Title

GREENING THE GRID: Pathways to Integrate 175 Gigawatts of Renewable Energy into India’s Electric Grid, Vol. I—National Study EXECUTIVE SUMMARY

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GOVERNMENT OF INDIA
MINISTRY OF POWER

GREENING THE GRID:

Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid, Vol. I—National Study

EXECUTIVE SUMMARY

GREENING THE GRID PROGRAM
A Joint Initiative by USAID and Ministry of Power

JUNE 2017

This report was produced by the National Renewable Energy Laboratory, Lawrence Berkeley National Laboratory, Power System Operation Corporation, and the United States Agency for International Development.

Prepared by

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Disclaimer

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EXECUTIVE SUMMARY

21st Century POWER PARTNERSHIP
Accelerating the transformation of power systems

ESMAP
Energy Sector Management Assistance Program

EXECUTIVE SUMMARY

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) 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.[1] India's contribution to global efforts on climate mitigation extends this ambition to 40% non-fossil-based generation capacity by 2030. Global experience demonstrates that power systems can integrate wind and solar at this scale; however, evidence-based planning is important to achieve wind and solar integration at least cost.

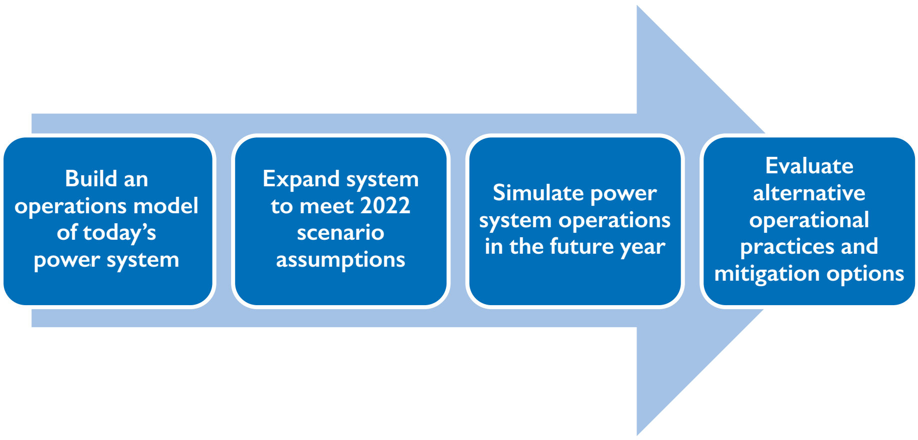
This study demonstrates that a coal-dominated system can successfully integrate significant shares of RE—meeting over 20% of demand.

Objective and Scope of Analysis

The purpose of this analysis is to evaluate the operation of India's power grid with 175 GW of RE in order to identify potential cost and operational concerns and actions needed to efficiently integrate this level of wind and solar generation. 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 (USAID), and includes collaboration with World Bank, the U.S. Departments of Energy and State, and the 21st Century Power Partnership. This work is aimed to support the initiatives taken by India's Ministry of Power for large-scale integration of RE.

Our primary tool is a state-of-the-art production cost model, which simulates optimal scheduling and dispatch of available generation by minimizing total production costs subject to physical, operational, and market constraints. We treat fixed costs as sunk investment costs when comparing scenarios and sensitivities; savings come from minimizing the variable (production) costs of installed capacity. The objective is to mimic the scheduling and dispatch decisions that are based on variable or production costs. We developed this model to identify how the Indian power system is balanced every 15 minutes in a future year (2022). The model quantifies RE generation, including variability and curtailment, changes in least-cost scheduling and dispatch, flexibility of thermal generation, and periods of stress. We use these results to inform regulatory and policy decisions, including actions to improve system flexibility to accommodate large-scale RE generation. The results can also be used to inform policies that support different RE investment pathways, by demonstrating, for example, the impacts to integration of wind versus solar. As a follow-up to this study, the modeling team will conduct a separate set of system stability analyses to analyze the ability of a system with high RE penetrations to recover from contingency events.

RE curtailment is a reduction in the output of a generator from what it could otherwise produce given available wind and solar resources.



Process for building and simulating the 2022 system

1. This RE target also includes 10 GW from biomass and 5 GW from small hydro; the current capacity installations reflect installations at the start of 2017.

Modeling Participants and Stakeholder Review Committee

A hallmark of this grid study is extensive engagement and validation with experts from across the Indian power system—through a multi-institutional modeling team and a broad stakeholder review committee. The objective of this rigorous review is to harness the experience, judgment, and expertise of the committee, and therefore maximize the accuracy and benefit of this study.

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 (NREL), and Lawrence Berkeley National Laboratory (Berkeley Lab), and a broader modeling team of more than 20 engineers representing central and state agencies: Central Electricity Authority (CEA), POWERGRID (the central transmission utility, CTU), and State Load Dispatch Centers in Maharashtra, Gujarat, Tamil Nadu, Karnataka, Rajasthan, and Andhra Pradesh. All modelers received formal training on the use of the production cost software.

Technical stakeholder review was provided by three teams of Grid Integration Review Committees. A technical review committee is an instrumental component of a rigorous, industry-grounded RE grid integration study. The purpose of the committee is to ensure that the direction of the study is relevant to industry and that the results are technically accurate. We met four times in each of three locations (Delhi, Bangalore, Mumbai) with more than 150 technical experts from central agencies (the Central Electricity Regulatory Commission [CERC], Solar Energy Corporation of India, National Institute of Wind Energy), 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). The Review Committees provided peer review and guidance at all stages of the study, from scenario design and modeling assumptions through implications of results. In addition, individual consultations were conducted with central agencies, including the Ministry of Power, the Ministry of New and Renewable Energy, and the CEA.

Study Scenarios

Under the guidance of the Review Committees and the Ministry of Power, this study adopted five RE growth scenarios to evaluate, as described in the table below.

The study year for each scenario is 2022. We adopted official projections for load, and plans for conventional generation and transmission for 2022. We further augmented the generation capacity with the above combinations of wind and solar. The aim of the study is not to predict what will happen in 2022 or assess the timing of infrastructure investments, but to evaluate the operational impacts and mitigation strategies of high wind and solar scenarios. The combinations of generation, transmission, and load are intended to represent scenarios that could occur at any point in the 5- to 10-year horizon. Because the 100S-60W scenario represents the official government of India target for 2022, we focus the bulk of our analysis on this scenario.

Description and Purpose of Scenarios Used in the Study

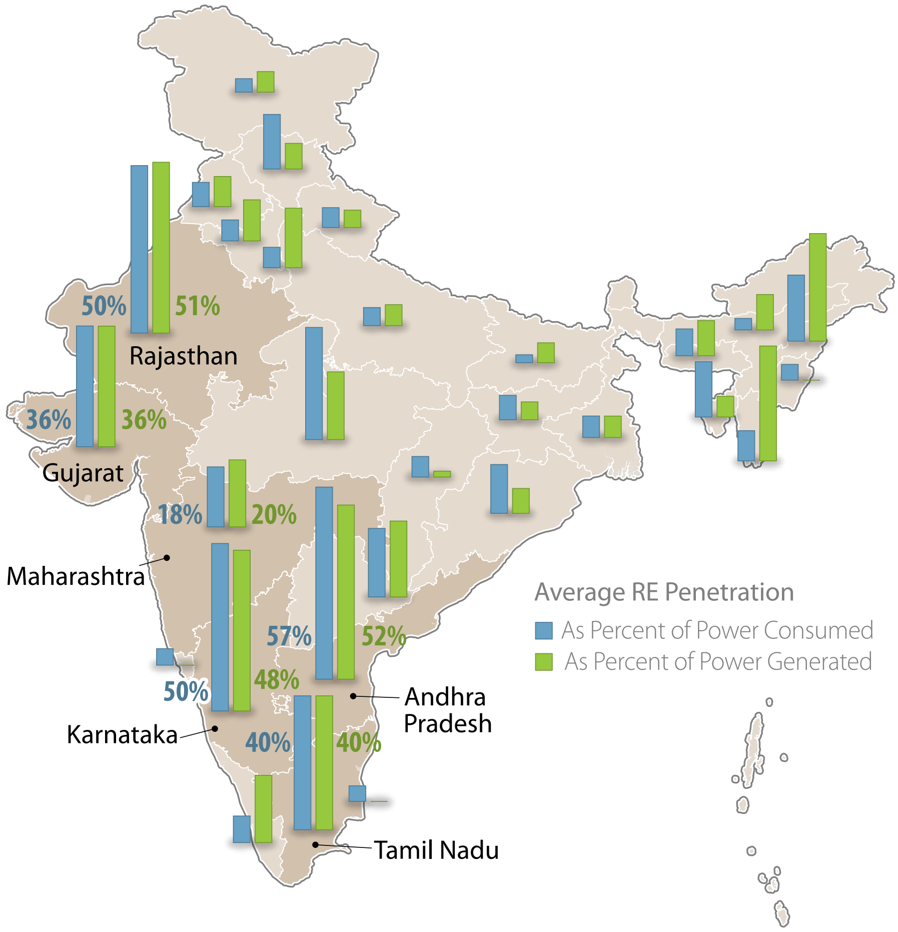
Scenario	Solar (GW)	Wind GW)	Description	Purpose
No New RE	5	23	Wind and solar capacities in 2014	Establish a baseline to measure impact of adding new RE to the system
20S-50W	20	50	Total installed capacity as targeted in Green Energy Corridors & National Solar Mission	Evaluate changes to power system planning and operations to meet near-term targets
100S-60W	100	60	Current government of India target for 2022	Evaluate changes to planning and operations to meet the official target of 175 GW RE
60S-100W	60	100	Solar and wind targets reversed in comparison to official target	Understand differential impacts of wind versus solar on need for system flexibility
150S-100W	150	100	Ambitious RE growth	Evaluate how needs for system flexibility would change under a higher wind and solar build-out

KEY FINDINGS OF THIS STUDY

Core Scenario: 100 GW Solar, 60 GW Wind

The overarching conclusion from this study is that integrating 160 GW of renewable energy—22% of electricity generation—is achievable based on projected power system plans and regulations, and with optimal siting of RE with regards to intrastate transmission. Integrating this level of RE offers benefits of fuel savings and reduced emissions, while still fully meeting projected demand for electricity. The following key findings offer further insight into how the power system with this level of RE would operate, and how actions to improve RE integration impact production costs, curtailment, and system flexibility.

160 GW of solar and wind generate 370 TWh of energy annually, meeting 22% of India's electricity demand and reaching an instantaneous peak of 54%.



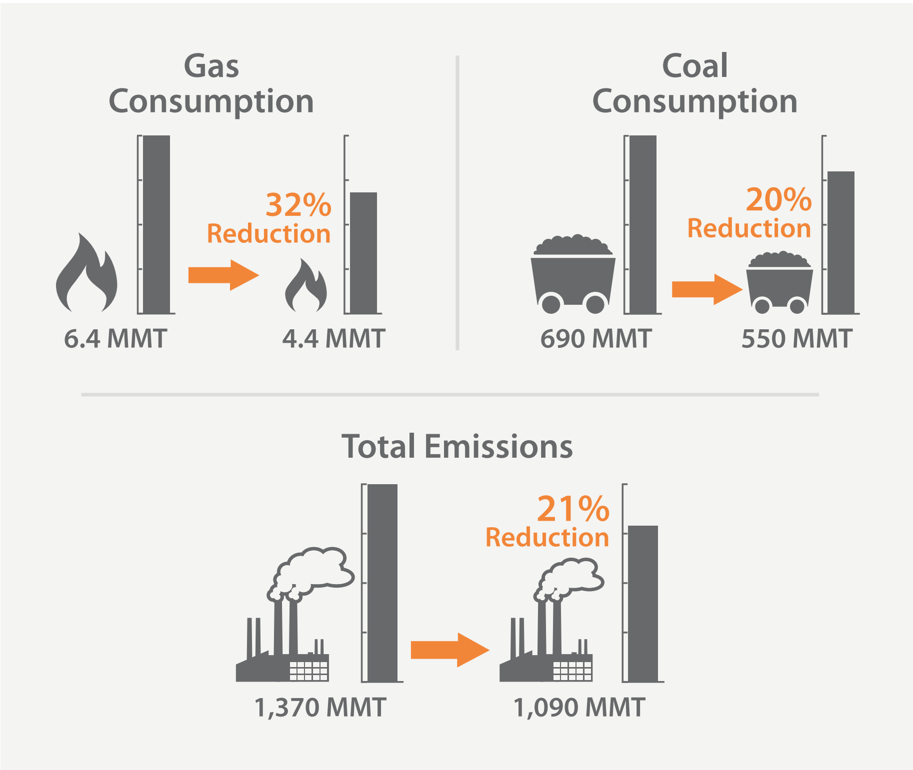
Annual RE penetration exceeds 50% of load in three states

Power system balancing with 100 GW of solar and 60 GW of wind is achievable at 15-minute operational timescales with minimal RE curtailment.

Based on existing plans for transmission and generation capacity expansion, optimal siting of RE and in-state transmission, and fulfillment of current efforts to improve access to the physical flexibility of the power system, system balancing at 15-minute timescales is achievable with only 1.4% RE curtailment.[2] Further, new fast-ramping infrastructure for the RE, such as combustion turbines or storage, is not necessary to manage the added variability of wind and solar. The planned fleet of generation and transmission provides sufficient capacity to handle errors from state-of-the-art RE forecasts, changes in net load (ramps), and times of the day and year when RE generation is low. However, continued investment in transmission would be essential at both state and interstate levels to ensure minimal RE curtailment. While physically, the system has the flexibility to manage added variability and uncertainty, the challenge going forward is accessing this flexibility through appropriate regulations, operational rules, operating reserve requirements, market mechanisms, and software and control systems.

2. This level is within the range of experiences in other countries with significant RE. For example, Spain and Ireland have wind penetration levels of around 20% with 2-3% RE curtailment (Bird et al. 2016).

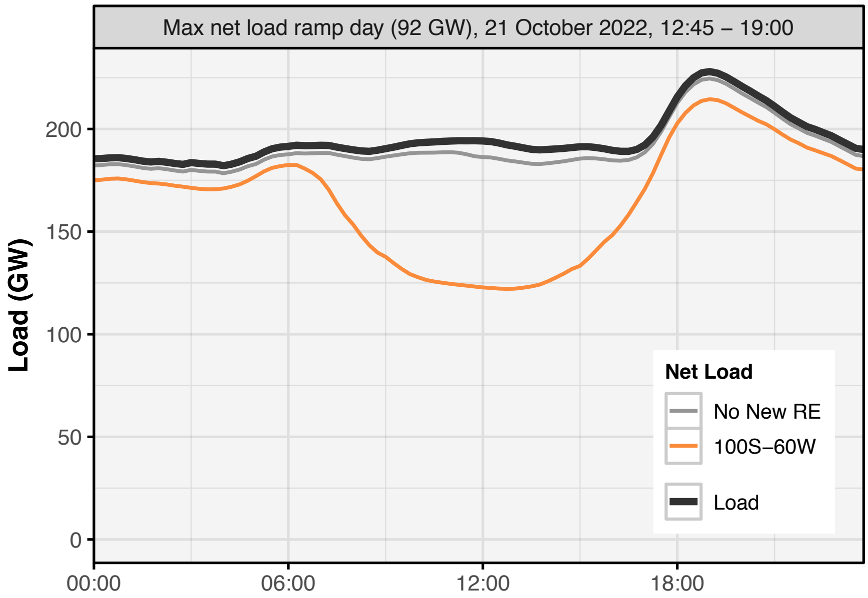
Unique weather for each RE generation site helps smooth the variability of wind and solar.



Fuel consumption reduction of 20% coal, 32% gas compared to the No New RE scenario. Total CO_2 emissions reduction of 21%

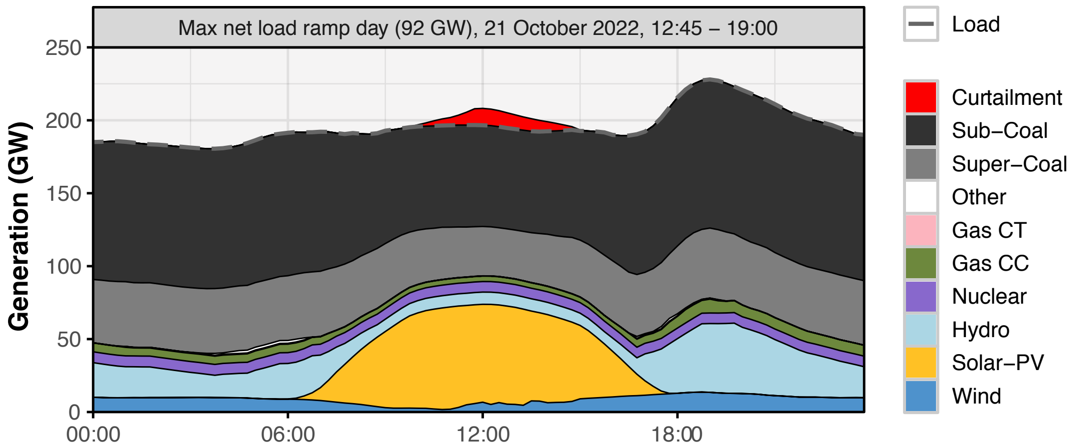
The peak systemwide 1-hour up-ramp increases 27% compared to a system with no new renewables, to almost 32 GW, up from 25 GW. This ramp rate can be met if all generating stations exploit their inherent ramping capability.

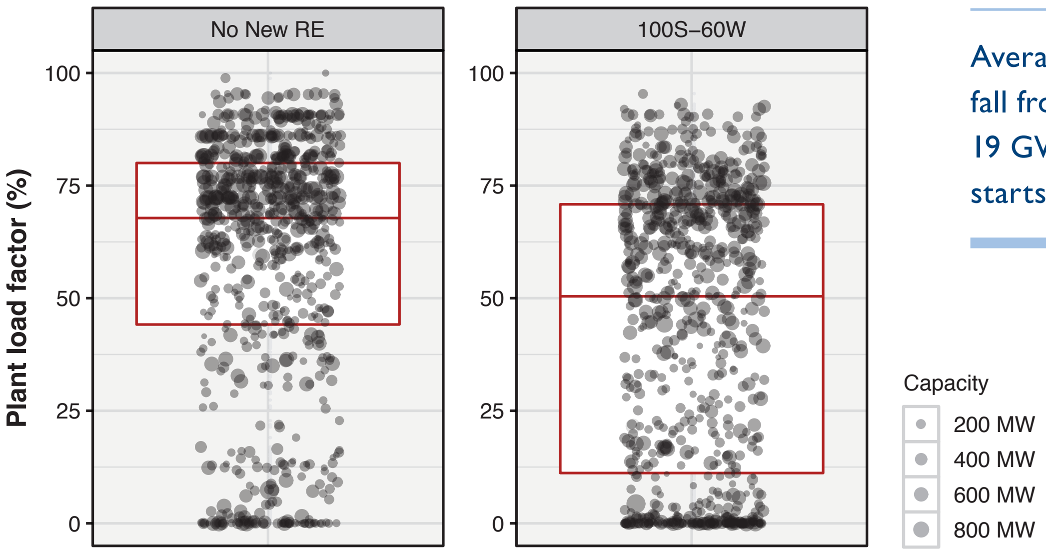
Aggregated nationally, for 56 hours of the year, systemwide 1-hour up-ramps exceed 25 GW, greater than any ramp requirement in the No New RE scenario, and peak at almost 32 GW. The current generation fleet is shown to successfully respond to these ramp events within our operating assumptions. We found no 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.



The existing flexibility in the coal-dominated power system can handle RE forecast errors, net load changes, and exchanges of energy between regions. System ramps can be met if all generating stations exploit their inherent ramping capability.

Net load (above) and generator dispatch (below) on the day with the maximum net load ramp (92 GW over 6 hours)





Average coal plant load factors fall from 63% to 50%, with over 19 GW of capacity that never starts.

Coal PLFs, No New RE and 100S-60W. Dots represent individual plants sized to nameplate capacity.

The latent flexibility in hydroelectric generation helps maintain system balance.

With RE, net load (load minus wind and solar generation, i.e., the demand that must be met by other generation sources if all the RE power is consumed) takes on a dual-peak pattern that is different than today. Hydroelectric (hydro) generation, subject to various flow constraints, is dispatched during the periods of highest value, which occur during the net demand peaks. The adaptability of hydro helps the power system to absorb the variability that RE adds to the system, complementing the flexibility from the thermal fleet. Additionally, sensitivities representing high- and low-hydro years did not hinder RE integration, as the flexibility of the system is still sufficient to maintain balance.

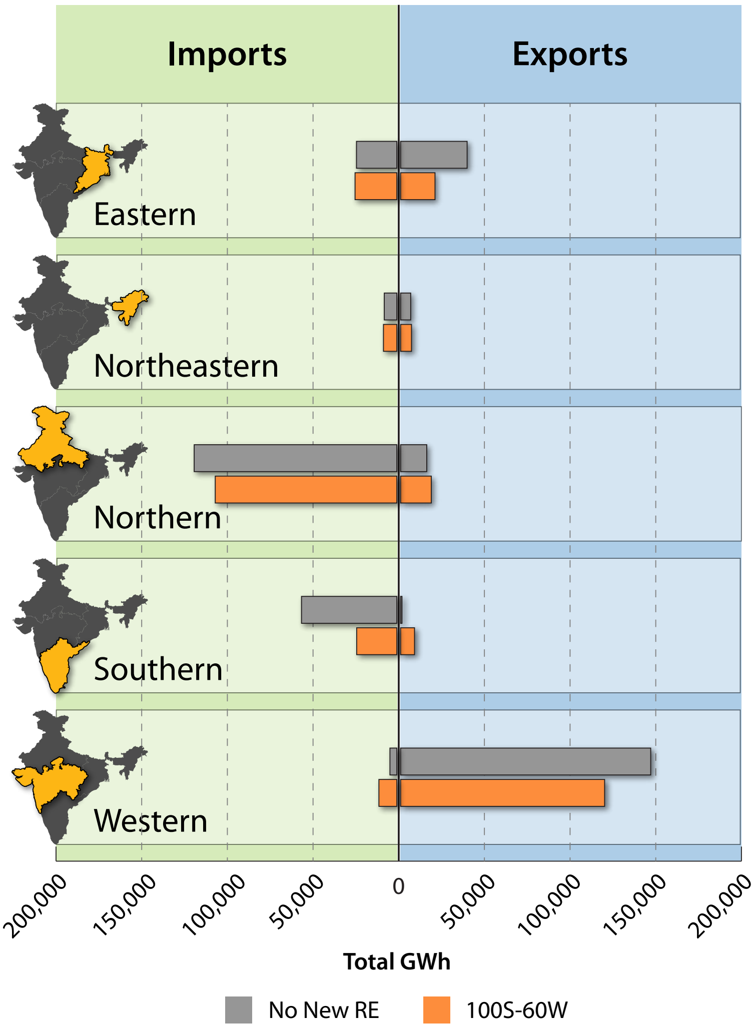
High- and low-hydro years impact production cost and CO_2 emissions but do not significantly handicap RE integration.

Annual energy flow on major corridors does not change significantly, although corridors connected to the Southern region frequently carry power in both directions, a change from today's system and a low RE future scenario.

We find that total energy flows change somewhat under the 100S-60W case and interregional corridors are congested some periods during the year; however, these changes do not appear to hinder the effective integration of 160 GW of RE. Without the growth of RE, the Southern region is a steady importer. But under the 100S-60W scenario, the major change to flows occurs between the Western and Southern regions, causing more bidirectional flows than in the No New RE case. Overall, the total energy moving around the country decreases because certain states and regions are more self-sufficient in their generation supply with the addition of RE.

National and regional optimization of scheduling and dispatch eases RE integration by smoothing variability and broadening the supply of system flexibility.

Existing merit-order operations, in which generators with lower variable costs are dispatched before higher variable cost generators, capture many of the efficiencies necessary to integrate 160 GW of wind and solar. The 2022 analysis



Southern region net imports decline 57% in the 100S-60W scenario due to its much higher wind and solar generation.

Changes to operational practices can reduce the cost of operating the power system and reduce RE curtailment but are not essential for RE integration of 100 GW of solar energy and 60 GW of wind energy.

suggests that existing operations, which follow a decentralized state-by-state level unit commitment and dispatch, can integrate future levels of RE with only 1.4% RE curtailment nationally.

Nevertheless, we find that scheduling and dispatch optimized at the regional or national level can support more efficient operations of thermal plants and help achieve more economical operations with annual operating cost savings of roughly 2.8%, or INR 6300 crore[3] in today's rupees (approximately USD 980 million) for regional coordination and 3.5% or INR 7800 crore for national coordination. In addition to improving access to least-cost generation, coordination between states helps reduce the number of coal plants at part load, providing greater operational range to the remaining committed coal plants to lower generation output when RE generation is high.

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 CERC 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.[4] 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%.

An idealized "copper plate" sensitivity delivers a best-case transmission benchmark of 4.7% production cost savings and 0.13% RE curtailment.

Our copper plate scenario, which represents a market based on a nationally optimized least-cost dispatch principle, a transmission system with no constraints, and operations with no barriers to scheduling, reduces RE curtailment to 0.13% and production costs by 4.7%. Though not physically plausible, this scenario provides insights into how the modeled results of other, feasible cost- and curtailment-mitigation measures compare to those that would be achieved if all transmission and market constraints could be relaxed. For example, scheduling and dispatch optimized at the regional level and with transmission constraints delivers over half of the production-cost savings of the copper plate, and nationally coordinated dispatch combined with an additional 25% interregional transmission capacity delivers 84% of the savings of the idealized copper plate.

Meeting CERC regulations that require plants to operate at a minimum of 55% rated capacity reduces RE curtailment from 3.5% to 1.4%.

The copper plate sensitivity results in a peak of 36 GW power transfer from west to north and leads to loop flows from west to north to east, providing insights into transmission plans and highlighting the need for further study.

The copper plate sensitivity indicates the likely transmission requirements for 2022 for least-cost generation dispatch. Under this scenario, power flow on the Western-to-Northern region corridor would reach a maximum 36 GW. Additionally, flows typically go from Northern to Eastern, which leads to loop flows of Western to Northern to Eastern. Flow on the Western-to-Southern region corridor may also become bidirectional depending upon the wind generation. Further, full AC power flow and related analyses would be necessary to complement the existing studies by the transmission planning teams in India (who use power flow software extensively). Through this integration study, stakeholders within India have identified the need for a mandatory production cost modeling study for the purpose of transmission planning for a large country like India with diverse resources. CERC will be updating regulations on transmission planning and could consider this aspect to ensure the right plan and build-out of transmission.

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 charge

3. Crore, a widely used term in India, equals 10 million.

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

Batteries do not add value to RE integration from a 15-minute scheduling and dispatch perspective.

during the early afternoon when multiple resources, including coal, are online and displace coal at night, resulting in an insignificant drop in total coal generation. Peak coal generation is decreased by less than the capacity of the batteries in both the 100S-60W and 60S-100W scenarios. 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).

Retiring 46 GW of coal (20% of installed coal capacity) does not adversely affect system flexibility.

In the 2022 projections for generation capacity, the least efficient coal plants are rarely dispatched. Even in the absence of new RE capacity (No New RE scenario), nearly 10 GW of coal plants never run at any point of the year. Retiring coal plants that operate at less than 15% of their capacity annually (205 generation units totaling 46 GW in capacity in 100S-60W) has almost no effect on system operations. With retirements, the average plant load factor of the coal fleet is 62%, up from 50%. RE curtailment remains constant at 1.4%, with negligible impact to annual production costs. This suggests that in the long term there may be an opportunity to save money on fixed-cost contracts by strategic retirements of excess generation.

46 GW of coal plants operate very little in a high-RE future. A system with 160 GW of RE could support some combination of higher demand growth or retirements of generation.

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.

Coordinated planning for transmission, operations, and generator flexibility will support cost-effective integration of even higher levels of RE, while minimizing RE curtailment. These changes to operations and planning will reduce operating cost regardless of the level of renewable energy that is ultimately integrated into the Indian power grid. The specific approaches to achieving coordinated planning are beyond the scope of this study but can be developed to address Government of India and stakeholder policy preferences.

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.

With effective state-level planning, curtailment may not be a barrier to RE investment.

Visit **https://maps.nrel.gov/IndiaGTG** to see the study's full year of generation and transmission flows for multiple RE integration strategies.

Summary of Key Findings for the Core Scenario of the 160-GW India RE Integration Study: How a System with 100 GW Solar and 60 GW Wind Is Balanced.

100S-60W Core Scenario RE Generation
RE generates 370 TWh energy annually.
Annual RE penetration is 22%, with an instantaneous peak of 54% of total demand.
Annual capacity factors of the RE plants are 21% for solar PV and 36% for wind.
RE curtailment averages 1.4% of total available RE energy, for a total of 5.1 TWh. The Southern region experiences the highest curtailment levels of 2.9% annually.
RE curtailment occurs somewhere in the country during 1,057 hours, or roughly 12% of the year, and peaks at 27 GW in September.
Impacts on Thermal Units and Plant Operations Compared to the No New RE Scenario
Coal and natural gas generation decrease 270 TWh and 15 TWh, respectively, a drop of 21% and 32%.
CO_2 emissions drop 21% (280 MMT).
Plant load factors of coal drop from 63% to 50% with nearly 20 GW of capacity that never starts, and 65 GW of capacity that experiences plant load factors below 30%.
Coal plants on average experience 2.8% more starts and operate three times longer at minimum generation level.
Aggregated nationally, for 0.64% of the year, systemwide up-ramps exceed 25 GW/hour, greater than any ramp requirement in the No New RE scenario, and peak at almost 32 GW/hour.
Hydro generation follows a two-peak net load profile.
Impacts on Imports and Exports and Transmission Flows Compared to the No New RE Scenario
Annual interstate energy exchanges within the Western and Southern regions decrease 9.6% and 5.9% to 120 and 45 TWh, respectively.
Total annual net energy exchanges between regions decrease 16% to 180 TWh.
The magnitude of flows and number of changes in direction of flows between Southern and Western regions increase significantly during the monsoon period, when wind generation is highest.
Impacts on Production Costs and RE Curtailment from RE Integration Strategies Compared to Reference Scenario of State-Level Dispatch and 55% Minimum Generation Levels on Coal Plants
Improved scheduling and dispatch coordination • Regional coordination: 2.8% cost savings, 1.3% RE curtailment (down from 1.4%) • National coordination: 3.5% cost savings, 0.9% RE curtailment
Different coal minimum generation levels • 40% min gen: negligible cost savings, 0.76% RE curtailment • 70% min gen: 0.9% cost increase, 3.5% RE curtailment
Combined regional coordination with 40% min gen: 3.3% cost savings, 0.73% RE curtailment
Combined national coordination with 25% increase in interregional interface capacity: 3.9% cost savings, 0.74% RE curtailment
Copper plate (no transmission constraints or barriers to optimal scheduling): 4.7% cost savings, 0.13% curtailment

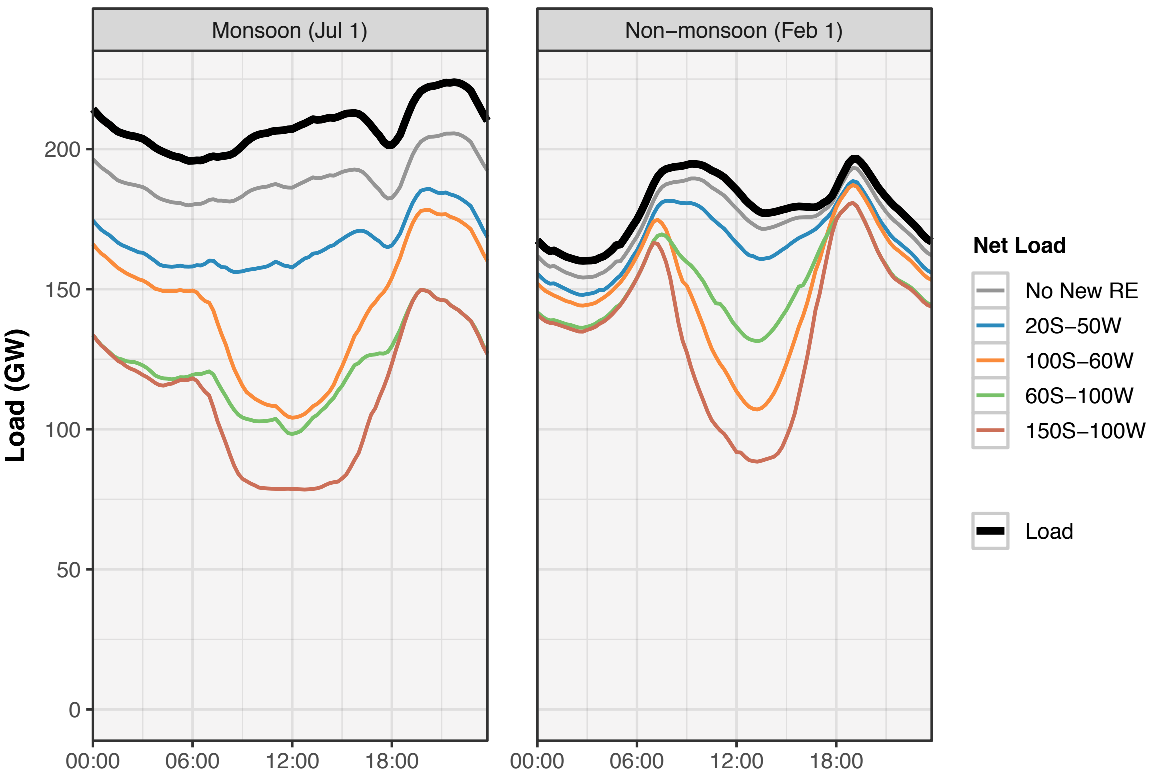
Key Findings for Scenarios with Different RE Penetration Levels

A wind-dominated system achieves higher RE penetration rates and requires less thermal fleet flexibility.

We developed two 160 GW RE scenarios: the official target of 100 GW solar and 60 GW wind (100S-60W scenario), and the opposite 60 GW solar and 100 GW wind (60S-100W scenario). In the latter scenario, greater wind capacity, which has higher capacity factors than solar, helps achieve a higher annual RE penetration rate (26% as compared with 22% in the 100S-60W scenario), reduces CO_2 emissions (6.1% lower than the 100S-60W scenario), and has lower RE curtailment (1.0% compared to 1.4% in the 100S-60W scenario). Because of its relatively less variable net load profile, the higher wind scenario creates fewer conditions requiring thermal plant flexibility. Consequently, the coal fleet in the 60S-100W scenario experiences 7.3% fewer starts and, while operating, spends 31% less time at minimum stable level than in 100S-60W. The reduced flexibility required of the thermal fleet in the 60S-100W scenario results in greater cost and emissions savings per unit of RE generation (2.3% and 3.6%, respectively) than in the 100S-60W scenario.

A 250-GW RE system could achieve India's Nationally Determined Contribution targets early (by 2022) but would likely result in levels of RE curtailment that may not be cost effective unless additional mitigation actions are taken. In this high-RE scenario, high curtailment in the wind- and solar-resource-rich Southern region suggests the need for new RE integration strategies.

At 250 GW solar and wind, the Nationally Determined Contribution target of over 40% of non-fossil generation could be achieved, but curtailment in the Southern region would rise to 16% while curtailment in other regions remains under 3%. RE contributes 33%

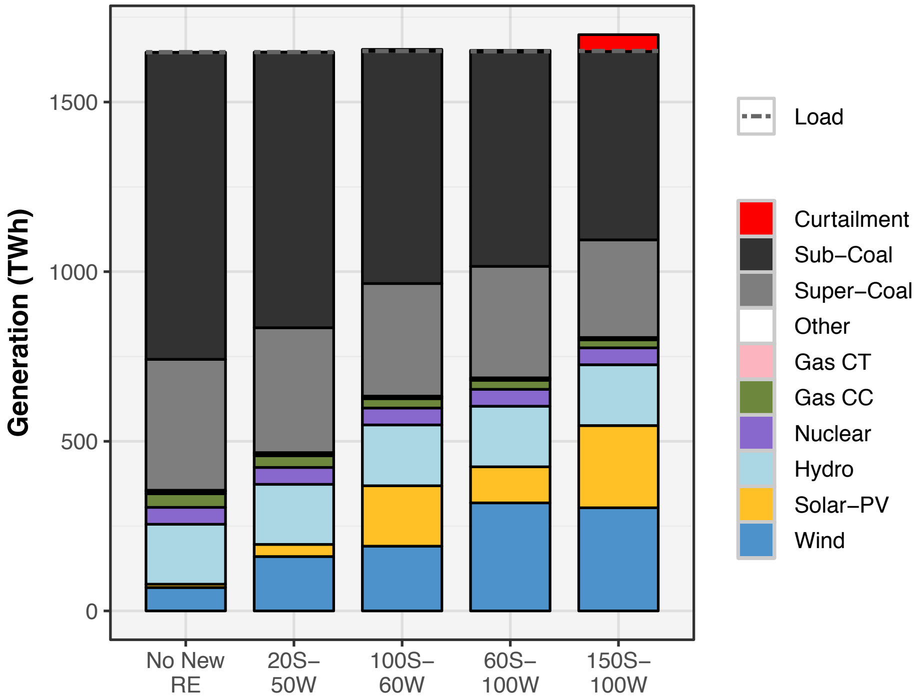


Net load ramping on a monsoon and non-monsoon day, all scenarios of the energy demand in this scenario, which in combination with hydro and nuclear generation would achieve the 40% target. Eliminating the national average of 8.3% annual RE curtailment through a combination of integration strategies, such as load shifting to support electric vehicle charging, would enable an annual penetration rate of 36% with just wind and solar energy. Given that RE curtailment is only a significant issue in the Southern region, additional studies can evaluate whether locating more of the 250-GW RE capacity in other regions would alleviate this curtailment and thus provide a more viable pathway toward 250 GW.

The table at right summarizes RE generation, curtailment, and reductions in CO_2 emissions across the scenarios.

RE Penetration Level, Curtailment, and Reductions in CO_2 Emissions, All Scenarios

Scenario	Wind and Solar Penetration Rate of Annual Generation	RE Curtailment	Percentage CO_2 Reductions Compared to No New RE
No New RE	4.8%	0.0%	—
20S-50W	12%	0.0%	8.6%
100S-60W	22%	1.4%	21%
60S-100W	26%	1.0%	25%
150S-100W	33%	8.3%	34%



Annual generation by fuel across RE build-out scenarios

POLICY IMPLICATIONS

A number of insights from this study help inform policy. Although specific policy recommendations are outside the scope of this study, there are several broad directions that may increase India's capability to efficiently plan and operate the power system in a way that is consistent with national goals related to climate and renewable energy deployment. At the same time, the study provides insights to areas that may *not* be particularly helpful in reliably and cost-effectively integrating renewable energy. Policymakers who are mindful of these distinctions can adopt the efficient methods while avoiding potentially costly new policies that have little or no positive impact on the desired outcome. Table 4 summarizes the policy implications.

Policies That Have a Positive Effect on RE Integration

1. State-Level Planning

The RE targets of 175 GW are achievable, and continued investment in both interstate and intrastate transmission will help facilitate these targets. The interstate transmission as planned under Green Energy Corridors[5] is shown to be sufficient for meeting demand requirements as analyzed in this study, but additional intrastate transmission planning should consider project locations of new RE development, which may differ somewhat from the scenarios evaluated in this study. If nationally coordinated scheduling and dispatch is pursued in which trade barriers between regions are removed, this study highlights the value of reducing RE curtailment via increasing transmission capacity in at least some interregional corridors.

Existing interstate transmission plans appear to be sufficient, but intrastate transmission could be a significant bottleneck to RE integration

Potential Action

At a minimum, coordinate RE generation and transmission at the state level to ensure sufficient in-state transmission. Create a nationwide model that helps optimize generation and transmission build-outs. Create regulatory or policy guidelines to support institutionalization of cost-optimized capacity expansion planning.

2. Larger Balancing Footprint

Enhancing operations by moving toward larger electrical balancing footprints (e.g., regional or national instead of state-level dispatch) has the potential to reduce system operating costs and curtailment of RE. In coordination with strategic transmission planning and development, larger operational footprints are investments that can help with efficient system operation regardless of the pathway to, and ultimate build-out of, renewable energy. Enhanced operational methods also do not suffer from depreciation, making this an attractive policy direction. India already implements some elements that enable a larger electrical balancing footprint: state utilities utilize their long-term allocations from the central sector plants and independent power producers, power exchanges facilitate day-ahead and intraday trades,

Supplemental Studies to Further Inform Policy Decisions
Evaluate intrastate transmission planning that considers project locations of new RE development.
Create a nationwide model that helps optimize generation and transmission build-outs and can inform investment decisions and RE policies; make such studies mandatory for generation planning, transmission planning, and operational planning.
Perform detailed analysis of market designs and regulatory changes to improve coordination of scheduling and dispatch over larger areas.
Apply production cost simulation tools to evaluate the production cost impacts between curtailment and other options to reduce or eliminate curtailment; update periodically as changes to the power system are anticipated.
Conduct detailed, model-based planning, including both capacity expansion and production cost modeling to inform long-term trade-offs and sensitivities to changing technological and economic conditions.
If faster ramping is identified as a future need, evaluate trade-offs between new fast-ramping infrastructure and mechanisms to reduce ramp requirements, such as improved dispatch coordination or demand response
Evaluate strategies or technological improvements that could strengthen the value of batteries, such as improved battery efficiencies and batteries operated to mitigate local transmission constraints and/or provide ancillary services.

5. http://www.powergridindia.com/green-energy-corridor-report

and recent central ancillary services provide spinning reserves via central generators. India may also be moving toward a change in dispatch, an "all India merit order" for central plants that fall under Regional Load Dispatch Center jurisdiction. This will likely move India further toward a more coordinated operational future. Evaluating a move toward more centralized dispatch or markets or something similar may prove effective in helping to efficiently integrate the planned levels of RE.

Although we do not analyze the complex policy and regulatory changes required to implement more coordinated scheduling and dispatch over larger areas, we briefly list some strategies that could be further explored:

- Facilitating an increased number of bilateral exchanges, such as through existing power exchanges, for both day-ahead and imbalance management, to help optimize resources nationally
- Reducing information asymmetry (e.g., costs, generator availability) to enable more coordinated dispatch
- Using coordinated electricity markets to facilitate least-cost dispatch
- Customizing contracts and allocations to allow greater scheduling and dispatch flexibility.

Establishing a mechanism to improve coordination requires detailed analysis of market designs and regulatory changes, which are outside the scope of this study.[6]

Potential Action

Evaluate options for enhanced coordination. Design questions include: markets vs. non-market options; regional vs. national participation; voluntary vs. mandatory participation; and energy imbalances only or full day-ahead scheduling and dispatch.

3. Flexibility from Coal

This study finds that the minimum stable operating level of coal plants can limit the flexibility of the power system and can therefore increase curtailment of RE. Modifying the minimum generation levels of all coal plants so that the plants can operate at a lower fraction of their rated capacity is one option among many RE integration strategies that policymakers may want to consider, at minimum on a plant-by-plant basis. Reducing the minimum generation levels will come at a cost of greater wear and tear on the plants (Lew et al. 2013), and this cost can be evaluated against the costs and benefits of this and other mitigation measures. Because there are many complex system interactions, some combination of mitigation approaches may be most useful.

Potential Action

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 (current CERC regulation applies to central generators but not state generators). Encourage states to match or exceed CERC guidelines for central generators that require 55% minimum operating levels for coal plants; evaluate on plant-by-plant basis further reductions. Provide training curricula that help coal plant operators minimize damage from cycling.

4. Flexibility from Hydro

The flexibility derived from operating hydro and pumped hydro is important for absorbing renewable energy. This study shows that the pump operation is required to be shifted to midday to coincide with greater solar generation output, and the generation operation is required during evening peak. The study further shows that hydro generation operates at 16% of installed capacity during high RE periods.

Potential Action

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.

5. Weighing Options

Multiple approaches to alleviate RE curtailment exist, which can be compared to the economics of continuing relatively low-level RE curtailment. Some curtailment may be the most cost-effective option. Approaches to consider here include points raised above: transmission expansion, balancing area expansion, and minimum generating operations of existing plants.

Potential Action

Apply production cost simulation tools to evaluate the production cost impacts between curtailment and other options to reduce or eliminate this curtailment. This analysis can be updated periodically as changes to the power system are anticipated.

6. Note, a companion study under USAID and the India Ministry of Power's Greening the Grid program is analyzing policy and regulatory issues associated with scheduling, balancing, and forecasting for improved RE integration. This study is based on field investigations at the Indian state and central levels with regulators, utilities, and private sector actors; analysis of central and state Indian regulations; analysis of strategies used in the western United States; and cross-analysis based on stakeholder input.

6. Compensating Flexibility

Central thermal generators receive an availability-based tariff, which is paid based on availability to be scheduled and dispatched, with separate tariff components for the fixed and variable costs. The fixed-cost portion is used to pay off fixed (capital) costs of the plant. Distribution utilities must still pay this tariff even as overall plant load factors decline. At the same time, flexibility that will be needed to help manage RE is not explicitly contracted for, reducing the incentive for plants to provide such services. A new framework surrounding power purchase agreements (PPAs) could consider (a) a mechanism to compensate for the plant fixed cost, especially for coal units during the transition to a higher-RE future in which they would be scheduled less and (b) how to compensate for flexibility that will be needed to manage the increase in variability and uncertainty from higher levels of RE. The challenge is to develop a new framework that can simultaneously address legacy generating plants during the transition to a higher-RE future, plants that come online during the transition, and plants that will be developed after the transition has largely occurred. The solution to this issue is also related to whether India moves to more coordinated system operation and, if so, whether this is facilitated by some type of wholesale power market or a coordinating entity.[7] Under a market-based construct, PPAs need to be developed with market design as a backdrop. In either case, however, PPA structures (and market designs) can be revised to recognize, compensate, and incentivize the characteristics that would be needed to operate the power system under a high level of RE. These characteristics include minimum operating levels, ramping, and short start-up, shutdown, and minimum up-/down-times so that investments in power system assets can facilitate efficient system operations.

Potential Action

Create a model tariff contract that can be used for contracts that are new and up for renewal based on economics of coal plants with lower plant load factors. For existing contracts, explore options used in other countries to renegotiate contracts. 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 shutdown times, minimum generation levels, along with notification times and performance objectives that achieve flexibility goals. The tariff structure should allow for full cost recovery, be applicable to both renegotiated contracts and new contracts, and be effective both during the transition to a high-RE future and after the high-RE future has been reached.

Physically, the power system has the flexibility to manage 160 GW RE. The challenge going forward is accessing this flexibility through operational rules, market designs, incentive mechanisms, and other factors that influence operations.

7. Flexibility from RE

Once RE is brought into the grid, its value should be maximized by dispatching it when it is economical for the system. Traditionally, this value has been achieved through must-run status, as is present in the Indian grid code. However, in some cases RE curtailment is cheaper than costs of, for example, avoided shutdowns and start-ups of coal generation units. The power system could have the physical flexibility to integrate RE, but access to this flexibility could be limited by contract terms. Policymakers could explore alternative means to facilitate merit order dispatch (based on production costs rather than tariffs) and to build confidence in RE investors that financial risks related to RE curtailment are limited. Policymakers can also require economic optimization (cost minimization) explicitly in power system operations and planning.

Potential Action

Use the regulatory platform to require merit order dispatch based on production costs; 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 various other factors.[8] Create model PPAs for RE that move away from must-run status and employ alternative approaches to limit financial risks, such as annual caps on curtailed hours. PPAs or regulations can also be used to require commercially available controls and communications systems that help extract the full value of RE from a system perspective.

7. This coordinating entity could be at the respective state levels (vs. the existing paradigm in which distribution utilities self-schedule, as is the case in many states) or the regional or central level.

8. Various forms of software could support economic dispatch. In the United States, these programs are known as Security Constrained Unit Commitment and Security Constrained Economic Dispatch tools, which are integrated into the Energy Management Control Systems.

8. Additional Transmission

A market that is based on a nationally optimized least-cost dispatch principle with no transmission constraints and no barriers to trade between the states and regions is represented by our copper plate sensitivity. This kind of market in India would require additional transmission on certain corridors. The result for this scenario shows that the power flow on the Western-to-Northern region corridor would go up to a maximum 36 GW, and flow on the Eastern-to-Northern region corridor would get reversed for most of the time, leading to loop flow from west to north to east. Further, the flow on the Western-to-Southern region corridor would become bidirectional depending upon wind generation in the South.

Potential Action

Additional investment in transmission is required for a nationally optimized market based on least-cost dispatch principle with no constraint. More transmission needs to be planned for bulk transfer of power, especially on the Western-to-Northern region corridor. This kind of market would also require a shift in the transmission planning process for which necessary regulatory and policy level guidelines need to be issued.

9. Analysis-Based Targets

Alternative mixes of wind and solar energy in the overall national RE portfolio impact system operations differently. Based on this study, a 175-GW RE target that places greater emphasis on wind over solar (100 GW wind, 60 GW solar) achieves higher RE capacity factors and therefore higher RE penetration levels (26% compared to 22% in the 100 GW solar, 60 GW wind scenario) and lower CO_2 emissions. The characteristics of wind generation (the timing of its availability, its smoothing over large geographies, its impacts on net load ramp rates) make it easier to operate, but this report does not assess the full suite of questions that would be required for a policy cost-benefit analysis, including fixed costs and financing availability, among other factors.

Potential Action

Create and maintain a nationwide model that helps optimize generation and transmission build-outs, which can then be used to inform investment decisions and RE policies. Develop an institutional home for this model and for staff that can support it. Make such studies mandatory for generation planning, transmission planning, and operational planning.

10. Planning for Beyond 175 GW

At higher RE levels, such as the 250-GW level evaluated here, continued evaluation of actual and likely RE sites will be important so that system planning can maximize the cost-effectiveness of network design, power system operation, and reliability. At 250 GW RE, the best wind and solar resources remain in the Southern region, but continued siting of RE in that region may create excessively high levels of RE curtailment in the absence of additional mitigation strategies. This issue can be more fully explored in a detailed evaluation of the various trade-offs between high levels of RE in the South with more transmission development vs. diversifying RE development to other, potentially less energetic, locations that require fewer changes. The implications of the type and location of non-RE plants may also be significant.

Potential Action

To achieve more ambitious RE levels, use detailed, model-based planning, including both capacity expansion and production cost modeling. This will inform long-term trade-offs and sensitivities to changing technological and economic conditions.

11. Forecasting

The real-time model used in this study assumes certain RE forecast errors based on existing state-of-the-art RE forecasting facilities and perfect load forecast. It is important that each state have state-of-the-art load and RE forecasting facilities to address the challenges posed by large-scale RE integration into the grid.

Potential Action

Equip all states with the 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 so that in-house capability is developed to create and customize such tools in the future.

12. Data Sharing

As is typical for integration studies, acquiring required data for the production cost model was a challenge, and assumptions had to be made wherever required data were not available. It is important that data sets for performing basic studies like power flow and production cost studies are made available in the public domain.

Potential Action

Regulatory guidelines may be issued to make it mandatory for stakeholders to provide data required to perform production cost studies.

Other strategies may be beneficial to RE integration in the Indian context but were not analyzed in this study. For example, demand response—increasing the responsiveness of electricity demand to operator controls and/or price signals—can improve system flexibility and better align demand with RE supply. This type of flexibility can be accessed through a combination of software, controls, regulatory interventions, retail tariffs, and incentives. For example, air-conditioning and agricultural pumping may be possible sources of flexible load.[9]

Policies That Have a Neutral Impact on RE Integration at This Time

1. Ramping

This study found that fast-ramping (non-RE) plants are not necessary at the penetration levels associated with 160 GW of wind and solar because ramping as low as 0.5% of maximum capacity per minute resulted in no significant change in either production cost or RE curtailment. Although it is possible that ramping could become a constraint in high-RE futures, there are several technologies that could provide fast ramping. Rather than dictating a specific flexible technology, policies can instead focus on the attribute. If faster ramping is identified as a future need, a policy approach that focuses on the needed capability in a technology-agnostic way can incentivize the most cost-effective technology (which may be some new, unforeseen technology). We did not evaluate ramping capabilities in time periods less than 15 minutes.

2. Storage

As modeled in this study, batteries reduce RE curtailment, but the value of that gain in electricity is offset by efficiency losses generated by the battery in operations. Batteries have almost no effect on production costs or CO_2 emissions. A number of changes could affect the value of batteries, including improvement to battery efficiencies and broadening the value of batteries to include mitigation of local transmission constraints and/or provision of ancillary services. Valuing these services is outside the scope of this study.

Implications for Policy

RE targets of 175 GW are achievable with continued investment in interstate and intrastate transmission.

Interstate transmission identified through Green Corridors is sufficient to reliably operate the system, but intrastate transmission will require new planning based on projected locations of RE.

New fast-ramping plants and storage are not necessary at these penetration levels.

Improving the operations of existing infrastructure, however, does provide high value to RE integration. Operating the power system from a regional or national perspective, rather than state-by-state, achieves efficiencies in operations by reducing the need for costly start-ups and shutdowns. Operating coal plants more flexibly reducing their minimum output to 55% as currently mandated for central generators, or even to 40% provides additional flexibility in managing midday peak RE output.

At high RE penetration levels, coal plant load factors will decline to near 50%, which calls into question economic viability. This will create economic implications for distributions utilities that pay for availability.

Strategic uses of RE curtailment will become an important source of flexibility to minimize system-level costs. Regulations and PPAs that mandate must-run status could restrict access to this flexibility. To maintain confidence for RE investors, removing must-run status will need to accompany an adherence to merit order dispatch (based on production costs, not tariffs) at the system operator level.

A 175-GW RE target that places greater emphasis on wind over solar (100 GW wind, 60 GW solar), achieves higher RE capacity factors, and therefore higher RE penetration levels (26% compared to 22% in the 100 GW solar, 60 GW wind scenario) and lower CO_2 emissions. The characteristics of wind generation make it easier to operate, but this report does not assess the full suite of questions that would be required for a policy cost-benefit analysis, including fixed costs and financing availability, among other factors.

At 250 GW RE, the best wind and solar resources remain in the Southern region, but continued siting of RE in that region will create excessively high levels of RE curtailment without additional mitigation strategies, such as new transmission or improved coordination of scheduling and dispatch.

Achieving more ambitious RE targets will require detailed, model-based planning, and will benefit from an institutionalized process for maintaining the model and sharing data.

9. Efforts under way in this regard include an automated demand side management pilot under Greening the Grid, which is a partnership between USAID, BESCOM, SRLDC, Karnataka Power Transmission Company Limited, and Innovari. This pilot aims to provide the utility and grid operators with a software platform to access flexibility in large commercial and industrial consumer end uses. A companion study under way by U.S. Department of Energy laboratories will investigate how to scale automated demand side management in India for the purpose of supporting RE integration.

Access both volumes of the *Greening the Grid* India grid integration report at **www.nrel.gov/india-grid-integration/.**

About USAID

The United States Agency for International Development (USAID) is an independent government agency that provides economic, development, and humanitarian assistance around the world in support of the foreign policy goals of the United States. USAID's mission is to advance broad-based economic growth, democracy, and human progress in developing countries and emerging economies.

About the Ministry of Power, Government of India

The Ministry of Power is primarily responsible for the development of electrical energy in the country. The Ministry is concerned with perspective planning, policy formulation, processing of projects for investment decision, monitoring of the implementation of power projects, training and manpower development, and the administration and enactment of legislation in regard to thermal, hydro power generation, transmission, and distribution.

About NREL

The National Renewable Energy Laboratory (NREL) is the U.S. Department of Energy's (DOE's) primary national laboratory for renewable energy and energy efficiency research. NREL deploys its deep technical expertise and unmatched breadth of capabilities to drive the transformation of energy resources and systems.

About Power System Operation Corporation Limited

Power System Operation Corporation Limited (POSOCO) is an independent government company in India that operates the National Load Despatch Centre and Regional Load Despatch Centres. POSOCO ensures integrated operation of regional and national power systems to facilitate transfer of electric power within and across regions.

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Berkeley Lab is a member of the national laboratory system supported by the U.S. Department of Energy through its Office of Science. It is managed by the University of California (UC) and is charged with conducting unclassified research across a wide range of scientific disciplines.

About the Energy Sector Management Assistance Program

The Energy Sector Management Assistance Program (ESMAP) is a global knowledge and technical assistance program administered by the World Bank. It provides analytical and advisory services to low- and middle-income countries to increase their know-how and institutional capacity to achieve environmentally sustainable energy solutions for poverty reduction and economic growth.

About the 21st Century Power Partnership

The 21st Century Power Partnership, an initiative of the Clean Energy Ministerial, aims to accelerate the transition to clean, efficient, reliable, and cost-effective power systems. The initiative engages in a broad range of research and technical assistance activities to support bilateral and multilateral collaboration that accelerates the diffusion of high-impact policy and regulatory strategies.

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