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Impact of deep wind power penetration on variability at load centers

Michael Waite*, Vijay Modi

Department of Mechanical Engineering, Columbia University, USA

HIGHLIGHTS

- Regional deep wind power penetration analysis at high time resolution.
- Significant intraregional disparities in wind power supply, variability and ramping.
- Transmission expansion improves wind utilization, but exacerbates integration needs.
- Large shift of dispatchable resources providing energy to providing reliability.
- Implies new paradigm for intraregional planning and infrastructure investment.

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ABSTRACT

Increasingly, variable renewable energy capacity will be added distant from load centers in much of the world. How such intraregional heterogeneity in variable supply and load will impact the energy system in a deep renewable penetration scenario is studied here. Heterogeneous reliability requirements imposed by such scenarios are not well understood. Some unique geographic settings, such as the Nordic grid with weeks of pumped hydro backup, manage to circumvent this issue without significant curtailment, but most regions have yet to achieve the renewable energy levels at which the issue will arise. Using simulations of wind power expansion in New York State, we illustrate the intraregional effects by quantifying the net load, net load ramping, operating reserve and regulation requirements, and the associated distribution of infrastructure investments and ancillary services. The study finds that only at wind capacities exceeding 100% of the average statewide load does the wind-generated electricity meet significant portions of the distant demands. However, the peak net load in these areas is not reduced, requiring that dispatchable generation capacity be maintained. Moreover, the net load becomes highly variable, with large ramp rates that increase ancillary service requirements (operating reserves and frequency regulation) to ensure reliable system operation. A major finding is that the additional ancillary service requirements become more concentrated in the distant load centers. A second significant finding is that while transmission capacity upgrades greatly increase the wind-generated electricity that reaches load centers, the increased variability in that supply can exacerbate both the magnitude and heterogeneity of ancillary service requirements. These services would presumably be provided by the same local dispatchable resources that would now be operating at lower capacity factors but with higher variability. Such changes in the scale and distribution of intraregional integration measures and infrastructure investments may require new energy planning approaches and market structures to achieve anticipated future renewable energy targets.

1. Introduction

With rapid worldwide urbanization [1] and the urgency of addressing global climate change [2], reforming energy usage in urban areas is of paramount importance [e.g. 3,4]. Much prior research has evaluated potential electricity generation from variable renewable energy (VRE) sources within urban areas, including means of increasing output from solar power [5], improving estimations of urban wind resources [6] and technical advances to better utilize those resources [7]. However, despite these efforts, deep VRE penetration is likely to rely on resources distant from urban areas, presenting challenges to integrating such resources and realizing their technical and economic potential to meet urban energy demands [8].

At the root of many challenges related to integrating VRE is the resulting "net load," the remaining demand after utilizing the renewable-generated electricity [9]. Even when considering only hourly

* Corresponding author at: Mechanical Engineering Department, Columbia University, 220 S. W. Mudd Building, 500 West 120th Street, New York, NY 10027, USA.
E-mail address: mbw2113@columbia.edu (M. Waite).

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Nomenclature

B	baseload electricity generation (MW)
CF	capacity factor
D	electricity demand (MW)
DR	down-ramp (MW)
E	electricity generation (MW)
h	hydropower generation (MW)
L^+	positive flow transmission limit (MW)
L^-	reverse flow transmission limit (MW)
l	transmission line loss factor
$low.c$	aggregate electricity generation from low-carbon resources (MW)
$wind$	aggregate electricity generation from wind power (MW)
n_{hrs}	number of hours
n_{ts}	number of time steps corresponding to t_s for net load ramp computations
NL	net load (MW)
NLR	net load ramp (MW)
q	inner quantile probability
S_c	set of sites included in analysis for a given systemwide wind capacity
S_z	set of sites in a zone
T	transmission (MW)
t_s	time scale for net load ramping calculations (mins)
U	wind-generated electricity utilized (MW)
UR	up-ramp (MW)
W	potential wind power output (MW)
Z	set of all zones
z	zone identification
α	fraction of capacity committed to ancillary services
μ	operating reserve requirement (MW)
P	statewide regulation services requirement (MW)
ρ	regulations services requirement assigned to region or zone (MW)
T	total number of time steps

Subscripts

c	Statewide wind power capacity
h	hour
$hydro$	time-varying hydropower generation
$hydro\text{-}const$	constant hydropower baseload generation
m	month
nuc	nuclear power
R	region
t	time step
z	NYISO zone index

effects, analyses of deep VRE penetration scenarios indicate the need for significant increases in energy storage to shift higher supply to times of higher demand, integration of temporally and spatially heterogeneous resources over larger areas, and controllable loads (e.g. through demand-side management) [10]. Wind power, specifically, exhibits unique intermittency effects at diurnal, synoptic (i.e. due to multiple-day weather variations) and seasonal [11]. At the high levels of wind power capacity envisioned by the U.S. National Renewable Energy Laboratory (NREL) [12] and evaluated in a previous study by the authors of this paper [13], regional wind power output may approach, then exceed current peak electricity demands, potentially resulting in supply variable far out of scale with current demand variability [14]. At the heart of this paper are open questions regarding the net load effects at higher spatial (intraregional) and temporal (sub-hourly) resolutions.

In one of the most comprehensive large-scale wind power integration studies to date – the National Renewable Energy Laboratory (NREL) Eastern Wind Integration and Transmission Study (EWITS) – the Eastern Interconnection's largest regions (e.g. the Midcontinent, PJM and New York Independent System Operator control areas) were treated as single regions, ignoring intraregional transmission constraints [12]. Another particularly well-formulated study assumed low transmission costs more in line with long-distance high-voltage DC and not the AC systems likely to be built over relatively shorter intrastate distances [15]. This and other similar studies also often treat a future high-VRE energy system as independent of the challenges and opportunities presented by existing system components, rather than investigating an evolving system [16]. Where building on existing systems has been included in some detail in Jacobson's studies of achieving 100% renewable energy (wind, solar and hydropower) in the U.S. [17], individual states [18] and in New York with more specificity [19] the cost of new transmission has been applied to all electricity generated when such investments are likely only to benefit output from the marginal wind power installations that necessitate new transmission. That the largest aggregate wind power variability also occurs at these margins is not widely understood.

There is, therefore, a research gap to evaluate intraregional impacts of deep wind power penetrations in existing transmission-constrained regional systems. Additional insight is to be gained by comparing net load effects with and without transmission upgrades intended to improve wind-generated electricity utilization. Implicit in these open questions is the intraregional geographical distribution of large-capacity VRE integration effects, particularly in cases of highly heterogeneous supply and demand (e.g. high VRE potential distant from high load areas). To build on earlier research, we also emphasize the need to analyze sub-hourly effects [20], which have largely driven the most challenging curtailment issues to date [21], particularly following transmission capacity upgrades that alleviated curtailment in earlier phases of wind power buildout [22].

Means of providing grid flexibility to integrate VRE have been reviewed extensively elsewhere [23], and include adaptable market functions [24] and effects particular to wind power [25]. In larger regional systems, wind (and solar) power integration has significantly improved, largely via imbalance ("real-time") markets [26] and transmission expansion [21]. The current market approach is largely evolutionary, instituting or improving higher time resolution market clearing mechanisms and fast-responding ancillary services to adjust to VRE supply variability rather than the demand variability and emergency situations for which they were initially developed [27]. This evolutionary approach has been successful at nearly eliminating wind power curtailment up to approximately 10% energy penetration in California [28] and Texas [29]. However, in most recent years curtailment has increased at accelerated rates in, for example, Texas (2.5% curtailment [29] at 14.8% penetration [30] in 2017, compared to 0.5% curtailment [29] at 9.1% penetration [30] in 2014), Germany (4.4% curtailment at 13.0% penetration in 2016, compared to 0.70% curtailment at 8.4% penetration in 2012 [31]) and the UK (5.6% curtailment at 11.1% penetration in 2016, compared to 0.44% curtailment at 5.6% penetration in 2012 [31]). Deeper penetrations have been achieved in some unique geographic settings, such as Denmark's connection to the Nordic grid's large traditional and pumped hydro storage capacity [32] and Portugal's availability of significant run-of-the-river hydropower flexibility [21].

Recent trends indicate that the evolutionary market approach may no longer continue to be effective at deeper penetration rates and that regular adjustments will be needed as wind power capacity grows. This raises the need for further research to compare anticipated needs for reliability to previously published methodologies for computing ancillary service needs [33] and their application to large regional systems [34], as well as to those computed for comprehensive studies such as NREL's EWITS [12]. The widely known "3% load plus 5% wind" rule-of-thumb also offers a useful comparison for operating reserve requirements [35]. It is also essential to evaluate the geographically heterogeneous needs in a regional system and whether such effects are exacerbated by expanded transmission; the significance of these points is absent from the existing literature. In addition to the scale of such measures, their distribution within a system is also likely to inform technological and market solutions for wind integration.

To investigate the intraregional effects of wind power expansion, we analyzed New York State's electricity system, operated by the New York Independent System Operator (NYISO). New York provides a particularly attractive case study because the boundaries of the state and the NYISO control area align, and it contains a dense urban area (New York City; NYC) and distant high-wind potential areas. NYC is projected to continue to require approximately 33% of the state's annual electricity demand, yet renewable energy potential in NYC represents merely 0.1% of "economically viable" statewide renewable energy resources [36]. We characterize the effects of the variable supply by employing common electricity system metrics to allow for comparison to other systems. In presenting the technical, non-market-specific results, we offer support for understanding the impact on other existing market structures or conceived future markets; we do not simulate markets themselves, which is a separate significant area of research itself that can be informed by the findings of this study.

The paper is organized to first describe the methodology of computing net load effects, operating reserves and regulation services (Section 2). Section 3 presents pertinent results, and Section 4 discusses the implications of our findings. Section 5 summarizes our conclusions, as well as plans and needs for further research.

2. Methodology

An optimization model was formulated as a linear program with 11 zones and interzonal transmission limits consistent with the current NYISO system. Actual zonal electricity demand for six years (2007–2012) at five-minute time steps [37], monthly hydropower electricity generation [38], and nuclear generation for a representative year [39] were used to establish the baseline model. In a previous study, we developed a wind power expansion model that analyzed six years (2007–2012) of model wind power data at five-minute time steps [13]; the description of the simulated wind power time series, which modified a NREL model data set [40], is not repeated in detail here. For the current study, additional analytical models were developed to (1) identify cost-effective transmission upgrades, (2) compute the zonal net load and ramping effects in different zones and regions, and (3) estimate ancillary service requirements to ensure operational reliability. In post-processing, several additional analyses were performed to present pertinent findings.

The methodology described in this section was applied to the NYISO control area, which shares the boundaries of New York State. Geographical disparities in existing electricity demands and wind power potential are shown in Fig. 1. Differences between areas surrounding NYC (closely represented by zones H-K) and the remainder of the state are particularly striking: Whereas approximately half of the electricity demand is concentrated in Zones H-K, more than 96% of potential on-shore wind-generated electricity production is located in Zones A-G, with 86% in Zones A-E alone.

2.1. Zonal net load

The zonal net load, $NL_{c,z,t}$, at each time step, t, for each statewide wind capacity, c, is computed by:

$$NL_{c,z,t} = D_{z,t} - U_{c,z,t} - B_{z,t} + \sum\nolimits_{z' \in Z} [T_{c,zz',t} - (1 - l_{zz'})T_{c,z'z,t}] \tag{1}$$

where $D_{z,t}$ is the actual zonal electricity demand, $U_{c,z,t}$ is zonal wind-generated electricity utilized, $B_{z,t}$ is zonal baseload-generated electricity, $T_{c,z'z,t}$ is electricity transmitted into zone, z, from another zone z', $T_{c,zz',t}$ is electricity transmitted out of the zone to another zone, and Z is the set of all zones, $Z = \{A, B, C, D, E, F, G, H, I, J, K\}$; zone definitions and geographic boundaries are those of the existing NYISO system [37]. A single fixed loss factor $l_{zz'}$, is applied to energy transmitted between any two zones. While $l_{zz'}$ is not the precise transmission loss (which would vary with actual conductor sizes and transmission line load factors, among other parameters), a relatively high loss factor of 5% per 100 miles was assumed to ensure that wind-generated electricity is first used close to its source.

Uncurtailed baseload generation is assumed to include existing nuclear and hydroelectric generators with some modifications: Continuously operating nuclear power of 523 MW in Zone B and 1740 MW in Zone C contribute annual energy equivalent to the 2014 electricity generation from those facilities [39]. The nuclear baseload, $B_{nuc,z}$, excludes one plant in Zone C that has been under consideration for closure and one plant in Zone H that is slated to closed as early as 2021. Baseload generation, $B_{z,t}$, also includes (a) monthly constant

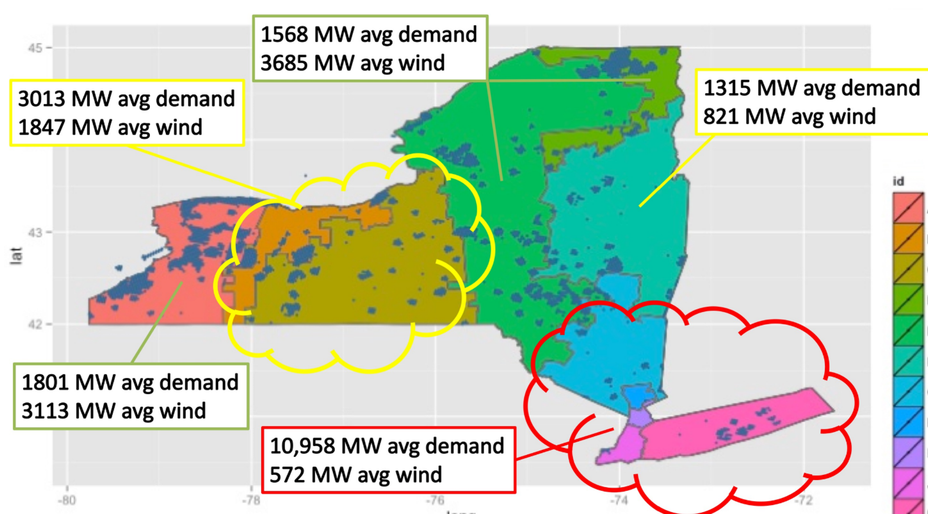

Fig. 1. NYISO zones [37] and distribution of average electricity demand [37] and average potential wind power [13]; both correspond to the years 2007–2012. Wind values correspond to average output in the full 37.8 GW capacity data set at wind sites indicated by points [40].

hydroelectric power output for each zone, computed by dividing the actual monthly electricity produced in each zone [38], $E_{hydro,z,m(t)}$, by the number of hours in the respective month, $n_{hrs,m(t)}$, and (b) a constant hydroelectric baseload, $B_{hydro\text{-}const,z}$, of 1000 MW in Zone J, in anticipation of a potential transmission project directly from Hydro Quebec [41].[1]

$$B_{z,t} = B_{nuc,z} + B_{hydro-const,z} + \frac{E_{hydro,z,m(t)}}{n_{hrs,m(t)}} \tag{2}$$

The purpose of the analysis is to compute requirements for the balance of the system, largely expected to be dispatchable fossil fuel-based electricity generation. As individual fossil fuel generators are not modeled, the net load, as defined by Eq. (1), is used to analyze system resources other than the explicitly modeled low-carbon generation; the model is formulated so as to minimize the need for electricity from these other resources. As such, for a given systemwide wind power capacity, c, the model minimizes the statewide net load through the following objective function:

$$\min_{t} \sum_{z \in Z} NL_{c,z,t} \tag{3}$$

subject to the following constraints:

$$U_{c,z,t} \leq \sum_{s \in S_{z,c}} W_{s,t}, \quad \forall\, z \in Z, \forall\, t \in \mathrm{T} \tag{4}$$

$$T_{c,zz',t} \leq L^{+}_{c,zz'}, \quad \forall\, z, z' \in Z, \forall\, t \in \mathrm{T} \tag{5}$$

$$T_{c,z'z,t} \leq L^{-}_{zz'}, \quad \forall\, z, z' \in Z, \forall\, t \in \mathrm{T} \tag{6}$$

$$NL_{c,z,t} \geq 0, \quad \forall\, z \in Z, \forall\, t \in \mathrm{T} \tag{7}$$

where $W_{s,t}$ is the potential wind power output at site, s, at time, t; $S_{z,c}$ is the set of wind sites in zone, z, included for a given statewide wind power capacity, c; $L^{+}_{c,zz'}$ is the positive flow transmission limit on line z-z'; and $L^{-}_{zz'}$ is the reverse flow transmission limit on line z-z'. In this formulation, which includes the definition of net load shown in Eq. (1), the decision variables are the wind-generated electricity utilized, $U_{c,z,t}$, in each zone, as well as positive ($T_{c,zz',t}$) and reverse ($T_{c,z'z,t}$) interzonal transmission flows, all at each time step, t.

Simulated interzonal transmission limits are actual limits as included in operational reliability assessments of the existing system [42]. Anticipating that a significant expansion of wind power capacity may be accompanied by some increase in transmission capacity, the limits for transmission lines identified as potential "bottlenecks" (zonal interfaces A-B, B-C, E-G and G-J) were increased to the maximum line capacities at which the marginal cost of transmission remained less than the marginal reduction in cost of wind-generated electricity.[2] Therefore, for a given statewide wind power capacity, the positive flow transmission limits between zones, $L^{+}_{c,zz'}$, are given by the sum of the existing limits [42], $\{L^{+}_{zz'}\}'$, and a transmission capacity upgrade, $\{L^{+}_{zz'}\}^{up}_{c}$:

$$L^{+}_{c,zz'} = \{L^{+}_{zz'}\}' + \{L^{+}_{zz'}\}^{up}_{c} \tag{8}$$

The above optimization problem with constraints was formulated as a Linear Program (LP) in the computing software R [43] and solved using the mathematical programming solver Gurobi [44]. As further computations are instructive at regional levels incorporating multiple zones, z, the net load was then computed for a given region, R, by:

$$NL_{c,R,t} = \sum_{z \in R} NL_{c,z,t} \tag{9}$$

2.2. Wind-generated electricity and total low-carbon-generated electricity

Because only low-carbon electricity generation is simulated in this study, the low-carbon electricity meeting regional electricity demand, $low.c_{c,R,t}$, is given by the difference between the regional demand, $D_{R,t}$, and the regional net load at a given statewide wind power capacity, $NL_{c,z,t}$, at each time step, t:

$$low.\, c_{c,R,t} = D_{R,t} - NL_{c,R,t} \tag{10}$$

The wind-generated electricity, $wind_{c,R,t}$, used to meet the demand in a region, R, is thus the difference between the low-carbon electricity meeting regional demand, $low.c_{c,R,t}$, and the low-carbon electricity meeting regional demand with no wind power, $low.c_{0,R,t}$, for a given total wind power capacity, c, at all times, t:

$$wind_{c,R,t} = low.\, c_{c,R,t} - low.\, c_{0,R,t} \tag{11}$$

2.3. Net load ramping

The system also must respond to the rate of change in net load – typically referred to as the "net load ramp rate" or, as a more general concept, "net load ramping". Previous studies have shown the importance of evaluating the net load ramping effects at a sub-hourly time step [20], consistent with the five-minute time step used for the study described in this paper and in many energy markets. For each statewide wind power capacity, c, and a given region, R, the net load ramp rate, $NLR^{(t_s)}_{c,R,t}$, was computed for various time scales, t_s, corresponding to current typical grid operational markets and services:

$$NLR^{(t_s)}_{c,R,t} = NL_{c,R,t} - NL_{c,R,t-n_{ts}}, \quad \forall\, t \in \{(1 + n_{ts})\text{: T}\} \tag{12}$$

Net load ramp rates are only calculated for the time steps $t \in \{(1 + n_{ts})\text{:T}\}$ for which the time series data is sufficient to compute differentials across time steps. Here, n_{ts} is the number of time steps before the time step of interest necessary to calculate $NLR^{(t_s)}_{c,R,t}$ at time scale, t_s, and T is the total number of time steps in the time series. Table 1 summarizes the NLR scenarios considered and corresponding relevant computational parameters.

To determine the magnitude of extreme ramp rates occurring under a particular wind capacity and HP penetration scenario, various inner quantile ranges of $NLR^{(t_s)}_{c,R,t}$ were considered outside of which NLR events were rare. The upper bound net load (positive) up-ramp, $UR^{(t_s,q)}_{c,R}$, and lower bound net load (negative) down-ramp, $DR^{(t_s,q)}_{c,R}$, for a given inner quantile probability range, q, are given by:

$$UR^{(t_s,q)}_{c,R} = \left\{ \max_{t \in (1+n_{ts}):T} NLR^{(t_s)}_{c,R,t} \,|\, P\left(NLR^{(t_s)}_{c,R,t'} \leq NLR^{(t_s)}_{c,R,t}\right) \leq \left(q + \frac{1-q}{2}\right) \right\} \tag{13}$$

$$DR^{(t_s,q)}_{c,R} = \left\{ \min_{t \in (1+n_{ts}):T} NLR^{(t_s)}_{c,R,t} \,|\, P\left(NLR^{(t_s)}_{c,R,t'} \geq NLR^{(t_s)}_{c,R,t}\right) \leq \left(q + \frac{1-q}{2}\right) \right\} \tag{14}$$

2.4. Ancillary services requirements

We deployed methodologies consistent with a NYISO wind power expansion study [45] to compute increases in frequency regulation and operating reserve requirements, collectively "ancillary services," under the simulated wind power capacities. Regulation requirements are assessed at a five-minute timescale and operating reserve requirements at 10-min and 30-min timescales.

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[1] The baseload generation assumptions do not reflect any political opinion of the authors, but represent one reasonable future scenario given current trends in the state.

[2] Based on cost and financing assumptions consistent with the U.S. Energy Information Administration's Annual Energy Outlook [49]: Overnight capital cost of wind power is \$1980/kW, a location adjustment multiplier of 1.01 for wind power in New York State, a 6.1% annualization rate for capital costs and \$39.53/kW-yr operation and maintenance.

Table 1
Net load ramping scenarios and parameters.

NLR scenario	Corresponding existing markets/services	Time scale, t_s (min)	Number of time steps, n_{ts}
5 Minutes	Regulation	5	1
10 Minutes	10 Minute Spinning Reserve 10 Minute Total Reserve	10	2
30 Minutes	30 Minute Total Reserve	30	6
1 Hour	Day-Ahead Market	60	12

2.4.1. Regulation services

Regulation requirements are currently set for four different seasons: April-May, June-August, September-October and November-March [46]. Because of the potential for significant intraseasonal variation in wind power supply, we computed monthly regulation requirements, $P_{c,m,h}$, for each hour, h, in each month, m, for each statewide wind power capacity, c. Regulation requirements were computed based on three times the standard deviation, SD, of the net of the five-minute difference in demand and 10-minute difference in wind power output; the different time steps are due to NYISO's five-minute dispatch model and a five-minute-ahead persistence forecast model for wind power output; computed results are then rounded up to the nearest 25 MW. Where our simulations indicate possible lower regulation requirements, we maintain the existing requirement. This approach to computing $P_{c,m,h}$ is described by:

$$P_{c,m,h} = \max_{t\in m,h}\begin{cases} P_{existing,m,h} \\ \left[25 \times \left\lceil \frac{3\times SD\left(\left(\sum_z (D_{z,t} - D_{z,t-1}) - (U_{z,t} - U_{z,t-2})\right)\right)}{25}\right\rceil\right] \end{cases} \tag{15}$$

Regulation services are assessed statewide; however, for the purposes of some computations in this study, it is useful to distribute the capacity committed to regulation among regions. For each wind power capacity, c, the regional regulation commitment, $\rho_{c,R,t}$, in this study is assumed to be prorated by the regional net load, $NL_{c,R,t}$, at every time step, t:

$$\rho_{c,R,t} = P_{c,m(t),h(t)} \times \frac{NL_{c,R,t}}{\sum_z NL_{c,z,t}} \tag{16}$$

2.4.2. Operating reserves

Several reliability conditions inform the establishment of operating reserve requirements, which are set for four regions: Zones A-K (all of NYS), Zones F-K, Zones G-K and Zone K. This study takes the existing locational operating reserves [47] as given and employs a method, based on a NYISO wind expansion study [45], to compute increased locational reserve requirements from maximum simulated 10-min and 30-min net load ramp rates. Although 10-min reserve requirements are set for synchronous ("spinning") and total reserves, we compute total reserves only, consistent with the approach of [45].

At each wind power capacity, c, the 10-minute operating reserve, $\mu_{c,R}^{(10)}$, and 30-minute operating reserve, $\mu_{c,R}^{(30)}$, are computed based on the existing respective operating reserve requirements, $\mu_{existing,R}^{(10)}$ and $\mu_{existing,R}^{(30)}$, and the respective maximum net load up-ramps, $UR_{c,R}^{(10,max)}$ and $UR_{c,R}^{(30,max)}$, for each region, R:

$$\mu_{c,R}^{(10)} = \max\begin{cases} \mu_{existing,R}^{(10)} \\ UR_{c,R}^{(10,max)} \end{cases} \tag{17}$$

$$\mu_{c,R}^{(30)} = \max\begin{cases} \mu_{existing,R}^{(30)} \\ UR_{c,R}^{(30,max)} \end{cases} \tag{18}$$

3. Results

The subsections below present the computed statewide and intrastate results of wind-generated electricity utilization, net load and ramping effects with increasing capacities of wind power. In addition to a simulated case with no wind power, a subset of wind power growth scenarios is presented: 5, 10, 20 and 30 GW, as well as 20 and 30 GW wind power scenarios with upgraded transmission capacity. The most aggressive of these scenarios represents potential wind-generated electricity of 46.6% of total demand and 70% of total demand minus fixed hydropower and nuclear generation. By comparison, in 2017 New York State had a total installed wind power capacity of 1.8 GW [48] supplying 2.4% of the system's 18.7 GW average demand [37]. All results presented in this section reflect simulations of six years (2007–2012) at five-minute time steps, as described in Section 2; aggregate supply and demand values presented were computed for the full time period unless otherwise noted.

3.1. Wind-generated electricity

Rather than repeat the dominant causes of curtailment in deep wind power penetration scenarios assessed in our previous study [13], here we simply summarize the contribution of wind-generated electricity, in combination with low-carbon nuclear and hydro baseload generators, to meet the overall system's electricity demands. Fig. 2 shows the computed values with the following effects:

(a) wind turbines being installed at sites with diminishing production after the best sites are first used; this effect is reflected in the nonlinear relationship between wind power output and capacity for the "Uncurtailed" case shown in Fig. 2;
(b) curtailment due to a combination of continuously operating baseload generation and insufficient demand to be met by potential wind supply, reflected in the difference between the "Uncurtailed" and "Upgraded Transmission" cases; and
(c) curtailment due to transmission constraints between zones (in addition to the demand and baseload constraint), reflected in the "Existing Transmission" case shown in Fig. 2.

In an actual electricity grid, there can be significant geographic disparities in electricity sources meeting demand, particularly with greater reliance on utility-scale VRE resources, even in a relatively contained grid such as New York; this can be seen in Fig. 3 (with the width of each bar scaled to the regions' average electricity demand). The West region of the state (Zones A-E) contains the vast majority of suitable wind power sites (and much of the existing low-carbon

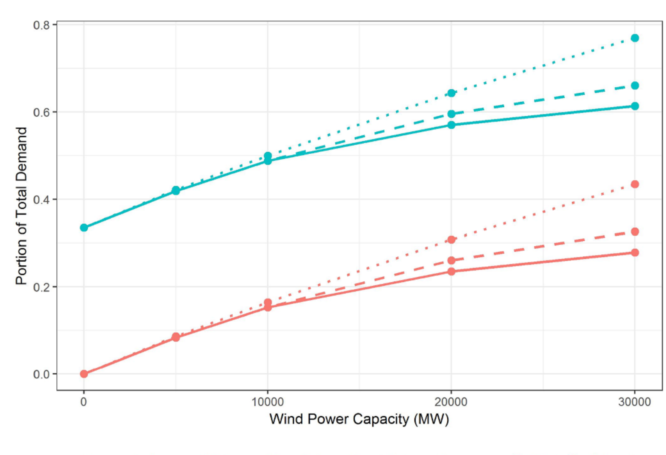

Fig. 2. Share of New York State demand met by wind-generated electricity and all low-carbon resources over full six-year analysis period.

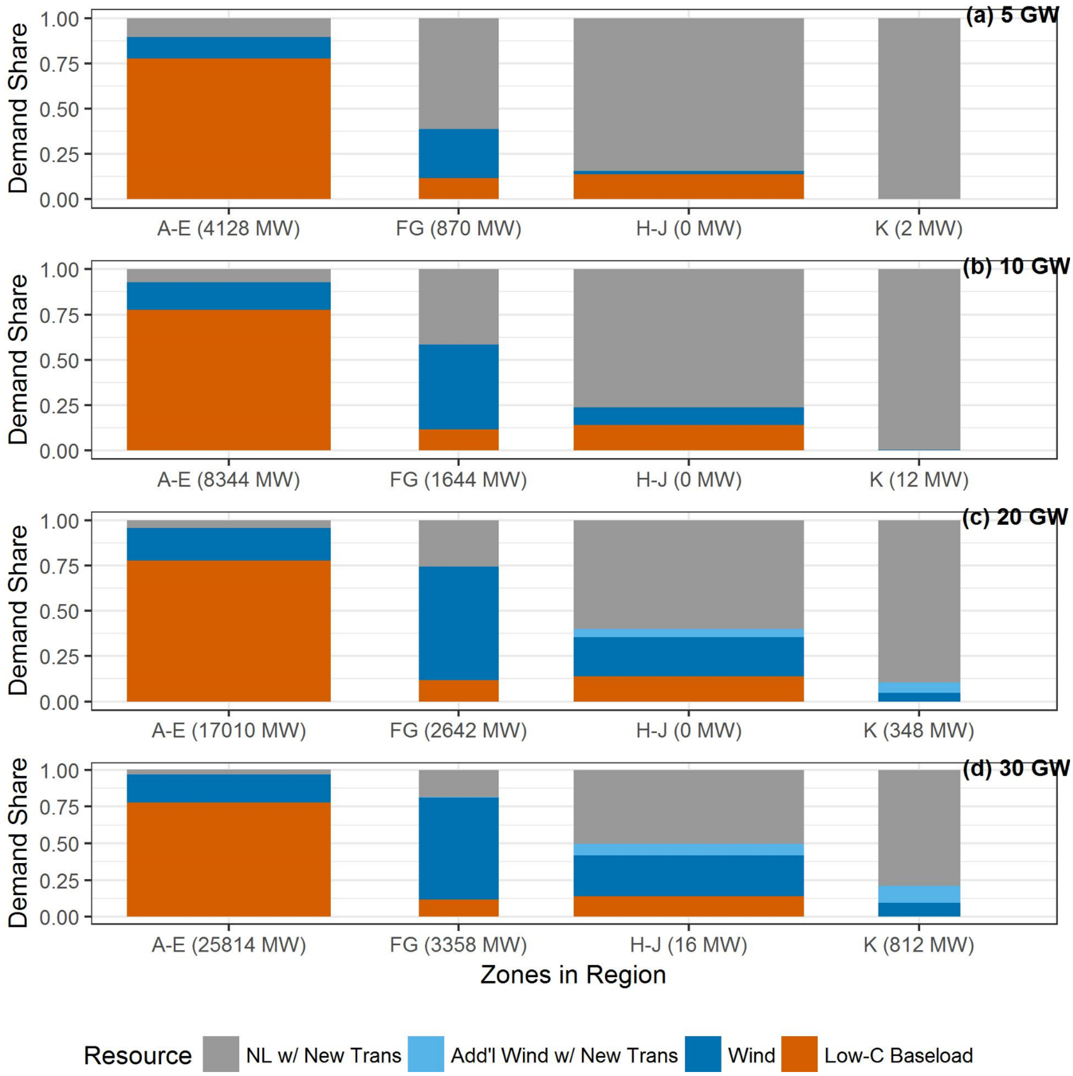

Fig. 3. Simulated share of total six-year demand met by low-carbon generation in select regions for statewide wind power capacity scenarios of (a) 5 GW, (b) 10 GW, (c) 20 GW and (d) 30 GW. The width of each bar is scaled to the average demand: Zones A–E 6383 MW, Zones F–G 2495 MW, Zones H–J 7211 MW and Zone K 2567 MW.

hydropower and nuclear generators), whereas southeastern areas (the "NYC Metro" area of Zones H-J and Long Island of Zone K) have the highest demand; Zones F-G sit between these regions. As wind power capacity first expands (5–10 GW), the wind-generated electricity meets loads in Zones A-E and Zones F-G with some portion reaching Zones H-J. However, with larger capacities (20–30 GW), much of the marginal increase in wind-generated electricity serves NYC Metro's demand and, to a lesser degree, Zone K. Transmission upgrades allow additional wind-generated electricity utilization, nearly the entirety of which meets loads in NYC Metro and Zone K.

Fig. 3 also shows the remaining electricity required from other generators in the regions distant from the wind resource even with low-carbon resources providing more than 60% of the state's total electricity demand. The nature of that net load has significant implications for generation capacity and system operational reliability.

3.2. Net load after utilizing low-carbon electricity

In general, the net load after utilizing existing low-carbon resources and future wind power dictates the need for other generation capacity; this will presumably be fossil fuel-based. Electricity demand and, thus, net load after existing low-carbon nuclear and hydropower, has always exhibited seasonal trends; however, intermittent wind supply will almost certainly require larger net generation *capacity* than may be implied by the *energy* needs computed for the full simulation period (Fig. 3). As such, despite the addition of up to 30 GW wind power capacity, coupled with transmission upgrades, the analysis indicates that a relatively small amount of capacity reduction from other generators is possible, as seen in Fig. 4. (In Fig. 4, and subsequent relevant figures, we use the designation "transup" to indicate scenarios that include the transmission capacity upgrades indicated by Eq. (8).)

For the "30 GW wind with upgraded transmission" scenario, in the month with the largest Statewide net load peak reduction, June, the reduction is 4835 MW, 16% of the total installed wind power capacity and 15% of the peak electricity demand in that month. At the peak statewide net load during July, 30 GW wind power capacity and upgraded transmission reduces the peak net load by only 1584 MW, 5.3% of the total installed wind power capacity and 4.7% of the peak electricity demand. The needs for other generation capacity are more pronounced in Zones H-K, distant from the wind resource: At the peak summer load, the net load reduction is 120 MW, less than 1% of the Zone H-K peak demand. This suggests that, even with large wind power and transmission expansions, the full generation capacity in NYC Metro and Zone K will need to be maintained. The reduced need for energy from these generators imply reduced capacity factors of generators.

Sampling one day from the simulation period can illustrate some of

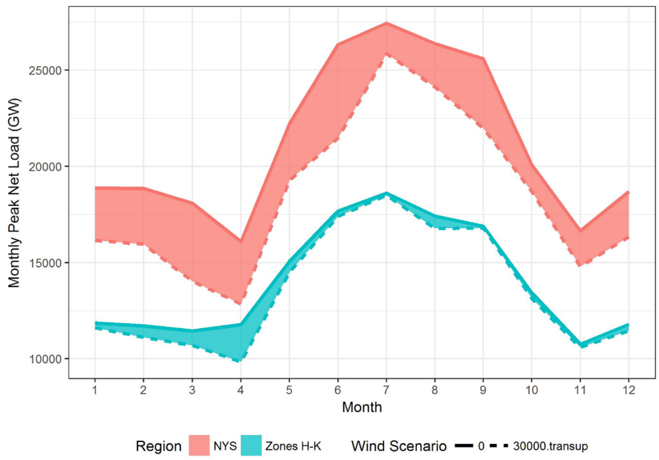

Fig. 4. Monthly peak net load over the six year analysis period for New York State (NYS) and NYC Metro (Zones H-K). The upper bounds represent the no new wind power scenario; the lower bounds represent the scenario with 30 GW statewide wind power capacity and select transmission upgrades.

the most extreme effects of expanded wind power on net loads. Fig. 5 shows the day in the six-year time series with the largest increase in net load (corresponding to the largest decrease in wind power output for the 30 GW capacity scenario); simulations with both existing and expanded transmission capacities are shown. During the first approximately eight hours of the day, the wind-generated electricity exceeds the total statewide demand. This extended period of zero or near-zero load alone is unlike any existing operational characteristics of the electricity grid; other similar periods occur throughout the simulation period. The net load ramping effects are also striking: One large, sharp increase in net load and one more gradual, though still large, increase in net load; this behavior is exacerbated by expanded transmission capacity. This behavior implies the need for significant generation capacity that can ramp up quickly, but that may not be called upon to deliver large amounts of electricity over the course of a full year.

The most variable net loads occur in zones distant from the wind resource. As more wind power is installed, the low-carbon electricity generated in Zones A-E first meet the loads in those zones, then in Zones F-G, before reaching Zones H-J (NYC Metro); lastly Zone K loads are met (though some Zone K wind power is included in this scenario). However, because significant amounts of wind-generated electricity reach these distant zones only at high power outputs, these zones see the largest fluctuations in supply and resulting net load.

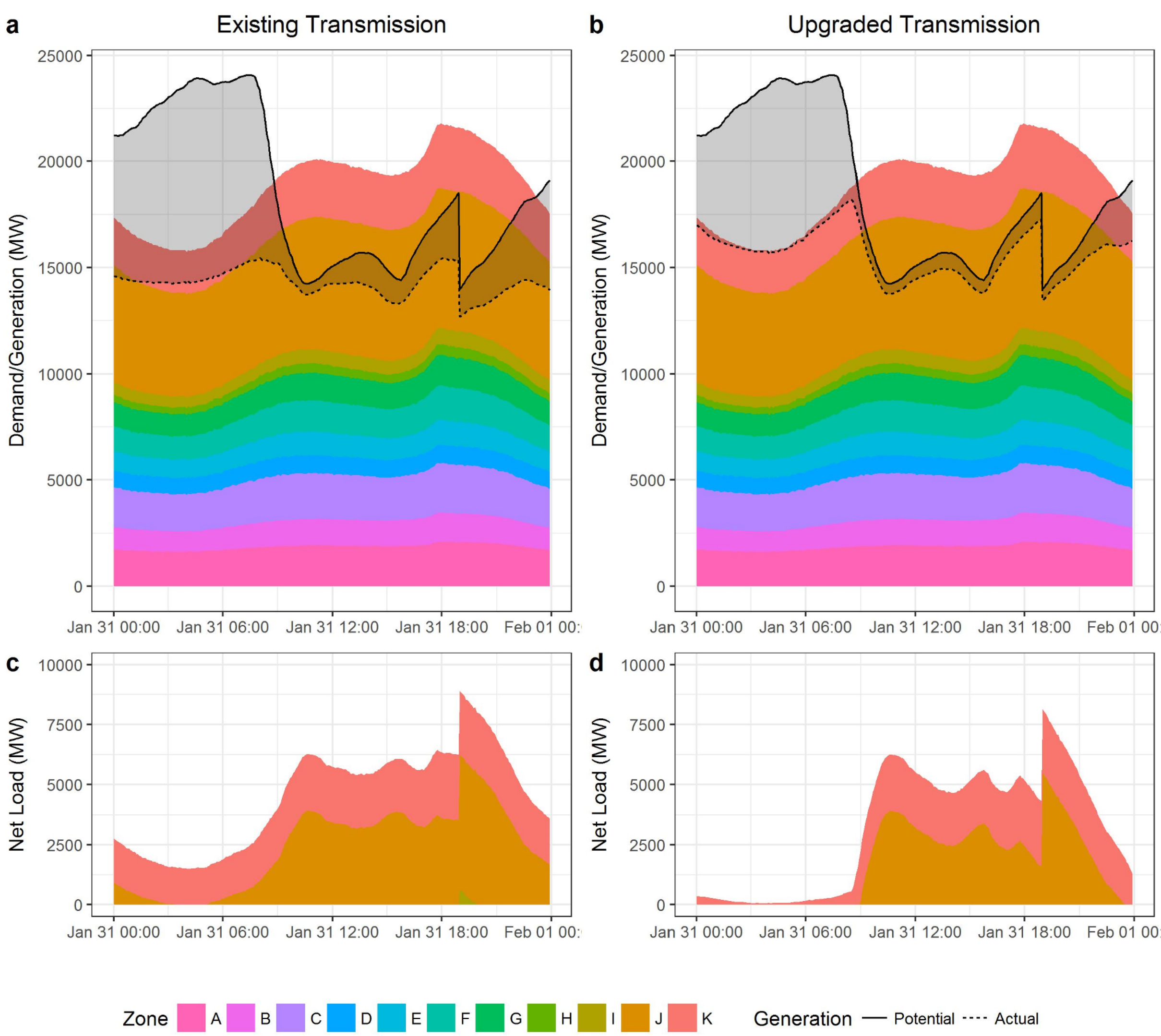

Fig. 5. Time series, with five-minute time steps, of simulated day with largest net load ramp in 30 GW wind power scenarios: (a) Zonal electricity demands (stacked areas), total statewide potential and actual low-carbon electricity for existing transmission constraint scenario; (b) analogous to (a) with upgraded transmission limits; (c) zonal net load corresponding to (a); and (d) zonal net load corresponding to (b).

Assessing the most extreme net load ramps over the full simulation period further illustrates the spatial imbalance in the system response to wind supply variability. Fig. 6 shows that, for all time periods considered (5, 10 and 30 min; 1 h), three general trends can be observed: (1) Extreme statewide net load up-ramps increase with increasing wind power capacity, (2) the portion of extreme statewide net load up-ramps that occurs in Zones H-K (combining the NYC Metro area and Zone K) increases with increasing wind power capacity, and (3) upgraded transmission capacity intensifies the first two trends.

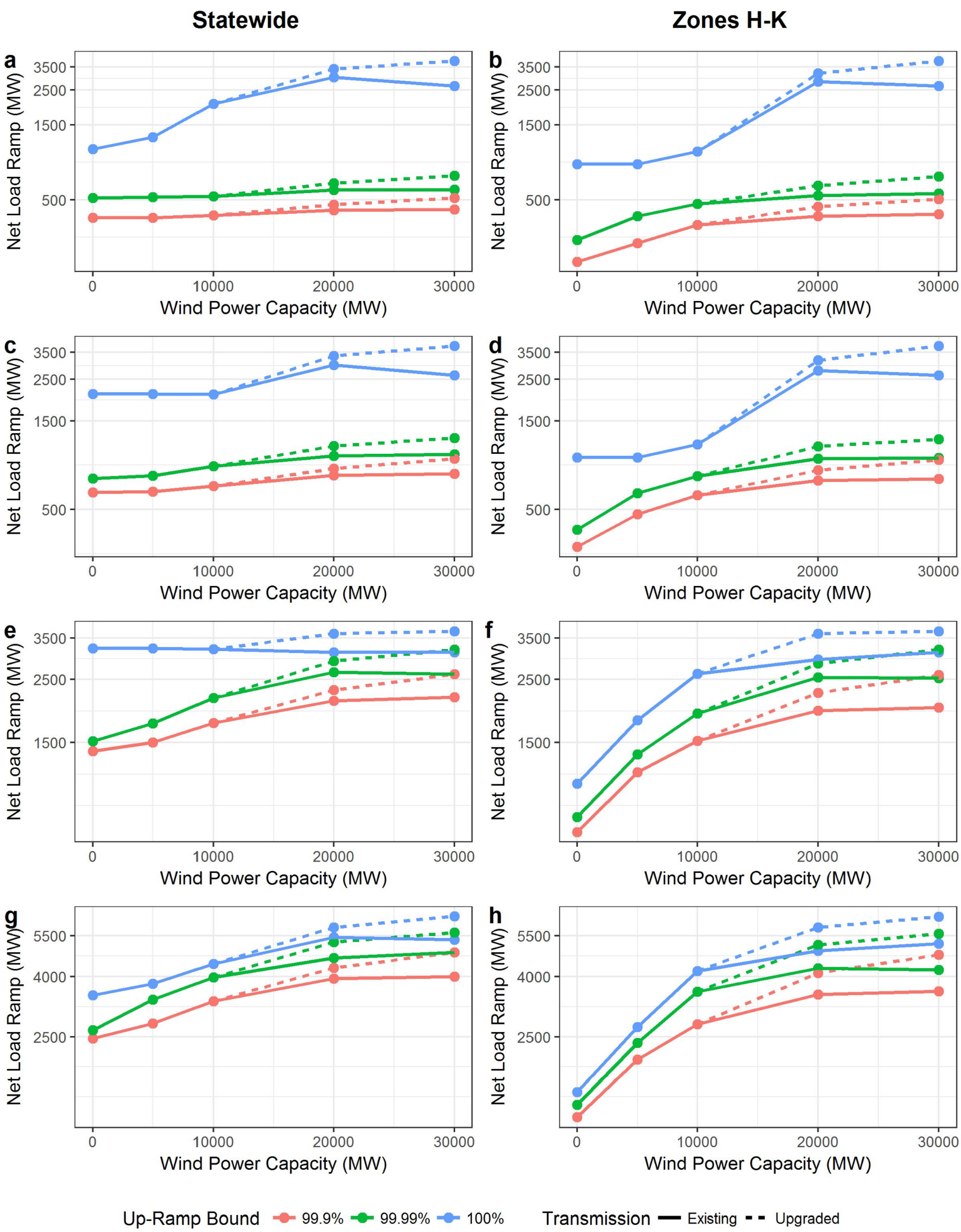

Fig. 6. Extreme net load up-ramps Statewide and in Zones H-K over the six-year analysis period: (a) Statewide 5-min NLR, (b) Zones H-K 5-min NLR, (c) Statewide 10-min NLR, (d) Zones H-K 10-min NLR, (e) Statewide 30-min NLR, (f) Zones H-K 30-min NLR, (g) Statewide one-hour NLR, (h) Zones H-K one-hour NLR.

3.3. System operational reliability needs

Grid operators ensure reliable transmission of electricity to power purchasers through a set of market mechanisms referred to as "ancillary services." NYISO ancillary services – including regulation and operating reserves – are similar to those of other grid operators and are highly sensitive to variations on the timescales shown in Fig. 6.

3.3.1. Regulation services

To maintain system frequency, generation resources are continuously balanced to changes in load. We computed hourly regulation requirements for each month. By reviewing the monthly average regulation requirements, we can identify overall trends across wind power capacities and across months (Fig. 7). The simulation with no wind power indicates a few hours in which existing regulation requirements may be slightly lower than computed, but this can likely be explained by the monthly approach employed here in place of NYISO's seasonal approach. Only minor changes are seen in the 5 GW scenario during the spring and fall seasons, but without a major shift in the regulation regime. For the discussion below, we set aside the 0 GW and 5 GW simulations so that differences between existing regulation requirements and computed increases can be more easily observed.

With increasing wind power capacities at and beyond 10 GW, regulation requirements begin to increase when observed at both the monthly average and hourly resolutions (Fig. 8). Increasing simulated wind power capacity from 10 GW to 20 GW results in sharp increases in summer regulation requirements, tapering off through the shoulder seasons into more modest increases in winter months. Increasing wind power capacity from 20 GW to 30 GW does not substantially increase regulation requirements with existing transmission limits. The result is that, at 30 GW wind power capacity, computed average regulation requirements are only 1.0% of the capacity; the maximum computed hourly regulation requirement reaches 1.8% of the capacity.

Upgrading transmission concurrent with large capacity additions has a significant influence on regulation requirements; increased transmission limits exposes the system to larger supply fluctuations when they may have otherwise been curtailed (see Fig. 5). One indicative result is that more than 50% of the increase in annual regulation requirements computed for the "30 GW wind power with upgraded transmission" scenario can be attributed to the increased transmission. While significant, the computed average regulation requirement of 413 GW is only 1.4% of the 30 GW capacity; the maximum computed hourly regulation requirement reaches 2.6% of the capacity.

Increases in hourly regulation requirements are most pronounced at times of demand up-ramping in the morning and the more modest demand down-ramping in the evening. This indicates that the combined effects of changes in demand and wind output may cause wider variation in system response needs than would be implied by demand or wind variations alone. Transmission upgrades exacerbate these effects with potentially major shifts in regulation requirements in some hours: There are times that computed regulation requirements are 3–4 times existing levels.

3.3.2. Operating reserves

The expected changes in regulation requirements are significant, yet more capacity is currently committed to operating reserves. With increasing simulated wind power capacity, this study indicates two general trends: (1) Significant increases in both 10-min and 30-min reserves and (2) concentration of these reserves in the state's Southeast that includes the dense NYC Metro area and grid edge, Zone K. At the largest wind power capacities, 20 and 30 GW, transmission upgrades further increase Statewide and Southeast operating reserve requirements, as shown in Fig. 9. (Note: The regions shown in Fig. 9 reflect those for which NYISO sets requirements.)

At any given time, various amounts of dispatchable generation capacity (and, to a considerably lesser degree, energy storage and demand-side resources) are committed to providing energy to meet loads and to the various ancillary services described above. As a result of, primarily, the predicted increase in operating reserves and the reductions in net load, an increasing portion of this total committed capacity is allocated to ancillary services in our simulations. The overall trend can be observed by comparing the dispatchable capacity committed to energy services and ancillary services in the "no new wind power" and "30 GW wind power with upgraded transmission" scenarios. Fig. 10 implies that the resource itself and the reliable service it provides may become increasingly valuable vis-à-vis the actual energy they supply to meet loads. There even may be times when no energy is required from fossil fuel generators, but operating reserve requirements remain high in order to ensure reliable operation of the overall system.

3.4. Distribution of energy infrastructure investments

Sections 3.1–3.3 describe statewide, intrastate and zonal trends in simulations of scenarios with increasing wind power capacity. As the scale of wind-generated electricity utilization, operating reserves, regulation requirements and, in some defined cases, transmission capacity all increase, the benefits of incremental changes accrue to different regions. As such, we can allocate those "investments" to the regions they benefit; we quantify investments in energy terms as predicting the future market costs of such services is beyond the scope of this study. Fig. 11 summarizes our findings. The primary result clearly shown in Fig. 11 is that, despite the vast majority of wind power capacity being installed in Zones A-E, wind-generated electricity utilization is mostly in the eastern regions of the State at the largest wind power capacities simulated. As such, the benefits of new regulation and operating reserves accrue to areas with little or no wind power. This is particularly stark for the NYC Metro (Zones H-J) and Zone K areas and is intensified with upgraded transmission, which almost entirely benefits the NYC Metro area and Zone K.

4. Discussion

The modern electricity grid's primary function has been to provide the least cost reliable service. Due to the imperative to reduce energy-related greenhouse gas emissions and the best variable renewable energy (VRE) resources generally being in less densely populated areas, load centers may increasingly rely on more distant, intermittent

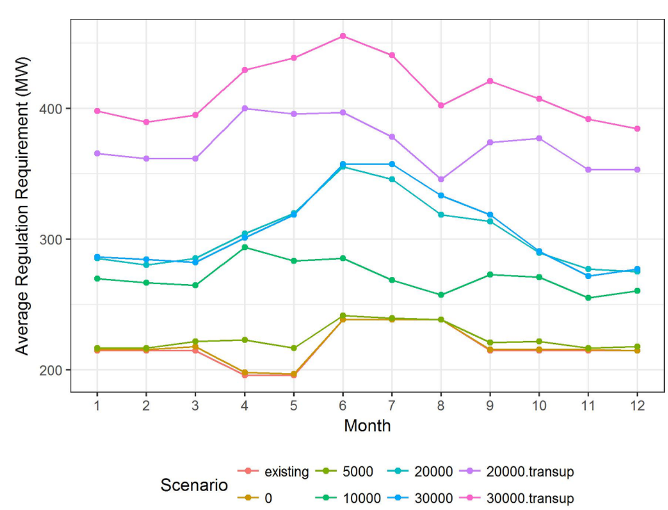

Fig. 7. Monthly computed average regulation requirements. (Note: The "existing" regulation requirements can be difficult to see because, aside from some slight variation in Months 3–4, they align with the 0 GW wind power capacity simulation.)

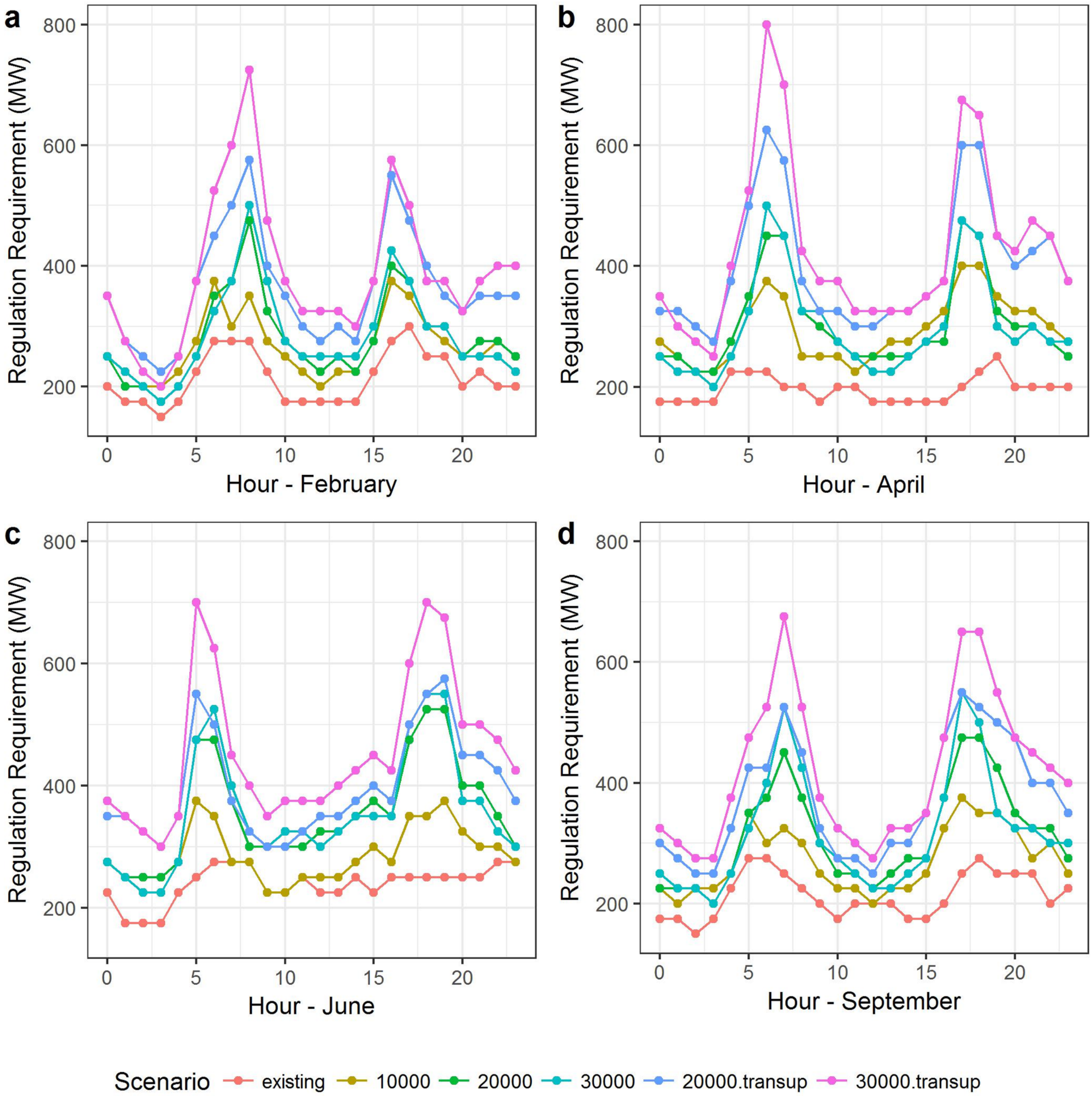

Fig. 8. Hourly computed regulation requirements for representative months and select simulated wind power capacities.

electricity generation. However, electricity first meets demands near the generator; only then is any additional supply available to meet more distant loads through the transmission system. Significant portions of the load centers' demands can be served by low-carbon resources only through very large capacity VRE installations. However, when VRE output is high, these load centers are particularly exposed to large fluctuations in supply. This leads to a pronounced increase in ancillary service requirements overall and concentration of those requirements in the load centers. Relieving transmission constraints allows more VRE-generated electricity to come through, but does not abate ancillary service requirements. In fact, increased transmission capacity can intensify ancillary service needs.

While this paper uses simulated wind power expansion in New York as a case study, significant distances between VRE supply and the highest demands are common, particularly in future scenarios including large VRE capacities. Counterintuitively, integration effects can be particularly acute at the grid "edge" where transmission lines terminate. Similar effects would be possible in a radial system with a load center at its hub.

It is instructive to examine a scenario of 30 GW wind power, both under existing transmission constraints and with targeted transmission upgrades, to synthesize the individual effects presented in detail in Section 3. With expanded VRE, the most fundamental needs for the balance of the system are the energy from and capacity of generators (or other resources) to meet the net load after utilizing low-carbon electricity; useful metrics are (a) total net load (in energy terms) and (b) peak net load (in power terms) over the six-year analysis period. We start in the West (Zones A-E) where most wind power is located, move through the intermediate Zones F-G, reaching the dense NYC Metro area (Zones H-J) and ending in Long Island (Zone K) at the opposite grid edge:

- Reduction in total net load compared to simulations with no new wind power: 86% (West), 79% (Intermediate), 32% (NYC Metro) and 9% (Long Island). With upgraded transmission, any changes in the West and Intermediate regions are negligible, whereas the values for NYC Metro and Long Island increase to 42% and 21%, respectively. (See Fig. 3 for additional detail.)

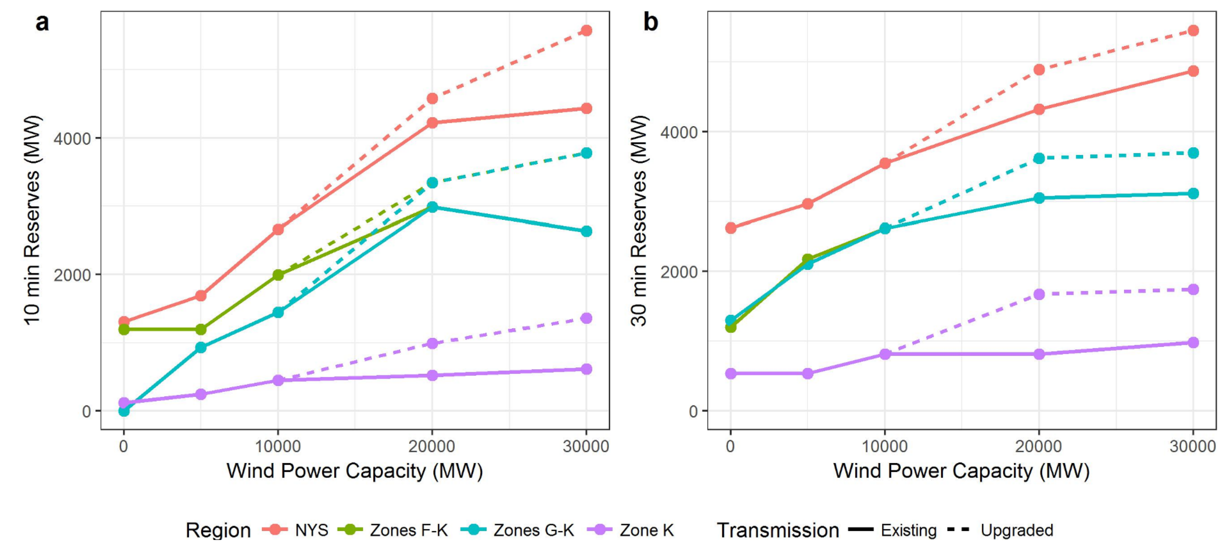

Fig. 9. Regional operating reserve requirements with increasing wind power capacities with existing and upgraded transmission limits: (a) 10-min total reserves and (b) 30-min total reserves. Note: The existing Zone K 30-min reserve requirement varies by hour; for simplicity here, only the peak existing 540 MW is shown.

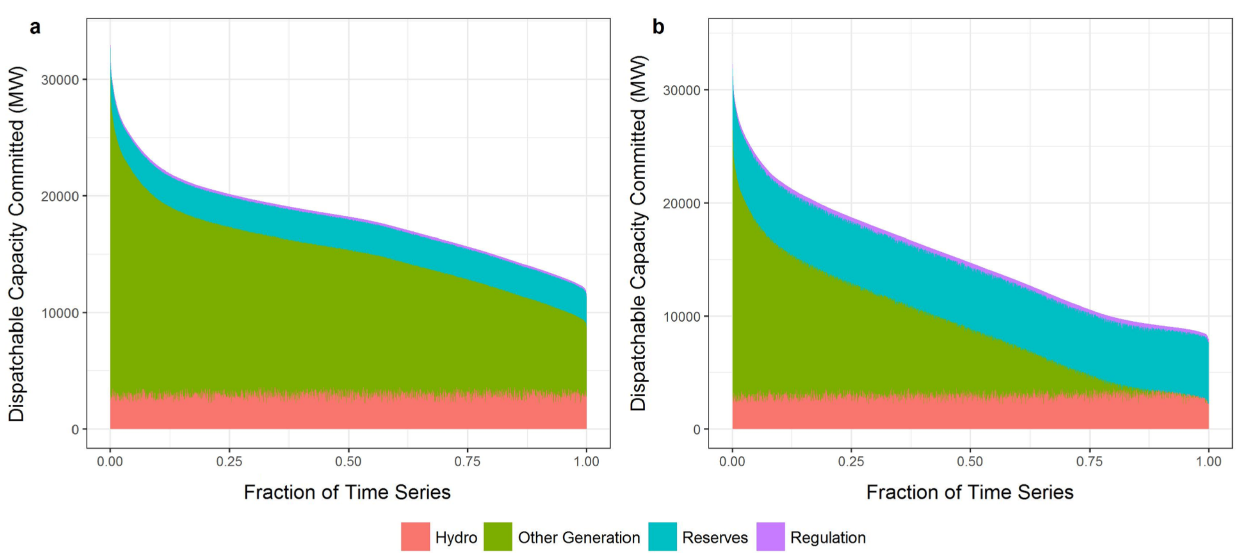

Fig. 10. Distribution of total dispatchable capacity committed to energy services (i.e."Hydro" and "Other Generation) and ancillary services ("Reserves" and "Regulation") over the full simulation time series: (a) No new wind power scenario; (b) 30 GW wind power with upgraded transmission scenario.

- Reduction in peak net load compared to simulations with no new wind power: 20% (West), 1.0% (Intermediate), 0.0% (NYC Metro) and 1.7% (Long Island). Upgraded transmission does not further reduce any peak net load.

The reduction in dispachable energy decreases from the wind rich zones of the West to the load centers of the Southeast. Further, there is no significant reduction in dispatchable generation capacity (to meet peak net loads). Combining these two effects results in lower capacity factors for the dispatchable sources. Current energy planning approaches, would then suggest higher electricity prices and/or the use of even lower efficiency fossil fuel generators. A more optimistic future scenario would be: This new net load regime may provide opportunities for resources such as energy storage, demand-side management and other distributed energy resources that can also provide the requisite ancillary services.

Looking at a zone on one edge of the grid– fossil fuel-dependent Long Island (Zone K) – and comparing it to the low-carbon energy-rich West (Zones A-E), we can further illuminate the heterogeneity of wind integration effects. In the 30 GW wind power scenario without transmission upgrade, 9% of Zone K's demand is met by low-carbon electricity (97% in Zones A-E). While this represents an average of 244 MW power reaching Zone K (1226 MW in Zones A-E), its variability increases Zone K's need for total operating reserves by 443 MW (nearly twice of the average wind reaching the Zone) compared to 438 MW in Zones A-E (about one-third of the average wind supply to those Zones). Upgrading transmission exacerbates the issue; average wind power reaching Zone K increases to 538 MW but the operating reserves increase by 1205 MW relative to existing requirements. This is a very significant increase. Under such a scenario, the total reserves in Zone K – including both the current reserve requirement and the wind-associated addition – could reach 68% of average demand.

The study highlights the heterogeneous effects. Despite the heterogeneous effects highlighted in this study, at a statewide level, the operating reserves as a percentage of wind power capacity are comparable to those in a review by the International Energy Agency [34]. Spinning reserves based on our computations would be approximately 17% higher than those computed for NREL's Eastern Wind Integration and Transmission Study for a similar penetration level [12]. Our largest computed increase in wind-associated operating reserve requirement

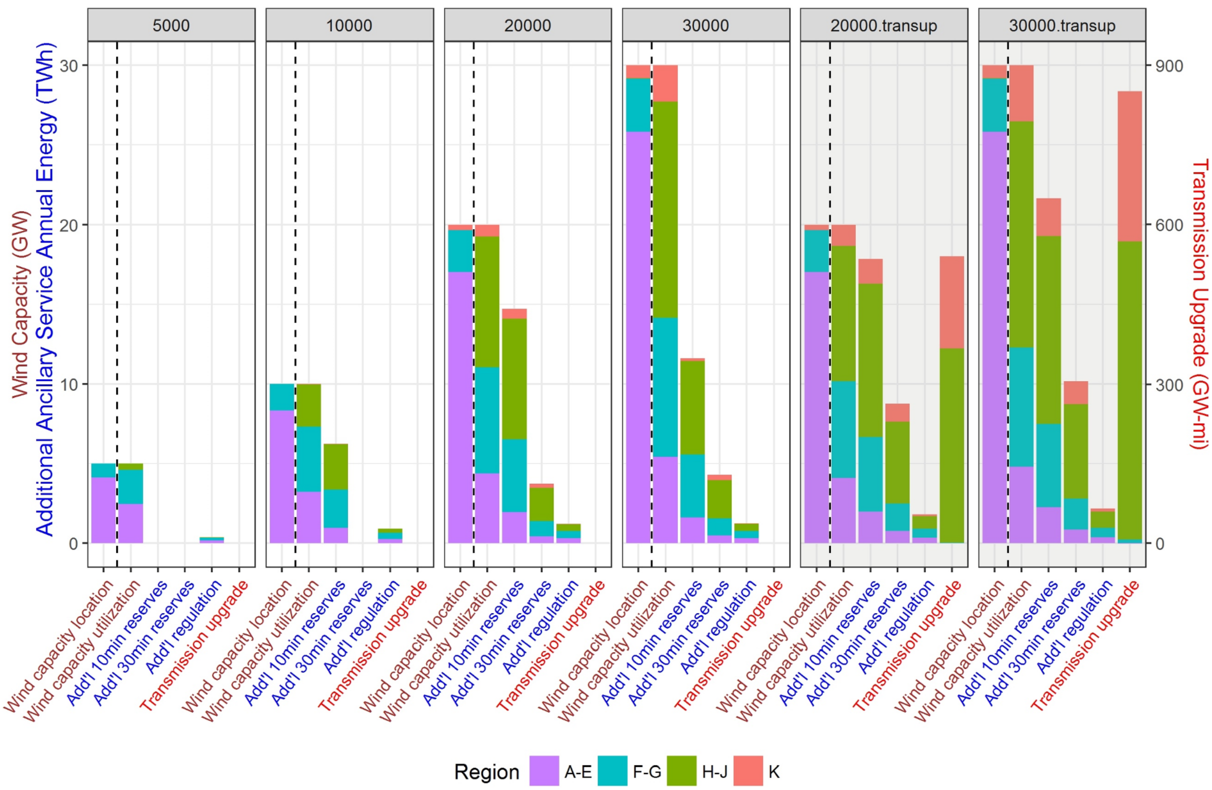

Fig. 11. Distribution of investments in and utilization of energy infrastructure with increasing wind power and transmission capacities. Note: horizontal axis text color corresponds to text color for corresponding vertical axis parameter.

represented 8% of wind power capacity, exceeding the widely known "3% load plus 5% wind" rule [35]. While our computed reserves are higher than this common heuristic, we employed NYISO's methods, which with current operating reserves at 14% of average demand (8% of peak demand) already requires significantly higher operating reserves than this simple rule.

It is important for practitioners and planners to understand this would present a very different energy system than any that exists today and one that may be masked by analyses of a large grid area that does not evaluate intraregional effects. The results of this study strongly recommend a rethinking of providing ancillary services as progressively larger VRE capacities are installed, with the potential for increasing supply from some zones and increasing flexibility measures within others. Increases in operating reserves are the primary driver of a potential shift to larger resource commitments to ancillary services. As a consequence, annual dispatchable generator commitments to ancillary services could approach the amount of energy required to meet loads in high load areas if reliability-focused market mechanisms simply evolve from current approaches; as discussed in Section 1 of this paper, this has been the primary approach to date. Conclusions as to the form of future markets is beyond the scope of this paper; however, the results presented here offer initial guidance for real-world systems with growing VRE.

This study provides a framework by which practitioners can begin to account for which regions require and benefit from significant new infrastructure and operational investments. Wind power capacities, especially at the deep penetrations needed to meet VRE generation and GHG emissions reduction targets, are likely to be located in areas that will benefit from neither the resulting low-carbon electricity generation nor the increased transmission and ancillary services that would accompany such a buildout. This paradigm will necessitate development of policy that properly attributes associated costs to the high-demand, low-supply regions that require such significant changes in the overall system.

5. Conclusion

This paper describes simulations of deep penetration of variable renewable energy in a regional electricity grid to evaluate the effects of the resulting net load regime on statewide and intrastate infrastructure investments and operational reliability needs. The study summarized here focuses on wind power in New York State.

The central finding is that both wind-generated electricity utilization and ancillary service requirements are highly heterogeneous across zones. An additional significant finding is that transmission upgrades to reduce wind power curtailment can exacerbate both the magnitude and heterogeneity of ancillary service requirements.

The study finds that only at wind capacities exceeding 100% of the average statewide load do significant portions of wind-generated electricity reach distance load centers. At such large wind capacities, increased supply variability originates in the wind-rich West, but manifests itself in the Southeast load centers surrounding New York City, leading to more frequent and intense extreme net load ramp rates. Additional energy flow enabled by relaxing model transmission limits allows additional supply variability to pass through to the load centers, further increasing local net load variability. This supply variability increases ancillary service requirements across the state in magnitudes comparable to those identified by others; however, the geographic heterogeneity of those requirements, including high concentration in load centers distant from the supply, has not been previously identified.

The computed increase in ancillary service requirements occurs while the energy required from dispatchable resources decreases (due to deep penetration of wind-generated electricity) even while the total dispatchable capacity required in the load centers remains the same (because of periods during which no wind-generated electricity reaches them). This finding indicates a far greater share of dispatchable capacity is likely to be committed to ancillary services than in current systems. There are simulated time steps at which no dispatchable energy is required yet ancillary services must still be provided.

The simulated energy system paradigm implies the most significant investments need to be made in areas distant from the wind resource. New market design and policy may be necessary to properly allocate the associated costs of such investments to the areas and customers that benefit. Further research is needed to identify and evaluate market structures that ensure reliable service in such scenarios and the energy technologies best suited to provide these services; these issues may require innovation beyond the evolution of traditional market mechanisms pursued to date. The implications of including more capital-intensive renewable energy resources (e.g. behind-the-meter solar photovoltaics and offshore wind power) in an integrated approach should also be investigated.

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