The Total Impact of Wind Energy Variability on Fossil Fuel Emission Rates in Texas

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Abstract

In this paper we studied both direct and indirect impacts of wind energy generation on fossil fueled generator emission rates within the same interconnected region. Specifically, we examine the relationship between increased levels of wind energy generation and emissions per unit of electricity produced using historical data for electricity output and CO$_2$, SO$_2$ and NO$_x$ emissions in the Electric Reliability Council of Texas (ERCOT).

Using EPA’s Clean Air Markets hourly emissions data, we calculate the total combustion emissions of CO$_2$, SO$_2$ and NO$_x$ per MWh of electricity output for the ERCOT system from 2008 – 2011. The EPA database includes CO$_2$, SO$_2$ and NO$_x$ emissions reported by facility owner and operators on an hourly basis in a manner that incorporates facility inefficiencies during ramping periods, allowing us to fully evaluate the emissions reductions achieved in ERCOT as a result of increased wind generation. Incorporating these impacts we find that primary impacts from wind generation outweigh secondary impacts by several orders of magnitude.

The paper is organized as follows: After the introduction the second section discusses regional implications of our research. The third section gives a brief overview of the existing literature covering research and analyses used to determine emissions impacts related to wind energy. The fourth section discusses the data used in our analyses, while the fifth section addresses our empirical methodology for establishing causal relationships using empirical data from ERCOT, including a comparison with existing literature. In section six we examine the results of our analysis in comparison with results found using different methodologies in the literature. We conclude our paper with a summary of estimated impacts as well as policy implications arising from our results.

1 Introduction: Renewable Energy as a Public Policy Alternative to Direct Greenhouse Gas Regulation

This analysis builds on prior research presented at the American Society of Mechanical Engineering’s (ASME) 2012 International Conference on Energy Sustainability, which examined the relationship between increased levels of wind energy generation and emissions per unit of electricity produced using hourly historical data for electricity output and CO$_2$, SO$_2$ and NO$_x$ emissions in the Electric Reliability Council of Texas (ERCOT). Limiting this analysis to ERCOT provides two important advantages: transmission of wind energy output is constrained by the physical boundaries of the ERCOT grid, simplifying the analysis and avoiding associated ‘leakage issues’; ERCOT shows significant diurnal and seasonal swings in demand; ERCOT is big enough to be a suitable snapshot of the nation as a whole, but small enough to analyze; and ERCOT has the highest level of wind generation as a percentage of total system demand of any grid in the continental U.S.
In the prior work (Meehan, 2012), using several regression models, a low level of statistical correlation was found between wind energy output and emission rates of various pollutants. Based on published research to date, the intermittent nature of wind generation might result in some in the need to ramp conventional thermal generation up and down to compensate for variability in wind output. Such ramping might lead to inefficiencies in fossil-fueled power plants and sub-optimal scrubber performance that increase emissions of CO$_2$, SO$_2$, and NO$_x$ relative to a respective unit’s peak efficiency emissions rate. Building on those findings, our ongoing research seeks to develop a model of causal relationships between wind energy variability, system variability, and emission rates.

In addition to developing a more sophisticated model, our analysis for the work presented here uses a more detailed set of data to examine the influence of the intra-hourly change in wind energy output on system-wide emissions. The analysis in Meehan (2012) relied on a dataset of hourly interval power plant output provided by ERCOT, along with an hourly interval emissions dataset from the Environmental Protection Agency (EPA). This analysis incorporates 15-minute interval power plant output from ERCOT, although it continues to rely upon the EPA's hourly emissions dataset. We use the data to examine the total net efficacy of wind energy in offsetting emissions from fossil fuel sources; accounting for empirically verifiable emissions increases resulting from any fossil fuel increased ramping due to wind energy variability.

Our analysis examines several issues:

- The extent to which variations in net load (total load – wind output) exert upward pressure on fossil-fuel EGU emission rates in ERCOT.
- The role wind EGU output plays in the creation of variability in intra-hourly net load.
- Whether it is appropriate to assume any reduction in net emission benefits from the use of wind generation to offset thermal EGU output.

Renewable energy has been offered in many situations as a policy alternative to reducing Greenhouse Gas (GHG) emissions through direct regulation of emissions - primarily CO$_2$ - and other pollutants in the U.S. without the need for direct GHG regulation (Lutsey and Sperling, 2008). In many states this effort to promote renewable energy as an alternative or in addition to GHG regulation has taken the form of a Renewable Portfolio Standard (RPS), with variations from state-to-state for the extent and nature of the requirements. However, concerns have been raised regarding the efficacy of an RPS, and renewable energy in general, in reducing CO$_2$ emissions (BENTEK, 2010). Furthermore, it has been suggested that renewable power actually causes increases in emissions of other pollutants BENTEK (2010) and Katzenstein (2009).

Of the three pollutants recorded in the EPA database, emissions of CO$_2$ remain unregulated. Consequently, no existing fossil fuel electric generation facility currently controls emissions of CO$_2$, while many control emissions of SO$_2$ and NO$_x$. For these reasons policies that incentivize renewable energy are often seen as a proxy to mitigate GHG emissions, thus an analysis of CO$_2$ emissions during times of large changes in wind output is called for.

It is important to note that hydroelectric power can be quickly ramped to compensate for wind energy variability, and that the increasing use of energy storage and demand response may provide opportunities to compensate for such variability without exacerbating emissions from thermal generators. Less than 0.5% of electric generation in ERCOT comes from hydroelectric generation, and although energy storage and demand response resources are being developed they are not currently at a stage of deployment to balance wind energy variability. As a result in ERCOT firming power for wind energy generally comes from thermal units; in other regions, such as the Pacific Northwest, this particular issue is less relevant as hydroelectric generation can be used to firm wind power.

It has been hypothesized that renewable generation such as wind and solar can increase emissions rates of pollutants, despite the low emissions of the wind turbines and solar panels themselves is because their variable nature means that fossil-fueled electric generation units (EGUs) that are used as firming power must frequently ramp up and down. At the same time, scrubbers used to reduce emissions from fossil-fueled EGUs also are ramped up and down, rather than operating at steady-state conditions. This ramping nature can cause inefficiencies in fossil-fueled EGUs, raising their per-unit...
fuel consumption and emissions, because some coal fired boilers and their emissions control equipment might lack the flexibility to ramp up and down quickly. It is the potential for efficiency losses by thermal generator induced by variable power sources from renewables that most often calls into question the benefit of renewable energy in reducing emissions. For the purposes of this paper we will call this efficiency loss and any resulting emissions impacts the “secondary effect” of wind EGU output on emissions.

Researchers at Carnegie Mellon University, including Dr. Jay Apt and Dr. Warren Katzenstein have studied this problem through the application of a theoretical model based on select natural gas generator characteristics, but did not incorporate changes in overall demand. Dr. Joseph Cullen has examined this question as well but did not use time-resolved historical data to establish correlations or causality between wind and emissions rates, focusing instead on identifying specific power plants commonly offset by wind. To the best of the author’s knowledge, this work is the first to examine problem of emission rate changes induced by wind energy variability and the resulting impact on net emission reductions from wind in ERCOT in such detail.

Our analysis seeks to answer similar questions through an examination of detailed historical emissions and heat rates of power plants over time. Using the EPA's Clean Air Markets Emissions Database for all reporting EGU's, hourly data for fossil fuel EGU's within the ERCOT electric grid in Texas were analyzed with the intent of determining whether increased wind generation impacted emissions from these power plants. Additional data from ERCOT with EGU hourly output by fuel type was also analyzed for this research. ERCOT, the source of electricity for 85% of Texas' electric needs provides a good basis for this analysis for several reasons (ERCOT, 2012). As a relatively isolated electric grid within a single state, ERCOT's electric generation serves a physically constrained region with only minor imports and exports of electricity and a common regulatory structure among most electric generation owners, additional characteristics make ERCOT an ideal geographical testbed (see above).

The lack of synchronous interconnections with other regional transmission organizations results in a level of isolation that is helpful in determining the impacts of changes in the region's generation energy portfolio that would not be possible in a state or electric grid that is part of one of the two other interconnections covering the rest of the continental U.S. (the Eastern Interconnect and the Western Electricity Coordinating Council). In contrast with the other interconnections, which are impacted by the policies from multiple states, ERCOT represents a unique case study because only a single RPS policy is relevant. For Texas, the key policy context was established in 1999, when Senate Bill 7 was passed by the Texas State Legislature to restructure the electric market and establish a goal for the state to achieve 2,000 MW of new renewable energy generating capacity by 2015.

In contrast with other states, whose RPS regulations typically set requirements for an amount of energy produced (in MWh), the Texas RPS set a standard for capacity (in MW) without specification about whether that capacity needed to be on or not. This unique approach was favorable for wind, whose low capacity cost was appealing despite its intermittent nature. The 2,000 MW goal was on track to be met many years ahead of schedule, and so in 2005, the RPS standard was set at a higher level of 10,000 MW by 2025. As a result of this policy mechanism, market conditions and federal Production Tax Credits, ERCOT now has over 10,000 MW of installed wind power. The history of wind development in Texas combined with the isolated nature of ERCOT provides us with an ideal data source to examine correlations between wind output and fossil-fueled EGU combustion emissions.

2 Regional Variations in the Role of Renewable Energy in Reducing GHG Emissions

The impact and efficacy of renewable energy in reducing GHG emissions depends largely on regional differences in both renewable resources and regional electric generation portfolios. Variations in solar insolation and wind speed consistency cause substantial inter-regional cost differentials for renewable energy.

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2 EPA's Clean Air Markets Emissions Database website: http://camdataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard
Consequently, as generation portfolios vary across regions that have historical different power generation mixes, the effective regional CO₂ emissions reduction rate will also vary, yielding a range of CO₂ emissions reductions per MWh of renewable energy. For instance if wind offsets hydroelectric generation, as in in Pacific Northwest, there are essentially no CO₂ emissions reductions; if wind offsets coal generation is in the Midwest, CO₂ emissions reductions will be substantial. In determining the impacts of renewable energy on GHG mitigation, such regional differences in GHG emission reductions must be taken into account. In the future, it is possible that transmission infrastructure could be used to mitigate this regional differential (for example, wind in Texas could be used to displace Midwestern coal).

The most common method for determining GHG emissions avoided by renewable energy is an assessment of marginal CO₂ emissions rates, i.e. the tons of CO₂ for the next MWh of generation needed without renewable energy. This methodology often uses marginal cost and dispatch data to develop an understanding of the marginal unit in a system at any given time, information unavailable to us at the time of this analysis. The analysis developed by Cullen uses publicly available data to estimate the marginal units offset by wind energy, thereby establishing a marginal emissions profile. Coupled with a more sophisticated model of the emissions rate impacts of system variability such an analysis would provide a comprehensive view of the overall GHG impact of renewable energy.

Additionally the PJM ISO has undertaken an internal marginal CO₂ rate analysis and presented their findings for use by market participants and PJM members involved in the Regional Greenhouse Gas Initiative (PJM, 2011). Their findings in Table 5 show a higher marginal CO₂ rate during peak times relative to the system average, a departure from the peak emission rates in ERCOT suggested by our model. These and similar differences in time-dependent marginal CO₂ rates for other regions might have important implications as policymakers consider alternatives to direct regulation of GHG emissions.

<table>
<thead>
<tr>
<th>Table 5: Average CO₂ Emissions Rates of Marginal Units in PJM</th>
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<tbody>
<tr>
<td>Year</td>
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<td>2011</td>
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Emission rates, whether marginal or averaged across all fossil fuel units over a period of time provide us with an important perspective into the effects of wind energy on fossil fueled EGUs, however emission rates are only important to the extent that they allow us to calculate total emissions. It is possible for emission rates to increase as a result of ramping induced by wind energy variability but ultimately the impact of wind energy output is to curtail or reduce overall fossil fueled output, thus reducing total net emissions.

From a public policy, health and environmental perspective total net emissions determine social benefit and are the final determinant by which we must evaluate the social benefits of wind energy as they relate to emissions.

Other researchers have examined the impact of wind energy on total emissions as well as emission rates using a variety of analytical methods, focusing on ERCOT and other regions with RPS policies. Brief summaries of three of those (Bentek, 2010; Katzenstein, 2010; and Cullen, 2011) are discussed in detail below, with each analysis informing our approach to this problem.

### 3 Previous Analyses of GHG Emissions Reductions From Renewable Energy

#### BENETEK Analysis

In “How Less Became More: Wind, Power and Unintended Consequences in the Colorado Energy Market,” prepared in 2010 by BENETEK Energy, LLC for the Independent Petroleum Association of Mountain States, BENETEK evaluates the impacts of modulating output from coal-fired power plants to balance grid needs in response to varying wind EGU output. Examining these impacts for 5 coal-fired units during specific periods of high wind output, BENETEK finds that instantaneous rates for SO₂ increase substantially, while NOₓ and CO₂ rates increase somewhat or in some cases not at all.

Extrapolating these results to all hours of the year when wind turbines are generating electricity in Colorado, BENETEK finds that total emissions of SO₂, NOₓ, and CO₂ are actually increased by the use of wind generation. This methodology has several flaws that have been pointed out by wind energy
industry supporters (AWEA, 2011), namely the extrapolation of specific grid characteristics during high wind output periods to the larger Colorado generation portfolio without a clear basis for doing so.

Specifically, in their analysis BENTEK focuses on EGU specific case studies during periods of extreme wind variability, primarily in Colorado during a period when wind generation was a relatively small portion of the state’s electricity portfolio. By extrapolating extreme short-period, local events across the state portfolio on an annual basis, BENTEK uses an unrealistic “worst case scenario” in which wind energy is constantly experiencing extreme swings in output, which BENTEK asserts would be exacerbated by further development of wind energy in the state. As discussed below, the analysis from Katzenstein demonstrates that as wind generation grows and is deployed across a geographically diverse region, total wind generation variability is substantially reduced. Katzenstein’s findings, as well as BENTEK’s questionable methodology call into question the results of their analysis.

Katzenstein Analysis

An analysis from Katzenstein (2010) contained two important findings contradicting BENTEK’s methods and conclusions: 1) geographic diversity substantially reduces the need for frequent ramping of fossil fuel resources, and 2) “Over a wide range of renewable penetration, we find CO2 emissions achieve ~80% of the emissions reductions expected if the power fluctuations caused no additional emissions.” The study draws similar results to an earlier analysis of wind energy in Ireland (Denny and O’Malley, 2010) which found that CO2 would be reduced 9% for a wind penetration level of 11%.

Both analyses focus on pairing wind power plants with gas turbines, thus sidestepping the issue of emissions associated with ramping coal-fired units that experience greater reductions in efficiency during ramping periods BENTEK (2010). Furthermore both are based on a detailed modeling of the ramping efficiency of a gas turbine type and associated emissions.

Katzenstein’s model is developed using emissions data from natural gas combustion turbines in one minute increments, examining emissions and heat rate changes associated with a generator’s deviation from the optimal output. To understand the impacts of wind output changes, the author compares the variability of a single wind EGU with that of up to 20 wind EGUs, finding that 15-minute interval variability is reduced 95% reduction at higher levels of wind penetration. The author uses this analysis to understand the impacts of wind variability using data from natural gas-fired General Electric LM600 combustion turbines and Siemens-Westinghouse 501FD combined cycle EGUs. By pairing varying levels of wind penetration with up to 20 gas-fired EGUs, Katzenstein determined that pairing multiple wind EGUs with multiple gas EGUs is a key strategy to optimize CO2 reductions.

This approach provides meaningful results; it is important to understand the impacts that variable generation can have on fossil fuel power plants as well as potential strategies for mitigation. The model has its limitations however; this approach inherently assumes static demand, wherein wind EGUs are the only factor introducing variability into the system. Additionally, the emissions analysis is limited to the two natural gas-fired turbines discussed above, while the ERCOT system has a diverse fossil fuel technology portfolio.

Cullen Analysis

Our analysis adapts the methodology used by Cullen (2011) to estimate the impacts of wind EGU output on individual EGU dispatch decision-making. In a working paper, Cullen develops an econometric model that exploits exogenous changes in wind EGU outputs and other exogenous factors to identify EGUs offset by wind power using observed data rather than simulations. Using these estimates Cullen evaluates the overall emissions impact of wind EGU output using average annual EGU emission rates. The question we seek to answer is slightly different – rather than focusing on the offset generators we seek to determine the marginal impact to the ERCOT system emission rates of wind EGU output.

The Cullen analysis focuses on a period in ERCOT when wind capacity averaged ~3,000 MW whereas during our analysis period wind capacity averaged closer to 9,000 MW, providing insight into the impacts of greater wind EGU penetration. This distinction raises another important question that will be discussed in further detail later in the paper: the relationship between marginal offsets of CO2
from EGUs and the longer term impact low marginal cost wind units may have in shaping the supply curve by impacting the profit margins of EGUs commonly offset by wind output.

As wind output continues to grow it is likely that EGUs commonly offset by lower marginal cost wind resources might fall from the supply stack. Wind energy is likely to remain a “price taker” and continue offsetting marginal EGUs during high wind output periods. In this way wind can shape future CO$_2$ emissions in a manner not accurately reflected in a marginal emission offset approach. However, the Cullen model informs our approach, allowing us to gain greater insight into the impact of wind EGU variability on system-wide emission rates.

### 4 Data Sources

The implications of renewable energy on GHG emissions might differ when statistical methods are applied to a theoretical model as opposed to historical data from an interconnected electric grid as in our analysis. Tradeoffs do exist between the two approaches: historical approaches are more tightly grounded in reality, but lose insights into intra-hourly impacts; theoretical approaches can achieve better intra-hourly resolution, which is relevant when contemplating wind power, but are less capable of reflecting a complex, real world system.

Similarly to some studies discussed above, our analysis addresses the issue of efficiency impacts to fossil fueled EGUs and resulting increases in emissions (the secondary effect of wind EGU output on emissions).

Efficiency is commonly described by the ratio of the heat content (in Btu) input into a facility relative to the output (in kWh) of electricity from the facility, called “heat rate.” Heat rate has an inverse relationship with efficiency: the higher a heat rate, the more fuel must be burned to produce a single kWh and thus the less efficient is the EGU (Fig. 1). At the same time, heat rate is positively correlated with emissions rates, as the need to burn more fuel to achieve the same level of electric output leads to greater emissions per unit of energy. For power plants with emissions controls, ramping behavior can influence current emissions in a more complex manner due to delays in heat transfer and control methods, meaning that emission rates will not be as strongly correlated with heat rates as they are in uncontrolled units.

The efficiency of power plants during periods of increasing or decreasing output (“ramping”) is referred to as “ramping efficiency.” Ramping of EGUs occurs commonly in grid management operations, a result of the need to preserve reliability in the electric grid as demand and power plant outputs vary over time. This relationship is described in Maddaloni et. Al. (2009), with ramping efficiency for coal EGUs generally being lower than ramping efficiency for natural gas EGUs.

Changes in wind generation are a subset of these fluctuations in electric grid characteristics that might cause power plants to operate at suboptimal levels. Operating at suboptimal thermal efficiency can result either from ramping or from consistently level output that is non-optimal for the EGU.

![Figure 1: Illustrative Generation Unit Efficiency](image)
Datasets Used in Analysis

The analysis presented herein uses historical data from the EPA and ERCOT from 2008-2011. While EPA data are only publicly available at an hourly temporal resolution, ERCOT data are available in more highly resolved intervals. For our analysis 15-minute temporally resolved ERCOT data is used, allowing the impacts of intra-hourly variations in EGU output on hourly average emission rates and total hourly emissions to be examined. The impacts of variability in wind generation are intra-day, making data granularity critical to this analysis; annual or monthly data used most often for renewable energy policy discussions will not capture the intra-day impact of wind on fossil fuel heat rate and could produce misleading results. The EPA dataset includes heat input, electricity output, emissions of SO₂, NOₓ, and CO₂ for all ERCOT facilities required to report data to the EPA under the Clean Air Act.

The time period from 2008-2011 was chosen for several reasons, first, in 2008 wind energy capacity reached 10% of total ERCOT capacity and 5% of total EGU output. As of 2011 wind has grown to 13% of total capacity and 8.5% of EGU output, making this period ideal for examining the impact of large amounts of wind energy (Fig. 2). During this period ERCOT also underwent a significant transition from a zonal dispatch model – one in which EGU dispatch decisions were made by generation owners based on congestion constraints across 5 ERCOT zones – to a nodal market in which dispatch decisions are centrally organized at ERCOT and based on congestion and other factors across more than 4,000 nodes. This new market structure has the potential to shift dispatch decision-making in ways that could alter the impact of wind EGU variability on thermal EGU emission rates. As a result our analysis examines the difference due to the transition from the zonal market to the nodal market, which was fully implemented 12/1/2010.

To preserve proprietary information ERCOT provides only MWh data aggregated to the fuel type level and ERCOT zone. While the EPA’s heat input and emissions data are critical to our analysis, the ERCOT data provides needed information for non-fossil fuel generation output, in particular nuclear and wind power. Additionally, the EPA dataset only includes information for fossil-fueled EGUs required to report to the EPA under the Clean Air Act. The ERCOT data enables us to understand whether the EPA dataset represents a comprehensive profile of ERCOT’s generation resources by comparing ERCOT’s coal and natural gas generation data to the EPA data. The mean difference ([MWh_{ERCOT} - MWh_{EPA}] / MWh_{ERCOT}) between these datasets for each 15 minute interval from 2008-2011 is <5%, with a standard deviation from the mean of 5%, indicating that the EPA dataset provides ample data for the purposes of our analysis.

Developing an Empirical Model

Using EPA’s Clean Air Markets hourly emissions data, the most granular data set available of emissions from electric generating

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6 Email conversation with EPA staff

31st USAEE/IAEE North American Conference
units, we calculate the total combustion emissions of CO$_2$, SO$_2$ and NO$_x$ per MWh of electricity output for the ERCOT system from 2008 – 2011. The EPA database includes CO$_2$, SO$_2$ and NO$_x$ emissions reported by facility owner and operators on an hourly basis in a manner that incorporates facility inefficiencies during ramping periods, allowing us to fully evaluate the CO$_2$ emissions reductions achieved in ERCOT as a result of increased wind generation. This database is combined with generation output data aggregated by fuel type, provided by ERCOT on a 15 minute interval basis, which is used to determine both total system variability and wind energy output variability on a time dependent basis (Fig. 3, above).

This combined dataset allows us to develop two regression models: the first model examines the role wind energy output variability plays in increasing overall system variability; the second model examines the relationship between overall system variability and changes in unit level emission rates. To the extent that changes in intra-hourly output affect emissions output, those changes will be reflected in the hourly emissions dataset as well.

5 Modeling Emission Rates

A simple average of EPA facility emissions rates fails to capture emissions impacts of EGUs with greater output, an important factor in understanding total system emissions. Weighted average system emissions rates were developed for CO$_2$ (tons/MWh), SO$_2$ (lbs/MWh) and NO$_x$ (lbs/MWh) respectively:

\[
\begin{align*}
\text{CO}_2_{t} &= \frac{\sum_{n=0}^{N} \text{CO}_2_{n,t} \cdot \text{Output}_{n,t}}{\sum_{n=0}^{N} \text{Output}_{n,t}} \\
\text{SO}_2_{t} &= \frac{\sum_{n=0}^{N} \text{SO}_2_{n,t} \cdot \text{Output}_{n,t}}{\sum_{n=0}^{N} \text{Output}_{n,t}} \\
\text{NO}_x_{t} &= \frac{\sum_{n=0}^{N} \text{NO}_x_{n,t} \cdot \text{Output}_{n,t}}{\sum_{n=0}^{N} \text{Output}_{n,t}}
\end{align*}
\]

For \( N = \# \) of ERCOT fossil-fuel EGUs, time \( t \)

(1)

In addition to estimating emission rates our model determines average system-wide heat rates for coal and gas-fired EGUs which serve as a measure of total system efficiency. System efficiency might be a key indicator of emission rate sensitivity to ramping needs during certain periods. In general coal fired facilities have a higher heat rate than natural gas combined cycles, although gas fired combustion turbines tend to have even higher heat rates. Using EPA hourly heat inputs and electric outputs, hourly heat rates were developed using the following methodology:

\[
\text{Heat Rate} \left(\frac{\text{Btu}}{\text{kWh}}\right) = 1,000 \times \frac{\text{Heat Input} (\text{MMBtu})}{\text{Output} (\text{MWh})}
\]

(2)

The issue of intra-interval ‘spikes’ in emissions, whether within an hourly or 15 minute interval, is often raised during discussions of appropriate methodologies to identify the impact of wind energy or other exogenous factors forcing power plant ramping. Emission spikes might are ‘smoothed’ as emission rates are averaged over the course of an hour, as a result, average emission rates cannot reflect the severity of such intra-hourly spikes. Regardless, because such spikes are measured by emission monitoring devices and included in hourly totals, the impact of emission rate spikes on total hourly emissions is captured in this analysis. When monitoring emissions for public health reasons (related to asthma, etc.), hourly NO$_x$ emission data is suitable because ozone forms over a timespan of hours, not minutes, thus sensors that integrate (or sum) emissions over hourly intervals provide sufficient data for our purposes. For SO$_2$ and CO$_2$, hourly resolution is also sufficient as the impacts of SO$_2$ and CO$_2$ on acid rain and climate change respectively are the result of accumulation of emissions over a timespan of years. In some cases spikes may be more extreme than can be captured by installed monitoring systems, however existing EPA measurement standards require that the “span value” of a monitor be set at or above the maximum potential concentration of the relevant gas (EPA, 2009).

Applied Regression Models

Our focus for this study is to develop a more refined version of the model used in Meehan, (2012) which includes the decoupling of wind output’s impact on net load as well as the impact of net
load variability on system emission rates. In addition we model potential non-linear relationships between the change in wind EGU output, change in net load and CO₂ emission rates. In decoupling regression models we seek to better understand any causal relationship between changes in net load and CO₂ emission rates, while isolating the impact of wind EGU output within variations in net load.

In order to account for exogenous weather impact on net load, specifically temperature responsive demand, we include hourly temperature readings from 8 major cities in Texas as well as a simple hourly average of those temperatures. To further account for exogenous factors we incorporate 15 minute interval lagging variables for net load over the prior 2 hours. Finally we expand our dummy variable set to include day of week, hour of day and month of year.

As a first step in our analysis we examine the impact of net load \( \gamma \) on emission rates (as defined above), defined for time \( t \) as:

\[
\gamma_t = \text{System MWh}_t - \text{MWh wind}_t
\]  

(3)

Our first model seeks to identify the impact that variability in net load has on CO₂ emission rates for all units in the EPA dataset:

**Equation 4:**

\[
\text{CO}_2\text{Emissions} = \beta_1x_1 + \beta_2x_2 + \beta_3x_3 + \ldots + \beta_{49}x_{49} + \beta_{50}x_{50}
\]

where:

\[
x_1 = \gamma \]

\[
x_2 = \Delta \gamma = \gamma_t - \gamma_{t-1}
\]

\[
x_3 = \text{system heat rate}
\]

\[
x_4 \ldots x_{10} = \text{day of week}
\]

\[
x_{11} \ldots x_{33} = \text{hour of day}
\]

\[
x_{34} \ldots x_{42} = \text{temperatures for 8 select cities and system average temp}
\]

\[
x_{43} \ldots x_{50} = \gamma \text{ lagging variables for prior 8 periods (2 hours)}
\]

(4)

Our second model seeks to identify the impact that wind EGU output has on changes in \( \gamma \):

**Equation 5:**

\[
\Delta \gamma = \beta_1x_1 + \beta_2x_2 + \beta_3x_3 + \ldots + \beta_{40}x_{40} + \beta_{41}x_{41}
\]

where:

\[
x_1 = \text{wind EGU output}
\]

\[
x_2 = \Delta \text{wind} = \text{wind}_t - \text{wind}_{t-1}
\]

\[
x_3 = \Delta \text{wind}^2
\]

\[
x_4 = \text{system heat rate}
\]

\[
x_5 \ldots x_{10} = \text{day of week}
\]

\[
x_{11} \ldots x_{33} = \text{hour of day}
\]

\[
x_{34} \ldots x_{42} = \text{temperatures for 8 select cities and system average temp}
\]

(5)

Distribution for both CO₂ emission rates and change in net load follow a normal distribution pattern although CO₂ emissions (Fig. 4) are slightly skewed and change in net load has minimal spread with several extreme outliers, though the frequency of those outliers is too low to observe visually in Fig. 5. This Gaussian distribution characteristic indicates both dependent variables are suitable candidates for regression analysis.
While the primary goal of our analysis is to understand secondary impacts to system wide CO₂ emissions we can apply this model more specifically to thermal EGUs to understand the impact that Δγ and Δwind may have on specific units. In Cullen (2011), ten thermal EGUs are identified as being offset by wind EGU output the most often, and although the analysis looks at a timeframe of higher marginal cost for natural gas units – thus placing some natural gas units on the margin – and lower wind penetration, most of the units listed in his analysis are still in use. Of these units, several exhibit characteristics that make them non-optimal for modeling purposes, including non-Gaussian emission rate distributions and low capacity factors. Low capacity factors indicate both that there might be too few data points available from the unit to develop a robust model, and that the units are conventional ‘peaking’ units, meaning that a number of exogenous factors beyond wind EGU output are likely to force these units to ramp. Filtering for these units, only coal-fired units identified in the Cullen paper are candidates for such an analysis, however the 5 coal-fired units do account for 69% of total emissions offset by the top ten units. A final set of analyses is performed using two modified versions of this approach in which CO₂ emissions from coal and gas are considered in separate models. Due to the different operating characteristics of each resource, examining the potential impact of wind generation on each provides useful insights into how or whether wind variability impacts one resource more than the other.

It is worth examining emissions of NOₓ and SO₂ independently of CO₂ because of the concern that emissions controls might experience inefficiencies and time lags that would exacerbate the impact of heat rate increases (Katzenstein, 2009). Unintended consequences might result from increased output of variable wind and solar EGUs intended to mitigate global warming impacts of CO₂ primary among these unexpected impacts are increases in emission rates or total emissions of NOₓ and SO₂.

6 Results

Equation 4 Results: Correlations Between Net Load and Emission Rates

In general, the CO₂ models had the closest fit across fuel types (coal, natural gas, all fossil fueled generation) with adjusted R squares ranging from a high of .8204 in the all fossil fuels model to .48 in the coal EGU model. The closer fit indicates that this model is most effective at predicting CO₂ emissions as a result of the combined exogenous factors in equation 4 relative to NOₓ and SO₂ emissions which exhibit poor model fit. As noted earlier, this better fit for CO₂ is likely due to the fact that CO₂ emissions are currently uncontrolled in the U.S. and thus should more closely track fossil-
fueled EGU output while NOx and SO2 emissions are often controlled resulting in a potentially non-correlated relationship with EGU output. Likewise the full system model which uses data from all fuel types (including non-coal and non-natural gas) exhibited the best fit, with natural gas showing the next best fit and coal EGUs showing a relatively poor fit for the model. Table 1 below shows modeling results including adjusted R square and correlation coefficients for key independent variables.

Table 1: Equation 4 Results

<table>
<thead>
<tr>
<th>Independent Variable</th>
<th>All Fossil Fuels</th>
<th>Natural Gas EGUs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CO2 tons/MWh</td>
<td>NOx lbs/MWh</td>
</tr>
<tr>
<td>Adjusted R Square</td>
<td>0.8204</td>
<td>0.5941</td>
</tr>
<tr>
<td>γ</td>
<td>-1.16E-05</td>
<td>-6.03E-06</td>
</tr>
<tr>
<td>Δγ</td>
<td>6.50E-06</td>
<td>2.14E-05</td>
</tr>
<tr>
<td>Δγ^2</td>
<td>-1.32E-10</td>
<td>-7.39E-10</td>
</tr>
<tr>
<td>system heat rate</td>
<td>1.10E-04</td>
<td>2.84E-04</td>
</tr>
</tbody>
</table>

Table 1: Regression analysis results from equation 4, showing model fit and correlations coefficients for key independent variables. The results show a relatively good fit (“Adjusted R Square”) for the CO2 “All Fossil Fuels” model. Directionality of independent variables in the CO2 “All Fossil Fuels” model show that increasing γ correlates with lower emission rates, while increasing Δγ correlates with lower emission rates.

These results conform with prior analyses, most often using data from periods with higher natural gas prices which conclude that natural gas is most often on the margin in the ERCOT market and thus most likely to be impacted by changes in net load. There is some question regarding the extent to which recent low natural gas prices have affected the the merit order – the order in which EGUs are selected for dispatch based on marginal price – moving coal to the margin in some hours of the year.

Our study period includes 3 years reflecting current low prices and only one year (2008) where wellhead prices were above $5/Tcf allowing us to examine whether current low prices have resulted in a noticable shift in the merit order. Specifically our results confirm that that although low natural gas prices may have moved some coal facilities higher in the merit order stack, natural gas generation is still impacted more than coal by changes in net load. Furthermore an analysis of 2011 using the same methodology yields similar results, although with notably higher adjusted R Squares, natural gas remains a better fit (i.e. is more highly correlated) with changes in net load.

In Table 1 above, increases in net load clearly lead to decreased emission rates across all fuel types with the exception of natural gas NOx emission rates, indicating that natural gas units higher in the supply stack, and therefore run less frequently, have higher NOx emission rates. EPA’s Air Markets Program Data (Fig. 6) shows that a substantially greater number of outliers with

Figure 6: NOx Rates for EGUs by Capacity Factor

Figure 6: As EGU capacity factors decrease emissions increase, indicating higher NOx emission rates for peaking EGUs.
high NOx rates exist in the population of plants with lower capacity factors (i.e. less operating time per year), specifically below 20%.

Δγ and Δγ² however show that changes in net load (as opposed to simply total net load) have varying impacts on system, natural gas and coal EGU emission rates respectively. Specifically increases in Δγ appear to increase emission rates, indicating that EGU inefficiencies induced by ramping lead to increased emissions, although the correlation coefficient is small enough to be negligible. In this context CO₂ and NOx emissions from natural gas EGUs stand out as being negatively correlated with Δγ possibly resulting from a combination of natural gas EGU’s greater ramping flexibility and the fact that both CO₂ and NOx are uncontrolled in many of the natural gas EGUs presumed to be offset to meet intra-interval net load needs. Across all analyses the system heat rate is positively correlated with emission rates as expected.

Individual Plant Results

Results using this model for individual EGUs exhibited a poor fit. However, the poor fit might simply indicate that on an individual level, broad system-wide changes in net demand are unlikely to impact individual units that might be responding to a mixture of system-wide and localized changes. To fully account for localized and economic dispatch effects it might be necessary to incorporate transmission congestion and other local as well as economic factors, but such an analysis is beyond the scope of this paper.

Table 2 shows the EGUs identified in Cullen (2011) as being frequently offset in the dispatch curve by wind energy output, and as such they are likely to see the highest level of impact to emission rates as a result of frequent ramping induced by wind EGU output. These results do not invalidate those from Cullen’s analysis, rather these results can be seen as a further indicator that changes in net load, including wind EGU output do not seem to drive changes in EGU emission rates. It is possible that the supply curve has shifted to such an extent since 2007 that a different set of EGUs would be offset more frequently than the units in Table 2. The plants listed below are known to be offset either by wind directly or as a result of their place in the economic dispatch order, for instance Austin Energy has stated an operational preference for reducing output from their ownership share of Fayette 1 and 2. In September 2012, Energy Future Holdings announced plans to idle Monticello units 1 and 2 due to higher marginal costs relative to current market conditions, placing the unit in a more marginal position in the dispatch order.

<table>
<thead>
<tr>
<th>Independent Variable</th>
<th>Big Brown 1</th>
<th>Big Brown 2</th>
<th>Fayette 1</th>
<th>Fayette 2</th>
<th>Monticello 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted R Square</td>
<td>0.03811</td>
<td>0.02651</td>
<td>0.2206</td>
<td>0.1068</td>
<td>0.0115</td>
</tr>
<tr>
<td>γ</td>
<td>2.11E-06</td>
<td>-5.36E-06</td>
<td>4.84E-06</td>
<td>1.77E-05</td>
<td>1.81E-05</td>
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<tr>
<td>Δγ</td>
<td>-2.27E-05</td>
<td>1.49E-05</td>
<td>-1.61E-05</td>
<td>-2.35E-05</td>
<td>-1.34E-05</td>
</tr>
<tr>
<td>Δγ²</td>
<td>-2.19E-08</td>
<td>-2.47E-09</td>
<td>-1.77E-08</td>
<td>-3.19E-09</td>
<td>-7.71E-09</td>
</tr>
<tr>
<td>system heat rate</td>
<td>-3.21E-05</td>
<td>3.96E-05</td>
<td>-1.83E-04</td>
<td>-2.20E-05</td>
<td>2.68E-04</td>
</tr>
</tbody>
</table>

Table 2: Plant Specific CO₂ Rate Impacts

Despite the model’s weak correlation of changes in net load to emission rates for individual EGUs identified in Cullen (2011) as likely to be offset by wind, the fact that the Δγ variables on a system-wide level have a minimal impact on emission rates indicates that cycling caused by changes in net load have a minimal impact on emission rates. In the individual and system-wide models, as well as the models disaggregated by fuel type the orders of magnitude for Δγ correlation coefficients are between 10⁻⁴ and 10⁻² across all emissions, with SO₂ emissions often having the highest correlation coefficient. Using these correlation coefficients to model the impact of Δγ and Δγ², in order to incorporate both the impact of both the direction and magnitude of changes in net load we find emission rates between 10⁻⁴ and 10⁻⁵ lbs (NOx and SO₂) or tons (CO₂) per MWh. As a result it seems that changes in net load lead to little attributable emission rate increases, an important consideration in evaluating the environmental benefits associated with variable generation resources.
Equation 5 Results: Correlations Between Net Load and Wind Generation

In our analysis for the impact of wind generation on $\Delta \gamma$ it is only necessary to run a single model because $\Delta \gamma$ is a system-wide variable. The regression model using Equation 5 has a relatively poor fit with an adjusted R square of .57, indicating that the descriptive variables included only account for a fraction of the total $\Delta \gamma$. While it would be ideal to have a better model fit, the as they stand results are telling; to the extent that wind is included in the descriptive statistics (wind EGU output, $\Delta \text{wind}$, $\Delta \text{wind}^2$) this model demonstrates that wind is a poor indicator of $\Delta \gamma$. The strongest indicators by far are seasonal, temporal and temperature variables, all of which are likely to exhibit some multicollinearity with wind EGU output, which could in effect ‘mask’ the impact wind EGU output has on $\Delta \gamma$.

![Table 3: Equation 5 Results](image)

Table 3: Net load and wind generation correlations show a net slight increase in emission rates over time.

EGU output and $\Delta \text{wind}^2$ is correlated with increased $\Delta \gamma$ while increases in $\Delta \text{wind}$ correlate at the highest order of magnitude of all variables with decreased $\Delta \gamma$, indicating that large changes in wind output seem to correlate with lower overall system changes in net load. The relationship between $\Delta \text{wind}$ and $\Delta \gamma$ illustrates that the primary impact wind EGU total MWh output may have on $\Delta \gamma$ is the ramping down of fossil fuel EGUs as wind EGU output increases, while changes in MWh output correlate directly with increases in $\Delta \gamma$. These results indicate that wind EGU MWh, which averages approximately 2 orders of magnitude greater than $\Delta \text{wind}$ and $\Delta \text{wind}$, with a coefficient 2 orders of magnitude higher than wind EGU output, may exert opposing influences of a similar scale upon $\Delta \gamma$. With the direct correlation of $\Delta \text{wind}^2$ and $\Delta \gamma$ we expect a noticeable but slight positive upward pressure on emission rates resulting from increased wind EGU output and $\Delta \text{wind}$.

Combining these two equations allows us to evaluate the secondary effect that wind EGU output has on overall system emission rates, i.e. to what extent the changes in net load induced by wind generation create effects in fossil fuel generation that impact emission rates. The equation used to estimate this impact is as follows:

First we calculate the amount of net load attributable to wind based on a simplified version of equation 5, identified as $\gamma_{\text{wind}}$:

$$\gamma_{\text{wind}} = \gamma(\text{wind}) = \beta_{1,\text{wind}}(\text{wind MWh}) + \beta_{2,\text{wind}}(\Delta \text{wind}) + \beta_{3,\text{wind}}(\Delta \text{wind}^2) \quad (6)$$

Next, inserting $\gamma_{\text{wind}}$, calculate the change emission rate attributable to wind ($\Delta E_{\text{wind}}$) through wind’s impact on net load:

$$\Delta E_{\text{wind}} = \beta_{1,\gamma}(\gamma_{\text{wind}}) + \beta_{2,\gamma}(\Delta \gamma_{\text{wind}}) + \beta_{3,\gamma}(\Delta \gamma_{\text{wind}}^2) \quad (7)$$

Substituting the values determined in equation 6 for $\gamma_{\text{wind}}$ into equation 7 as $\gamma_{\text{wind}}, \Delta \gamma_{\text{wind}}$ and $\Delta \gamma_{\text{wind}}^2$, we calculate an average secondary effect of wind EGU output over the study period for all three pollutants we have analyzed, using the respective correlation coefficients for each pollutant (wind MWh, $\Delta \text{wind}$, $\Delta \text{wind}^2$, $\gamma_{\text{wind}}, \Delta \gamma_{\text{wind}}, \Delta \gamma_{\text{wind}}^2$). These results indicate that wind induced variability causes a slight but noticeable increase in system-wide emission rates, most likely as a result of system inefficiencies introduced by wind generation variability. The critical question then, discussed below is the scale of
this secondary impact of wind relative to its primary impact of offsetting fossil fueled EGU output, curbing fossil fueled emissions.

For example, if there were no wind power in the ERCOT system, existing fossil EGU unit emission rates would likely be slightly lower, however their usage would be higher, resulting in a substantial increase in overall system emissions.

The Relationship Between Marginal Emission Rates and Total System Emissions

An exclusive focus on marginal emission rates produces results that are not satisfactory for understanding pollution reduction goals. An analysis of emissions offset by wind energy based solely on emission rates for the marginal unit offset as a direct result of wind EGU output may be useful for regulatory compliance purposes. Direct offsets of NOx and SO2 have effects that are highly time-dependent, specifically the status of those pollutants as precursors to ground level ozone and particulate matter means that a key societal benefit from the reduction of their emissions occurs during specific hours. It is the time dependent nature of this analysis that is most critical, however, and a focus solely on impacts to emission rates misses the larger goal of measuring total system emission impacts.

Emissions of SO2 and NOx also have less time dependent societal benefits such as the reduction of acid rain, while the societal benefit of CO2 reductions is only slightly impacted by the time of emission. As a result, a marginal emissions analysis only captures part of the societal benefit of wind EGU output while discount the impact contemporary output has on the shaping of future supply curves and thus future marginal emission rates. In a 2009 analysis the Public Utilities Commission (PUC) of Texas found that “for each additional 1,000 MW of wind that was produced, the analysis showed that the clearing price in the balancing energy market fell by $2.38 per MWh” (PUC, 2009). In the spring of 2011, wind EGU output reached an instantaneous peak of 7,599 MW (ERCOT, 201) at 8:41p.m., which would result in a reduction in wholesale power prices of approximately $18/MWh using the PUC’s methodology.

Table 4: Emission Rate Impacts of Wind Induced Variability

| ΔCO2 (tons/MWh) | 0.03 |
| ΔSO2 (lbs/MWh) | 0.47 |
| ΔNOx (lbs/MWh) | 0.16 |

Table 4: The secondary effects of wind generation on emission rates, representing a small portion of total EGU emissions.

While this price impact represents just one estimate, similar analyses have observed what has been termed the “merit order affect” – the reduction of wholesale power prices as a result of low energy marginal costs displacing higher marginal cost units in the merit order stack and lowering the marginal price of energy (Weigt, 2009). Over the long term these lower prices make it difficult for units that are only marginally profitable to remain operational, potentially leading to the retirement of fossil fuel generation that would have otherwise remained in operation. Coupled with a similar impact from historically low natural gas prices this might result in a changed ERCOT supply curve; although it is not certain that the resulting curve will be less carbon intensive such has been the trend during this study period (Figure 7). It is difficult to determine what role wind may have played in this decline without further analysis, however it is important to note that the societal benefits from emission offsets related to wind EGU output may extend beyond a marginal emissions impact. Likewise the societal benefits arising from the development of wind EGUs extend beyond avoided emissions; often economic development and international competitiveness under the sobriquet of “energy independence” are cited as justifications for policies supporting renewable energy.

Figure 7: ERCOT CO2 Rate Decline During Study Period

Figure 7: CO2 rates in ERCOT have declined over time
Developing a rigorous marginal emission analysis is beyond the scope of this paper, however our dataset does allow us to use hourly average system-wide emission rates to estimate total emissions offset by wind EGU output. An estimation of hourly system-wide emission rates is primarily useful to better understand the scale of direct emission reductions from wind relative to the impact to fossil EGU emission rates determined through our analysis. Our modeling results have shown a slight decrease in avoided emissions but as Figure 8 shows, those impacts across all measured emissions are still less than 0.05%.

The small scale of this secondary impact is primarily a result on the modeled correlation coefficients from equation 4 as used in equation 7 for $\gamma$, $\Delta\gamma$ and $\Delta\gamma^2$ and overall emission rates, which have orders of magnitude at or below $1\times10^{-5}$. While the correlation coefficients in equation 5 are higher orders of magnitude, giving the independent variables in that equation greater influence over $\gamma_{wind}$, as $\gamma_{wind}$ is substituted into equation 7 the ultimate effects are muted. As a result these results cannot be seen as statistically significant, nevertheless they do provide us with some insight into the scale of the impact, as well as the gradual growth in impact over time.

7 Conclusions

Our analysis quantitatively examines wind energy’s impact on emissions from fossil fueled EGUs: primarily wind reduces emissions, though because of secondary effects related to efficiencies and optimal scrubber performance, the reductions were not as big as would have been anticipated by a simple swap of MWH for MWH (termed “secondary effects”). In addition to an examination of secondary wind effects, our calculations include important time differentiated values for emission rates, where often conventional analyses apply annual average emission rates to wind EGU output to determine emissions offset by wind. For example, a simplistic calculation using 2011 average annual emission rates shows that 3,133 GWh of wind EGU output in June 2011 offset 2.488 MMT of CO$_2$ emissions, 2.448 million lbs of NO$_x$ and 8.518 lbs of SO$_2$. By simply using a more granular 15 minute interval measure of emission rates we see that emissions offset are approximately 1%, 3% and 6% lower for each of those emissions respectively.

Taking the analysis further by looking into the secondary effects of fossil EGUs ramping to follow wind fluctuations, only 99.992%, 99.995%, and 99.96% of the emissions reductions expected for CO$_2$, NO$_x$ and SO$_2$ are achieved respectively. This secondary effect is too small to be considered statistically significant (at least for the uncertainties with this work), however the lack of statistical significance may be due primarily to the difficulty in assessing the impacts of net load on system and individual EGU emission rates.

Using both a granular calculation of emission rates and incorporating the secondary effect of wind, the total emissions from 2008-2011 in the ERCOT system were 996.5 MMT of CO$_2$, .528 MMT of NO$_x$, and 1.87 MMT of SO$_2$. Without wind power we estimate that the emissions were 1.07 MMT of CO$_2$, .564 MMT of NO$_x$, and 2.0 MMT of SO$_2$. This
impact can be seen in an adaptation of Figure 8 (Fig. 9, above) where the red line represents what the average system emission rates would be without wind generation in ERCOT. This analysis assumes that replacement generation would have a similar emission rate to ERCOT’s current non-wind generation emission rate.

Our approach models the secondary effect of wind energy through its impact on net load, in order to capture the total net impact of wind variability in a dynamic system. While such an approach introduces additional uncertainties into our analyses it is key to understanding wind variability as a component of a system that is subject to a number of exogenous factors which create variability within the system. Incorporating these impacts we find that primary impacts from wind generation outweight secondary impacts by several orders of magnitude.
8 References


