Air Emissions Due To Wind And Solar Power

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Renewables portfolio standards (RPS) encourage large-scale deployment of wind and solar electric power. Their power output varies rapidly, even when several sites are added together. In many locations, natural gas generators are the lowest cost resource available to compensate for this variability, and must ramp up and down quickly to keep the grid stable, affecting their emissions of NO_x and CO_2. We model a wind or solar photovoltaic plus gas system using measured 1-min time-resolved emissions and heat rate data from two types of natural gas generators, and power data from four wind plants and one solar plant. Over a wide range of renewable penetration, we find CO_2 emissions achieve ∼80% of the emissions reductions expected if the power fluctuations caused no additional emissions. Using steam injection, gas generators achieve only 30–50% of expected NO_x emissions reductions, and with dry control NO_x emissions increase substantially. We quantify the interaction between state RPSs and NO_x constraints, finding that states with substantial RPSs could see significant upward pressure on NO_x permit prices, if the gas turbines we modeled are representative of the plants used to mitigate wind and solar power variability.

Introduction

Renewable electricity generated by sources whose output varies rapidly—wind and solar photovoltaic—provided 0.79% of the United States' 2007 net electricity generation (*1*), but these sources are growing. Renewables portfolio standards (RPSs) enacted by 25 states, along with federal subsidies, have encouraged renewable energy sources (*2–4*). California requires that 20% of its electric power be generated from renewables by 2010, New Jersey requires 12% by 2012, and Texas requires ∼3% by 2015 (*5–7*).

When these sources provide a significant fraction of electricity, other generators or rapid demand response must compensate when their output drops (*8, 9*). Renewable energy emissions studies (*10–12*) have not accounted for the change in emissions from power sources that must be paired with variable renewable generators such as wind and solar. In many locations, natural gas turbines will be used to compensate for variable renewables. When turbines are quickly ramped up and down, their fuel use (and thus CO_2 emissions) may be larger than when they are operated at a steady power level. Systems that mitigate other emissions such as NO_x may not operate optimally when the turbines' power level is rapidly changed.

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Renewables that substitute for fossil generators avoid emissions (emissions displacement). Life cycle assessments (LCAs) estimate the emissions attributed to producing, constructing, operating, maintaining, and decommissioning a given technology (*13*). Although integration studies have discussed increased reserve requirements for variable renewable sources, Weisser notes the resulting ancillary emissions are not typically included in LCAs (*13*).

Two methods used to identify the displaced generators are economic dispatch analysis and generation portfolio analysis (*11*). Economic dispatch analysis assumes the displaced generators are those with the highest marginal costs of operation (transmission constraints are considered in a few studies). Typically these generators are natural gas and oil fired turbines, although coal plants are on the margin at times (*14*). In portfolio analysis the emissions displaced are the differences in a system's generation portfolio before and after variable renewable power is added. That approach assumes a renewable plant displaces generation equally from all assets, not solely from the generators operating on the margin (*10*).

LCAs and emissions displacement studies use emissions factors (kg of pollutant per MWh) to calculate produced or displaced emissions. When fossil-fuel generators are used to compensate for renewables' variability, their emissions are likely to be underestimated by emissions factors calculated for full-power steady-state operations.

Denny and O'Malley (*15*) modeled emissions reductions from wind power penetration using an economic dispatch model for Ireland and an emissions factor that varies with turbine power for a natural gas combined-cycle turbine (NGCC) and a simple-cycle natural gas combustion turbine (CT), concluding that CO_2 would be reduced 9% for a wind penetration factor of 11% (82% of the expected reduction for that penetration of wind) and NO_x emission reductions would be 90% of the expected reductions. Their model uses hourly data sets that are not able to capture a portion of the rapid fluctuations of wind (*8*) and does not depend on ramp rate; they did not examine the effects of different NO_x mitigation methods.

Model

To estimate emissions from fossil fuel generators used to compensate for variable wind and solar power, we model the combination of variable renewable power with a fast-ramping natural gas turbine to provide baseload power. We use a regression analysis of measured emissions and heat rate data taken at 1-min resolution from two types of gas turbines to model emissions and heat rate as a function of power and ramp rate (Supporting Information). The required gas turbine power and ramp rate to fill in the variations in 1-min data from four wind farms and one large solar photovoltaic (PV) plant are determined, then the emissions are computed from the regression model. The system emissions are compared to the emissions of a natural gas plant of the same size, and to the emissions reductions expected from displacement analysis.

Data

We obtained 1-min resolution emissions data for seven General Electric LM6000 natural gas combustion turbines and two Siemens-Westinghouse 501FD natural gas combined-cycle turbines. The LM6000 CTs have a nameplate power limit of 45 MW and utilize steam injection to mitigate NO_x emissions. A total of 145 days of LM6000 emissions data was

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used in the regression analysis. The Siemens-Westinghouse 501FD NGCC turbines have a nameplate power limit of 200 MW with GE's Dry Low NO_x system (lean premixed burn) and an ammonia selective catalytic reduction system for NO_x control. Emissions data for 11 days were obtained for the 501FD NGCC.

The renewables data includes 1-s, 10-s, and 1-min resolution and are from four wind farms and one large solar photovoltaic facility located in the following regions in the United States: Eastern Mid-Atlantic, Southern Great Plains, Central Great Plains, Northern Great Plains, and Southwest (Supporting Information Table S6).

Approach

The objective of the model plants is to maintain a constant power output by minimizing the error ε between the expected output and the realized output of the model plant at time i (eq 1). The gas turbine model is subject to physical operating constraints: the upper and lower power limits (eq 6) and how quickly the turbine can change its power output (eq 7). As discussed in the Supporting Information, the emission and heat rate data we obtained for the gas turbines did not cover all combinations of power and ramp rate. We therefore further constrain the model to operate only in regions of the power-ramp rate space for which we have data. Here we focus on estimating the additional emissions caused by variability, and caution that we have made no attempt to ensure the stability of an electrical grid. Grid dynamic response may somewhat change our results.

$$Min\ \varepsilon_{P,i} = Min|P_{A,i} - P_{I,i} - \varepsilon_{P,i-1}| \quad (1)$$

where $\varepsilon_{P,i} \equiv$ error in power plant output, $P_{I,i} \equiv$ ideal power plant output

$$\begin{aligned} P_{A,i} &\equiv P_{W,i} + n \cdot P_{GT,i} \\ &\equiv \text{wind power + natural gas power} \\ &\equiv \text{actual power generated} \\ i &\equiv \text{time index} \\ n &\equiv \text{number of gas turbines} \end{aligned} \quad (2)$$

$$\dot{P}_{GT} \equiv \frac{dP_{GT}}{dt} \equiv \text{ramp rate of gas turbine} \quad (3)$$

Subject to:

$$P_A = \text{constant} \quad (4)$$

$$\text{Max}(P_W) = \text{Max}(n \cdot P_{GT}) \quad (5)$$

$$P_{\text{Min}} < P_{GT} \le P_{\text{Max}} \quad (6)$$

$$\dot{P}_{\text{Min}} \le \dot{P}_{GT} \le \dot{P}_{\text{Max}} \quad (7)$$

We average the wind data to 1-min resolution to match the time resolution of the natural gas generator emissions data and scale each wind or PV data set's maximum observed power generated during the data set to the nameplate capacity of the paired natural gas turbine. From each renewable data set we calculate the required power levels and ramp rates of the natural gas turbine needed to keep the output of the baseload power plant constant. The operating and data constraints of the natural gas turbine are applied, causing the model gas generator's output power to differ slightly from this ideal power profile, as it would in practice.

The power level and ramp rate of the turbine are used as inputs for an emissions model based on a multiple regression analysis of the measured emissions of two types of natural gas turbines. We model only NO_x and CO_2 emissions from the turbine. Power plant CO emissions account for less than 1% of CO emissions in the United States and are not considered in our analysis (*16*).

We calculate CO_2 emissions from the measured heat rate of the generator and the type of fuel used. Assuming complete combustion, the CO_2 emission rate can be derived from the heat rate by multiplying by EIA's natural gas conversion factor of 0.053 t of CO_2 per MMBTU (*17*). Although operating a turbine at low or medium power loads generally results in incomplete combustion, assuming complete combustion is a reasonable approximation for calculating CO_2 emissions, since most CO and hydrocarbon radicals are oxidized to CO_2 in the atmosphere (*18*). Using 1-min resolution emissions data obtained from an electric generation company for two types of gas turbines, we modeled CO_2 emission rates as a function of power level and ramp rate. We use the emissions models to calculate the mass emitted during a given time interval and sum over all time intervals to obtain the mass emitted during a simulation:

$$M = \sum_{t=1}^{T} \frac{dM_t}{dt} \Delta t \quad (8)$$

where:

$$\begin{aligned} M &= \text{total mass of pollutant emitted} \\ \frac{dMt}{dt} &= f(P_{GT,t}, \dot{P}_{GT,t}) = \text{mass emission rate of gas turbine for time period } t \\ \Delta t &= \text{time interval of data set} \\ T &= \text{time length of data set} \end{aligned} \quad (9)$$

Results

If a given level of penetration α of wind or solar energy causes no additional emissions from gas generators, we can define the mass of expected emissions (φ) in terms of the mass of emissions from the gas units (M_{GT}) as

$$\varphi = M_{GT} * (1 - \alpha) \quad (10)$$

The expected emissions reductions are M_{GT} *α. That is, emissions are expected to be displaced linearly according to the penetration factor of the renewables, an assumption we refer to as equivalent displacement. Dividing eq 10 by the energy produced, we define the emissions expected predicted by an equivalent displacement model:

$$\varphi_F = \varphi / \sum_{\text{time}} P \quad (11)$$

If the actual system mass emissions are M_A then the fraction of expected emissions reductions (η) that are achieved is

$$\eta = (M_{GT} - M_A)/(M_{GT} - \varphi) \quad (12)$$

We define the difference between the expected emissions and the actual emissions of a system as

$$M_V = M_A - \varphi \quad (13)$$

Consider a system with generators that emit 2 tons of CO_2 per MWh without renewables in the system. Suppose with 10% variable renewables in the system, system emissions are 1.8 tons per MWh. Then η would be (2 − 1.8)/0.2 = 100% and M_V would be 0. On the other hand, if the emissions were 1.9 tons per MWh with 10% renewables, η would be 50% and M_V would be 0.1 tons per MWh. This framing allows an assessment of the degree to which the introduction of variable renewables displaces emissions from fossil generators, and of the equivalent displacement assumption.

Table 1 summarizes results for the five variable power data sets when used in their entirety (without nights for the solar data). A system with renewables that uses LM6000 turbines for fill-in power achieves 76−79% of the expected

TABLE 1. Baseload Power Plant Model Results for 5 Variable Renewable Power Plant Data Sets (Note That with Night Periods Removed, the Day-Only Capacity Factor for the Solar PV Plant Was 45%; the 95% Prediction Intervals Are Shown for a Least Squares Multiple Regression Analysis) (*19*)

	energy produced			NO_x		CO_2	
	renewable (MWh)	natural gas (MWh)	baseload total (MWh)	percent of expected emissions reduction (η)	variability emissions (M_V, in kg)	percent of expected emissions reduction (η)	varibility emissions (M_V, in tonnes)
LM6000							
Eastern Wind	1,300	9,600	11,000	45% ± 4	270	79% ± 1	160
Northern Great Plains Wind	660	450	1,100	20% ± 3	350	76% ± 1	88
Central Great Plains Wind	3,400	2,800	6,200	33% ± 4	820	76% ± 1	440
Southern Great Plains Wind	7,700	9,000	17,000	22% ± 3	2,300	77% ± 1	1,000
Southwest PV (days)	170,000	210,000	380,000	23% ± 3	36,000	78% ± 1	15,000
501FD							
Eastern Wind	6,000	42,000	48,000	−220 (+300, −120)	1,000	76% ± 1	770
Northern Great Plains Wind	2,900	2,000	4,900	−620% ± 100	1,100	76% ± 1	400
Central Great Plains Wind	15,000	13,000	28,000	−500% (+150, − 10)	4,500	76% ± 1	1,900
Southern Great Plains Wind	34,000	38,000	72,000	−600% ± 100	13,000	76% ± 1	4,800
Southwest PV (days)	730,000	930,000	1,700,000	−640% ± 100	230,000	77% ± 1	70,000

CO_2 emissions reductions and 20−45% of the expected NO_x emissions reductions. An emissions displacement analysis would have overestimated emissions reductions by ~23% for CO_2 emissions and by 55−80% for NO_x emissions. Similar penalties of 24% are incurred for 501FD CO_2 emissions reductions, but NO_x emissions increase by factors of 2−6 times the amount emissions were expected to be reduced, because of the unoptimized NO_x performance of the 501FD system below 50% power.

To investigate the dependence of system emissions on the penetration of renewable energy, we select time periods in our long data sets that have different capacity factors. For wind power data, a sliding window of 1,000 min was used. We note the high correlation between the *n*th data subset and the *n*+1 data subset, which differ by only 2 data points, but this method allows us to explore a wide range of penetration of renewable power. For solar data, each day was treated as a data subset (night periods are removed from the data). The solar data was 732 days in length, yielding 732 different capacity factor results. We combined the results from each analysis and in penetration factor intervals of 1% plot the mean and area encompassed by two standard deviations in Figure 1a−d.

Our model predicts that CO_2 emission factors decrease linearly with renewable penetration at a slope of −0.5 (compared to the expected −0.65, the negative of the

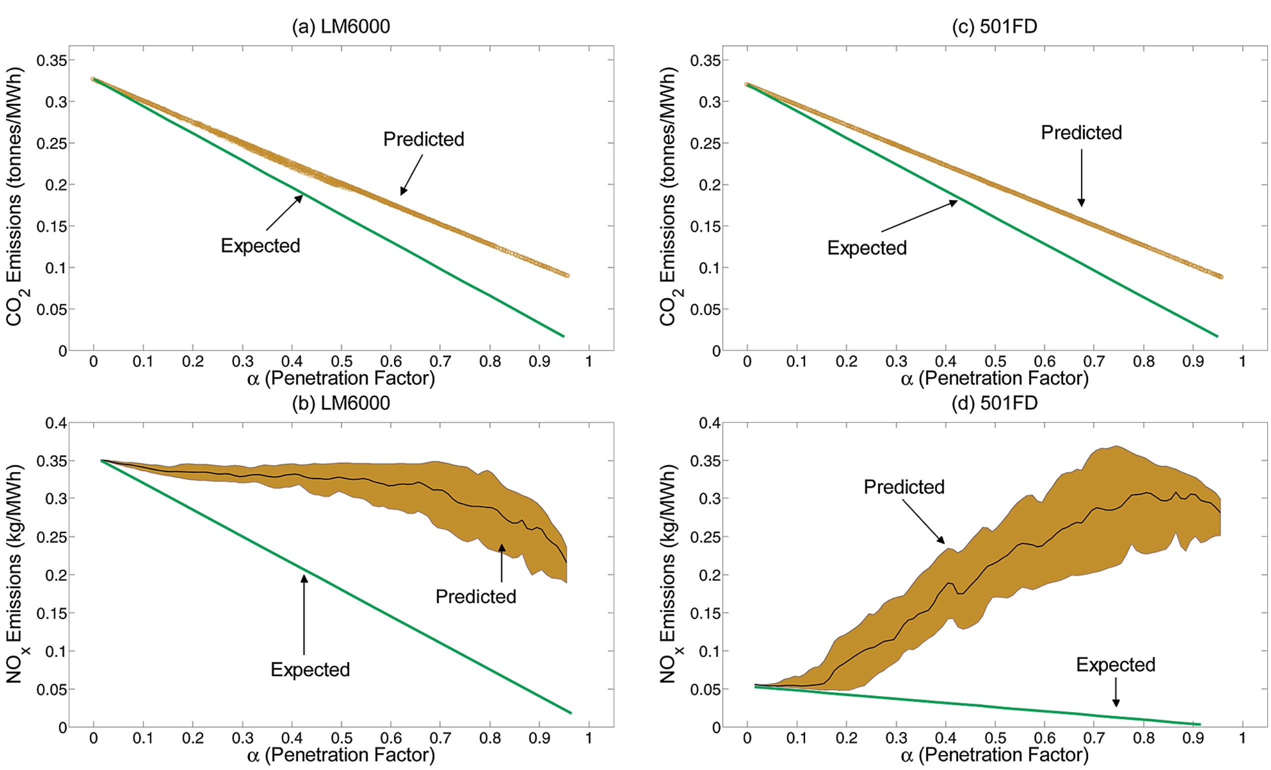

FIGURE 1. Mean renewable plus natural gas emission factors vs renewable energy penetration levels (α) (solid black line); area shown represents 2 standard deviations of all five data sets (shaded brown area); see Figure 2 for representative single data set variability. The expected emissions factor (green, lower line in each figure) is shown for comparison. (a) LM6000 CO_2. (b) LM6000 NO_x. (c) 501FD CO_2. (d) 501FD NO_x.

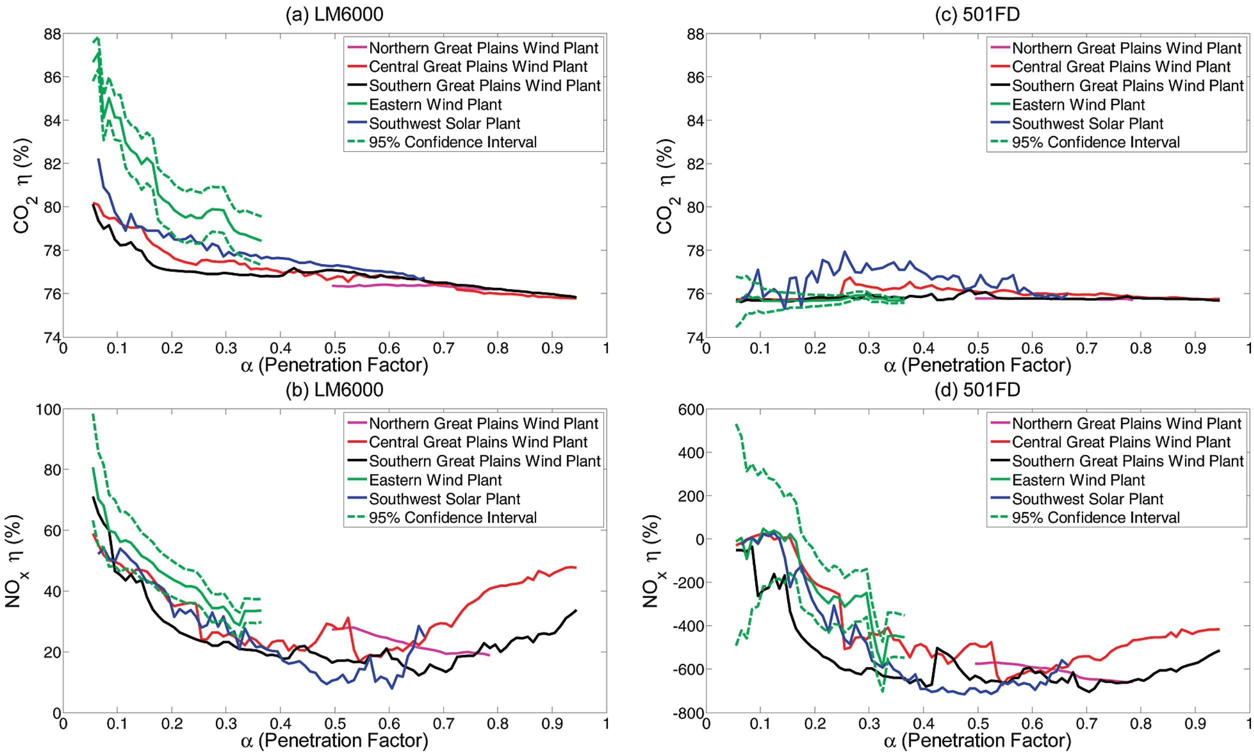

FIGURE 2. Renewable plus gas generator system mean expected emission reductions (η) vs variable energy penetration factors (α). 95% prediction intervals (dashed lines) are shown only for the Eastern Wind plant. (a) LM6000 CO_2. (b) LM6000 NO_x. (c) 501FD CO_2. (d) 501FD NO_x.

emissions factor, eq 11) for LM6000s and −0.48 compared to −0.64 (expected) for 501FDs (Figure 1a and c). At penetration levels of 1, predicted emissions are not eliminated because the natural-gas turbine is modeled as a spinning reserve.

Below 65% renewable penetration, the LM6000 NO_x emission factor is roughly constant. Thus, adding renewables is not effective in reducing NO_x for such a system (Figure 1b).

A threshold effect is observed for the 501FD turbine: for penetration values below ~15%, the predicted NO_x emission factor nearly matches the expected emission factor (Figure 1d). Since the dry low NO_x control system is optimized for constant high power operations, it is not surprising that this turbine design exhibits high NO_x emissions as the penetration of wind or solar energy increases to the point that the turbine must cycle to low power. Limiting the 501FD's $P_{\min}$ limit to >50% nameplate capacity avoids the poor NO_x regions of the DLN system (discussed in the Supporting Information), and results in NO_x emissions reductions. This approach is applicable only if the ratio of energy provided by natural gas generators with DLN to variable power plants is greater than 2:1.

Viewed in terms of η, as the penetration of variable power increases the fraction of expected emissions reductions achieved from a system with LM6000 turbines decreases from ~87% to 78% for the Eastern wind data and from 80% to 76% for the Southern and Central Great Plains wind data sets (Figure 2a). Increasing the penetration factor of variable power effectively reduces the natural gas turbine from steady-state full power conditions to transient-state cycled power conditions and results in higher NO_x emissions. NO_x reductions from a system using LM6000 turbines are roughly half the expected value at 10% penetration, reaching a minimum of 10−30% at a penetration of ~50% (Figure 2b).

Emissions of CO_2 from a system with 501FD turbines are ~76% of that expected with no significant dependence on penetration (Figure 2c). The large inertia of the 501FD combined-cycle plant results in a heat rate that depends only on power (Supporting Information Figure S6), and the deviations from a constant fraction of achieved expected emissions are caused by the constraints we impose on operating the turbine to stay within the limits of the data. As more variable renewable power is added, the NO_x emission factor (Figure 2d) increases because the 501FD is forced to spend a higher percentage of its time operating in high NO_x emissions regions (as discussed previously).

Interactions between RPSs and CAIR

We examine the implications of our results by analyzing the potential interaction between state RPSs and the Clean Air Interstate Rule (CAIR). The District of Columbia Circuit Court of Appeals vacated CAIR in July 2008 (*20*), but here we examine the interactions between an RPS and CAIR, under the assumption that a similar NO_x emission rule will come into force in the future. CAIR was designed to reduce annual NO_x emissions 60% by 2015 (*21*). States with large RPSs may experience NO_x emissions from gas turbines used to fill in the variable renewable power that can make it more difficult to meet CAIR requirements. We estimate what percentage these ancillary emissions could consume of a state's CAIR annual NO_x emissions allocation in 2020 (*22*) (most RPSs are fully phased in by 2020; here we assume that the 2020 NO_x limits are the same as those in 2015).

We assume all RPSs in CAIR states are fulfilled and that all RPS targets that can be met by wind are. We convert RPSs that are specified by a percentage to MWh of wind generation in 2020 by using the EIA assumption that load will grow linearly to 3% above 2008 load (*23*). We also assume all displaced and fill-in generators are similar to either LM6000s or 501FDs. We estimate the expected emission reductions ($M_{GT} - \varphi$) by using NO_x emission factors of 0.2 kg/MWh for LM6000s and 0.15 kg/MWh for 501FDs obtained from EPA's AP-42 database (*24*). For each state, we average the estimated η for the four wind farm data subsets and use eq 12 to estimate

TABLE 2. Summary Results of CAIR Analysis for the 12 CAIR States with a Renewables Portfolio Standard (The Wind Penetration Fraction Is the Larger of the Fraction of the State's 2020 RPS Requirement That Could Be Fulfilled by Wind, or Currently Installed Wind. The CAIR Allowance is the 2015 Allowance. Note: Fractions May Not Match Exactly Due to Rounding)

			LM6000 with steam injection		501FD with DLN	
state	wind penetration fraction (α)	state's annual CAIR NO_x allowance (thousand tonnes)	M_V annual (tonnes)	% M_V of state's CAIR allowance	M_V annual (tonnes)	% M_V of state's CAIR allowance
Delaware	0.18	8.6	48	0.56	140	1.6
Illinois	0.18	60	1200	2.0	3400	5.8
Iowa	0.07	43	29	0.07	59	0.13
Maryland	0.075	11	40	0.37	260	2.4
Minnesota	0.25	34	730	2.2	2000	6.0
Missouri	0.11	60	250	0.42	220	0.37
New Jersey	0.16	12	350	3.0	910	7.7
New York	0.077	19	120	0.64	820	4.2
North Carolina	0.11	44	320	0.72	290	0.65
Pennsylvania	0.07	65	180	0.27	1000	1.6
Texas	0.033	150	590	0.04	120	0.08
Wisconsin	0.1	31	140	0.45	120	0.40

M_A. Finally, we use eq 13 to derive the mass of NO_x emissions attributed to variability that are not currently included in most emissions displacement studies.

Table 2 summarizes the CAIR analysis. When LM6000 turbines are used, the potential emissions associated with variability are significant for Illinois, Minnesota, and New Jersey: countering wind's variability could consume 2–3% of each state's annual CAIR allocations. If 501FDs are used, 7 of the 12 states could have 2–8% of their annual CAIR allocations used to provide fill-in power for wind or PV power plants.

In states like New Jersey, careful selection of the NO_x controls used for wind compensation may be warranted to avoid upward pressure on NO_x permit prices, similar to when the NO_x budget was first implemented (*25*). Using the emissions from Table 2 and assuming an annual NO_x emission permit price of $2,800 per ton, the costs associated with degraded emissions performance can be as high as 0.24 cents per kWh of renewable energy for NO_x emissions. With a carbon price of $50 per ton carbon dioxide, the added costs can be as high as 0.50 cents/kWh for CO_2 emissions. These costs do not include the additional maintenance costs that may arise from cycling the gas turbines to compensate for the renewables' variability.

As part of their NO_x control strategy, states may choose to award NO_x allowances to eligible renewable energy and energy efficiency projects. These awards range from a few percent of the NO_x allowances to as much as 15%. New Jersey's set-aside is 5%, and Minnesota has proposed a 15% renewable set-aside (*26*). Our results caution that annual average emissions factors may not be appropriate for the summer ozone control months, since the character of the variability of both wind and solar PV is dependent on the season.We note that the awards are based on the equivalent displacement assumption, and states that use gas generators to compensate for wind or solar PV variability may find that assumption is not warranted.

The calculations above assume that variability in renewable generation results in similar variability in the natural gas generators used to compensate. There are several reasons this may not be correct, including use of coal and oil generators for compensation and interaction between renewable variability and load variability (*8*), so the estimates in Table 2 are likely to provide an upper bound on estimates of the emissions increase associated with wind and solar generation's variability. Storage systems other than pumped hydroelectric are presently not cost-effective (*27*), but may reduce the need for ramping generators should their costs fall.

Discussion

Carbon dioxide emissions reductions from a wind (or solar PV) plus natural gas system are likely to be 75–80% of those presently assumed by policy makers. Nitrous oxide reduction from such a system depends strongly on the type of NO_x control and how it is dispatched. For the best system we examined, NO_x reductions with 20% wind or solar PV penetration are 30–50% of those expected. For the worst, emissions are increased by 2–4 times the expected reductions with a 20% RPS using wind or solar PV.

The fraction of expected emissions reduction, η, is calculated assuming that the emissions predicted to be displaced originate from the same generator type that provides fill-in power: Figure 2a and b assume a LM6000 is displaced and a LM6000 is providing compensating power; Figure 2c and d assume 501FDs. Realistically, displaced generators will differ from the generators providing fill-in power and would produce different results. We have shown that the conventional method used to calculate displaced emissions is inaccurate, particularly for NO_x emissions. A region-specific analysis can be performed with knowledge of displaced generators, dispatched compensating generators, and the transient emissions performance of the dispatched compensating generators. The results shown here indicate that at large scale variable renewable generators may require that careful attention be paid to the emissions of compensating generators to minimize additional pollution.

If system operators recognize the potential for ancillary emissions from gas generators used to fill in variable renewable power, they can take steps to produce a greater displacement of emissions. By limiting generators with GE's DLN system to power levels of 50% or greater, ancillary emissions can be minimized. Operation of DLN controls with existing (but rarely used) firing modes that reduce emissions when ramping may be practical. On a time scale compatible with RPS implementation, design and market introduction of generators that are more appropriate from an emissions viewpoint to pair with variable renewable power plants may be feasible.

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Supporting Information Available

Additional data and information. This material is available free of charge via the Internet at http://pubs.acs.org.

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