Cost and Value of Wind and Solar in India's Electric System in 2030

Ranjit Deshmukh
International Energy Studies Group
Lawrence Berkeley National Laboratory
Berkeley, CA 94720
Email: rdeshmukh@lbl.gov

Duncan Callaway
Energy and Resources Group
University of California at Berkeley
Lawrence Berkeley National Laboratory
Berkeley, CA 94720
Email: dcal@berkeley.edu

Nikit Abhyankar
and Amol Phadke
International Energy Studies Group
Lawrence Berkeley National Laboratory
Berkeley, CA 94720
Email: nabhyankar@lbl.gov
Email: aaphadke@lbl.gov

Abstract—**We evaluate the impact of different targets and shares of wind and solar photovoltaic (PV) buildouts on the cost and value of renewable energy in the Indian electric system in 2030. We define costs as those required for installing and operating VRE generators. Value represents the avoided costs from conventional generators that include avoided capital investments in new plants (capacity value) and displaced variable fuel and operations and maintenance costs (energy value). We developed a unique set of models to first create different spatially-explicit build-outs of solar and wind, and estimate their costs, then build new conventional generation capacity using a screening curves-based capacity expansion model, and finally assess system operation costs using an hourly unit commitment and economic dispatch model. We find that the economic value of variable renewable energy (VRE) decreases with increasing penetration across all mixes of wind and solar. Value of solar PV decreases at a higher rate than wind because generation profiles of solar sites are temporally correlated, even across larger geographical regions. The temporal correlation also increases the likelihood of curtailment of solar at high penetration levels because of minimum generation constraints on thermal generators, thus increasing costs. The limited temporal correlation of VRE generation with load during the peak net load hours of the year leads to a relatively small conventional generation capacity being avoided by VRE, thus resulting in low capacity values across all VRE build-outs. Using our base assumptions, we estimated the average additional costs to the entire electricity system for the initial 200 GW VRE (14%-20% VRE share by energy generation) to be 2-7% more than a system without any VRE. These costs increase with higher VRE penetration (6-14% for 300 GW and 11-23% for 400 GW) because of decreasing economic value and increased curtailment of VRE.**

I. Introduction

Electricity generation from solar and wind has emerged as one of the main strategies to mitigate climate change with many countries setting explicit targets and incentives for these variable renewable energy (VRE) sources. The overall cost of mitigation of carbon emissions through the strategy of deploying VRE depends on both the cost and value of VRE generation to the overall system.

Previous studies have shown the inadequacy of levelized cost of energy as a metric to assess VRE costs and highlighted the need to better understand the economic value of VRE based on the time of its generation and other conditions in the power system [1], [2]. Some studies used a short-run analysis to examine the economic value of VRE using current wholesale prices [3], [4], [5]. Other studies have simulated future systems to examine the effect of higher penetration of VRE on its value in the long run [6], [7], [8].

In this study, we focus on the long run costs and value of VRE for different targets and mixes of solar and wind. Estimating the additional cost of VRE to an electricity system in the long run is a difficult question because it is difficult to attribute any additional costs to VRE alone [9]. However, comparing future versions of an electricity system with and without VRE can enable us to estimate these additional costs and provide insights for long-term policy decisions.

Costs include those required for installing and operating VRE generators. Installed costs of solar PV and wind generation continue to decline due to technological improvements and economies of scale. In addition to the capital and operations and maintenance (O&M) costs, VRE energy generation costs depend on the resource quality at the location. As more VRE capacity is installed, cost of VRE generation may increase as newer sites with lower resource quality are sought.

Value of VRE generation represents the avoided costs from conventional generators that include avoided capital investments in new plants (capacity value) and displaced variable fuel and operations and maintenance costs (energy value). Value varies for different electric systems depending on the temporal variability of both demand and VRE generation within that region, and the share of each technology in the overall generation. Although variability and uncertainty of VRE generation may impose additional costs to maintain the same level of reliability as conventional generation, we do not include those costs in this analysis.

We developed a unique set of models to first create different build-outs of solar and wind, and estimate their costs, then build new conventional generation capacity using a screening curves-based model, and finally assess system operations cost using a dispatch model.

In this analysis, we estimated the costs and value of VRE in India's national electric system in 2030. With the goal to reduce carbon intensity of its economy, the Government of India (GoI) has set targets of 100 GW for solar and 60 GW of wind capacities by 2022, and a goal of 40% non-fossil generation capacity share by 2030 in its Nationally Determined Contribution submitted to the United Nations [10]. In 2016, seventy percent of India's electricity generation was from coal making the Indian grid not only a high carbon-emitting large electric system, but also one of the least flexible, which makes integrating large shares of VRE challenging.

II. Methods

There are three main steps in our overall methodology. The first step includes site suitability and site selection of VRE for different build-out scenarios, estimating the costs of those build-outs, and creating generation profiles for use in the subsequent steps. In the second step, we use the VRE generation profiles, the load forecast profile for 2030, existing generators, and costs of future conventional generators to build the new conventional generation fleet to meet future load. In the third step, we simulate the electric system operations for all 8760 hours of the future year, and estimate energy generation from different sources and total system costs.

A. VRE build-out scenarios and generation profiles

The site suitability analysis (also known as renewable energy resource assessment) for wind and solar PV follows the methodology outlined in [11] and [12]. Using Python and Arcpy package for spatial analysis, we conducted the site suitability analysis using thresholds for annual average wind speed (5.5 m/s) and global horizontal irradiance (GHI) (4.9 kWh/m^2-day) for wind and solar PV respectively, as well as for elevation (2500 m) and slope (20% for wind and 5% for solar PV). We also excluded protected areas, water bodies, and certain land use land cover types (e.g. agricultural land in the case of solar, forested land in case of both technologies) from areas considered suitable for wind and solar development. For wind, we used 10-year averages of wind speeds at a hub height of 80 m and a spatial resolution of 3.6 km^2 from Vaisala's mesoscale modeled wind data set [13]. For solar PV, we used the 2014 annual average GHI data from the National Renewable Energy Laboratory's (NREL) National Solar Radiation Database (NSRDB) [14]. All analyses were performed at 500 m resolution using South Asia Albers Equal Area Conic projection.

We aggregated the suitable areas into larger units of analysis - VRE suitable sites - with a maximum size of 5km. Applying a land use factor of 30 MW/km^2 for solar PV and 9 MW/km^2 for wind [15], [11], and an additional land use discount factor of 75% for both technologies to account for on-the-ground uncertainties (e.g. land ownership, conflict areas), each site can accommodate between 15 - 187.5 MW size solar PV plants and 4.5 - 56.25 MW size wind plants. These plant sizes roughly represent the capacities of utility-scale solar PV and wind plants.

For each suitable site, we then estimated the annual average capacity factor. For solar PV, we used NREL's System Advisor Model (SAM) for estimating the annual average capacity factors, assuming that all systems are south-facing fixed tilt systems, with their tilt equal to the latitude of the location. For wind, we assumed a Weibull distribution of wind speeds for each site, and estimated the air density based on elevation and annual average temperature to account for the effect of air density on wind power generation. Depending on the annual average wind speed, we then applied a normalized wind power curve for one of three International Electrotechnical Commission (IEC) classes [16], adjusted for air density [17], [18], to estimate the annual capacity factor for each site.

We analyzed three VRE installed capacity targets - 200 GW, 300 GW, and 400 GW - each with five combinations of solar and wind capacity shares - 100%-0%, 75%-25%, 50%-50%, 25%-75%, and 0%-100%. These combinations result in 15 build-out scenarios plus one scenario with no VRE. For each of the build-out scenarios, we selected sites that had the highest capacity factors across the country to meet the specific installed capacity targets for solar and wind. For those scenarios that had non-zero targets for wind or solar, we selected sites to meet the existing installed capacities in 2016 in each state before meeting the rest of the target for that scenario. We also limited the capacity built in each state to 15% of the country's overall target for a scenario to ensure geographical diversity.

We created hourly generation profiles for each of the selected sites using simulated wind and solar resource data for 2014 from a limited number of locations. For solar PV, we first converted hourly GHI and temperature data for 617 locations from NREL's NSRDB into hourly capacity factor profiles using the System Advisor Model (SAM) [14] . We then spatially associated each of selected site to the nearest of the 617 time-series locations. For wind, we first converted the wind speed hourly time series for 100 locations from Vaisala into capacity factor time series. We then associated each wind selected site to the nearest of the 100 time series locations. For each solar and wind selected site, we adjusted the hourly capacity factor profile of the associated times series location by the ratio of the annual average GHI (for solar PV) or annual Weibull distribution-based capacity factor (for wind) for that selected site and that for the associated time series location. The power generation time series is simply the product of the installed capacity potential of the selected VRE site and its hourly capacity factors.

B. Load forecast

For creating the hourly load time series for 2030, we use the hourly load profile for the base year of 2014 [19] and the peak load and energy generation forecast from India's 19th Electric Power Survey [20]. We first linearly extrapolated the 2014 load duration curve (load values sorted from highest to lowest) for each state in proportion to the forecasted increase in energy generation in 2030. If the resulting peak load was lower (or higher) than the forecast, we uniformly reduced (or increased) the load duration curve in all intervals by a small amount using a heuristic. We then distributed this reduced (or increased) energy in the peak hours using an exponential function by pegging the start of the function at the peak load forecast value. We then re-sorted the load values on hour of the year to create the hourly time series for 2030. Because the simulated VRE data are also based on 2014 weather, we capture the implicit correlation between VRE and load.

Daily and seasonal load shapes are likely to change in the future because of changing consumption patterns such as increasing air-conditioning load. Such load shape changes can affect the value of VRE e.g. higher demand during the day can increase the value of solar PV. However, for this study, we have assumed a similar load shape for 2030 as that in 2014.

C. New conventional generation build-out

In creating India's future electricity system, we allowed only three technologies to be built - coal, combined cycle gas turbine (CCGT), and combustion turbine (CT). With reserves of 300 billion tonnes, coal is India's single largest domestic resource [21]. Although domestic natural gas resources are limited, liquefied natural gas (LNG) imports are increasing. In 2014, imports constituted 32% of total natural gas consumption [22]. In the last 7 years, India doubled its LNG imports, and has plans to more than double its import capacity to 55 million tonnes in the next 5 years [23].

We assumed all new coal units to be super-critical running on domestic coal. Both new CCGT and CT generators are assumed to use imported LNG, with a price of USD 10 per MMBtu based on the World Bank 2030 forecast for LNG landed price in Japan. CT generators and existing diesel plants are considered peaker units i.e. they have fast ramps and can start and stop in less than an hour. See Table I for assumptions for new conventional generators.

TABLE I
PARAMETERS FOR NEW CONVENTIONAL GENERATION

	Coal	CCGT	CT
Capital cost [USD/kW] [24] [25]	976	775	678
Fixed annual O&M costs [USD/kW] [26]	42	11	7
Variable annual O&M costs [USD/MWh] [26]	5	4	11
Discount Rate (real)	7%	7%	7%
Plant life [years] [27]	25	25	25
Auxiliary consumption	10%	3%	1%
Minimum stable level [% of rated capacity]	55%	50%	0%
Fuel cost [USD/GJ] [28] [29]	2.6	9.5	9.5
Heat rate [MJ/kWh] [30]	9.4	8.4	12.1
Annualized fixed cost [USD/kW-y]	126	78	65
Variable cost [USD/MWh]	33	85	127

Because of their relatively limited potential (either technical or economic), we did not consider other technologies such as nuclear, hydro, or biomass as part of the new conventional generation build-out. However, inclusion of these technologies could affect the ability of the future electric system to absorb VRE e.g. greater share of nuclear capacity may make the system less flexible due to constraints on minimum stable levels and lower ramp rates; more storage and pumped hydro plants would increase the ability of the system to absorb variability in net load; new storage technologies would enable the smoothing of short-term (diurnal) and long-term (seasonal) variability introduced by higher shares of VRE.

To create a new conventional generation build-out that reliably meets demand in 2030 for each of our scenarios, we used a simple screening curves approach [31], [32]. This approach is typically used by regulated utilities where both price of generation and the load duration curve are fixed, i.e. there is no competition and demand is inelastic. Further, fixed and variable costs are assumed to adequately describe all generators. Fixed costs are annualized capital costs and fixed operations and maintenance (O&M) costs. Variable costs include fuel and variable O&M costs. To generate the resource screening curves, these costs for different technologies are plotted as lines with the fixed cost as the y intercept and variable cost as the slope. The capacity factor (defined by the number of hours that a plant operates during the year) dictates the annual overall cost or revenue required by the plant to break even. The screening curves for coal, CCGT, and CT are shown in Figure 1, which represent the "base", "mid" and "peaker" types of generation plants.

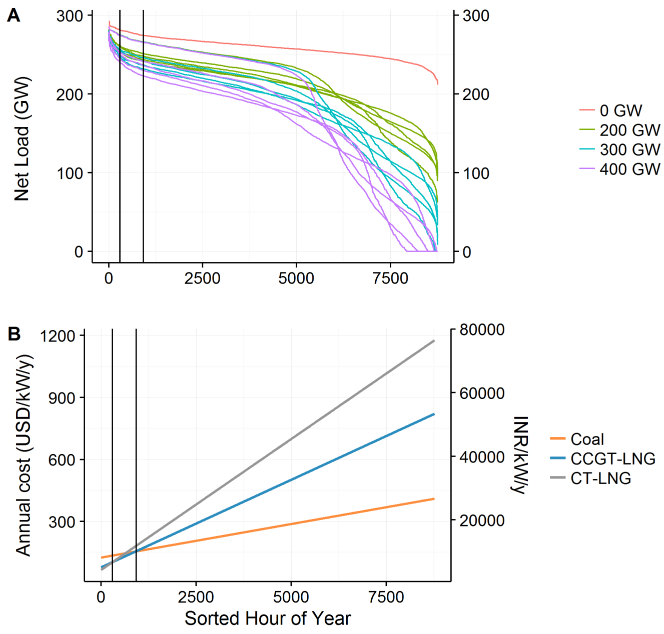

Fig. 1. Net load duration curves for all VRE build-out scenarios and screening curves with three technologies - coal, combined cycle gas turbines (CCGT), and combustion turbines (CT), the latter two powered by liquefied natural gas (LNG). In this set of scenarios, CCGT capital and variable costs are higher than coal. Only new CTs and coal plants are built with shares dependent on the intersection of the vertical line and the net load duration curve for a scenario. Each group of VRE target scenarios includes five combinations of shares of solar PV and wind.

For each of the VRE build-out scenarios, we generated the hourly net load profile for India by subtracting 2014 generation from must-run generators (nuclear, run-of-river hydro, and minimum generation from storage hydro) [33] and expected generation from future wind and solar build-outs from the load forecast for 2030. We then distributed the daily available dispatchable energy from the storage hydro fleet over the peak demand hours of each day to minimize daily peak net load without violating the constraint of maximum available hydro capacity. Dispatchable energy from storage hydro is the energy left after accounting for minimum generation required for environmental flows, irrigation needs, or releases due to high water levels in the monsoon season. We assumed this dispatchable energy to be all used for "peak-shaving", and not for other grid services such as balancing short-term, sub-hourly variation. We sorted the remaining hourly net load across the whole year to create the final net load duration curves.

The crossover points from the resource screening curves when extended to the net load duration curves give the optimal mix of total conventional generation capacity as determined by the y coordinates of the intersection points on the net load duration curves (Figure 1). To estimate the new required capacity for "base", "mid" and "peaker" plants, we subtracted the existing capacity in each of the categories from the total capacity determined by the screening curves. We assumed a reserve margin of 15% of annual peak load [34] to ensure resource adequacy, and assigned this reserve margin to the CT, CCGT, and coal generators in proportion to their overall share.

In its investment decisions, the screening curves methodology does not value generator capabilities such as higher ramp rates, minimum stable levels, quick and low cost start up and shut down that may prove crucial for balancing the increased variability and uncertainty in net load due to VRE. However, it is a simple methodology to determine the optimal mix of conventional generation using fixed and variable costs and times-series profiles of load and must-run generation.

D. System operations and economic dispatch

To estimate the overall system operating costs in 2030 for each scenario, we developed a mixed-integer unit commitment and economic dispatch model to simulate India's future electricity system. Our model (Equation 1) commits and dispatches generators based on their marginal cost in order to meet demand in every hour while minimizing total system cost over a period of 24 hours. In other words, the model runs in steps of 24 hours (1 day) over the whole year (8760 hours), ensuring that the supply and demand are balanced in every hour of the day. We used the Python-based open-source optimization modeling language (Pyomo) to develop the economic dispatch model [35].

We did not simulate an explicit unit commitment process. Instead, for coal and CCGT plants, which are base and mid-merit order plants, we constrained the plants to be online throughout the day if they are committed during that day. In other words, if a plant needs to be dispatched during any time period in a particular day, we do not allow the plant to be shut down during the low net load hours of the day. This assumption constrains the plants to operate at their minimum generation levels, and may force VRE generation to be curtailed. However, the plant can be shutdown or another plant can be started on the subsequent day.

We assumed a "copperplate" electricity system, which implies no transmission constraints. Although transmission capacities in an electricity system significantly affect flows and overall cost of the system, we ignore existing and new transmission build-outs in our model. Because we are simulating a system in 2030, there are uncertainties in how the transmission build-out will evolve. Simplifying the model to a single node allows us to understand the broader impacts on cost and value of VRE generation.

The objective function of the model (Equation 1) minimizes the overall cost of generation and the cost of unserved energy. The first constraint ensures conservation of energy where generation needs to equal demand minus unserved energy. The second constraint requires the generation of a plant in any time period to be less than its available capacity. The available capacity of a generator is its rated capacity derated by its expected outage rate. The third constraint forces generation of certain types to generate at a minimum generation level if they are committed during the day. Coal, CCGT, and generator types such as oil and biomass have a minimum stable level below which they cannot operate due to technical limitations. In reality, generators can shut down during times of low net demand and start back up during the day, and have costs associated with the start-ups and shut-downs. However, the generators included in this constraint typically have high start-up costs and have technical requirements for minimum down and up times. So it is realistic to constrain these generator types to stay online. Peaker plants that include CTs and diesel plants are excluded from this constraint, which allows them to start and stop during the day without incurring any additional costs. For storage hydro, the minimum generation level ensures the mandated environmental flows, usage for irrigation, or discharges due to overflowing reservoirs. Storage hydro minimum generation levels, which vary throughout the year, are based on historic data [33]. For must-run generators (run-of-river hydro and nuclear), the generation capacity factors are also based on historic data and are fixed through constraint four.

Constraint five limits the generation from variable RE to their maximum capacity factors in all time periods. However, variable RE generators are allowed to be curtailed for technical or economic reasons. For example, because several conventional generator types cannot reduce their outputs below their minimum generation levels if they are committed for a particular day, VRE generators may be curtailed in the event of excess generation and low demand. Finally, constraint six ensures that generation from storage hydro fleet does not exceed its daily energy limit.

The economic dispatch model estimates the hourly dispatch for all generator types and the total annual dispatch cost for each scenario. We did not include any ramp constraints in the model because even coal generators, the most inflexible technology among the dispatchable conventional generators included in this analysis, can ramp up to 1% of their rated capacity per minute, which allows them to ramp from 55% (minimum stable level) to 100% rated capacity within one hour. Intra-hour ramping capabilities will become more important with higher penetrations of VRE, but the hourly time resolution model will be unable to capture those constraints. We ignored costs due to uncertainty (forecast errors) and do not include transmission constraints.

$$
\begin{aligned}
\min \quad & \sum_{t=1}^{T}\sum_{i=1}^{G} q_{it} * c_i + UE_t * VOLL \\
\text{s.t.} \quad & \sum_{i=1}^{G} q_{it} = D_t - UE_t && \forall t \in T \\
& q_{it} \leq Q_i * u_i && \forall i \in G; \forall t \in T \\
& q_{it} \geq minCF_i * Q_i * u_i && \forall i \in G_c, G_{ccgt}, G_{hs}, G_o; \forall t \in T \\
& q_{it} = CF_i * Q_i && \forall i \in G_{hror}, G_{nu}; \forall t \in T \\
& q_{it} \leq maxCF_i * Q_i && \forall i \in G_{vre}; \forall t \in T \\
& \sum_{t=1}^{T} q_{it} = H_i && \forall i \in G_{hs}
\end{aligned}
\tag{1}
$$

a) Decision variables:

q_{it}	Power generated by generator i in time period t
UE_t	Unserved energy in time period t
u_i	Binary variable indicating whether generator i is committed

b) Parameters:

c_i	Variable cost of generator i, includes fuel and variable O&M costs
$VOLL$	Value of lost load or cost of unserved energy
D_t	Demand in time period t
Q_i	Available capacity of generator i
$minCF_i$	Minimum capacity factor of generator i across all time periods
$maxCF_it$	Maximum capacity factor of variable RE generator i in time period t
H_i	Total energy available for hydro generator i across all time periods

c) Sets:

G	Set of all generators
G_c	Set of coal generators, subset of G
G_{ccgt}	Set of CCGT generators, subset of G
G_{ct}	Set of CT generators, subset of G
G_d	Set of diesel generators, subset of G
G_o	Set of 'other' generators that include oil and biomass generators, subset of G
G_{hs}	Set of storage hydro generators, subset of G
G_{hror}	Set of must-run run-of-river hydro generators, subset of G
G_{nu}	Set of must-run nuclear generators, subset of G
G_{vre}	Set of wind and solar generators, subset of G
T	Set of time periods

E. Cost and Value

We estimated the cost and value of implementing a VRE target in terms of per unit of renewable energy absorbed by the system. We estimated the cost of VRE generation by the product of installed wind and solar PV capacities and their respective annual fixed costs using assumptions from Table II divided by the total VRE generation after curtailment.

We define the capacity value of VRE as the investment in new conventional generation capacity that is avoided by VRE, and depends on the correlation between load and the combined VRE generation profile in the peak load hours of the year. A higher correlation lowers the annual peak net load, thus necessitating a lower amount of new conventional generation capacity to reliably meet load.

We define the energy value of VRE as the annual variable costs of conventional generation including fuel and O&M costs that the VRE generation displaces. These costs are determined by the economic dispatch model. Both capacity value and energy value for a particular VRE build-out scenario are estimated as the difference in costs between the No RE scenario and the VRE scenario.

All costs are estimated in constant 2016 INR or USD.

TABLE II
PARAMETERS FOR WIND AND SOLAR PV GENERATION COST ESTIMATES

	Wind	**Solar PV**
Capital cost C_g [USD/kW]	1,100	900
Fixed annual O&M costs $OM_{f,g}$ [USD/kW]	15	10
Discount Rate i	7%	7%
Plant life N [years]	25	25

Capital costs adjusted to get costs similar to those seen in recent auctions.
O&M costs and plant life are from [36].

III. RESULTS

A. New conventional and VRE generation build-out

The conventional generation build-outs for all VRE build-out scenarios are shown in Figure 2. Only new coal and CT gas generators are built in all except one of the scenarios. Although there is a requirement for CCGT generators in all scenarios, this was met by the existing capacity. More CT generators are built in the 25%-75% and 50%-50% solar-wind mixes because of their "peakier" net load profiles. Avoided conventional generation capacity per MW of VRE installed capacity is 0.03-0.09 MW for 200 GW, 0.02-0.07 MW for 300 GW, and 0.02-0.06 MW for 400 GW VRE targets. These low values are a function of India's weather patterns and the VRE sites chosen for these scenarios. As VRE energy generation increases with higher installed capacities, the plant load factors of conventional generators drop. But the high installed capacities for conventional generation are required to reliably meet demand in all hours. Additional storage, ability to shift demand to non-peak hours through demand response, and energy efficiency measures can reduce the need for new conventional generation capacity.

Because the capacity factors of solar PV are lower than wind, the energy generation potential of VRE build-outs with higher solar shares is lower than those with higher wind shares. As shown in Figure 3, for the same overall VRE installed capacity target, the share of potential VRE generation in the total energy generation mix reduces as the share of solar PV capacity in the VRE mix increases.

B. Cost of VRE generation

The cost of VRE generation depends on the capital costs of wind and solar PV, and their annual capacity factors. Greater number of installations lead to higher average costs as better resource quality sites are exhausted and developers seek lower resource quality sites. Resource quality of wind varies much more than that of solar PV [cite: Deshmukh]. So the effect of changing resource quality on levelized cost of VRE generation is much more pronounced for wind. This is illustrated in Figure 4 where the average LCOE of uncurtailed VRE generation rises by 7% between the 200 GW and 400 GW all-wind scenarios, whereas the same increase for the all-solar scenarios is less than 1%. In this analysis, we have assumed the same average costs for the entire fleets of solar PV and wind. In reality, both solar PV and wind costs are expected to decline with technology progress and economies of scale. The average levelized cost

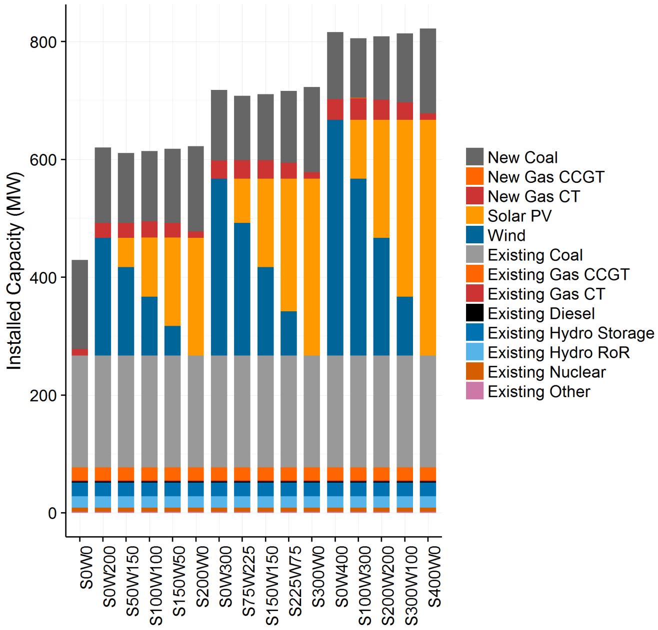

Fig. 2. Existing and new conventional and VRE generation build-outs. VRE installed capacity targets include 200 GW, 300 GW, and 400 GW, each with five combinations of shares of solar PV and wind - 0%-100%, 25%-75%, 50%-50%, 75%-25%, and 100%-0%.

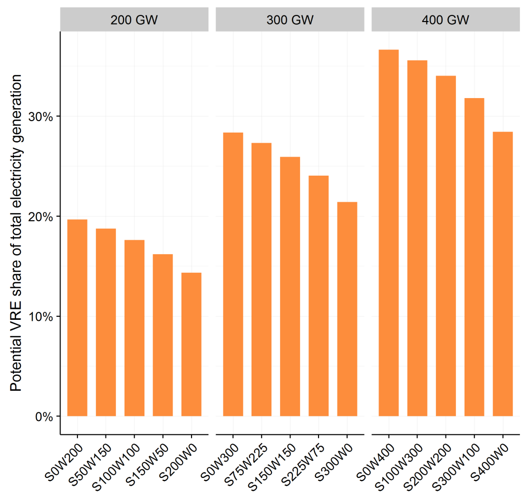

Fig. 3. Potential VRE generation as share of total demand. VRE installed capacity targets include 200 GW, 300 GW, and 400 GW, each with five combinations of shares of solar PV and wind - 0%-100%, 25%-75%, 50%-50%, 75%-25%, and 100%-0%.

of the entire fleet of solar PV and wind in 2030 will depend on the rate of decline of real costs of these VRE sources.

Curtailment of VRE increases its levelized cost of generation that is absorbed by the system. As curtailment increases, the cost of installing and operating VRE is spread across a smaller amount of clean energy that avoids environmental externalities. Curtailment increases with greater penetration of VRE and with more shares of solar PV (Figure 5). Because of the high temporal correlation of generation profiles among solar PV sites, on some days, it is more economical to dispatch coal to meet peak neat load and curtail VRE during low net load periods of the day than to dispatch more flexible but significantly more expensive gas

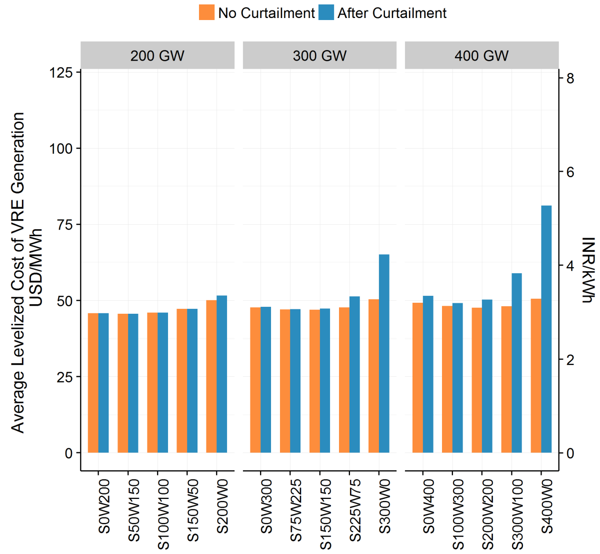

Fig. 4. Average levelized cost of VRE potential generation (no curtailment) and generation after curtailment during system operations shown for conventional generation build-outs with high (A) and low (B) capital costs for coal. VRE installed capacity targets include 200 GW, 300 GW, and 400 GW, each with five combinations of shares of solar PV and wind - 0%-100%, 25%-75%, 50%-50%, 75%-25%, and 100%-0%.

CT or diesel generators that could meet peak load but shut down during high solar (low net load) periods. Curtailment increases when coal plants are less flexible and are unable to reduce output to 55% minimum generation level.

VRE is not curtailed in the 200 GW VRE build-out scenarios (except the all-solar scenario) because of the relatively low shares of VRE generation in the overall mix. For the 300 GW and 400 GW scenarios, VRE curtailment is lowest for the 25%-75% solar-wind mix, which is reflected in their average LCOEs (Figure 4).

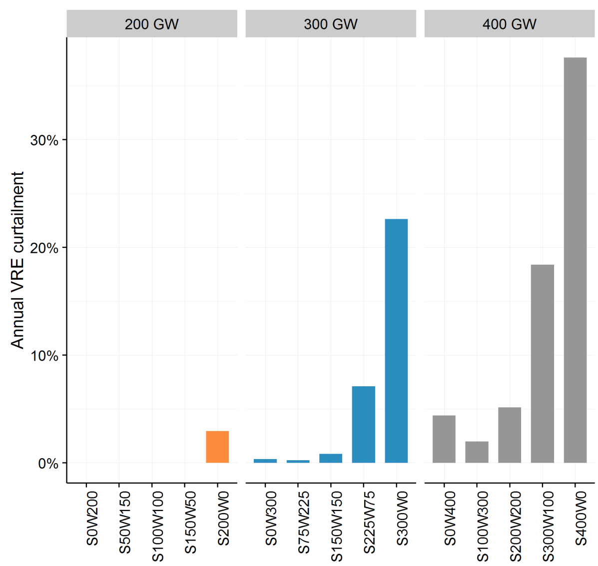

Fig. 5. Curtailment of variable renewable energy shown for conventional generation build-outs with high (A) and low (B) capital costs for coal. VRE installed capacity targets include 200 GW, 300 GW, and 400 GW, each with five combinations of shares of solar PV and wind - 0%-100%, 25%-75%, 50%-50%, 75%-25%, and 100%-0%.

C. Energy and capacity value of VRE generation

The energy value of VRE is the difference between the system operation costs of a VRE scenario and those of the No-RE scenario, estimated per MWh of VRE generation after curtailment. Average energy value of the 25%-75% solar-wind mix scenarios is greater than the other mixes because their generation avoids more expensive conventional generation (Figure 6). However, overall the energy value is similar across all VRE mixes and build-out targets. The main reason for this similarity is the dominance of low (and similar) cost coal generation in all build-outs. The energy value of the 25%-75% solar-wind mix for 400 GW of VRE drops by only 4% over that for the same mix for the 200 GW capacity. Because of adequate capacity to meet load in all time intervals of the simulation, there was no unserved energy across all scenarios, and hence, no cost associated with unserved load.

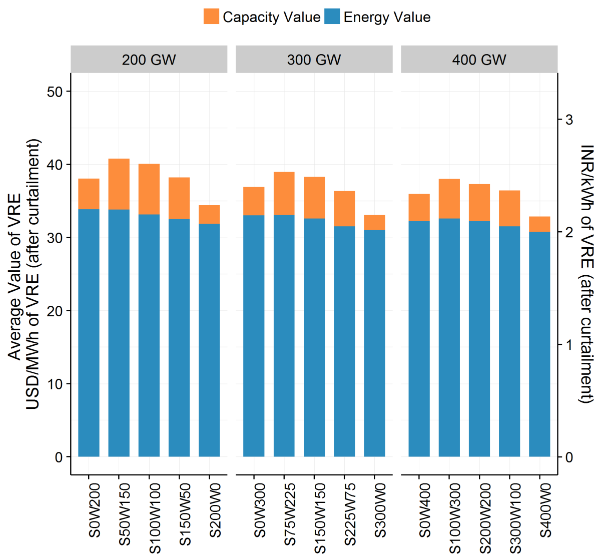

Fig. 6. Energy and capacity value of VRE generation absorbed by the system (after curtailment) shown for conventional generation build-outs with high (A) and low (B) capital costs for coal. VRE installed capacity targets include 200 GW, 300 GW, and 400 GW, each with five combinations of shares of solar PV and wind - 0%-100%, 25%-75%, 50%-50%, 75%-25%, and 100%-0%.

The capacity value of VRE is the savings from avoided investments in conventional generation capacity, and depends on the capital costs of the new conventional generators and the amount of avoided capacity compared to the No-RE scenario. Average capacity value across all scenarios is relatively low because of both, low capital costs of coal plants and low amounts of conventional generation capacity avoided by VRE generation. The latter is because of two reasons. First, daily peak net load on most days occurs in the evenings when there is no solar generation. Second, hourly capacity factors of the entire wind fleet are very low for several hours during the year - wind fleet capacity factors were below 5% during 7-10% of hours for all VRE build-out scenarios.

Average capacity value also varies across scenarios. It reduces with increased overall VRE targets, especially of solar. As more VRE generators with similar temporal profiles are added to the system, VRE generation gets more concentrated during low net load periods, and not contribute towards avoiding conventional generation capacity. As a result, conventional generators experience reduced plant load factors, as observed in other studies [37].

Comparison between scenarios with different shares of VRE show that the 25%-75% and 50%-50% solar PV - wind mixes have the most favorable combined VRE generation temporal profiles during the peak hours of net load, and therefore, are able to avoid the most conventional generation capacity.

The higher total value for the 25%-75% and 50%-50% solar PV - wind mixes agrees with other studies focused on other regions [38], [6], [39]. Although capacity value estimates using reliability models and effective load carry capacities can provide more accurate estimates, our methodology enables us to evaluate multiple scenarios and provide reasonable estimates within reasonable computing times. Our estimates can be improved by using multiple years of data. Capacity value of solar is likely to increase if the peak load hours shift from evening to afternoon as demand for air conditioning increases. Choosing VRE sites (especially wind) based on their generation profiles in order to minimize the overall peak net load as opposed to choosing sites with the highest capacity factors would increase the capacity value of the VRE fleets. Our wind data is limited to 100 modeled wind sites. Higher spatial resolution and ground-validated wind data sets will improve the accuracy of these results.

D. Additional cost of VRE generation

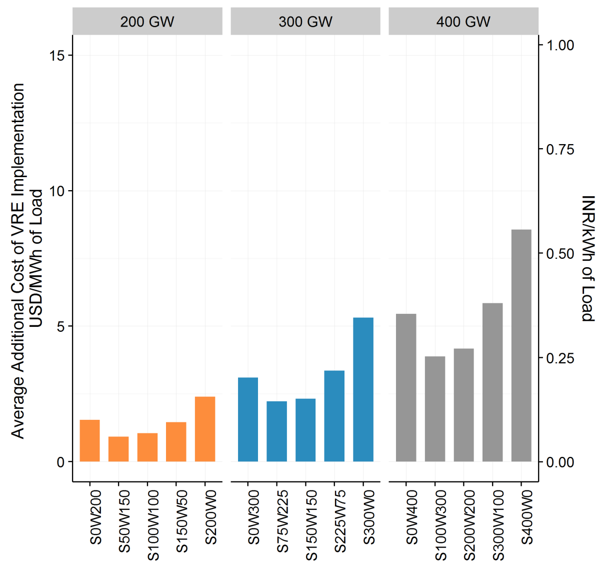

Fig. 7. Average additional cost of VRE generation per load served. VRE generation is generation after curtailment. VRE installed capacity targets include 200 GW, 300 GW, and 400 GW, each with five combinations of shares of solar PV and wind - 0%-100%, 25%-75%, 50%-50%, 75%-25%, and 100%-0%.

An important question is how much additional cost per MWh of load served would be required to implement a particular VRE target. On one hand, if the energy and capacity value of VRE is greater than its cost, then it is cost-effective to implement a particular VRE target. On the other hand, if the economic value is lower than the cost of VRE, then the additional cost will be borne by the electricity consumers and potentially taxpayers depending on the type of incentives available for VRE. Figure 7 shows the average additional cost for different VRE targets and mixes per MWh of load served. Based on our cost assumptions, the 25%-75% solar-wind mix for each of the three VRE targets incurs the lowest cost per MWh load served. For the 200 GW VRE target, the additional average cost ranges from USD 0.9 - 2.4 per MWh (INR 0.06 - 0.16 per kWh) of load served. This additional cost increases to USD 2.2 - 5.3 per MWh (INR 0.14 - 0.34 per kWh) for 300 GW scenarios, and USD 3.9 - 8.6 per MWh (INR 0.25 - 0.56 per kWh) for the 400 GW scenarios. These costs are highly sensitive to VRE costs. As wind and solar PV costs continue to decline, the average cost of VRE generation will also decrease, and result in lower additional average costs per MWh of load served.

Note that we did not include the costs of VRE integration such as those for ancillary services including regulation, load following, and ramping reserves, and for handling potentially larger day-ahead forecast errors of net load. These costs will increase the additional costs incurred to implement VRE targets. Results from [7] show that these costs together reduce the overall economic value by less than 10% for up to 30% VRE penetration levels. We also ignored costs for any additional transmission infrastructure that may be required for evacuating VRE generation to load centers. These costs will increase the overall additional costs of achieving high VRE targets.

IV. Conclusion

We examined the effects of different wind and solar installed capacity mixes and total targets on overall system cost and avoided emissions. In agreement with previous studies, we find that value of VRE decreases with increasing penetration across all mixes of wind and solar. Value of solar PV decreases at a higher rate than wind mainly because of the greater temporal correlation between solar profiles across larger geographical regions. The high temporal correlation increase the likelihood of solar being curtailed because of minimum generation constraints on thermal generators, thus increasing costs. The low temporal correlation of VRE generation with load across the year leads to a relatively small conventional generation capacity being avoided by VRE, thus resulting in low capacity values across all VRE build-outs.

Although the specific results in this analysis are likely to change as VRE costs and electric systems evolve, the methodology outlined in this paper can be used to evaluate policies and VRE targets on an ongoing basis. Including integration costs due to forecast errors and additional requirements for ancillary services, transmission constraints and investments, and strategies such as demand response and storage will improve our analysis.

Acknowledgment

The authors would like to thank the Power Systems Operation Corporation (POSOCO) for system operation and load data.

References

[1] P. L. Joskow, "Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies," *The American Economic Review*, vol. 101, no. 3, pp. 238–241, May 2011.

[2] S. Borenstein, "The Private and Public Economics of Renewable Electricity Generation," *The Journal of Economic Perspectives*, vol. 26, no. 1, pp. 67–92, Jan. 2012.

[3] ——, "The Market Value and Cost of Solar Photovoltaic Electricity Production," *Center for the Study of Energy Markets*, Jan. 2008. [Online]. Available: http://escholarship.org/uc/item/3ws6r3j4

[4] N. Boccard, "Economic properties of wind power: A European assessment," *Energy Policy*, vol. 38, no. 7, pp. 3232–3244, Jul. 2010. [Online]. Available: http://www.sciencedirect.com/science/article/pii/S0301421509005515

[5] L. Hirth, "The market value of variable renewables: The effect of solar wind power variability on their relative price," *Energy Economics*, vol. 38, pp. 218–236, Jul. 2013. [Online]. Available: http://www.sciencedirect.com/science/article/pii/S0140988313000285

[6] P. Denholm and M. Hand, "Grid flexibility and storage required to achieve very high penetration of variable renewable electricity," *Energy Policy*, vol. 39, no. 3, pp. 1817–1830, Mar. 2011. [Online]. Available: http://www.sciencedirect.com/science/article/pii/S0301421511000292

[7] A. Mills and R. Wiser, "Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California," Lawrence Berkeley National Laboratory, Tech. Rep. LBNL-5445E, 2012.

[8] G. Gowrisankaran, S. Reynolds, and M. Samano, "Intermittency and the value of renewable energy," NBER, Tech. Rep., 2015.

[9] M. Milligan, E. Ela, B.-M. Hodge, B. Kirby, D. Lew, C. Clark, J. DeCesaro, and K. Lynn, "Integration of Variable Generation, Cost-Causation, and Integration Costs," *The Electricity Journal*, vol. 24, no. 9, pp. 51–63, Nov. 2011. [Online]. Available: http://www.sciencedirect.com/science/article/pii/S1040619011002636

[10] GoI, "India's Intended Nationally Determined Contribution, as submitted to the United Nations Framework Convention on Climate Change," Government of India, Tech. Rep., 2016.

[11] G. C. Wu, R. Deshmukh, K. Ndhlukula, T. Radojicic, and J. Reilly, "Renewable Energy Zones for the Africa Clean Energy Corridor," International Renewable Energy Agency and Lawrence Berkeley National Laboratory, LBNL#187271, Oct. 2015.

[12] R. Deshmukh, G. Wu, and A. Phadke, "Renewable Energy Zones for Balancing Siting Trade-offs in India," Lawrence Berkeley National Laboratory, Tech. Rep. 1007272, 2017. [Online]. Available: http://escholarship.org/uc/item/4p6886mz.pdf

[13] Vaisala, "Wind resource dataset," Vaisala, Tech. Rep., 2015.

[14] NREL, "National Solar Radiation Database," National Renewable Energy Laboratory, Tech. Rep., 2016. [Online]. Available: https://nsrdb.nrel.gov/

[15] S. Ong, C. Campbell, P. Denholm, R. Margolis, and G. Heath, "Land-Use Requirements for Solar Power Plants in the United States," National Renewable Energy Laboratory, Golden, CO, Tech. Rep. NREL/TP-6A20-56290, Jun. 2013.

[16] J. King, A. Clifton, and B.-M. Hodge, "Validation of Power Output for the WIND Toolkit," National Renewable Energy Laboratory, Tech. Rep. NREL/TP-5D00-61714, Sep. 2014.

[17] IEC, "International Standard IEC 61400-12- Wind Turbine Generator Systems - Part 12: Wind turbine power performance testing," 1998.

[18] L. Svenningsen, "Power Curves Air Density Correction and Other Power Curve Options in WindPRO," 2010.

[19] POSOCO, "System operation data 2014-15," Power Systems Operation Corporation Limited, Tech. Rep., 2015.

[20] CEA, "19th Electric Power Survey," Central Electricity Authority, Tech. Rep., 2017.

[21] GoI, "Coal Reserves | Ministry of Coal, Government of India," 2014. [Online]. Available: http://coal.nic.in/content/coal-reserves

[22] ——, "India Energy Security Scenarios - User Guide for 2047 Energy Calculator - Coal and Gas Power Stations," NITI Aayog, Government of India, Tech. Rep., 2016.

[23] Bloomberg, "LNG Price Slump Sends Biggest Indian Refiner on Buying Binge," *Bloomberg.com*, Aug. 2016. [Online]. Available: http://www.bloomberg.com/news/articles/2016-08-28/lng-price-slump-sends-biggest-indian-refiner-on-buying-binge

[24] A. Phadke, N. Abhyankar, and R. Deshmukh, "Techno-Economic Assessment of Integrating 175gw of Renewable Energy into the Indian Grid by 2022," Lawrence Berkeley National Laboratory, Tech. Rep., 2016.

[25] CERC, "Benchmark capital cost (hard cost) for thermal power stations with coal as fuel," Central Electricity Regulatory Commission, Tech. Rep. No. L-1/103/CERC/2012, 2012.

[26] EIA, "Cost and performance characteristics of new generating technologies, Annual Energy Outlook," US Energy Information Administration, Tech. Rep., 2016.

[27] CERC, “Central Electrcity Regulatory Commission (Terms and Conditions for Tariff Determination for Renewable Energy Sources) (Second Amendment) Regulations 2014,” Central Electricity Regulatory Commission, Tech. Rep., 2014.
[28] R. Banerjee, “Coal-Based Electricity Generation in India,” 2016. [Online]. Available: http://cornerstonemag.net/coal-based-electricity-generation-in-india/
[29] World Bank, “Forecast for LNG prices - Landed price of LNG in Japan in 2030,” World Bank, Tech. Rep., 2017.
[30] CEA, “Draft National Electricity Plan Vol I Generation,” Central Electricity Authority, Tech. Rep., 2016.
[31] S. Stoft, *Power System Economics - Designing Electricity Markets*, 2002.
[32] G. Masters, *Renewable and Efficient Electric Power Systems*, 2004.
[33] POSOCO, “2014 Load time series SCADA data,” Power Systems Operations Corporation, Tech. Rep., 2015.
[34] NERC, “2016 Summer Reliability Assessment,” North American Electric Reliability Corporation, Tech. Rep., 2016.
[35] W. Hart, C. Laird, J.-P. Watson, and D. Woodruff, *Pyomo âĂŞ Optimization Modeling in Python*, 2012. [Online]. Available: http://www.springer.com/us/book/9781461432258
[36] CERC, “Terms and conditions of tariff determination from renewable energy sources (Fifth Amendment) Regulations 2016,” Central Electricity Regulatory Commission, Tech. Rep., 2016.
[37] L. Hirth, F. Ueckerdt, and O. Edenhofer, “Integration costs revisited âĂŞ An economic framework for wind and solar variability,” *Renewable Energy*, vol. 74, pp. 925–939, Feb. 2015. [Online]. Available: http://www.sciencedirect.com/science/article/pii/S0960148114005357
[38] D. Heide, L. von Bremen, M. Greiner, C. Hoffmann, M. Speckmann, and S. Bofinger, “Seasonal optimal mix of wind and solar power in a future, highly renewable Europe,” *Renewable Energy*, vol. 35, no. 11, pp. 2483–2489, Nov. 2010. [Online]. Available: http://www.sciencedirect.com/science/article/pii/S0960148110001291
[39] S. Becker, B. A. Frew, G. B. Andresen, T. Zeyer, S. Schramm, M. Greiner, and M. Z. Jacobson, “Features of a fully renewable US electricity system: Optimized mixes of wind and solar PV and transmission grid extensions,” *Energy*, vol. 72, pp. 443–458, Aug. 2014. [Online]. Available: http://www.sciencedirect.com/science/article/pii/S0360544214006343