



GREENING THE GRID:

Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid

About the Study

The use of renewable energy (RE) sources, primarily wind and solar generation, is poised to grow significantly within the Indian power system. The Government of India has established an installed capacity target of 175 gigawatts (GW) of RE by 2022 that includes 60 GW of wind and 100 GW of solar, up from current capacities of 29 GW wind and 9 GW solar. Using advanced weather and power system modeling designed specifically for this project, the multi-institutional study team explored operational impacts of meeting India's RE targets and identified actions that are favorable for integration.

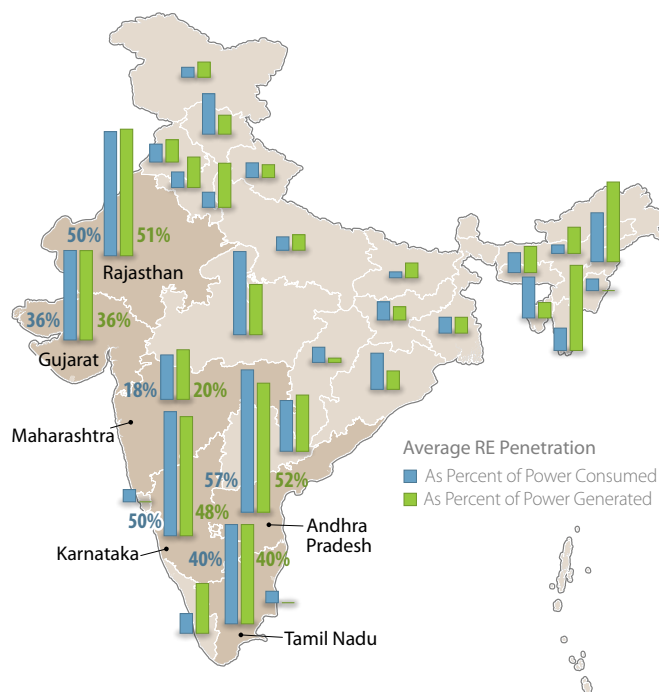
The study team's primary tool was a detailed production cost model, which simulates optimal scheduling and dispatch of available power generation in a future year (2022) by minimizing total production costs subject to physical, operational, and market constraints. They used this model to identify how the Indian power system is balanced every 15 minutes, the same time frame used by power system operators. The results can be used to inform policy and regulatory decisions that support system flexibility and RE investments.

KEY FINDINGS:

How India's Power System Could Operate with 100 GW Solar and 60 GW Wind

Power system balancing with 100 GW of solar and 60 GW of wind is achievable at 15-minute operational timescales with minimal RE curtailment. This RE capacity generates 370 terawatt hours (TWh) annually, a 22% share of total electricity consumption in India, reaching a nationwide instantaneous peak of 54%. Annual RE curtailment (assuming sufficient in-state transmission) is 1.4%, consistent with experiences in other countries with this level of RE penetration.

1. Crore, a widely used term in India, equals 10 million.
2. Exchange rate in late June 2017 was INR 64.5 to USD 1.



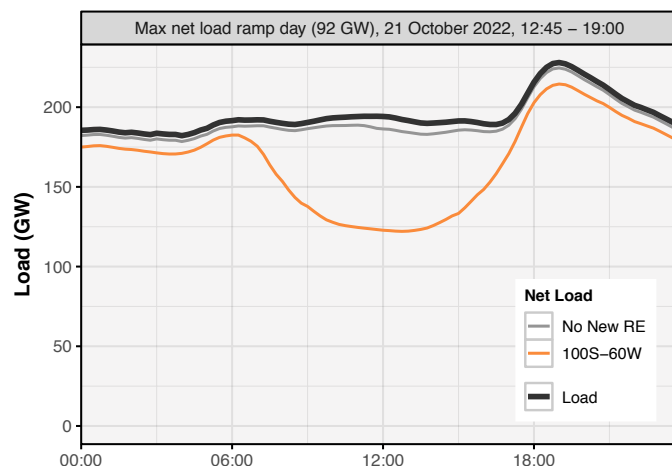
RE is expected to meet over 50% of electricity demand in three states.

Fuel requirements for coal and gas fall 20% and 32%, respectively, and CO₂ emissions fall 21% (280 million tonnes) in the scenario adding 100 GW of solar and 60 GW of wind (the 100S-60W scenario) compared to a scenario in which no new RE resources are added (the No New RE scenario).

As a result, in the RE scenario, plant load factors for coal drop from 63% to 50%, with nearly 20 GW that is never economical to start.

Changes to operational practices can reduce the cost of operating the power system and reduce RE curtailment but are not essential for 160 GW RE integration. Optimizing power scheduling and dispatch at the regional, rather than state, level can support more efficient operations of thermal plants and reduce annual operating costs by 2.8%, or INR 6300 crore¹ (approximately USD 980 million).² In addition to improving access to the least-cost power generation sources,

coordination between states helps reduce the number of coal plants that are not operating at full capacity, providing greater operational range to the remaining committed coal plants to lower the quantity of energy they produce when RE generation is high. Coordinating energy production at the national level provides even further cost savings (3.5% savings) and reduced RE curtailment (to 0.9%).

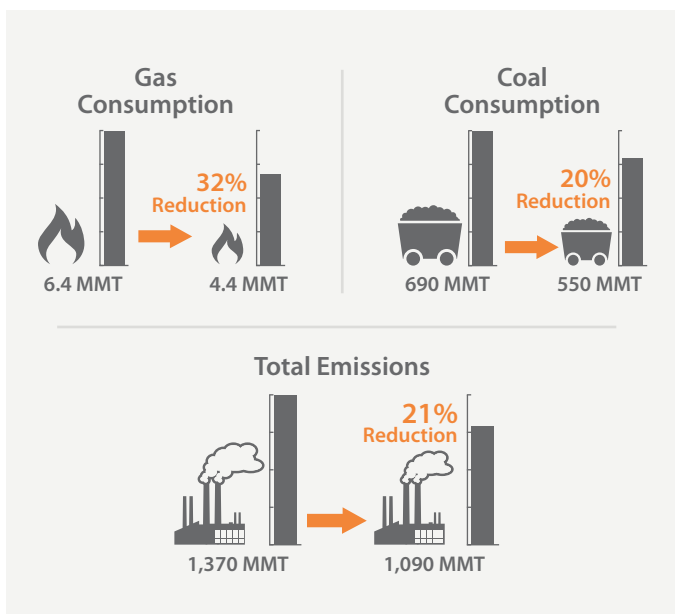


Load and net load on the day with the maximum net load ramp (92 GW over 6 hours)

significant change in either production cost or RE curtailment when coal generation ramp rates were made less flexible in the simulations, although this study assumes a similar load shape for 2022 as prevailing today. A significant change in load shape could affect the net load ramp rate. Five-minute scheduling and dispatch has been demonstrated elsewhere to better handle ramping, if required at a later stage.

An idealized “copper plate” sensitivity shows a possibility for 4.7% production cost savings and 0.13% RE curtailment. This copper plate scenario represents a transmission system with no constraints and operations with no barriers to scheduling. Though not physically plausible, this scenario provides insights into the maximum achievable savings if all transmission and market constraints could be relaxed. Such a scenario reduces RE curtailment to 0.13% and electricity production costs by 4.7%. In comparison, scheduling and dispatch optimized at the regional level and with transmission constraints delivers over half of these savings. Nationally coordinated dispatch combined with an additional 25% interregional transmission capacity delivers 84% of the savings of the idealized copper plate.

Batteries insignificantly impact emissions and total cost of generation. Batteries do reduce curtailment (from 1.4% to 1.1%); however, the value of this curtailment is offset by the batteries’ efficiency losses during operation. In the 100S-60W scenario, 2.5 GW of batteries (75% efficient) reduce RE curtailment by 1.2 TWh annually but lose 2.0 TWh annually due to inefficiencies. Also, there is insignificant impact on the total cost of generation because the overall generation mix changes little. Batteries could be economically desirable for RE integration for grid services that are outside the scope of the study (e.g., frequency regulation, capacity value, local transmission congestion).



Fuel consumption reduction of 20% coal, 32% gas compared to the No New RE scenario. Total CO₂ emissions reduction of 21%.

Reducing minimum generation levels of large thermal plants is the biggest driver to reducing RE curtailment. Changing minimum generation levels of all coal plants, from 70% today to 55% of rated capacity (consistent with the Central Electricity Regulatory Commission regulations) reduces RE curtailment from 3.5% to 1.4% and annual operating cost by 0.9%, or INR 2000 crore. Reducing minimum generation levels further, to 40%, reduces RE curtailment to 0.76%, with negligible decreases to annual operating costs.³ If only centrally owned plants achieve 55% minimum generation levels but state-controlled plants maintain minimum generation levels of 70%, RE curtailment is 2.4%.

The peak systemwide 1-hour up-ramp increases by 27% to 32 GW compared to 25 GW in a system with no new renewables. This ramp rate can be met if all generating stations exploit their inherent ramping capability. Aggregated nationally, for 56 hours of the year, system-wide up-ramps exceed 25 GW/hour, greater than any ramp requirement in the No New RE scenario, and peak at almost 32 GW/hour. The current generation fleet is shown to successfully respond to these ramp events within the study’s operating assumptions. The study found no

3. In this report, changes to production costs that are less than 0.5% are considered negligible.

Retiring 46 GW of coal (20% of installed coal capacity) does not adversely affect system flexibility, assuming adequate in-state transmission. Retiring coal plants that operate at less than 15% of capacity annually (205 generation units totaling 46 GW in capacity) has almost no effect on system operations.

Summary: Power system balancing with 100 GW of solar and 60 GW of wind is achievable with minimal integration challenges, bringing benefits of reduced fuel consumption and emissions. Meeting existing regulatory targets for coal flexibility, enlarging geographic and electrical balancing areas, expanding transmission in strategic locations, and planning for future flexibility can enable efficient and reliable operation of the power system now and in the future.

wind, 60 GW solar) enables a higher annual RE penetration rate (26% compared to 22%, due to wind's higher capacity factors), reduces CO₂ emissions an additional 6.1%, and results in less RE curtailment, 1.0% compared to 1.4%. Because of its relatively less variable net load profile, the higher wind scenario creates fewer conditions requiring thermal plant flexibility.

A 250-GW RE system could achieve India's Nationally Determined Contribution targets, but 16% annual RE curtailment in the Southern region would likely signal the need for modified strategies. To identify a more viable pathway toward 250 GW, additional studies can evaluate the trade-off of increasing system flexibility versus locating more of the RE capacity in other regions.

Potential Planning and Policy Actions That Can Support RE Integration

1. Coordinate RE generation and transmission at the state level to ensure sufficient in-state transmission.
2. Create regulatory or policy guidelines to support institutionalization of cost-optimized capacity expansion planning. Create and maintain a nationwide model that helps optimize generation and transmission buildouts, which can then be used to inform investment decisions and RE policies.
3. Evaluate options for enhanced coordination of scheduling and dispatch between states and regions.

KEY FINDINGS: Different Pathways to Meeting RE Targets; Looking Beyond 2022

A wind-dominated system achieves higher RE penetration rates and requires less thermal fleet flexibility. Compared to the official RE targets, a scenario with more wind (100 GW

RE INTEGRATION STRATEGIES					
100 GW SOLAR 60 GW WIND					
NORMAL OPERATIONS	COORDINATED SCHEDULING AND DISPATCH		COAL PLANT FLEXIBILITY		
STATE-LEVEL DISPATCH, 55% MINIMUM GENERATION	REGIONAL	NATIONAL	LOWER MINIMUM PLANT GENERATION (40% of capacity)	HIGHER MINIMUM PLANT GENERATION (70% of capacity)	LOWER MINIMUM PLANT GENERATION (40% of capacity) WITH REGIONAL BALANCING AREA COORDINATION
230,000 INR Crore Annual Production Cost	2.8% Savings annually ↓	3.5% Savings annually ↓	Negligible Savings annually	0.90% Increased cost annually ↑	3.3% Savings annually ↓
1.4% Renewable energy curtailment	1.3% Renewable energy curtailment	0.89% Renewable energy curtailment	0.76% Renewable energy curtailment	3.5% Renewable energy curtailment	0.73% Renewable energy curtailment

Impact of RE integration strategies on production costs and RE curtailment

4. Establish at central and state levels comprehensive regulations regarding flexibility of conventional generators, including minimum generation levels, ramp rates, and minimum up and down times.
5. Develop a new tariff structure that moves away from focusing on energy delivery. Agreements can specify various performance criteria, such as ramping, specified start-up or shut-down times, and minimum generation levels, along with notification times and performance objectives that achieve flexibility goals.
6. Revise policy/regulatory-level guidelines to use the full capability of hydro and pumped hydro stations. Suitable incentive mechanisms can encourage operation of hydro and pumped hydro depending upon system requirements.
7. Change requirements so that the scheduling and dispatch of power is based on production costs (merit order dispatch); supplementary software may be required to identify economic scheduling and dispatch that considers the combined effects of conventional and renewable variable costs, transmission congestion and losses, and other factors.
8. Create model power purchase agreements for RE that move away from must-run status and employ alternative approaches to limit financial risks, such as annual caps on curtailed hours.
9. To achieve more ambitious RE levels, use detailed, model-based planning, including both capacity expansion and production cost modeling. Issue regulatory guidelines to make it mandatory for stakeholders to provide data required to perform such studies.
10. Equip all states with latest, state-of-the-art load forecasting facilities. In addition, equip RE-rich states with state-of-the-art RE forecasting tools. Further, build capacity of all system operators in this regard, developing in-house capability to create and customize such tools in the future.

Sponsors and Contributors

This work is conducted under a broader program, Greening the Grid, which is an initiative co-led by India's Ministry of Power and the U.S. Agency for International Development, and includes collaboration with the World Bank Energy Sector Management Assistance Program and the 21st Century Power Partnership. The modeling team comprised a core group from the Power System Operation Corporation, Ltd. (POSOCO), which is the national grid operator (with representation from the National, Southern, and Western Regional Load Dispatch Centers), National Renewable Energy Laboratory, and Lawrence Berkeley National Laboratory, and a broader modeling team drawn from Central Electricity Authority, POWERGRID (the central transmission utility), and State Load Dispatch Centers in Maharashtra, Gujarat, Rajasthan, Tamil Nadu, Karnataka, and Andhra Pradesh.

Technical stakeholder review and guidance was provided by more than 150 technical experts from central agencies, state institutions (grid operators, power system planners, RE nodal agencies, distribution utilities), and the private sector (RE developers, thermal plant operators, utilities, research institutions, market operators, other industry representatives).

Learn more:

www.nrel.gov/india-grid-integration/



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