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Health and climate benefits of different energy-efficiency and renewable energy choices

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Energy efficiency (EE) and renewable energy (RE) can benefit public health and the climate by displacing emissions from fossil-fuelled electrical generating units (EGUs). Benefits can vary substantially by EE/RE installation type and location, due to differing electricity generation or savings by location, characteristics of the electrical grid and displaced power plants, along with population patterns. However, previous studies have not formally examined how these dimensions individually and jointly contribute to variability in benefits across locations or EE/RE types. Here, we develop and demonstrate a high-resolution model to simulate and compare the monetized public health and climate benefits of four different illustrative EE/RE installation types in six different locations within the Mid-Atlantic and Lower Great Lakes of the United States. Annual benefits using central estimates for all pathways ranged from US\$5.7–US\$210 million (US\$14–US\$170 MWh^{-1}), emphasizing the importance of site-specific information in accurately estimating public health and climate benefits of EE/RE efforts.

Implementing EE/RE technologies can displace the emissions of greenhouse gases, both from EGUs and from upstream processes, thus producing climate benefits[1]. EE/RE will also have important public health 'co-benefits' by displacing air pollutant emissions, such as SO_2 and NO_x, which impact ambient concentrations of important public health drivers such as fine particulate matter ($PM_{2.5}$; refs 2–4). Benefits can vary substantially across EE/RE types and locations, which makes understanding the drivers of variability important for decisions and analyses around EE/RE development and siting, along with energy and environmental policies. Site-specific quantification of climate and public health benefits from EE/RE proposals is challenging because: GHG, SO_2, and NO_x emissions all contribute appreciably to EGU impacts[1,2,4,5]; the EGUs that EE/RE displaces depend on EE/RE performance, location and time dynamics, properties of other EGUs on the electrical grid, and the interaction of all these factors given electrical grid economics and transmission capabilities[6–12]; emissions of affected EGUs vary owing to fuel type, pollution controls and performance; and the public health impacts of $PM_{2.5}$ formed from SO_2 and NO_x emissions vary across EGUs as a result of atmospheric conditions and population distributions downwind[2,3,6]. Ideally, a model that compares benefits of different EE/RE types and locations should include all these dimensions with high geographic resolution[2,3,7–14]. A variety of studies have evaluated aspects of this question[1,2,5–9,12,14–23]. However, none have connected all of these key elements into a single simulation framework, and then simulated a set of EE/RE implementation scenarios, each differing by type and location, in a manner that facilitates comparison of benefits across both EE/RE type and location.

Here, we have developed the Environmental Policy Simulation Tool for Electrical grid INterventions (EPSTEIN), for the Eastern Interconnection (the electrical grid for regions of the United States (US) and Canada east of the Rocky Mountains) for 2012. The EPSTEIN model links output from a complex economic simulation electrical dispatch model to a public health impact assessment model that provides EGU-specific monetized health impact estimates for SO_2 and NO_x emissions[6–12] and monetized estimates of the impacts of CO_2 emissions[2,3,5,7,12,13,24]. We then simulated the effects of four different EE/RE installation types—500 MW wind, 500 MW solar, 500 MW peak demand-side management (DSM; reduction in electricity demand), and 150 MW baseload DSM (so it conserves an amount of energy comparable to what our wind and solar scenarios generate)—in six different locations on the PJM Interconnection. We simulated each installation type in each location independently, for a total of 24 simulated scenarios. Each scenario represents one installation type in one location, and the set of 24 scenarios represent all combinations of installation type and location. The PJM Interconnection is the Regional Transmission Organization (RTO, a contiguous electrical transmission area) within the Eastern Interconnection that manages the electrical grid and market in much of the Great Lakes and Mid-Atlantic region of the US. The locations are near Chicago (Illinois), North-central Ohio, Southern New Jersey, Eastern Pennsylvania, Virginia, and near Cincinnati (Ohio). We then compare benefits across EE/RE type and location, and examine differences on the basis of differing electricity generation or savings, economics and constraints of the local electrical grid, displaced EGUs, and populations downwind. This approach, using illustrative scenarios, allows direct comparisons between different EE/RE types and locations.

To explain variability in benefits across the 24 scenarios, we employed a basic theoretical decomposition of the model. Total benefits were modelled as a function of the electricity generation from RE installations or demand reductions from EE installations (termed 'capacity factor' herein for simplicity), displaced generation by fuel type, and then for each fuel type, the aggregated emissions rates of displaced EGUs and the aggregated health or climate

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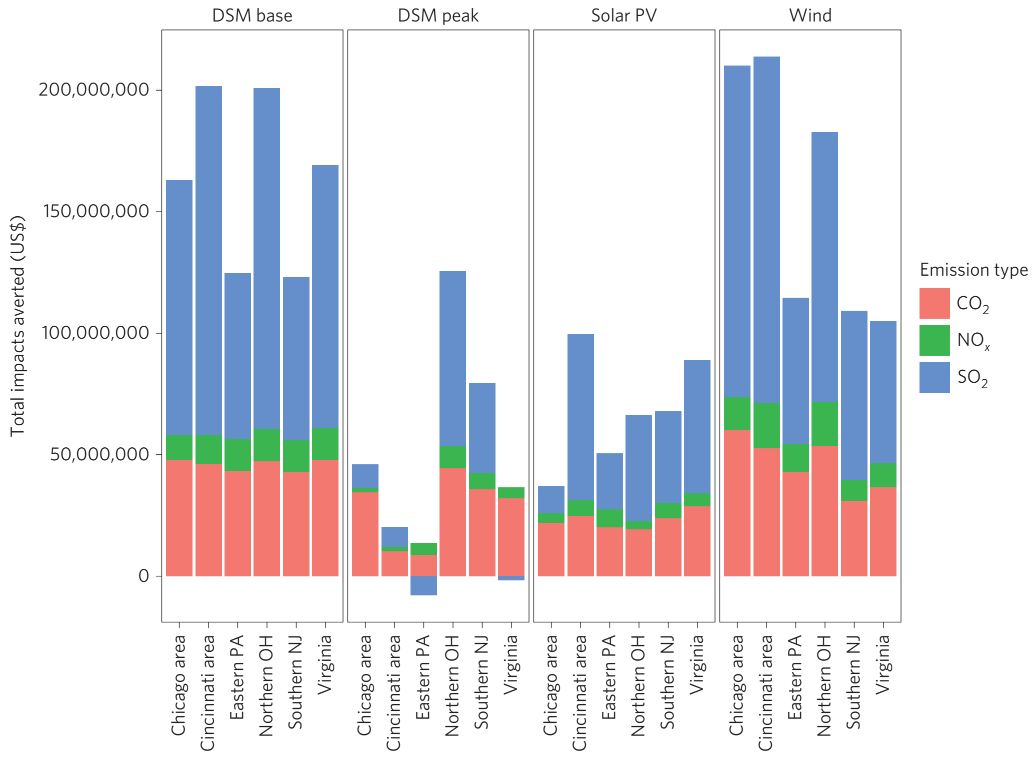

Figure 1 | Total impacts offset by emission type for each EE/RE installation type and location.

damages per unit emissions for the displaced EGUs. A simplified heuristic equation for this decomposition is presented below:

$$\text{Total benefits} = \text{Capacity factor} \times \text{Fuel types displaced} \times \text{Emissions displaced} \times \text{Impacts displaced} \quad (1)$$

We refer to this simplified heuristic equation within our manuscript as 'Benefits = CFEI'. We used this decomposition framework to examine drivers of variability across the 24 scenarios.

Health and climate benefits

Total annual health and climate benefits varied by a factor of approximately 37 across the 24 scenarios, with central estimates ranging from US$5.7 million for DSM peak in Eastern Pennsylvania to US$210 million for a wind energy installation in the areas of both Cincinnati and Chicago (Table 1 and Fig. 1). With central estimates for all parameters, displaced SO_2 from coal generally dominated the total benefits (Fig. 1 and Supplementary Fig. 3). Variability in total benefits is explained in part by large differences in EE/RE capacity factor (the 'C' term of Benefits = CFEI), which ranged from 1,431 GWh from a 500 MW wind energy installation near Chicago to 281 GWh for 500 MW DSM peak near Cincinnati (Supplementary Table 3). The benefits per unit electricity, related to the 'FEI' terms of our heuristic equation, also varied by a factor of 12, with values ranging from US$14 to US$170 MWh^{-1} across all 24 scenarios (Table 2).

First considering fuel displaced per unit generation, the 'F' term in our heuristic equation, the vast majority of EGUs displaced in all scenarios were fuelled primarily by natural gas or coal (Fig. 2), and so we focus on those fuels. The percentage of coal displaced varied across both EE/RE types and locations. DSM peak had the greatest variability in fuel composition displaced across locations, ranging from 85% coal displaced in Chicago to a 4% inducement of coal generation in Eastern Pennsylvania. Wind also displaced varying proportions of fuels, ranging from 38% coal in Eastern Pennsylvania to 79% coal in Northern Ohio.

Displaced coal was the most significant contributor to the total benefits across all scenarios, largely due to significantly lower emission rates for EGUs fuelled by natural gas compared to coal (Fig. 3 and Supplementary Fig. 2), therefore we focus on variability in emission rates from coal-fired EGUs across the 24 scenarios to examine the contribution of the 'E' term in our heuristic equation. The average SO_2 emissions per unit of electricity generation for displaced coal-fired EGUs ranged from 0.29 lb MWh^{-1} to 110 lb MWh^{-1}. For NO_x, emissions per unit of electricity generation from displaced coal EGUs ranged from 0.11 lb MWh^{-1} to 2.7 lb MWh^{-1}. Variability was less pronounced for CO_2 (1,900 lb MWh^{-1} to 2,900 lb MWh^{-1}). The emissions displaced for wind and DSM base were relatively similar to each other, whereas DSM peak had the most pronounced differences from other EE/RE types.

Finally, considering the benefits per unit emissions from displaced coal (the 'I' term in our heuristic equation), we first note that impacts of CO_2 do not vary, because the social cost of carbon (SCC) is independent of emission location. For impacts per ton of SO_2 emitted from coal EGUs, there is limited variability for DSM base (US$27,000 to US$30,000), solar PV (US$29,000 to US$36,000) and wind (US$29,000 to US$31,000), but greater variability for DSM peak (US$16,000 to US$39,000 across five locations with positive

Table 1 | Total benefits from CO_2, NO_x, and SO_2 emissions reductions for each of four EE/RE types in six locations, in 2012 US$ millions.

	Wind	PV	DSM base	DSM peak
North-central Ohio	180	66	200	130
Chicago area	210	37	160	46
Virginia	110	89	170	35
Cincinnati area	210	100	200	20
Eastern Pennsylvania	110	51	130	5.7
Southern New Jersey	110	68	120	80

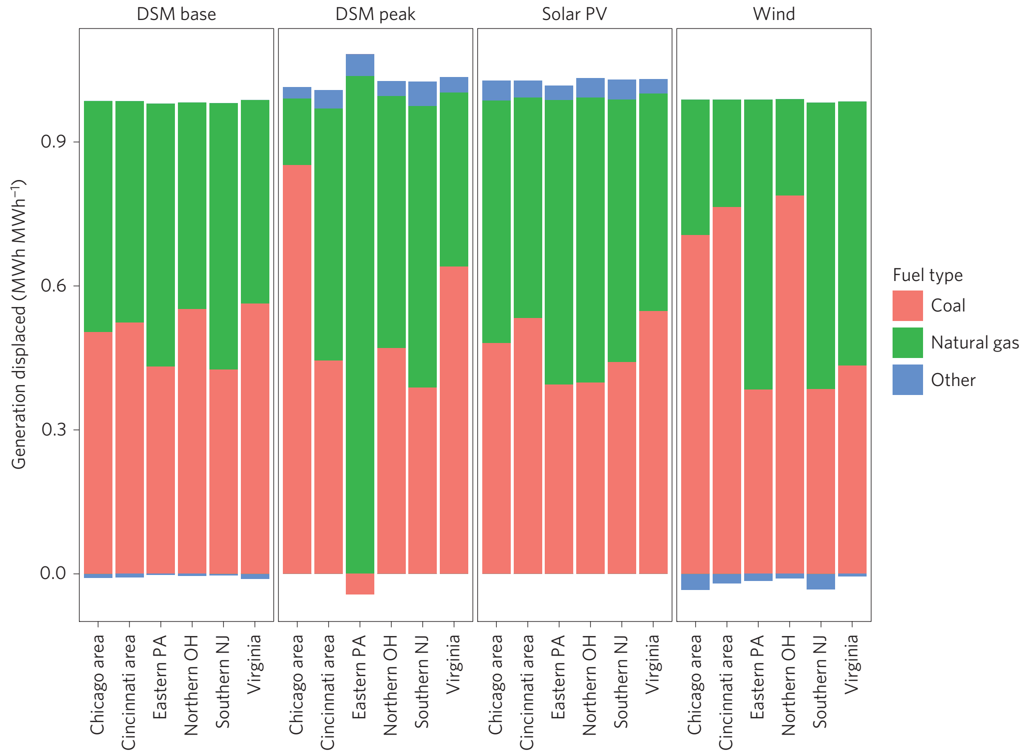

Figure 2 | The fraction of electricity generation displaced by fuel type for each EE/RE installation type and location.

damages per ton, along with -US$88,000 in Virginia) (Fig. 4). This variability reflects shifts in the geographic distribution of generating EGUs, including both EGUs that are entirely displaced and changes in operations of EGUs that are dispatched. The negative value for DSM peak in Virginia is composed of a slight reduction in net SO_2 emissions (Fig. 3) alongside generation shifting from EGUs with lower per unit damage estimates to EGUs with higher per unit damage estimates. For impacts per ton of NO_x emitted from coal EGUs, there was modest variability between locations for DSM base (US$12,000 to US$19,000), solar PV (US$7,700 to US$16,000) and wind (US$12,000 to US$16,000). Impacts per ton of NO_x displaced from DSM peak exhibited greater variability—US$11,000 to US$32,000 for five locations, and a high value of US$97,000 in Virginia (Fig. 4). The high value in Virginia is similarly composed of small net NO_x emissions displaced alongside geographic shifts in generation.

Complex dynamics and policy implications

There was substantial variability in benefits across all 24 scenarios, and generation displaced, proportion of fuel types displaced, emissions rates of displaced EGUs, and impacts per unit emission of the displaced EGUs equation (1) were all important in determining the total benefits of each EE/RE scenario. Although there were significant differences in the percentage of each fuel displaced between scenarios, most EE/RE types displaced substantial amounts of coal, especially wind and DSM base. A likely contributor to this is the recent decrease in natural gas prices and increase in coal prices[15,25,26], consequently making coal more likely to be displaced on the margin than it would have been in previous years.

There were some important differences in displaced fuel types due to both EE/RE type and location. Solar PV and DSM peak operate at times of relatively high electricity demand, so they tend to displace more expensive EGUs operating during times of peak electricity demand, generally natural gas. In contrast, wind and DSM base both operate at off-peak times, including spring, fall, and nights, resulting in more displacement of coal EGUs because they are closer to the margin during these times. Although there were small changes in generation across the entire Eastern Interconnection (Supplementary Fig. 4), the majority of the displaced EGUs were located near where EE/RE was implemented, even where coal generation is the major generation source. As a result, locations with greater amounts of coal generation generally had greater coal displacement, and higher benefits. This also occurred in areas where nuclear contributes substantially to baseload generation. These patterns indicate that EE/RE is capable of displacing coal generation in areas where peaking sources such as natural gas have small shares of generation. EE/RE can put coal in price competition with natural gas, which is much more flexible, and sufficient price pressure can force coal to reduce operation.

Our results demonstrate the importance of dynamics that our model and scenario design can simulate. EE/RE can relieve constraints on transmission capacity, can force some EGUs to operate below minimum operating capacity (thus forcing them to shut off completely and others to turn on), or can force some EGUs to operate at lower capacity and higher heat rates of fuel, resulting in higher emissions rates. The variability in emission rates of displaced EGUs is also predicated on underlying variability across all EGUs, owing to differences in EGU efficiency, emissions

Table 2 | Total benefits from CO_2, NO_x, and SO_2 emissions reductions for each of four EE/RE types in six locations, in 2012 US$ per MWh of generation.

	Wind	PV	DSM base	DSM peak
North-central Ohio	150	110	150	99
Chicago area	150	63	120	63
Virginia	91	120	130	44
Cincinnati area	170	150	150	72
Eastern Pennsylvania	81	81	95	14
Southern New Jersey	110	99	94	81

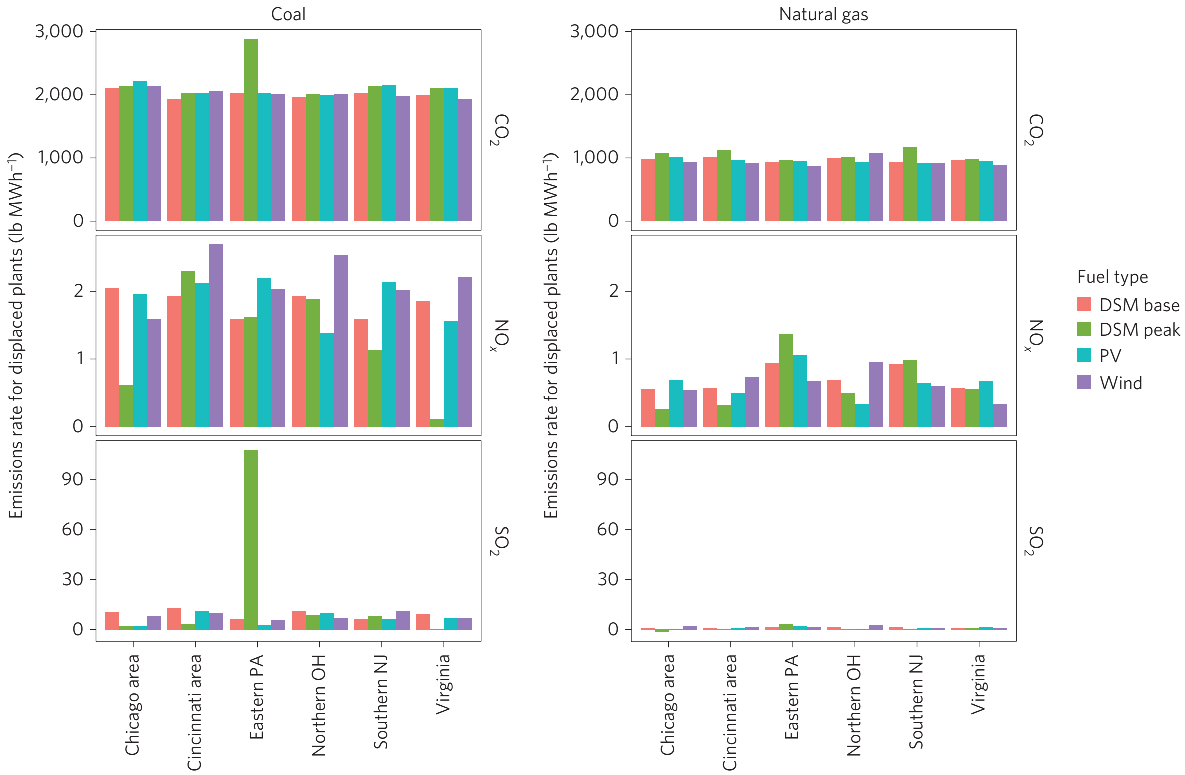

Figure 3 | Emissions per unit electricity generated for power plants offset by EE/RE installation.

control technologies, and fuel mix. The variability in emissions and impact rates of displaced EGUs is also partially due to EE/RE decreasing utilization of some EGUs but increasing utilization of others, which can result in net rates changing beyond the range of individual EGUs.

An example of these complex dynamics is that EE/RE displaces coal in areas with other baseload generation sources, for instance nuclear, such as the Chicago area (Supplementary Table 2). This may indicate that coal is on the margin frequently, owing to transmission constraints and the need for natural gas generation as a peaking source, emphasizing the importance of detailed dispatch modelling reflecting contemporary fuel prices. Another example of these dynamics is in Eastern Pennsylvania, where DSM peak has a small total benefit, including some induced impact from SO_2 emissions. Here, DSM peak displaces a substantial amount of natural gas while inducing use of coal-fired EGUs with high SO_2 emissions rates. This indicates that natural gas is the dominant peak generation type in this area, and that DSM peak installations can induce emissions by shifting the optimal dispatch order to higher-emitting sources, based on unit-specific minimum operation levels and commitment decisions.

In general, EE/RE has a net displacement of EGUs with high emissions rates, because EGUs operating in EE/RE scenarios have slightly lower emissions rates for both NO_x and SO_2 than EGUs operating in the baseline scenario (Supplementary Fig. 3). This is more pronounced for natural gas EGUs than for coal. The displaced coal EGUs are probably older, less efficient, run without SO_2 controls, and use higher-sulphur coal. For natural gas EGUs, these are probably older, less efficient EGUs or EGUs that co-fire with other fuels. These patterns indicate that the incremental costs to operate pollution control technologies may be generally small relative to other operating costs, or that higher-emitting EGUs are generally less efficient and more expensive to operate; otherwise, lower-emitting EGUs would probably be first to be displaced.

The impacts per unit emissions from displaced EGUs also varied across EE/RE scenarios. In general, impact rates of NO_x had higher variability than SO_2, probably owing in part to the complex chemistry of secondary particulate matter formation from NO_x emissions reflected in the health impact model[2,5,6]. Impact rates per ton of emissions for coal-fired EGUs tended to be higher than for natural gas-fired EGUs (Fig. 4), indicating that coal-fired EGUs tend to be located in places with larger exposed populations than natural gas plants.

Although our estimates are interpretable and reflect factors that influence site-specific benefits, our model has some limitations. We included only a subset of pollutants and impact pathways that dominated prior analyses[2,3,5,7,12,24,27,28] and for which we could construct detailed site-specific estimates. We did not include stack emissions of primary $PM_{2.5}$, methane, mercury, or other pollutants, nor morbidity effects of $PM_{2.5}$ or secondary formation of ozone. We also did not account for possible differences in impact/ton depending on emission timing, or slight changes in emissions rates due to power plants cycling in response to higher variability in both electricity supply and demand[13,25,26,29–31]. We also did not include full life cycle impacts of electricity generation—fuel extraction, building and decommissioning EGUs, and waste disposal. These impacts could contribute substantially to total benefits, but the impact pathways included here seem to be the dominant impacts from displaced EGUs (refs 2,5,32). Adding these pathways would increase our benefit estimates, although it should not materially influence our conclusions about the extent of variability across EE/RE scenarios and the importance of site-specific assessments. However, the rank ordering across EE/RE scenarios could change if including the above pathways changed the relative importance of coal and natural gas, which could occur if upstream GHG emissions were appreciable and much greater for natural gas than for coal. Further investigation would be required to understand how upstream impacts from coal compares to natural gas, especially given the complexities of hydraulic fracturing and mountaintop removal mining[13,27,28,33].

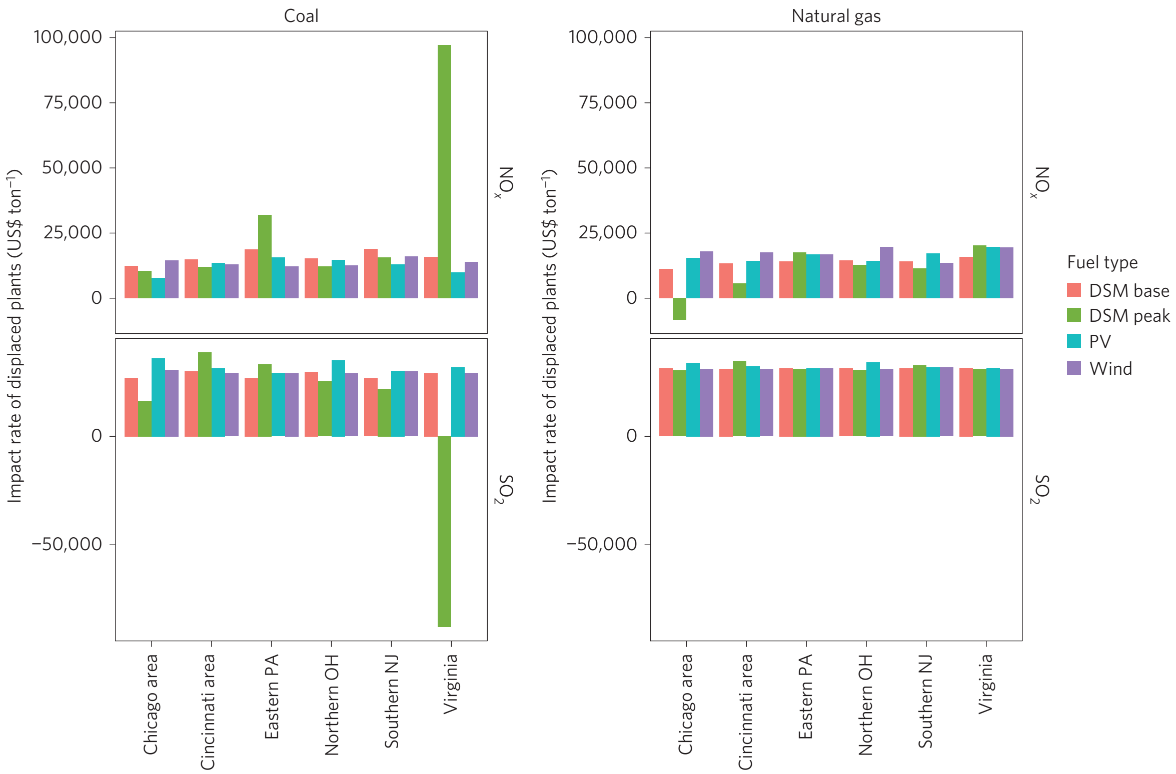

Figure 4 | Impacts per ton emitted of SO_2 and NO_x for power plants offset by EE/RE installation.

The methodology we used for monetizing climate change impacts is simplified and potentially underestimates the total impact of climate change, because the SCC includes only a subset of impacts, does not include changes to economic growth rate, and may apply too high a discount rate to future impacts[7,13,29–31]. Valuation of mortality from $PM_{2.5}$ also contains appreciable uncertainties inherent in the value of statistical life (VSL; refs 32,34), uncertainties related to the magnitude of the concentration-response function, and other parameters. Because of these uncertainties, any relative comparisons between the climate and public health pathways should be treated with caution. That said, both methods are robust and are designed for use in regulatory and benefit–cost applications[13,33,34]—we used central estimates for these parameters, which are generally used for governmental decision-making. Implications of alternative values for the VSL or SCC can be explored by linear scaling. Although some uncertainties will correlate across all scenarios and will scale linearly, uncertainties related to atmospheric dynamics and the electrical grid could differ by location. Both are complex and nonlinear systems and, in theory, these uncertainties could change the rank ordering of different scenarios. Exploring implications of changes to model parameters around the electrical grid and atmospheric fate and transport would require an explicit sensitivity analysis. That said, these uncertainties would probably not change our core conclusions about the substantial variability in site-specific benefits. These results also reflect the electrical grid in 2012, and the magnitude of the benefits of these installations in future years could differ owing to changes in the electrical transmission network, relative prices of fuels (particularly coal and natural gas), changes to existing EGUs (for example, efficiency upgrades, changes in fuel mixture, installation of pollution controls), construction of new EGUs, retirement of existing EGUs, and changes in regulations on air emissions or electricity generation.

Despite these uncertainties, we developed some important insights indicating the importance of geographically resolved impact assessment methods. Both generation and benefits will vary by location within a transmission area, owing to varying quantities of electricity generated or saved and characteristics of displaced EGUs. We demonstrated that the places where EE/RE generates or saves the most electricity are not necessarily the places with the most benefit, which has been shown before[7,12,35–37]. Our findings also highlight the importance of local conditions, grid constraints, and economics in determining which EGUs are displaced and what the benefits are. Although our benefit estimates have uncertainties, the SCC and VSL we applied are consistent with those used in regulatory analyses, and are central estimates. Our benefit estimates are of the same order of magnitude as US Energy Information Administration (US EIA) estimates of its levelized cost of energy (LCOE) of US\$40–70 MWh^{-1} (refs 34,38), but lower than that for solar PV (US\$150–US\$320 MWh^{-1}; refs 6,34). Although these comparisons should be interpreted with caution and a formal benefit–cost analysis is beyond the scope of our analysis, this indicates that the monetized health and climate benefits are appreciable and should be considered within formal analyses. Our research adds to the body of evidence that air quality and public health 'co-benefits' can be important to a full benefit–cost analysis for interventions primarily designed to reduce GHG emissions, ideally alongside full life cycle impacts and economic considerations[6,12,35–37]. Health 'co-benefits' can be relevant from a policy perspective because they are generally incurred in the near term, and in the region where EE/RE is being implemented. More broadly, our results can be used to estimate EE/RE benefits on the PJM Interconnection, demonstrate a framework that is applicable in designing and evaluating of energy and environmental policies, and possibly identifying high-benefit locations or EE/RE types on other electrical grids. The variability demonstrated here reinforces the importance and capability of incorporating location-specific characteristics in these evaluations.

Methods

Methods and any associated references are available in the online version of the paper.

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Author contributions

J.J.B., P.L., J.I.L., J.F. and B.B. designed the research. J.J.B. and P.L. carried out analyses. All authors contributed to interpretation of results and writing the paper.

Additional information

Supplementary information is available in the online version of the paper. Reprints and permissions information is available online at www.nature.com/reprints. Correspondence and requests for materials should be addressed to J.J.B.

Competing financial interests

The authors declare no competing financial interests.

Methods

To estimate the impacts displaced by each of the 24 illustrative EE/RE scenarios (four types by six locations), we created the EPSTEIN model by linking output from PROSYM Market Analytics[38], a complex economic simulation electrical dispatch model, to a health impact model that provides monetized health impact estimates for SO_2 and NO_x emissions[6,38]. The dispatch model provides plant-specific emissions estimates for CO_2, SO_2 and NO_x. The EGU-specific environmental health impact assessment model provides monetized estimates of the impacts of these emissions, based on models developed previously[6,38]. We then used the EPSTEIN model to simulate electrical generation and environmental impacts for a baseline scenario representing 'business-as-usual' in 2012 and 24 case scenarios that also included one EE/RE type in a defined location. The four EE/RE types were 500 MW solar PV, 500 MW wind, 150 MW of baseload (24 h a day, 7 days a week, all year) DSM and 500 MW of peak-shaving DSM; these were in separate simulations at one of the six load centres of Chicago (Illinois), North-central Ohio, Southern New Jersey, Eastern Pennsylvania, Virginia, and near Cincinnati (Ohio). All EE/RE types are illustrative. We selected wind and solar PV as our RE installations because they are readily available and in use in the region, and selected our DSM installations to be illustrative of a variety of different possible EE/RE installations. We selected our six locations to capture the broad spectrum of electricity demand characteristics, nearby power plant types, grid constraints, and populations downwind across major nodes in PJM. We chose 2012 as our base year to simulate fuel prices and system characteristics that reasonably represent the electrical grid for near-term policy decisions, without the need for long-term forecasting of fuel prices and other parameters. This choice of model year also allowed us to simulate a time period where natural gas and coal prices were relatively similar to each other on a per-MMBTU basis. By comparing the EE/RE scenarios against the baseline scenario, we are able to determine changes in generation, emissions and consequent benefits to public health and the climate from each EE/RE installation.

PROSYM economic dispatch model. We used Market Analytics, under licence from Ventyx[38], to estimate hourly unit dispatch by simulating the operation of the wholesale electricity market in the entire Eastern Interconnect, including imports and exports between regions within it. Market Analytics is a zonal locational marginal-price-forecasting model that simulates the operation of the energy and operating reserves markets using plant-specific operating characteristics, along with location-specific demand, transmission capabilities, and other constraints, including regulatory constraints, to simulate behaviour of power plants and the electricity market. We reviewed the default data, and, as appropriate, updated some of the default data, such as transmission-path capacity across PJM zones (to account for planned Renewable Portfolio Standard transmission overlays) and the underlying flexibility of new natural gas resource installations. We also reviewed and updated emissions rates for CO_2, SO_2 and NO_x based on the latest data reported by plant owners to the EPA.

The Market Analytics model uses the PROSYM simulation engine to produce optimized unit commitment and dispatch options[38]. The model is a security-constrained chronological dispatch model that produces detailed results for hourly electricity prices and market operations. Based on hourly loads, PROSYM determines generating unit commitment and operation by transmission zone based on economic bid-based dispatch, subject to system operating procedures and constraints. PROSYM operates using hourly load data and simulates unit dispatch in chronological order. Hourly electricity demand and pricing for each transmission zone is based on zonal electricity load and market rules and is generated for a prototypical model week of each month. This prototypical week represents a full month, and 12 of these prototypical weeks, one for each month, are used to represent the full year. Using this chronological approach, PROSYM takes into account time-sensitive dynamics such as transmission constraints and operating characteristics of specific generating units. For example, one power plant might not be available at a given time owing to its minimum down time (that is, the period it must remain off line once it is taken off). Another unit might not be available to a given transmission area because of transmission constraints created by current operating conditions. PROSYM models generating units with a high level of detail, including inputs for unit-specific ramp rates, minimum up/down times, and multiple capacity blocks, all of which are critical for accurately modelling hourly prices. These are realistic system dynamics that often cause generating units to be dispatched out of merit order. This modelling capability enabled production of locational prices by costing period in a consistent manner at the desired level of detail. Few other electric system models simulate dispatch in this kind of detail.

EGU information. PROSYM uses highly detailed information on generating units[38,39]. Data on specific units in the Market Analytics database are based on data drawn from various sources, including the US Energy Information Administration (EIA), US Environmental Protection Agency (EPA), North American Electric Reliability Corporation (NERC) and Federal Energy Regulatory Commission (FERC), and various trade press announcements as well as Ventyx's own professional assessment[38,40]. All generating units in PROSYM operate at different heat rates (efficiencies) at different loading levels. This distinction is especially important in the case of combined-cycle units, which often operate in a simple-cycle mode at low loadings[38,41].

Emissions. Market Analytics has the ability to model and apply unit costs of compliance for multiple emissions. For this analysis, we modelled the costs of complying with regulations governing the emissions of SO_2 and NO_x. The model includes the unit costs associated with each of these emissions when calculating bid prices and making commitment and dispatch decisions. In this way, we project market prices that reflect, or internalize, the unit-compliance costs for each emission, except mercury. The assumptions for SO_2 and NO_x allowances are based on the Market Analytics default data and consistent with the 2012 prices. No federal CO_2 policy is modelled, as no policy was in place at the time of our simulation, although states at present participating in the Regional Greenhouse Gas Initiative do see a small price of US\$1.86 ton^{-1} CO_2, consistent with 2012 auction results. Emissions rates for SO_2, NO_x and CO_2 are a product of the input fuel characteristics, control technologies installed, as well as the efficiency of the power plant. Model output emission rates were checked against actual emission rates reported in EPA eGRID (refs 39,42) and CAMD Air Markets Program Data[40], and corrected accordingly.

Variable renewable resources. To model the hourly generation of variable resources, a number of National Renewable Energy Laboratory (NREL) studies and data sets were used. To model hourly wind generation, data sets with three years of data in ten-minute intervals from NREL's Eastern Wind Integration and Transmission Study[41] were applied to the power curve of a GE 2.5 MW Turbine. This resulted in unique hourly generation profiles for new wind turbines in each of the six PJM transmission areas. We modelled wind farms at 500 MW capacity. To model solar output, site-specific data from NREL's PVWatts calculator[42] was used, which uses weather data from a typical year. We assume fixed-tilt PV panels. PV installations are again given a size of 500 MW. As an example, Supplementary Fig. 1 shows the annual hourly energy from wind and solar providing electricity to the Chicago Area transmission zone, for the week of 3 June. Solar energy clearly peaks during the middle of the day, although the size of this peak varies depending on cloud cover and other environmental variables. Wind is more variable; early in this week there is very little wind generation, but in the middle of this week it picks up rapidly, operating during both the day and night.

Two types of energy efficiency are modelled, to represent both a baseload and a peak-shaving resource. The baseload resource is modelled as a 150 MW generator that operates in all hours. A smaller capacity is used to give a comparable amount of annual energy to wind and solar resource additions. Peak-shaving resources are given a capacity equal to 10% of the annual peak in a given transmission area, and operate only in hours corresponding to the top 10% of load, scaling linearly from zero capacity at the 90th percentile to 50% of capacity at the 95th percentile and full capacity at the peak hour. Capacity factor of DSM Peak varies by location; see Supplementary Table 1 for these capacity values and Supplementary Table 3 for total generation. Although the capacities are much larger than the baseload resource, the annual energy produced is much smaller than that from a 150 MW baseload resource operating at all hours, which would generate 1,314 GWh in all locations.

Plant-specific climate and public health impact model. We estimated the public health impacts of EGU-specific SO_2 and NO_x emissions using a statistical model derived from a series of simulations using the Community Multiscale Air Quality (CMAQ) model[6]. CMAQ is a complex atmospheric chemistry, fate, and transport model frequently used by the EPA in regulatory and other applications[33]. CMAQ captures secondary formation of fine particulate matter ($PM_{2.5}$) from SO_2 and NO_x emissions with far greater fidelity than many reduced-form models. The statistical model we used here to estimate the health impacts of NO_x and SO_2 emissions was derived from a series of CMAQ simulations that produced source-specific estimates of the influence of SO_2 and NO_x emissions on $PM_{2.5}$ concentrations throughout the Eastern US and Canada, for a selected set of EGUs in the PJM Interconnection. The health impacts of these emissions were estimated by combining the concentration surfaces output from the simulations with grid cell resolution population and baseline mortality rate, along with a concentration-response function of a 1% increase in premature mortality risk per 1 $\mu g\, m^3$ increase in annual average $PM_{2.5}$ concentrations[43]. These impacts were monetized using a central estimate for the value of statistical life (US\$7.58 million, 2012 USD; ref. 32), which is commonly used in conjunction with this approach in regulatory impact assessments, among other applications[33,44,45], and normalized by the emissions to produce estimates of $PM_{2.5}$-related health impacts/ton emitted for NO_x and SO_2. The impact/ton values for NO_x and SO_2 were predicted using the population distribution downwind of each EGU in three distance bins, and the resulting statistical model was used to estimate the impacts of NO_x and SO_2 emissions. The resulting impact/ton estimates for SO_2 were similar to those found previously in the literature, when adjusted for inflation and use of different concentration-response functions for the relationship between annual $PM_{2.5}$ exposure and annual mortality risk. In contrast, the impact/ton estimates for NO_x were higher than values generally documented in the literature, reflecting aspects of secondary particulate matter formation not captured in simpler atmospheric models. More details about this health impact function methodology and the resulting functions are available elsewhere[6].

We monetize impacts of CO_2 emissions using the social cost of carbon (SCC)—an estimate of the impact of an incremental increase in carbon emissions—which is designed for use in regulatory applications[13]. The SCC represents monetized estimates of damage due to climate change for one ton of CO_2 emitted today to 2300, discounted to net present value. Here, the value we use is US$47.41/short ton, based on the value using a 2.5% discount rate, scaled to a year of emission of 2012, and converted to 2012 USD and from metric ton to short ton. As for public health impacts, we select a central estimate that is generally used within regulatory and other applications, and the monetized impacts can be linearly scaled to rapidly evaluate the implications of other SCC values.

PROSYM production cost model. PROSYM (ref. 38) is the simulation engine, and the model vendor Ventyx[38] provided the modelling system and the default data. PROSYM also models randomly occurring forced (that is, random) outages of generating probabilistically, using one of several Monte Carlo simulation modes[38]. These simulation modes initiate forced outage events (full or partial) based on unit-specific outage probabilities and a Monte Carlo-type random number draw. Many other models simulate the effect of forced outages by 'de-rating' the capacity of all generators within the system. That is, the capacities of all units are reduced at all times to simulate the outage of several units at any given time. Although such de-rating usually results in a reasonable estimate of the amount of annual generation from baseload plants, the results for intermediate and peaking units can be inaccurate, especially over short periods. The model's fundamental assumption of behaviour in competitive energy markets is that generators will bid their marginal cost of producing electric energy into the energy market. The model calculates this marginal cost from the unit's opportunity cost of fuel or the spot price of gas at the location closest to the plant, variable operating and maintenance costs, and opportunity cost of tradable permits for air emissions.

The input assumptions to the Market Analytics locational-price-forecasting model include market rules and topology, hourly load profiles, forecasted annual peak demand and total energy, thermal unit characteristics, conventional hydro and pumped storage unit characteristics, fuel prices, renewable unit characteristics, transmission system paths and upgrades, generation retirements, additions and uprates, outages, environmental regulations, and demand response resources[38].

Transmission. The smallest location in Market Analytics is a Location (typically representing a utility service territory), which for modelling purposes is mapped into a Transmission Area (TA; ref. 38). A TA may represent one or more Locations[38]. Transmission areas represent sub-regions of Control Areas such as PJM (ref. 38). Transmission areas are defined in practice by actual transmission constraints within a Control Area. That is, power flows from one area to another in a Control Area are governed by the operational characteristics of the actual transmission lines involved. In this study we modelled the addition of new resources within six PJM TAs: AEP (Northern Ohio), EPA (Eastern Pennsylvania), DEOK (Cincinnati Area), S (Virginia), CE (Chicago Area) and MidE (Southern New Jersey). PROSYM can also simulate operation in any number of Control Areas. Groups of contiguous Control Areas were modelled to capture all regional impacts of the dynamics under scrutiny.

Transmission-path assumptions were based on those developed by Ventyx using the transmission paths represented in PJM (ref. 38). The transmission system within Market Analytics is represented by links between transmission areas. These links represent aggregated actual physical transmission paths between locations. Each link is specified by the following variables: 'From' Location; 'To' Location; transmission capability in each direction; line losses in each direction; and wheeling charges.

Dispatch modelling shows changes in generation across regions. The addition of one large power plant can result in small repercussions throughout the electricity system. Each of the thousands of generators may (and frequently do) have very small changes in the total annual electricity production owing to changes in available energy and zonal wholesale prices. Some generators reduce output more substantially, owing to prices being pushed down below their operating costs. One way to get the big picture in looking at these effects is to explore the change in generation of from gas, coal and other generators as a fraction of the total energy added. Supplementary Fig. 5 shows these fractions for additions of wind and solar, and base and peaking energy efficiency.

In general, location matters. Energy is displaced across the Eastern Interconnect, but generally a larger fraction is displaced in the same region as the addition. For example, additions in MidE and EPA generally displace 55–75% of the energy added in PJM-East, the region in which they are located. The type of generation displaced is largely dependent on location, as well as the time of day. One example of this is the difference in generation displaced in the wind and PV cases in CE. Whereas the gas/coal split in PJM-West is relatively consistent between the two, in MISO almost all displaced energy is coal power in the wind case, but gas power in the PV case. PV operates during the day, and is much more coincident with peak power than wind. Marginal resources in MISO are largely gas in the peaking periods, and additional resources drive gas production downwards.

The effect is somewhat different in the case of baseload versus peaking energy efficiency. In CE, the peaking resource, given a capacity of 10% of the peak load, is substantially larger than the baseload resource, fixed at 150 MW. Going from baseload to peaking resource, a shift from coal to gas in MISO is seen again, but the more notable difference is the size of the change in PJM-West. Whereas in the baseload EE about 30% of the displacement was in PJM-West (the region containing CE), in the peaking case about 80% of the change occurred within PJM-West. PJM-West has a different mix of generation than MISO, resulting in more coal being displaced in the peaking case than the baseload case.

Regulations. Regulations are input into the model in several ways. Regulations that affect unit-specific retrofits and new builds (for example, Mercury and Air Toxics Rule and Renewable Portfolio Standards policies) are incorporated on a unit-by-unit level. Emissions regulations such as Cross-State Air Pollution Rule/Clean Air Interstate Rule are implemented as a per ton price on SO_2 and NO_x emissions. Note that as this study is done for the year 2012, future regulations such as Coal Combustion Residuals (CCR) and Cooling Water Intake Structure (316(b)) are not included, nor is EPA's proposed Clean Power Plan.

References

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