Negative Bidding by Wind: A Unit Commitment Analysis of Cost and Emission Impacts

by

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Abstract

A unit commitment model is used to quantify the operational impacts of subsidizing wind generator output during periods of negative energy prices, which occur with increasing frequency in US markets. Subsidies such as production tax credits, feed-in tariffs, and renewable energy credits motivate wind and other renewable generators to submit negative energy bids in power markets; this lessened flexibility may increase system fuel costs and, in some cases, air pollution emissions when energy prices are below zero. Our simulations of large negative bids can also be interpreted as representing European Union (EU) policies of granting wind absolute priority in dispatch.

Applications to four systems with different generation mixes and amounts of flexibility illustrate the effects that large negative bids/absolute priority can have on unit commitment and dispatch. Larger negative bids incent the system to accept more wind generation during periods of negative energy prices. This leads to more start-ups and shut-downs of conventional generators and higher total system costs. Further, CO₂ emissions sometimes, but not always, increase under those conditions. The emissions impact depends strongly on the generation mix and carbon price. In general, there would be economic and, often, environmental benefits to reforming renewable support policies to encourage flexibility in renewable operations.

1. NOMENCLATURE

Indices

t, τ: Index of time period (dispatch interval)
g: Index of generator
n: Index of starting step, n=1, 2, 3, …, T_g

Decision Variables

curt: Amount of wind power curtailment at time t [MW]
emis_{g, t}: CO₂ [ton] emissions of generator g at t
emis_{s, t}: SO₂ [pound] emissions of generator g at t
emis_{n, t}: NOₓ [pound] emissions of generator g at t

k_{g, t}: 0/1 variable indicating if the generator g has been offline for more than a certain amount of time Ω_g at t
pns: Amount of demand not supplied at time t [MW]
og: 0/1 variable indicating if g is off (1) or not (0) at t
q_{g, t}: Output of generator g at time t [MW]
q'_{g, t}: Output of generator g in excess of QMIN_g at t [MW]
q''_{g, t}: Output of g below the min run level QMIN_g at t [MW]
sc_{g, t}: Start-up cost incurred for generator g at t [$]
\( w_{g,t} \): 0/1 variable indicating if \( g \) is starting up or not at \( t \)

\( z_{g,t} \): 0/1 variable indicating if \( g \) is committed or not at \( t \)

**Parameters**

- \( A_g \): Marginal fuel consumption, generator \( g \) [MMBtu/MWh]
- \( B_g \): Fixed fuel consumption by \( g \) [MMBtu/h]
- \( CC \): Curtailment cost of wind (= -1*energy bid; so if bid is negative, this cost is positive) [$/MWh]
- \( C_{pmu} \): Cost of unserved energy (1000 $/MWh)
- \( DEM_t \): Load at time \( t \) [MW]
- \( EMC_g \): CO\(_2\) emission rate of generator \( g \) [ton/MMBtu]
- \( EMS_g \): SO\(_2\) emission rate of generator \( g \) [pound/MMBtu]
- \( EMN_g \): NO\(_x\) emission rate of generator \( g \) [pound/MMBtu]
- \( F_g \): Primary fuel cost of generator \( g \) [$/MMBtu]
- \( FS_g \): Start-up fuel cost of generator \( g \) [$/MMBtu]
- \( MD_g \): Minimum down time of generator \( g \) [h]
- \( P_C \): Price of CO\(_2\) [$/ton] emissions
- \( P_S \): Price of SO\(_2\) [$/pound] emissions
- \( P_N \): Price of NO\(_x\) [$/pound] emissions
- \( QMAX_g \): Maximum output of generator \( g \) [MW]
- \( QMIN_g \): Minimum output of generator \( g \) [MW]
- \( Q_{g,n} \): Output of \( g \) during the \( n \)th interval of the start-up [MW]
- \( R_g \): Multiplication of startup cost for generator \( g \) [-].
- \( RD_g \): Bound on downward ramp rate of generator \( g \) [MW/h]
- \( RU_g \): Bound on upward ramp rate of generator \( g \) [MW/h]
- \( S_g \): Start-up fuel use of generator \( g \) [MMBtu]
- \( SEMC_g \): Start-up CO\(_2\) [ton] emissions of generator \( g \) [ton]
- \( T_g \): Start-up time of generator \( g \) [h]
- \( WIND_t \): Wind power production at time \( t \) if no curtailment takes place [MW]
- \( \Omega_g \): A certain threshold value for offline time where the start-up costs increase by a certain factor [h]

## 2. INTRODUCTION

Targets and incentive mechanisms for investment in renewable power have been adopted around the world [1]. Examples include Australia’s 20% Expanded Renewable Energy Target and Spain’s Renewable Action Plan (REP) 2011-2020, for meeting EU 2020 targets. Most US states have adopted renewable portfolio standards in which renewable generation creates credits that can be sold, while the US govern-
ment has a production tax credit amounting to ~$26/MWh produced. In the EU, feed-in tariffs are more prevalent, which pay a guaranteed amount per MWh for renewable production.

As a result, renewable producers have a strong incentive to maximize the energy they generate from their facilities. This affects their bidding strategy, motivating them to submit large negative bids to ensure that they are dispatched; such negative bids are rational as long as their magnitude does not exceed the subsidy. Refs. [2], [3], [4] have studied the impact of regulatory interventions on wind investment, reaching conclusions about which policies might best stimulate investment.

Many studies have addressed the impacts of wind energy on the performance of system operations. Most are ex ante engineering-economic analyses that simulate operations accounting for wind variability or forecast errors as they interact with load, other types of generation, and transmission. Some are ex post statistical analyses of the past effects of wind. As examples, Barth et al. [5] apply a market model based on stochastic unit commitment. Voorspools et al. [6] use a stacking model to estimate wind’s impact on the Belgian power system, while Holttinen et al. [7] estimate CO₂ emission effects with a commercial model. Chen et al. [8] optimize the dispatch of wind and then solve for the optimal wind penetration for Taiwan’s power system. Li and Kuri [9] study cost, emissions and security effects of wind using dynamic programming. Denny and O’Malley [10] use a dispatch model to quantify CO₂, NOₓ and SO₂ emission impacts. Studies with similar goals include [11] [12]. Almost all of these studies conclude that wind helps reduce system operating costs and emissions. However, others [13] [14] point out that high wind penetration could increase the cycling of conventional plants, causing, in some times and places, increased emissions; however, the net effect of wind on emissions appears to be beneficial [15].

We focus here on the cost and CO₂ impacts of negative bids, as there is increasing concern about the need for greater flexibility in operations, while negative bidding decreases that flexibility. For example, the CAISO has identified inflexible bidding by both thermal and wind plants as contributing to future violations of energy balances during steep ramp events [16]; in response, the CAISO has changed market rules to encourage more flexible bids [17]. Since the impacts of negative bids depend on the size and flexibility of the system [18], we explore factors that affect the impacts of wind bidding under different generation mixes using a unit commitment model and generator performance data based on actual US experience. We find that the exact impacts depend strongly on generation mix, the magnitude of negative bids, and other factors.

The paper is structured as follows: Section 3 summarizes the commitment model. Section 4 documents load, fuel mix, and other assumptions for the four case studies. Results are presented in Section 5, followed by conclusions in Section 6.

3. Model Description

The model is a mixed integer linear program, doing a short run analysis with fixed generation capacity. Thermal capacity is committed and dispatched against one week (168 hours) of load, net of wind generation. Wind is bid in at a (generally negative) price, and can be curtailed. Transmission congestion is neglected, with all generation and load is modeled as taking place at one bus. There is neither storage nor demand response. Spinning reserve requirements are considered in addition to energy in a sensitivity analysis.
There are many formulations of UC problems \cite{ref1}-\cite{ref2}. Our model is a modification of the specific formulations in \cite{ref3}-\cite{ref4}.

### A. Basic Model

The objective function, as shown in (1), is a cost function that includes costs of start-ups, fuel costs, costs of emissions, the penalty cost for curtailing wind energy and the cost of the non-served power, in case demand is not fully met by actual generation. The objective function minimizes the sum of the above costs. Decision variables include two binary variables for each thermal generating unit and hour that describes the unit’s commitment status and whether a start-up occurs. Generation (MW) is a continuous decision variable (one for each hour and unit, including an aggregate wind unit).

\[
\begin{align*}
\text{Min} & \sum_{t} \left[ CC \times \text{curt}_t + C_{\text{pu}} \times \text{pu}_t \right] + \sum_{g,t} \left[ F_g \times \left( B_g \times z_{g,t} + A_g \times \left( z_{g,t} \times QMIN_g + q'_{g,t} \right) \right) \right] + \sum_{g,t} \left( \text{emis}_{g,t} \times P_g + \text{emis}_{\text{f},t} \times P_{\text{f},t} + \text{emis}_{\text{v},t} \times P_{\text{v},t} + \text{emis}_{\text{w},t} \times P_{\text{w},t} \right) + \sum_{g,t} \text{sc}_{g,t}
\end{align*}
\]

Equations (2) - (18) are the constraints. The motivation for using several variables rather than just one variable to express the generation output, as shown in (2), (3) and (4), is that it allows to represent specific start-up profiles of a generating unit in the model. We observed from the USEPA CEMS data that the heat input and generation have linear relationship when the generator is operated steadily (Fig. 1). However, this linear feature does not hold in the start-up period. Each generator has different start-up times and start-up ramp rates, and normally (especially for the coal generators) the heat input in the first several hours is for warming up without any generation output (Fig. 2). By using \( w_{g,t,n} \) one can pin the non-zero, effective generation output values to a specific output \( Q_{g,n}^* \) at each moment \( n \) of the start-up period, which allows the model to reflect the characteristics of different generators. The logic of this is further explained in Section B below.

**Fig. 1.** The relationship between power generation and fuel consumption for an example thermal generation unit after start-up is completed

\[ y = 6.0043x + 322.08 \quad R^2 = 0.9597 \]

**Fig. 2.** Power generation and fuel consumption of a coal generator over time

\[
q_{g,t} = q_{g,n}^* + q_{g,t}^* \quad \forall g, \forall t
\]

(2)

\[
q_{g,t}^* = z_{g,t} \times QMIN_g + \sum_n {Q_{g,n}^* \times w_{g,t,n}} \quad \forall g, \forall t, \forall n \in [1, 2, 3, \cdots T_g]
\]

(3)

\[
q_{g,t}^* \leq z_{g,t} \times [QMAX_g - QMIN_g] \quad \forall g, \forall t
\]

(4)
A start-up time $T_g$ of 3 hours is assumed in this model and thus the binary variables $w_{g,t,n}$ are limited to $w_{g,t,1}$, $w_{g,t,2}$ and $w_{g,t,3}$, although the model formulation accommodates more general start-up times. Any start-up time prior to those three hours is modeled by including it as part of minimum down time for the generator.

Equation (5), (6), (7), and (8) are used to ensure that a unit does not jump to normal operating mode (i.e., operation at $Q_{MIN}$ or above before starting up) nor that it shuts down in the middle of a start-up. Several constraints are needed to enforce the logic and predetermined order of the binary variables.

$$z_{g,t} + o_{g,t} + \sum_w w_{g,t,n} = 1 \quad \forall g, \forall t$$

(5)

$$w_{g,t,n} = w_{g,t,n-1} \quad \forall g, \forall t, \forall n \in [2,3,\cdots,T_g]$$

(6)

$$z_{g,t} \leq z_{g,t-1} + w_{g,t-1}T_g \quad \forall g, \forall t$$

(7)

$$o_{g,t} \leq o_{g,t-1} + z_{g,t-1} \quad \forall g, \forall t$$

(8)

Equation (9) is the start-up constraint. Every time a unit is turned on, a cost is added to the total cost function, represented by $sc_{g,t}$. This cost factor in combination with constraint (9) will be positive when $w_{g,t,1}$ becomes 1 at each start-up. The start-up cost consists of the amount of fuel $S_g$ (MMBtu) that is burned until the unit has ramped up above minimum run level, multiplied with the cost of the start-up fuel $FS_g$ ($/MMBtu)$ (which might be different from the fuel used for operating above minimum run), and the cost of the emissions that are exhausted during the start-up, with $P$ the price of the emissions and $SEM$ the amount of emissions in tons (CO$_2$) or pounds (NO$_x$ and SO$_2$). These start-up costs are added in the model only in the first hour of the start-up, but include the entire cost of the start-up period. Since there is no discounting, the time of occurrence does not matter. When analyzing the USEPA CEMS data, we noticed that units normally shut down immediately after producing at minimum run level or even at a higher output. Therefore, fuel costs and emissions during this short shutdown period (often less than 1 hour) can be neglected or considered included in the start-up cost.

Start-up fuel expenditure and emissions can vary greatly between cold starts and warm starts. However, the difference is not that obvious among the generators in the USEPA CEMS data base whose data we based the case studies upon. So we neglected the increase in fuel expenditures and emissions caused by longer downtimes of generators. But a more general model that includes the impact of downtime on start-up costs is presented in Section C, below.

$$sc_{g,t} \geq \left( FS_g \times S_g + P_c \times SEMC_g + P_s \times SEMN_g + P_s \times SEMS_g \right) \times w_{g,t,1} \quad \forall g, \forall t$$

(9)

CO$_2$ emissions ($emis_{CO_2}$) when generators operate steadily show a linear relation with generation MW output and thus can be modeled as shown in (10), by multiplying the output by an emission rate $EMC_g$ (ton/MMBtu). The same assumption and simplification method are applied also for NO$_x$ and SO$_2$ emissions, and their emission equations are (11) and (12).
The hourly ramping rates of thermal units are limited by constraints (13) and (14), where \( RU_g \) is the maximum observed hourly difference in generation output when ramping up and \( RD_g \) is the maximum (negative) change when ramping down (MW/h).

\[
q'_{g,t} - q'_{g,t-1} \leq RU_g \quad \forall g, \forall t
\]

(13)

\[
q'_{g,t} - q'_{g,t-1} \geq -RD_g \quad \forall g, \forall t
\]

(14)

In this model there is also a downtime constraint, constraint (15) is included that requires units to remain off-line during a certain period of time \( MD_g \) (h) once it has been shut down in order to prevent boiler wear and damage. A minimum on-time constraint can also be included but has been disregarded in our paper.

\[
\sigma_{g,t+\tau} + \sigma_{g,t-\tau} - \sigma_{g,t} \geq 0 \quad \forall g, \forall t, \forall \tau \in \left[1, \ldots, \min\{168 - t, MD_g - 1\}\right]
\]

(15)

Demand balance constraint (16) couples individual generator output together with the demand and available wind power. The power output of each generator together with the wind power generation \( WIND_t \) in each period equals the demand \( DEM_t \). In case of excess wind power, one might opt for curtailing wind \( curt_t \) at a certain cost, as shown in the objective function. Furthermore curtailment of electricity demand is also possible if capacity is inadequate, which results in non-served power \( pns_t \). Constraints (17) and (18) ensure that one cannot curtail more wind than available nor curtail more demand than possible.

\[
\sum_g q_{g,t} + WIND_t - curt_t = DEM_t - pns_t \quad \forall g, \forall t
\]

(16)

\[
WIND_t \geq curt_t \quad \forall t
\]

(17)

\[
DEM_t \geq pns_t \quad \forall t
\]

(18)

**B. Generation during Start-up Periods**

The output \( q_{g,t} \) of generator \( g \) in time period \( t \) is modeled as the sum of the output \( q''_{g,t} \) below the minimum stable production level \( QMIN_g \) and the output \( q'_{g,t} \) in excess of that load (see Fig. 3). If the generator unit is offline, \( z_{g,t} \) and \( w_{g,t,n} \) are all zero, so that output \( q_{g,t} \) is zero as well, based on (3) and (4). When starting up, \( q''_{g,t} \) becomes positive and follows the predetermined output \( Q_{g,t} \), as illustrated by Fig. 3 for a start-up time of 3 hours. Once the unit reaches the minimum run level, \( z_{g,t} \) becomes 1 and all \( w_{g,t,n} \) are zero so that \( q''_{g,t} \) constantly equals the minimum run level during operating mode.
In operating mode \( z_{g,t} = 1 \), the generator’s output cannot exceed its maximum capacity or be below its minimum level, as forced by (4). When the unit shuts down, \( z_{g,t} \) becomes zero and \( o_{g,t} \) jumps to 1.

![Diagram](image)

**Fig. 3. Illustration of Logic of Binary Variables and Generation Output**

### C. Start-up Constraints with Hot- and Cold-Starts

Start-up times, fuel expenditure and emissions can vary greatly depending on the time that a unit is offline. Even though that factor is not included in the model in our paper, we would like to introduce the way of adapting the model to the need of introducing the effect of off-line time. Certainly for steam units that need to reach a suitable boiler pressure and temperature in order to operate, this factor is non-negligible.

In our analysis of USEPA CEMS data, we observed that for some units, the start-up fuel and emissions can increase by a factor of 2 to 3 depending on the off time. Therefore, the factor \( R_g \times k_{g,t} \) is added to (9) and the startup cost equation changes to (19) in order to take this effect into account. \( k_{g,t} \) is a binary variable that indicates if generator \( g \) has been offline for more than \( \Omega_g \) hours, where \( \Omega_g \) is a certain threshold value where the start-up costs increase by a certain factor, based on the value of \( R_g \). For example, if start-up costs increase by a factor of 2 when offline exceeds 100 hours, the parameter \( R_g \) equals 1 and \( \Omega_g \) equals 100. The mechanism that enables the binary variable \( k_{g,t} \) to be equal to 1 when offline reaches or exceeds \( \Omega_g \) is modeled by (20). When \( w_{g,t,1} \) jumps to 1 at a start-up, the off-line hours before period \( t \) are counted by summing up all the offline hours \( o_{g,t} \) of the last \( \Omega_g \) hours and compared to \((\Omega_g - 1)\). This difference is divided by a “big M” and when it is positive, \( k_{g,t} \) is forced to be larger than a very small number, making it equal to 1 because it is defined as a binary variable. \( k_{g,t} \) will always equal zero if \( w_{g,t,1} \) is zero since adding a very small number to -1 will never give an outcome bigger than zero.

\[
sc_{g,t} \geq \left( FS_g \times S_g + P_c \times SEMC_g + P_s \times SEMN_g + P_s \times SEMS_g \right) \times \left( w_{g,t,1} + R_g \times k_{g,t} \right) \quad \forall g, \forall t
\]  

(19)
\[ k_{g,t} \geq -1 + w_{g,t} + \frac{\sum_{r=1}^{l-1} o_{g,r} - (\Omega_g - 1)}{M} \quad \forall g, \forall t \]  

(20)

The resulting mixed-integer linear program is solved using CPLEX with a branch-and-bound optimality gap of 0.00%, so that the global optimum is reached. For a model with \( G \) units, the model size is \( 504 \times G \) binary variables, \( 336 + 1512 \times G \) continuous variables, and \( 504 + 2520 \times G \) constraints.

4. **MODELING ASSUMPTIONS**

A. **Generator Data**

Electric Reliability Council of Texas (ERCOT) generator data is the basis for the fossil generating unit characteristics assumed in this study. A sample of 15 units includes the major types and sizes of fossil-fueled generators. Each has different costs, emissions and flexibility characteristics (Table I).

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
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<td>16907</td>
<td>750</td>
<td>7.8</td>
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<td>58/111</td>
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</table>

* The fuel cost depends on the fuel type of the generator. Based on US 2012 data, the assumed fuel costs are: coal $2.4/MMBtu, natural gas $3.39/MMBtu, and diesel oil $20.89/MMBtu. Gas Steam 3, Gas Steam 4, CCGT2, Gas CT 1 and Gas CT 2 use diesel oil as the start-up fuel.

Since the impacts of wind bidding strategies depend on the generation mix [18], we consider four systems based on different combinations of those units. The systems include: high nuclear and coal (NUCL), high coal (COAL), high combined cycle (CCGT), and high steam gas (SGAS) (Table II). These represent a range of actual conditions; e.g., the CAISO, Spanish and Texas systems have, respectively, a low, medium and high share of coal-fired generators. The least flexible system is NUCL because the nuclear unit always operates at its full capacity of 1000 MW. Consequently, it has the least amount of rampable capacity and the highest minimum production (Table II). The nuclear unit’s parameters are derived from [23], including a marginal cost of 7.49 $/MWh.

B. **Demand and Wind Curves**

Both wind and demand data for our modeled week are based upon a sample of hours from summer 2012 for the ERCOT system. Note that the generator, wind and demand data that we extracted from the ERCOT system are used only to formulate four sample systems, and our case studies are not meant to represent Texas. We rescale the ERCOT values to a peak load of 4500 MW and peak wind output of 3300
MW (Fig. 4). This wind level is equivalent to 35% of total energy demand (compared to the 9% experienced in Texas in 2012), which is comparable, for instance, to the CAISO target of 33% by 2020. Our peak load results in a thermal reserve margin in of 10%, slightly more than the ERCOT standard of 8.7% [24].

<table>
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<tr>
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<th>CCGT</th>
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<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Gas Steam1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Gas Steam2</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Gas Steam3</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>2</td>
</tr>
<tr>
<td>Gas Steam4</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Gas CT 1</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Gas CT 2</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Nuclear</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

# Generators | 9    | 14   | 16   | 13   |
Total Capacity (MW) | 4050 | 4095 | 4052 | 4103 |
Total Min Cap (MW) | 1650 | 2031 | 2091 | 1215 |
Max Ramp up (MW/hr)* | 853  | 1473 | 1369 | 2160 |
Max Ramp down (MW/hr) | 1577 | 2481 | 2271 | 2491 |

TABLE II. Composition of Test Systems

a. Unit’s ramp = MIN(hourly ramp rate, Max – Min output), from Table I

![Assumed wind and demand profiles](image)

Fig. 4. Assumed wind and demand profiles

A very high ($100,000/MWh) value of lost load is assumed. Lower values are considered in our sensitivity analyses.

5. RESULTS

By increasing the size of the (negative) energy bid for wind in the UC model, we force the systems to take more wind. We consider a broad range of negative bids, analyzing their effect on system costs (excluding wind penalties) and CO₂ emissions. The largest negative bid (~$300/MWh) can also be viewed as a simulation of the EU policy of absolute priority of wind in system dispatch, where wind must be taken unless system reliability is jeopardized.

A. Effects of negative bids on curtailment, cost and emission
Table III shows the percentage of wind production curtailed according to the changes of wind’s negative bid. In general, less flexible systems curtail more wind when zero is bid, and the amount of curtailment shrinks as the bid becomes more negative. Curtailment in the inflexible NUCL system is much higher than in other systems, and falls less rapidly as negative wind bids increase in magnitude. The other three cases have similar curtailments to each other, reflecting their similar ramp capabilities (last line, Table II). The table also shows that the curtailment falls as the magnitude of the wind bid increases (from $0/MWh to -$300/MWh).

Table III. Wind curtailment for different scenarios under decreasing wind negative bid

<table>
<thead>
<tr>
<th>Wind Bid [$/MWh]</th>
<th>0</th>
<th>-10</th>
<th>-20</th>
<th>-30</th>
<th>-40</th>
<th>-50</th>
<th>-60</th>
<th>-70</th>
<th>-80</th>
<th>-90</th>
<th>-100</th>
<th>-300</th>
</tr>
</thead>
<tbody>
<tr>
<td>NUCL</td>
<td>10.04%</td>
<td>9.10%</td>
<td>9.10%</td>
<td>8.41%</td>
<td>8.37%</td>
<td>8.39%</td>
<td>8.31%</td>
<td>8.11%</td>
<td>8.08%</td>
<td>8.08%</td>
<td>7.93%</td>
<td></td>
</tr>
<tr>
<td>COAL</td>
<td>1.55%</td>
<td>1.52%</td>
<td>1.50%</td>
<td>1.43%</td>
<td>1.43%</td>
<td>1.13%</td>
<td>1.11%</td>
<td>1.11%</td>
<td>0.80%</td>
<td>0.80%</td>
<td>0.30%</td>
<td></td>
</tr>
<tr>
<td>CCGT</td>
<td>1.51%</td>
<td>1.51%</td>
<td>1.28%</td>
<td>1.28%</td>
<td>1.28%</td>
<td>1.07%</td>
<td>1.07%</td>
<td>1.07%</td>
<td>0.86%</td>
<td>0.83%</td>
<td>0.32%</td>
<td></td>
</tr>
<tr>
<td>SGAS</td>
<td>1.70%</td>
<td>1.45%</td>
<td>1.43%</td>
<td>1.43%</td>
<td>1.21%</td>
<td>1.21%</td>
<td>1.00%</td>
<td>0.99%</td>
<td>0.99%</td>
<td>0.79%</td>
<td>0.43%</td>
<td></td>
</tr>
</tbody>
</table>

For each system, the number of starts increases when more wind is forced into the system when wind bids less flexibly (Table IV). A highly flexible system, like SGAS, can lower its output in anticipation of wind peaks without the need to shut down units, and so has fewer starts and stops.

Table IV. Increase in start-up frequencies at higher wind penetration

<table>
<thead>
<tr>
<th>Wind Bid [$/MWh]</th>
<th>0</th>
<th>-10</th>
<th>-20</th>
<th>-30</th>
<th>-40</th>
<th>-50</th>
<th>-60</th>
<th>-70</th>
<th>-80</th>
<th>-90</th>
<th>-100</th>
<th>-300</th>
</tr>
</thead>
<tbody>
<tr>
<td>NUCL</td>
<td>28</td>
<td>31</td>
<td>31</td>
<td>31</td>
<td>35</td>
<td>36</td>
<td>35</td>
<td>35</td>
<td>39</td>
<td>39</td>
<td>39</td>
<td>40</td>
</tr>
<tr>
<td>COAL</td>
<td>44</td>
<td>45</td>
<td>45</td>
<td>46</td>
<td>46</td>
<td>48</td>
<td>48</td>
<td>48</td>
<td>50</td>
<td>50</td>
<td>50</td>
<td>57</td>
</tr>
<tr>
<td>CCGT</td>
<td>54</td>
<td>54</td>
<td>54</td>
<td>55</td>
<td>55</td>
<td>55</td>
<td>56</td>
<td>56</td>
<td>57</td>
<td>58</td>
<td>57</td>
<td>64</td>
</tr>
<tr>
<td>SGAS</td>
<td>18</td>
<td>19</td>
<td>19</td>
<td>19</td>
<td>20</td>
<td>20</td>
<td>22</td>
<td>22</td>
<td>22</td>
<td>23</td>
<td>22</td>
<td>26</td>
</tr>
</tbody>
</table>

It might naively be assumed that since less thermal output is required as wind usage grows, costs and CO₂ emissions will decrease as well. Fig. 5 confirms that costs (other than wind bids) rise for all systems as wind’s negative bid grows. However, it is not a priori obvious whether CO₂ emissions should increase or decrease under larger wind negative bids. The behavior of CO₂ emissions varies both qualitatively and quantitatively among the four test systems (Fig. 5). For the two most inflexible systems (NUCL and COAL, as gauged by the amount of ramp and minimum capacities in the last two lines of Table II), CO₂ emissions monotonically increase as the size of the negative wind bid goes up (and thus as wind curtailment goes down). Thus forcing the system to take more wind when prices are negative increases both emissions and costs in those cases. So wind is, on the margin, harmful both economically and environmentally under such circumstances.
B. CO₂ price impacts on wind curtailment and emissions

Power plant owners in most of the US do not pay for CO₂ emissions, with the exception of California and the Regional Greenhouse Gas Initiative (RGGI) region. Here, we consider how the price of CO₂ interacts with negative wind bids. Above, we assumed a relatively high cost of carbon ($21/ton), while in this section we consider a lower value. The “social cost of carbon” (SCC) is used by the US federal government as an estimate of the monetized damages associated with incremental carbon emissions. In 2010, this value was $21/ton CO₂ (in 2007 dollars) [25], comparable to the 2008 value of European Union Emissions Trading System (ETS) carbon allowances (~€20/ton). However, by May 2013, the value of the ETS carbon spot price dropped to a record low of €2.63 (roughly the same as the cost of RGGI allowances today).

Structurally, for all the scenarios, the same observations hold as for the high CO₂ price scenario: curtailment still decreases with increasing curtailment cost, the amount of startups increases, operating costs and emissions decrease and startup costs and emissions increase.

The total CO₂ emissions increase, as expected, but the amount of increase depends on the system’s flexibility. For the inflexible NUCL system, the total CO₂ emission increase is tiny, around 1%. This is because coal units cannot displace nuclear units in the merit order. In contrast, for a flexible system, like SGAS, the increase in total CO₂ emissions is considerable, around 16%, as coal is moved up in the merit order, being base-loaded rather than cycled (Fig. 6).

Turning to cost impacts, total cost decreases significantly under the $5/ton carbon price mainly because the expense of carbon falls dramatically. Fuel expenses also fall slightly in three out of four systems because cheaper, dirtier plants (coal) can be used more, while more expensive units (gas) are used less.
6. **CONCLUSION**

A unit commitment model is used to assess the operational economic and environmental impacts of wind “must-take” requirements and negative bidding by wind generation, as a result of subsidies. Four test systems, including high nuclear, high coal, high CCGT and high gas steam, have been considered, as have the impacts of alternative assumptions about CO₂ prices, start-up costs, and spinning reserves.

Our main conclusions are the following. First, wind curtailment is greater when the overall generation mix is inflexible, as measured by total rampable capacity and total minimum run levels. Second, larger negative energy bids for wind force the system to accept more wind generation even though energy prices are negative. As a result, system costs unambiguously increase (disregarding penalties for curtailing wind). Third, such bids lead to more starts and stops for generators and associated CO₂ emissions, which partially and, in some cases, more than fully offsets emissions reductions due to decreased thermal generation.

Thus, the precise cost and environmental effects of allowing negative bids, or requiring that all wind be taken subject to reliability constraints, depend on the particular system. Furthermore, transmission, demand response, hydro generation, and energy storage could have a large impact on the flexibility of a power system and the impact of wind injections during negative price periods [26]. We can conclude that policies that encourage wind to bid flexibly (i.e., zero or low negative bids) will improve short-run system cost performance and in many cases emissions as well. This will help society to reap the full economic and, often, environmental benefits of wind power integration. Such policies might include, for instance, renewable energy credit or tax credit systems that provide credits even for curtailed wind, based on statistical estimates of how much wind would have been provided in the absence of curtailment.

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8. **REFERENCES**


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