions depends upon generation mix, dispatch order, demand, and storage round-trip efficiency [8].

Comprehensive evaluation of the environmental outcomes from the deployment of energy storage is only recently being explored. Reviewing prior studies on the operation of economically arbitrated storage, Lin et al. model emissions changes due to storage under different grid configurations in IEEE 9- and 30-bus systems using a dispatch model [9]. Their results indicate that net emissions from additional storage are likely to increase when non-flexible, high-emission systems provide base load and flexible, low-emission systems meet peak load. Similarly, Hittinger and Azevedo

calculated emissions from new storage using a Marginal Emission Factor approach. They conclude that, subject to the location and operation of storage, net CO₂ emissions consistently rise with addition of storage to the grid, varying between 100 and 400 kg/MWh (of delivered electricity) [10]. That work was performed for 20 eGRID sub-regions of the United States and modeled small storage systems (20 MW) as price-takers. However, large storage systems will substantially alter demand patterns, prices, and dispatched generation; marginal system emissions will change as more storage or renewable generation is added [11].

Prior work has established that, depending on the grid mix and how it is operated, storage can have positive or negative effects on carbon emissions. But important and unresolved questions remain as to how emissions due to storage evolve as intermittent renewables (wind and solar) are added to a grid and natural gas prices vary. More renewables increase the likelihood that storage is used to substitute fossil generation with excess wind or solar energy. But when natural gas is expensive relative to coal, storage tends to provide more peak power using energy from coal plants.

We address the above questions by modeling economic dispatch of price-making energy storage on two electricity systems while adding increasing quantities of wind and solar generation. The hypothesis is that, while storage will initially increase CO₂ emissions (or break even), emissions induced by storage will decrease as wind and solar are added and eventually become negative. Large storage systems often have a noticeable effect on electricity prices and should be modelled as price-makers [12]. Not accounting for this dynamic can lead to incorrect assessment of operation, revenue, and emissions [13]. In this work, we consider storage as a price-maker, and build an iterative dispatch model to investigate the effect of bulk energy storage additions. We apply our model to two electricity systems—the New York and Midcontinent ISO regions—and investigate the system emissions as wind/solar capacity is added, with the goal of better understanding how large quantities of new renewables and storage will interact to affect emissions.

The New York ISO (NYISO) and Midcontinent ISO (MISO) regions are modeled. There are plans in both to add large quantities of new wind or solar and, potentially, bulk energy storage [14, 15]. The mix of current generation resources is very different in the two regions. In NYISO, the power plants' capacity mix is 47% natural gas, 18% oil, 13% nuclear, 11% hydro, 6% coal, 4% solar and wind, and 2% biomass. In contrast, the MISO power plants' capacity mix is 41% coal, 29% natural gas, 10% nuclear, 10% solar and wind, 3% oil, 2% biomass and 2% other fuels [16].¹ The choice of these two case studies thus allows us to contrast between grids dependent and not dependent on coal. The NYISO and MISO grids are first modeled with the current generator mix and fuel prices, then modified with increased capacities of wind and/or solar power, keeping the capacity of other generators constant. This is not a forecast of an expected future grid mix, rather an exploration of relationship between new storage and renewables: How does storage affect grid emissions with differing amounts of added renewables, and differing natural gas prices? The result informs qualitative trends, in particular identification of a transition when storage decreases rather than

¹ Other fuels include waste heat, unknown, or purchased according to e Grid database.

increases emissions on a coal heavy grid. The two grids that we study are representative of many systems in the US and around the world. While there are no numerical results for other grids, the existence of an emissions transition with increased renewables for both suggests a general result: There is some level of renewable adoption for which storage is ensured to deliver emissions benefits, but this level can vary considerably based on the existing generation fleet and fuel prices.

These results are contingent on operating storage under economic arbitrage, i.e. maximizing income. Different operational modes could lead to different emissions outcomes. We explore an economic mechanism to shift storage operation towards emission reductions: a carbon tax on emission from generators. Also, currently low natural gas prices may not hold in the long term—an increase would affect the dispatch order of generation and, in turn, the CO_{2eq} emissions from storage. To address this, we calculate results for both a low (recent 2015–2016 prices) and a high natural gas price scenario.

2 Methods

We model the emissions from storage operations in NYISO and MISO, treating storage as a price-maker. We estimate the total grid emissions with and without storage. This allows us to estimate the change in emissions when storage is added to the system, which we refer to as the “storage-induced emissions”, estimated as given in Eq. (1):

$$\begin{aligned} \text{Storage induced emissions} = & (\text{Grid emissions with storage}) \\ & - (\text{Grid emissions without storage}) \end{aligned} \quad (1)$$

If the outcome is an increase in total grid emissions, we find the additional renewable generation (wind and solar) required to realize reductions, with and without a carbon tax. Finally, we perform sensitivity analysis under high and currently low (2015–2016) natural gas price scenarios.

2.1 Modeling framework

To estimate the storage-induced emissions (Eq. (1)), we combine models of different elements of grid operation. An economic dispatch model determines the lowest-cost operation of generating facilities that can reliably meet a given demand within the generators’ ramping constraints [17] and simulates the market clearing prices for electricity. These electricity prices are used in an optimization model to determine the schedule for storage operation, considering the effects of large storage on electricity prices. A model accounting for the diversity of plant efficiencies in a region estimates carbon emissions with and without storage. These sub-models are sequentially implemented as illustrated in the flowchart in Fig. 1. Wind and solar are incrementally added to the grid mix and the dispatch/storage/emissions sub-modules are run again in-order to determine the joint effect of large-scale renewables and energy storage. All models are developed using the Matlab software package, version R2016a [18].

Fig. 1 Flowchart of methodology for evaluating total grid emissions from adding storage and renewable generation. The model produces a “no-storage” time series of prices, simulates storage operation, then calculates the system emissions with and without energy storage. Wind and solar generation is added between simulations until the addition of storage no longer increases system emissions. *For simulating storage operation, we use an iterative dispatch optimization which is shown separately in detail in Fig. 3

2.2 Economic dispatch model and electricity clearing prices

The economic dispatch model is the first block of our framework (Fig. 1) used to generate electricity clearing prices, which are used as an input to model the operation of the storage. We assume an economic dispatch of generators, where generating facilities place bids based on their marginal costs. After placing bids, ISOs dispatch power plants sequentially from lowest to highest bid, within the ramp rate constraints of each generator, until electricity demand is fully met. This enables determination of market clearing prices. The clearing price is the bid price at which the last unit of electricity is supplied to meet the total demand.

We base the fleet of power plants on data for MISO and NYISO from the EPA eGRID database [16], and calculate each individual power plant’s marginal cost of operation based on their respective heat rate, fuel cost, and operations & maintenance (O&M) cost. The dispatch model includes ramping constraints but does not include

Table 1 Average fuel costs used for electricity production during the years 2015–2016

Fuel type	Cost	Units
Natural gas	2.6 [22]	\$/MMBtu
Coal	2 [22]	\$/MMBtu
Uranium	1.4 [23]	\$/MWh
Crude oil	7.99 [24]	\$/MMBtu

Four major types of fuels used for electricity production are considered. The normalized average price of coal includes the different qualities of coal used for electricity production. The original value of crude oil as per the reference is given in \$/barrel, and converted to MMBtu with the conversion: 1 barrel = 5.55 MMBtu for crude oil. Constant 2015-\$ are used

transmission constraints, assuming new transmission lines will be built in the future to sufficiently accommodate supply expansion.

The reference electricity demand is taken from market data available from NYISO and MISO for 2015 [19,20]. The fleet of power plants for electricity generation are taken from EPA's eGRID database [16] and the marginal cost (assumed as bid price) of operation for each power plant is calculated based on the power plant's heat rate [16], subsequent fuel costs (Table 1), and variable O&M costs [21].

The marginal cost (MC) given in \$/MWh is the summation of the fuel cost incurred per MWh and the variable O&M costs per MWh as shown in Eq. (2). The Heat Rate (HR) for each power plant, expressed in Btu/kWh, is considered (from eGRID data [16]) to estimate the fuel cost incurred to generate one unit of energy in MWh. Variable O&M costs for each power plant are considered based on the generator type and the primary fuel used for the generation of electricity (Table 2). A summary of data sources used in the economic dispatch model are provided in Table 1 of the Supporting Information (SI).

$$MC(\$/MWh) = HR * \frac{Price}{1000} + O\&M \quad (2)$$

where, MC, marginal cost of operation of a power plant (\$/MWh); HR, heat rate (in Btu/kWh); Price, average spot price of fuel (in \$/MMBtu); and O&M, variable operations and maintenance cost of the power plant (in \$/MWh).

With an additional carbon tax, the marginal cost of power plants increases based on their emission rates as in Eq. (3).

$$MC_{(carbon\ tax)}(\$/MWh) = HR * \frac{Price}{1000} + O\&M + \frac{Carbon\ Tax}{1000} * Emission\ Rate \quad (3)$$

where the carbon tax is expressed in \$/metric tonnes and the emissions rate is expressed in kg/MWh.

Tables 1 and 2 show fuels costs and variable O&M costs, respectively, used in the modeling.

How much wind and solar are needed...

Table 2 Variable O&M costs of technologies considered in this study [21]

Technology	Variable O&M costs (2015 \$/MWh)
Conventional hydropower	2.62
Coal power plants with steam turbines	6.96
Combined cycle power plants (gas/oil)	1.96
Conventional combustion turbine (gas/oil)	3.43
Gas turbine	3.43
Nuclear	2.26

All values are expressed in constant 2015-\$. The variable O&M cost of wind and solar power plants is taken as zero

Table 3 Ramping rates of the electricity generators used in the power plants [25–27]

Generator type	Ramping rate (% of rated capacity achieved/h)
Gas turbine/combustion turbine (natural gas)	100
Combined cycle (primary fuel: natural gas, secondary fuel: coal)	30
Steam turbine (coal)	15

The units are percentage change of rated capacity achievable in an hour

Using marginal cost as the bid price of power plants, the economic dispatch model is run with an objective of producing electricity at a minimum operating cost using a linear optimization method. Equations (4, 5) show the objective function without carbon tax scenario and with carbon tax scenario, respectively. Marginal cost of operation (MC) of power plants for these scenarios is calculated as shown in Eqs. (2, 3). The generators run with ramping constraints, shown in Eqs. (7, 8), and the total generation meets the total demand (Eq. (6)) in each hour (t). The ramping constraints are expressed in percentage of rated power a generator can ramp up or down in a given hour (% of MW/h). The dispatch model is run for every hour in a year. Ramping constraints for current hour ‘t’ depend upon the electricity generated by the power plant in the previous hour ‘(t–1)’ as shown in Eqs. (7, 8). Ramping rates of different types of turbines are shown in Table 3. Maximum electricity generated by a power plant in an hour ‘t’ does not exceed the name plate capacity of the power plant, shown in Eq. (9).

Objective function without carbon tax:

$$\text{minimize } C_t = \sum_p MC_{tp} * e_{tp} = \sum_p \left(HR * \frac{\text{Price}}{1000} + O\&M \right)_{tp} * e_{tp} \quad (4)$$

Objective function with carbon tax:

$$\begin{aligned} \text{minimize } C_t &= \sum_p MC_{tp} * e_{tp} \\ &= \sum_p \left(HR * \frac{\text{Price}}{1000} + O\&M + \frac{\text{Carbon Tax}}{1000} * \text{Emission Rate} \right)_{tp} * e_{tp} \end{aligned} \quad (5)$$

Subject to:

$$\sum_p e_{tp} \geq L_t, \quad (6)$$

$$e_{tp} \geq e_{(t-1)p} - \frac{RD_p}{100} * P_p, \quad (7)$$

$$e_{tp} \leq e_{(t-1)p} + \frac{RU_p}{100} * P_p, \quad (8)$$

$$e_{tp} \leq P_p, \quad (9)$$

$$e_{tp} > 0 \quad (10)$$

$$p \leq n, \quad (11)$$

$$t \leq 8760 \quad (12)$$

where, subscript p , power plant; subscript t , Time (in hours); C_t , cost of electricity generation at hour t (in \$); MC_{tp} , marginal cost of operation of power plant p at hour t (\$/MWh); e_{tp} electricity generated by power plant at hour t (MWh); L_t , load demand at t th hour (in MWh); and n , total number of power plants available for dispatch; RD_p , Ramp down rate of power plant p (% of MW/h); RU_p , Ramp up rate of power plant p (% of MW/h); P_p , Nameplate capacity of power plant p (MW); HR , heat rate (in Btu/kWh); Price, average spot price of fuel (in \$/MMBtu); and O&M variable operations and maintenance cost of the power plant (in \$/MWh); Carbon Tax, expressed in \$/metric tonne; Emissions Rate, expressed in kg/MWh

We do not model imports of electricity from regions outside of MISO and NYISO. Hourly variations and the resultant power output (e_{tp}) of wind and solar plants for a given location are taken from Eastern Wind Integration dataset [28], and Eastern Solar Integration Dataset [29] respectively.

2.3 Energy storage model

Using the dispatch model in an iterative storage optimization, we model storage as a revenue-maximizing entity. In other words, we treat storage as an energy arbitrage device used to move bulk energy from low price/demand periods to high price/demand periods. Our treatment of storage applies to operations at utility scale in power networks. Given that a significant percentage (88%) of storage operations in the US are arbitrage-based [7], provision of other grid services from storage, e.g. frequency regulation, is outside of the current scope. Likewise, we do not include Combined Heat and Power (CHP) networks in the modelling effort, as they require more complex coordination between the power and heat portions of the system and are not expected to grow quickly in the US, especially given the competition from cheap natural gas power plants [30]. However, CHP would likely reduce system emissions through much improved efficiency [31]. Further details on the breakdown of all the services provided by storage is provided in the Supplementary Information section.

Technically, the storage system is described by two parameters: round-trip efficiency and charge rate. Round trip efficiency, set to 80%, is the ratio of energy output from storage against the quantity of energy required to charge it. Charge rate, set

How much wind and solar are needed...

at 4 h in the base-case, reflects how rapidly the storage system can charge and discharge energy, measured here in terms of the minimum time needed for complete charge/discharge. We explore the sensitivity of net emissions on charge rate of storage by varying it from 4–24 h. A range of charge rate of 4–24 h is used since 90% of the storage in US is pumped hydro [7] that has charge rates in this range and many emerging bulk storage technologies would have similar charging rates [7]. It is assumed that storage has perfect information of the electricity clearing prices, justified by the fact that most electricity systems forecast electricity prices for the near future up to 48 h [32]. We model storage operation for capacities ranging between 5 and 20% of the average demand in each of the two systems.

The formulation of storage operation as a price-taker, given perfect information, is a simple maximization problem as shown in Eq. (13).

Objective function:

$$Revenue = \max \left(- \sum_{t=1}^{8760} C_t E_t \right) \quad (13)$$

Subject to:

$$S_0 = \frac{S_{max}}{4} \quad (14)$$

$$\forall t, S_t = S_{t-1} + E_t \times \sqrt{\eta}, \text{ if } E_t > 0 \quad (15)$$

$$\forall t, S_t = S_{t-1} + \frac{E_t}{\sqrt{\eta}}, \text{ if } E_t < 0 \quad (16)$$

$$\forall t, 0 \leq S_t \leq S_{max} \quad (17)$$

$$\forall t, -R \leq \frac{E_t}{hour} \leq +R \quad (18)$$

where, C_t , price of electricity in hour t (\$/MWh); E_t , electricity bought (positive) or sold (negative) by the storage (in MWh); S_0 , initial state of charge of storage (in MWh); S_t , state of charge in hour t (in MWh); S_{max} , maximum state of charge of storage (in MWh); η , round-trip efficiency of storage; R , max charge/discharge rate (in MW); t , hour in a year (1–8760).

Note that the revenue does not depend on capital cost, as this does not affect optimal operation. In the model, positive E_t indicates energy bought (charging) by the storage, and negative E_t indicates energy sold (discharging). The storage system is assumed to start with a 25% state of charge, given by S_0 (in MWh) as shown in Eq. (14). S_t (in MWh), the state of charge in each hour, is always less than or equal to the maximum amount of charge attainable by the storage, given by S_{max} in Eq. (17). The round-trip efficiency, η , is equally divided between charge and discharge cycles in Eqs. (15, 16) [10]. In any hour, energy in/out (E_t) ranges between the maximum charge/discharge rate, R (in MW) as shown in Eq. (18).

Conventionally, given perfect information, formulation of storage operation as a price taker is a simple profit maximization linear programming problem [10, 32–34]. However, operation of large amounts of energy storage will influence the market clearing prices and requires a different treatment. We show this in Fig. 2, where we model 1 week of operation of a 1000 MW storage plant in NYISO that takes 4 h

Fig. 2 Simulated energy storage operation of 1000MW capacity as a price taker based on clearing prices from an economic dispatch model of New York ISO (NYISO). The topmost figure shows the simulated clearing prices for a sample week in NYISO. The middle figure shows hourly energy storage operation for a plant that ignores its own effect on prices, where positive values indicate charging of storage and negative value indicates discharge. The bottom figure shows clearing prices after the effect of storage on net load has been taken into account. In this scenario, the storage expects to make a revenue of \$63,700 based on the topmost prices but makes only \$37,500, a 41% reduction resulting from the non-marginal effect of storage operation on prices

to completely charge without regard for the effect of storage operation on prices. Optimizing storage based on the clearing prices (top) yields an operation schedule (middle) that is subtracted from load and fed back into the dispatch model, determining the actual clearing prices after storage operation (bottom). Due to storage's effect on prices, neglected when calculating storage operation, storage income is 41% lower than expected from the original prices. This illustrates that profit maximization for large storage systems is no longer a simple linear optimization problem and must consider the effect on marginal generation and clearing prices.

Modeling of large energy storage as a price-maker is achieved using a self-learning optimization technique. The flowchart of this method is provided in Fig. 3. This is done by considering the moving average of the hourly storage charge/discharge at the end of each iteration until the solution converges. The storage operation converges/remains consistent after about 20 iterations, which we use as the number of iterations for estimating an optimized solution, maximizing revenue given the effect that storage has on prices. The convergence of this process is illustrated in Fig. 4.

Fig. 3 Flowchart of methodology for modeling energy storage as a price maker. Market clearing prices are estimated and the storage operation is generated using linear optimization, maximizing revenue based on the clearing prices. The change in demand pattern due to storage is then taken into account and a new time-series of prices are produced, which are used to re-calculate storage operation. This process is iteratively performed 20 times and the moving average of storage values is taken after end of each iteration. At the end of the cycle, the resultant load from additional storage is taken as the storage operation. Note: We choose 20 as the maximum number of iterations, as the storage operation remains consistent (converges) after this point

Fig. 4 Output from iterative optimization of storage operation during a sample week in New York region. Between iterations, the effect of storage operation on prices is considered and the storage adjusts accordingly to ensure that it is maximizing revenue while taking its own effect on prices into account. The storage operation remains consistent (converges) after approximately 20 iterations, which we use as the number of iterations

2.4 Emissions model

The total annual $\text{CO}_{2\text{eq}}$ emissions (in metric tonnes) from the grid are calculated based on the hourly dispatch of plants as shown in Eqs. (19, 20). The plant-level emission rates are in metric tonnes/MWh, taken from the eGRID database [16]. Total $\text{CO}_{2\text{eq}}$ emissions are comprised of all greenhouse gas emissions measured on a common scale based on their Global Warming Potential (GWP) relative to CO_2 [35].

The total $\text{CO}_{2\text{eq}}$ emissions in a given hour for a given operation schedule of generator plants is given by Eq. (19):

$$em_t = \sum_p m_p * E_p * N_{pt}, \quad t = 1, 2, \dots, 8760 \quad (19)$$

where, em_t , total emissions from all operating plants in hour t (metric tonnes); m_p , emissions of plant p per unit of produced electricity (in metric tonnes/MWh); E_p , electricity generated by plant p in 1 h of operation (MWh); $N_{pt} = 1$, when power plant p is operating in hour t , else the value is zero; t , hour in a year (1–8760); p , index number for power plant.

Summing em_t over 8760 h in a year gives the annual $\text{CO}_{2\text{eq}}$ emissions for the grid as shown in Eq. (20):

$$\text{Total Emissions} = \sum_{t=1}^{8760} em_t \quad (20)$$

To identify the point where adding storage becomes carbon neutral for the MISO grid (in NYISO, it is initially emission-reducing), wind and/or solar capacity is incrementally added. These additions are in compounded incremental additions of 10% until the

difference between emissions with storage and without storage are zero. The hourly generation profiles of solar and wind energy across various locations in MISO was estimated according to the Wind Integration National Database (WIND) toolkit [28] and Eastern Solar Integration Data [29].

The WIND Toolkit provides data related to wind energy production for over 126,000 current and potential locations across the United States for 7 years from 2007 to 2013 [28]. This dataset consists of meteorological data, 5-min resolution of wind power production, and capacity factors. We considered 30 potential locations in the Midwest region and the corresponding hourly wind output/MW. The average wind energy output (kWh/h) for a 1 kW system across these locations is used to generate the hourly variations of incremental wind capacities considered in the study. Similarly, the Eastern Solar Integration dataset by NREL consist of 5-min solar power and hourly day-ahead forecasts for approximately 6000 simulated PV plants. 30 potential sites from 15 states in the Midwest region are considered and a similar procedure to wind energy output is used to generate solar energy output/hour. Annual capacity factors of most of the potential wind power sites in MISO are greater than 40% and most of the solar power sites are greater than 16%. More details on the hourly variation of solar/wind energy output/hour and potential locations considered are provided in the Supplementary Information section.

3 Results

We first discuss differences between NYISO and MISO grids by showing the hourly mix of generation sources for a typical day for different seasons: winter, spring, and summer. Autumn is not included in the seasons as the demand during this season is similar to that observed in the spring. For illustration, we identified the type of power plants supplying electricity each hour to meet the given load. As seen in Fig. 5, the marginal generators in MISO are a mix of coal and natural gas power plants, though most often coal. Daily coal-based generation is about 30–43% of the total depending upon the season, highest during the summer. Daily natural gas generation is about 25% of the total generation during all the seasons. Summer peaks in MISO are met by coal and natural gas based plants. As the marginal cost of power from natural gas is close to that of coal in recent years, the dispatch of coal and natural gas power plants are intermixed in the dispatch stack.

In MISO, energy storage tends to increase the emissions if it charges from coal, consequently offsetting cleaner natural gas plants while discharging, which can be seen on a sample summer day in Fig. 6. In the same figure, when there is an increased quantity of wind energy (2–4 GWh/75 GW capacity), storage tends to charge using efficient combined cycle natural gas power plants, while displacing inefficient natural gas plants while discharging. In the second case, storage does not necessarily discharge only during peak periods because of the large difference in electricity prices when wind energy output is high versus low. However, lower natural gas prices mean that storage is also likely to charge from an efficient combined cycle natural gas plant, even without increased quantity of wind energy.

Fig. 5 Grid mix based on hourly dispatch of generators in Midcontinent ISO (MISO, top) and New York ISO (NYISO, bottom) on a sample day during summer, spring and winter seasons (output from economic dispatch model). Each color band indicates the typical type of fuel of the dispatched power plants. A generator is said to be “on the margin” if that type of generator is last to be dispatched (ie, at the top of the stack during a given hour). In the MISO region, coal/natural gas is normally on the margin during off-peak periods, and peak periods. In the NYISO region, natural gas/nuclear energy is on the margin during off-peak and natural gas is on the margin during peak periods. The effect of ramping constraints can be seen by the fact that some generators have non-horizontal bands, indicating a binding constraint in ramp-up or ramp-down

The grid in NYISO has natural gas plants as the marginal supplier of electricity when the demand peaks during the summer and winter. During spring and autumn seasons, nuclear energy or natural gas is the marginal generator during the off-peak period, and natural gas is the marginal generator during peak period of the day. In Fig. 5 below, during the off-peak period, a mix of biomass and natural gas power plants are on the margin on a sample day taken during the spring season. In NYISO, energy storage tends to increase the usage of more efficient natural gas power plants or nuclear power plants (by charging during off-peak periods), consequently offsetting less efficient natural gas plants while discharging.

3.1 Emissions from storage operation in NYISO and MISO

We model generator and storage operation and resulting CO_{2eq.} emissions for addition of storage between 5–20% of the average load, which is 3000–12,000 MW in MISO and 1000–4000 MW in NYISO regions. Figure 7 shows storage-induced emissions for different storage charge rates between 4 and 24 h. Total grid emissions induced by storage are sensitive to changes in charge rates and round-trip efficiency of the storage. In the MISO region, storage-induced emissions increase both with increases in storage capacities and with more rapid charging rates. The annual emissions due to

How much wind and solar are needed...

Fig. 6 Grid mix based on hourly dispatch of generators in Midcontinent ISO (MISO) on a sample day during summer, with and without storage—with current generation fleet, and with additional wind energy (output from economic dispatch model). Each color band indicates the typical fuel of the dispatched power plants. The dotted outline represents the total load with storage operations, and the solid outline represents the total without storage operation. On the left, without additional wind energy, storage charges using additional coal energy at night and displaces natural gas plants during peak periods, thereby increasing emissions. On the same day on the right, with wind capacity of 75 GW producing 2–4 GWh of wind energy on a hot summer day, storage charges from more efficient combined cycle natural gas plants and displaces natural gas peaker plants

Fig. 7 Annual storage-induced emissions in New York ISO (NYISO) and Midcontinent ISO (MISO). The storage capacities are varied between 0 and 20% of the average demand, which is 3000–12,000 MW in MISO, and 1000–4000 MW in NYISO. The estimated storage-induced emissions are given in metric kilo tonnes of CO_{2eq}.

Fig. 8 Marginal emissions of Midcontinent ISO (MISO) generators, in order of economic dispatch. The graph shows a series of rectangles, with height equal to the plant's emissions rate and width equal to the capacity (GW) of the generator. The color gradient indicates the generators that are most often used to charge/discharge storage, over 1 year of operation (lighter color indicates more frequent use), shades of red refer to charging, shades of green refer to discharging. In MISO, storage-induced emissions increase due to charging when the marginal emissions of the grid are high (coal) and displaces generators that have lower emissions (natural gas)

storage additions vary between 11,000 and 65,000 metric tonnes of CO_2eq , depending upon the storage capacity and the charge rate.

Figure 8 illustrates why storage increases emissions in MISO, showing the emissions of each generator when in an economic dispatch order. Emissions increase when storage charges at night using coal plants and displaces natural gas power plants while discharging. The relatively high emissions of coal versus natural gas implies that storage operation, in this case, is increasing carbon emissions from the grid. In addition, because storage is a net consumer of electricity (due to losses), total electricity generation is increased in proportion to the quantity and operation of storage.

In the NYISO region, system emissions decrease with increases in storage capacities, and are sensitive to change in charge rates of the storage (Fig. 7). The annual net emissions due to storage additions range between $-91,000$ and $-235,000$ metric tonnes of CO_2eq , for charge rates between 4 and 24 h. Prior results by Hittinger and Azevedo [10] using a Marginal Emissions Factor method suggested small increases in emissions in NYISO as a result of storage additions. Performing sensitivity analysis with natural gas prices show that positive emissions in NYISO would be expected with higher natural gas prices, shown in Fig. 10 in the later sections, which was the case during the 2010–2012 period over which the Hittinger and Azevedo model operated.

3.2 Solar and wind capacity additions required to make storage carbon neutral

As of 2016, MISO has 14 GW of installed wind capacity and 290 MW of solar capacity [16,36]. Results in Fig. 9 show that 20.6 GW of wind power (without solar) or 22.6

How much wind and solar are needed...

Fig. 9 Quantity of wind and solar required before storage-induced emissions are negative in MISO, at two different carbon taxes. The figure compares a no carbon tax scenario with a carbon tax of \$20/metric tonne. Because of the effect on the dispatch order of generators, a carbon tax results in much lower quantities of required wind/solar to make storage emissions-reducing

GW of solar (without wind) is estimated to be required in MISO before deployment of large storage (3000 MW/12,000 MWh) results in zero increase in emissions. Modelling energy storage as a price taker slightly over-estimates these results to 23.5 GW of wind power or 29 GW of solar power. A lower quantity of wind is required (than solar) because of the higher availability: a 40% annual capacity factor compared to 16% annual capacity factor of solar in MISO.

Could the playing field be changed so that storage delivers more carbon benefits to the grid? One approach would be to abandon the economic arbitrage approach altogether, i.e. operating the storage for environmental rather than economic benefits. We do not consider this option here. Instead, we look at another approach consistent with the current economic operation of energy markets: addition of a carbon tax. A carbon tax increases the marginal cost of dirtier coal-based power plants, thus motivating cleaner power plants to operate more often (lower in the dispatch order), leading to decreasing storage-induced emissions. We thus investigate how a carbon tax would affect the total amount of wind/solar energy required to make net-zero emissions with bulk energy storage. We analyze two carbon taxes—\$20/metric tonne and \$30/metric tonne of $\text{CO}_{2\text{eq}}$ emissions—using values consistent with valuations of the social cost of carbon from the EPA [37].

The amount of wind and solar capacities required in the grid reduces from around 18% of the grid generation capacity with no carbon tax to around 12% at \$20/metric tonne of $\text{CO}_{2\text{eq}}$ emissions, or to 10% (the current capacity of wind+solar in MISO) at \$30/metric tonne of $\text{CO}_{2\text{eq}}$ emissions.

3.3 Emission factors of storage with addition of solar and wind

While the above results indicate that adding storage to the current MISO grid increases carbon emissions, it is not yet clear if these emissions are high or low compared to other generation sources. It is common to measure the carbon impacts of electricity generation technologies with emission factors, i.e. the carbon emitted per quantity of electricity produced, e.g. 400–500 kg/MWh for combined cycle gas plants [38] and 980–1300 kg/MWh for coal plants [16, 38]. To compare the storage-induced emissions with those from other electricity sources, we calculate an emission factor equal to the additional emissions induced by storage (kg CO_{2eq.}) divided by the total energy (MWh) delivered by storage to the grid. This storage-induced emissions factor is the normalized emissions associated with moving energy from off-peak to peak periods, and accounts for both storage losses and differences in peak and off-peak emissions rates.

The emissions due to storage operation in MISO are approximately 450 kg/MWh for 4–8 h charge rates, and decrease as wind and solar are added. Storage-induced emissions factors for different wind and solar capacities are shown in the Supplementary Information section-Fig. 4.

4 Sensitivity analysis

We perform sensitivity analysis for natural gas price by re-calculating all results using a higher natural price as compared to the base case. From 2000 to 2016, the price of natural gas varied between \$2.5 and \$11 per MMBtu, with an average projected value of \$5/MMBtu through 2040 [39]. The base-case natural gas price used for the results in Sect. 3 is \$2.6/MMBtu, the average gas price in 2015–2016. This is increased to \$5/MMBtu in the high natural gas price scenario.

As seen in Fig. 10, at a higher natural gas price, total grid emissions induced by storage increase both in NYISO and MISO region at different storage charge rates between 4 and 24 h. In the MISO region, storage-induced emissions increase by 40–60 times as compared to the base-case scenario, both with increase in storage capacities and with slower charging rates. The annual emissions due to storage additions vary between 800,000 and 4,000,000 metric tonnes of CO_{2eq.}, depending upon the storage capacity and charge rate.

Figure 11 illustrates why MISO's storage-induced emissions increase by about 50 times for the high natural gas price scenario as compared to the base-case. In the high natural gas price scenario, the coal and natural gas are 'better sorted', and charging is almost completely met with coal generation while discharging almost universally displaces natural gas generation.

In the NYISO region, system emissions after adding storage increase between 150,000 and 370,000 metric tonnes of CO_{2eq.} depending upon the charge rate and the storage capacity in the high natural gas price scenario. This contrasts with what is seen in the base-case scenario. Though NYISO has a very small percentage of coal based power plants (3%) [16], these plants are available on-margin when the storage charges during off-peak periods as compared to gas turbines during the peak period.

How much wind and solar are needed...

Fig. 10 Net change in annual emissions after adding storage in New York ISO (NYISO) and Midcontinent ISO (MISO) at a higher natural gas price of \$5/MMBtu (compare with Fig. 6 showing base-case scenario of \$2.6/MMBtu). The storage capacities are varied between 5 and 20% of the average demand, which is 3000–12,000 MW in MISO, and 1000–4000 MW in NYISO. The estimated emissions are given in 1000 metric tonnes of CO_{2eq}.

Fig. 11 Comparison of marginal emissions of Midcontinent ISO (MISO) generators, in the order of economic dispatch for the base case scenario and high natural gas price scenario. This is essentially a series of rectangles, with height equal to the plant's emissions rate and width equal to the capacity (GW) of the generator. The color gradient indicates the generators that are most often used to charge/discharge, over 1 year of operation (lighter color indicates more frequent use). With high natural gas prices, storage is seen to increase emissions by 40 times since the difference between marginal emissions during charge-discharge phase are much higher than the base-case scenario

The wind and solar capacities required to decarbonize emissions induced by storage increase from 18% of grid capacity in the base-case scenario to about 35% with high natural gas prices (assuming no carbon tax), as shown in Fig. 12. With a carbon tax of \$20/metric tonne and high natural gas price, the amount of wind and

Fig. 12 Quantity of wind and solar required before storage-induced emissions are negative in MISO in the base-case scenario (at \$2.6/MMBtu) and high natural gas price scenario (at \$5/MMBtu). The figure compares between no carbon tax, and carbon taxes of \$30/metric tonne for both the scenarios

solar required to decarbonize emissions falls to 31% of grid capacity. At a carbon tax of \$30/metric tonne, the required grid share reduces further to 25% of the grid mix.

5 Discussion

At today's low natural gas prices and grid mix, we find that energy storage operated under economic arbitrage reduces carbon emissions in NYISO and increases emissions in MISO. At higher gas prices, storage increases emissions in both NYISO and MISO by enabling coal power to substitute for natural gas. Emissions changes induced by storage are much larger in the higher natural gas scenario due to large-scale substitution of coal for natural gas. This implies that a rising natural gas price relative to 2015–2016 prices, as per EIA projections [39], could mean that grids dominated by coal may not see carbon benefits from storage without significant restructuring of their generation mix. For example, though wind capacity in MISO is steadily growing and is projected

to reach 20GW of installed capacity by 2019 [40] (a growth rate of $\sim 1\text{GW}/\text{year}$), it is likely to be at least a decade before wind and solar capacities in total achieve 35% of the generation and induce storage emissions benefits under a high natural gas price scenario. The effect of natural gas price leaves the economic and environmental effects of storage at odds: we have found that storage-induced emissions that are zero or negative depend on the currently-low natural gas prices. However, storage providing energy arbitrage only makes financial sense if natural gas becomes more expensive, in which case energy storage will induce greater use of coal generation, increasing system emissions [41].

These results clarify the option space society faces with regards to storage. One choice is to accept increased carbon emissions in the short-term in some grids in order to achieve longer term benefits after more renewable energy is adopted. Arguments could be made justifying such a long-term perspective, but the current policy discourse does not frame the choice as a long-term one, instead asserting that storage delivers immediate benefits. Another option is to change the operation of storage to achieve environmental goals. For example, a storage system could be directly tied to a renewable generation plant to address intermittency. While technically possible, it is important to clarify the economic and environmental benefits delivered compared with alternative means of addressing intermittency, e.g. via flexible natural gas plants or improved transmission interconnection. A third option is to shift the economic context in which storage (and the grid) operates, e.g. a carbon tax, to ensure carbon benefits. We do not explore the benefits and cost of these three options here, but assert there is a need for a clearer framing of societal expectations from storage.

Our study shows that levying a carbon tax could significantly reduce the solar/wind requirements before storage delivers carbon benefits. These requirements are largely dependent on the level of the tax. At current social cost of about \$30/tonne, emission benefits from storage are plausible with the current installed wind capacity in MISO. On the other hand, if the natural gas prices start to increase, achieving wind capacities of 28 GW could take at least 10 years in MISO (though perhaps accelerated if such a carbon price is implemented), considering the current rate of projected growth in the absence of the Clean Power Plan [40]. Therefore, a reasonable carbon tax, set near the US EPA estimated social cost of carbon, without any support of other policies (such as the Clean Power Plan) would allow storage to deliver intended carbon benefits for MISO into the foreseeable future.

There are some encouraging outcomes in these results for energy storage and emissions. First, our analysis for NYISO illustrates that storage can be neutral or beneficial for emissions when it is routinely charged, during off-peak periods, with efficient combined cycle natural gas generation. In New York and similar grids (such as California), while storage is not expected to directly reduce emissions, it may indirectly mitigate carbon through improved integration of intermittent renewables. Second, the analysis for MISO illustrated that emissions due to storage additions is less related to the *quantity* of renewable energy in a system than the *curtailment* of renewable energy in a system. But the results show that any grid that has wind/solar curtailment of sufficient scale to be the primary source of charging energy for storage would experience excellent emissions benefits from storage. However, unless storage is predominantly

charged with otherwise-curtailed renewable energy, its emissions benefits are likely to be neutral or negative.

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How much wind and solar are needed...

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