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Relationship between wind power, electric vehicles and charger infrastructure in a two-settlement energy market

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ABSTRACT

This study investigates the technological and economic relationships of integrating wind power, plug-in electric vehicles (PEVs) and mixtures of Level 1/Level 2 charger infrastructures in New York Independent System Operator's (NYISO's) two-settlement wholesale electric energy market. Using 7560 scenarios constructed from various PEV penetrations, Level 2 charging and wind dispatch policies, this study reports findings that substantiate and challenge aspects of the previously envisioned synergy between wind power, PEVs and charging infrastructure. An econometric model based on historical market data, including system-level costs of load ramps, was used to study resource integration and to avoid data fidelity issues that plague traditional fundamentals-based models. Results show: (1) the existence of time-series correlation between PEV charging and wind dispatch depends on curtailment policy, (2) PEV charging with wind over-forecast nearly triples the rate of reduction in curtailed wind energy compared to under-forecast, (3) using wholesale energy cost as metric, PEVs can be adversely coupled to curtailable wind, and decoupled with must-take wind, and (4) PEV penetration, Level 2 charging and wind power may be economic substitutes in the energy market.

Introduction

As both renewable energy and PEV market penetrations increase, there is a growing intent of using the flexible charging of PEVs as a demand-side resource to improve the integration of intermittent generation resources into power systems [1,2]. In terms of wind energy, areas of improvement include reducing wind curtailment and diminishing the effects of wind variability and unpredictability on generation–load balancing. Consequently, traditional wisdom suggests the coupled benefit of these two resources, i.e. wind and PEVs mutually benefit their individual integration into electricity markets and that they both benefit the markets as system-level resources. However, given the complexity of the electricity markets, wind dispatch policies and charging infrastructure, whether this traditional wisdom holds has not been thoroughly investigated.

There is a growing body of literature on the charging of an aggregated number of PEVs and the dispatch of regional wind generation. Several charging control mechanisms and aggregation methods have been investigated in direct coupling of wind energy and PEVs [3–6], and many of them involve ancillary services enabled by vehicle-to-grid (V2G) technologies [7–9]. A single-settlement approach was adopted to model energy markets [10,11], which reported decreases in wind power curtailment with flexibly charged PEVs. A yearly generation planning algorithm was applied to assess the impact of PEVs on the mixture of Ireland's energy and capacity needs based on the island's existing units and potential new builds [12]. Another study optimized PEV charging and dispatch of renewable assets using a non-market approach based on thermal generator costs and emissions to report decreases in system costs and pollutant emissions [13].

This study adds to the body of literature on electric vehicles and wind integration by examining the dispatch linkage between PEVs and wind units with forecasted and realized wind profiles. By doing so, we aim to examine the traditional wisdom that wind and PEVs are coupled resources. A unique aspect of our study is to model the dispatch of PEVs and wind generators with various charging infrastructures in a two-settlement energy market—the common structure of U.S. energy markets. We quantify the validity of the commonly assumed coupled benefit of the two resources. Specifically, (1) we substantiate previous claims that more PEV

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Nomenclature

–	weighted average value	N	number of commuting vehicles at load center i
a	regression constants	P	net load
C	user defined load weight	p	peak load interval
CFC	Charge Flexibility Constraint	PEV	plug-in electric vehicle
ΔP	load ramp	RTM	real-time market
D	daily average distance per vehicle at load center i	s	shoulder load interval
DAM	day-ahead market	T	last market settlement
E	average electricity used per distance at load center i	T_1	last settlement in DAM
I_1	peak load interval	T_2	last settlement in RTM
I_2	valley load interval	v	valley load interval
LMP	locational marginal price	W	type-based load weight
M_{PEV}	PEV market penetration		

penetration decreases wind energy curtailment, and (2) we find that PEV charging and wind power injection are not correlated in time by cause-and-effect, rather by coincidence. Moreover, we reveal the existence of an economic substitution effect between EVs, level of charging infrastructure and wind power in minimizing wholesale energy cost.

We expand the two-settlement, econometrics-based market model previously developed, to be described in Section 'Modeling of a two-settlement energy market, wind power and PEVs'. The market model incorporates the steady-state production cost and system-level ramping cost of generators. Flexible PEV charging and wind power dispatch subject to curtailment and must-take regulations are optimized in the market model where the objective is to minimize total wholesale market cost. Level 1/Level 2 charger infrastructures at 95/5, 85/15, 70/30, 50/50 and 30/70 mixtures are incorporated based on a commuter transportation model [14]. The study spans 21 days in June, July and August of 2006—a summer of record breaking peak loads—with 0%, 2%, 5%, 10%, 15% and 25% wind power penetrations and the same six market penetrations for PEVs for a total of 7560 scenarios.

Modeling of a two-settlement energy market, wind power and PEVs

The New York bulk power system serves 19 million people and NYISO administers trades of power products worth \$7 billion annually. In 2006, the average generation mixture was 30% natural gas, 30% nuclear, 18% conventional hydro, 15% coal, 5% petroleum and 2% renewables. This was a much cleaner and more diverse mixture compared to the then national average of 49% coal, 21% natural gas, 19% nuclear, 7% conventional hydro, 2% petroleum and 2% renewables. For the 3 summer weeks studied, the average load was 22 GW, average locational marginal price (LMP) was \$71/MWh and highest LMPs were well over \$500/MWh.

The day-ahead market (DAM) dispatches generators and settles LMPs in advance of the actual system operation. On a 5-min basis, the real-time market (RTM) adjusts generation and LMPs according to actual system conditions. The commitment cost from the DAM and adjustment cost from the RTM form the total wholesale energy market cost.

A wholesale energy market model and cost of generator cycling

Statistical versus fundamentals-based modeling approaches

Flexibility in the power system is critical to better integrate renewable energy. Consequently, energy markets need to better describe the cost of load ramps. However, modeling renewables integration and ramping costs in the energy market are difficult tasks. Many power industry modelers use a fundamentals-based approach of incorporating unit-level cost information, fuels data, transmission topologies, interface limits, demand response levels, etc. They then use security-constrained unit-commitment and optimal power flow (SCUC–OPF) solvers to determine resource dispatch and market prices.

However, we did not choose this type of fundamentals-based model for the following reasons: (1) the fundamentals-based approach currently does not capture cost of generator ramping, (2) ramping costs of individual generators are not publicly available if they are reported at all, (3) actual unit-level cost of steady-state production are not publicly available, (4) lack of publicly available high-fidelity transmission models, (5) lack of publicly available network and unit contingency lists—potentially making security-constrained solvers inaccurate, (6) bid adders are usually used to calibrate fundamentals-based models to historical data. In essence, these bid adders are blunt instruments used to correct inaccuracies in the fundamentals-based approach, data- and method-wise, and (7) even in well-structured U.S. wholesale markets, significant market uplift payments are paid to suppliers in addition to market settlements—limiting the confidence of market fundamentals-based models.

Consequently, we explicitly modeled system-level generator ramping costs along with steady-state production costs in this and a previous study [15]. This econometrics-based two-settlement market model is regressed and calibrated to the historical loads, load ramps and LMPs in the day-ahead and real-time markets as administered by the New York Independent System Operator (NYISO) in 2006. This "top-down" approach avoids the aforementioned problems in the fundamentals-based approach in order to produce system-level outcomes of wind and PEVs, e.g., aggregate dispatch and economics benefits. The disadvantage of this statistical approach is the loss of unit-level information. Hence, this model is suitable for system-level assessments such as this study.

Statistical model details

The two-settlement energy market model was first published in a previous study and relevant aspects are explained here [15]. The wholesale energy cost is the sum of the DAM cost and adjustment cost in the RTM, where cost is the product of LMP and load served, i.e. net load [16]. This relationship is given in Eq. (1).

$$\begin{aligned}\text{Daily Total System Cost} = &\sum_{t=0}^{T_1} LMP_{DAM,t}(P_{DAM,t}, |\Delta P_{DAM,t}|) * P_{DAM,t} \\ &+ \sum_{t=0}^{T_2} LMP_{RTM,t}(P_{RTM,t}, |\Delta P_{RTM,t}|) \\ &* (P_{RTM,t} - P_{DAM,t}) \qquad (1)\end{aligned}$$