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How can India Meet its Rising Power Demand?

Pathways to 2030

Disha Agarwal, Arushi Relan, Rudhi Pradhan, Sanyogita Satpute, Karthik Ganesan, and Shalu Agrawal

Report | March 2025

Suggested citation: Agarwal, Disha, Arushi Relan, Rudhi Pradhan, Sanyogita Satpute, Karthik Ganesan, Shalu Agrawal. 2025. *How can India Meet its Rising Power Demand? Pathways to 2030.* New Delhi: Council on Energy, Environment and Water.

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Peer reviewers: Dr Puneet Chitkara, Chief Analytics Officer, The Lantau Group; Kandarp Mistry, Deputy Engineer, Centre for Net Zero Energy Transition, Green Energy Transition Research Institute (GETRI); Rutvij Patel, Deputy Engineer, Centre for Net Zero Energy Transition, Green Energy Transition Research Institute (GETRI); Alexander Hogeveen Rutter, Manager, Third Derivative; Deepak Maloo, Regional Leader, Onshore Wind, APAC, GE Renewable Energy; Dr Aman Malik, Programme Lead, CEEW and Dhruvak Aggarwal, Programme Lead, CEEW.

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India confronts challenges with greening its power system, while supplying quality and affordable power to consumers.

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Acknowledgment

We would like to express our sincere gratitude to Samir Chandra Saxena, Director (Market Operation), Grid Controller of India Limited (Grid India); Ammi Toppo, Chief Engineer (Integrated Resource Planning-I), Central Electricity Authority (CEA); Vijay Menghani, Chief Engineer (Clean Energy and Energy Transition), CEA; and Anshuman Swain, Deputy Director, CEA for their valuable inputs and guidance.

We acknowledge the feedback received from Grid India and CEA. The authors thank Priyam Jain, Chief Manager; Saif Rehman, Chief Manager; Phanisankar Chilukuri, Chief Manager; and Aman Gautam, Manager from Grid India, and Apporva Anand, Deputy Director; Jyotsana Kapoor, Deputy Director, and Girija Sankar Pati, Assistant Director from CEA.

We are grateful for the research inputs received from Arun Unni, Managing Director – ASEAN, GE Vernova's Consulting Services; Rushikesh Shrikant Deshpande, Senior Engagement Manager; Nitish Kumar, Senior Engineer; Pritam Sunil, Senior Engineer, and Sachin Kumar Pandey, Application Engineer from GE Vernova's Consulting Services (Power Economics). We also thank Dr Nikit Abhyankar, Scientist, Energy Markets and Policy Department, Lawrence Berkeley National Laboratory for his inputs during initial stages of this study. We appreciate the strategic inputs received from our CEEW colleagues Rishabh Jain, Senior Programme Lead and Dr Dhruba Purkayastha, Director – Growth and Institutional Advancement, and research inputs from Varadharajan Venkatesh, Rashi Singh, Amlan Bibhudatta and Pragya Maheshwari, and Ashwani Arora (formerly at CEEW).

As a part of this study, we consulted several experts to understand the barriers restricting faster deployment of renewable energy in India. We sincerely thank

- Subrahmanyam Pulipaka, Chief Executive Officer, National Solar Energy Federation of India
- Ajay Devaraj, Secretary General, Indian Wind Power Association
- Karunesh Chaturvedi, Head - Corporate Affairs and Strategy Planning, Welspun World
- Vinay Metha, Managing Partner, UVM Aditya Energy Private Limited
- Shiva Prashanth Kasina, Senior Manager, NTPC
- Pratik Prasun, Senior Manager (Contracts and Procurement), Solar Energy Corporation of India Limited
- U.B. Reddy, Managing Director, Enerfra Projects (India) Pvt Limited
- Rahul Jain, Vice President, Jindal Renewable Power Private Limited
- Sumit Joge, Head - Commercial and Regulatory, Sekura Energy Private Limited
- Inder Bhambra, Chief Business Officer, Envision Energy India Power Limited
- Vidyadhar Tagade, Director, Vestas Wind Technology India Private Limited
- Jeetendra Bisht, formerly, Vice President, BD & Sales (North America) and Policy Advocacy (India), Sterlite Power Transmission Limited, and
- Selvakumar Neethimani, Co-founder, Windplus Eagle Power Private Limited

Thank you all for your generosity and support in this endeavour.

The authors

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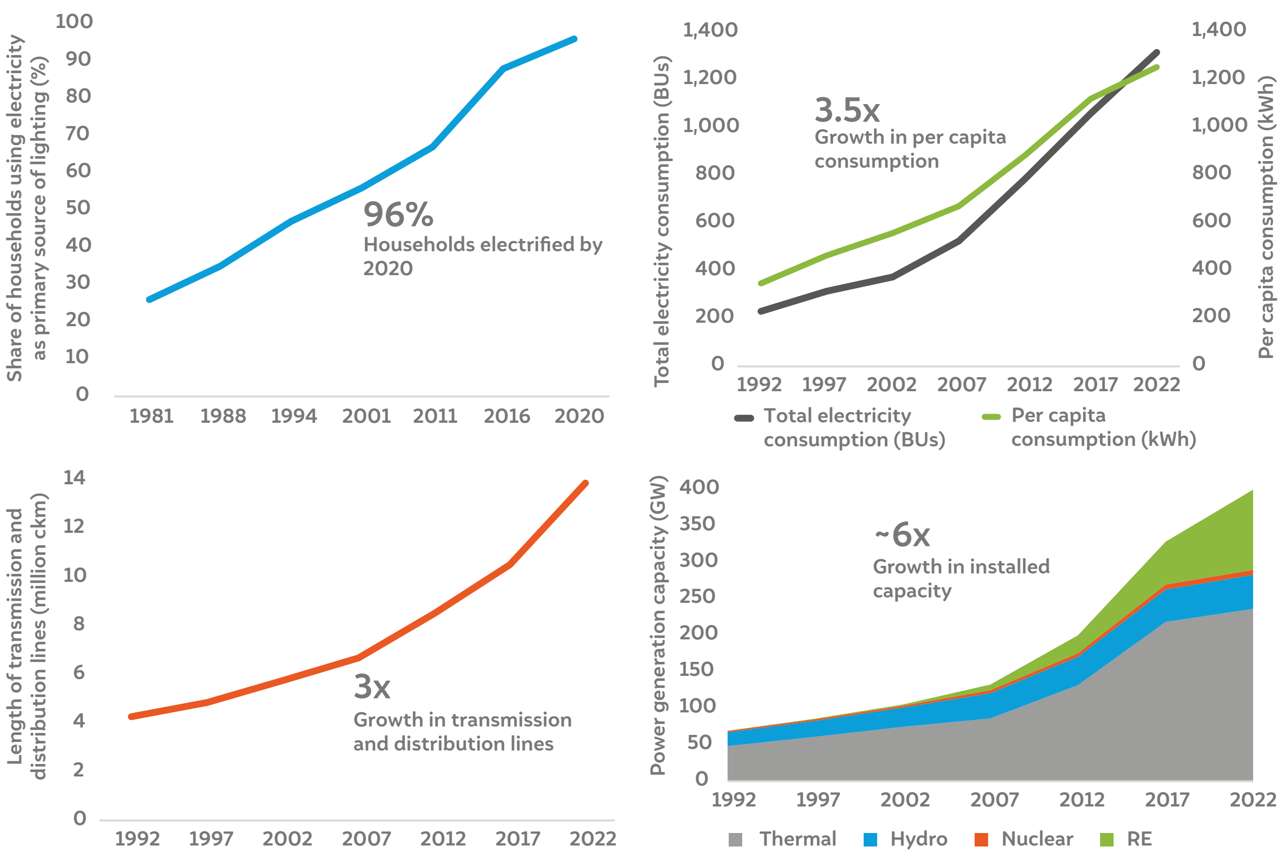
As India progresses towards 2030, renewable energy and storage will be the most cost-effective options to avoid power shortages.

Image: iStock

Executive summary

Since 2014, India has simultaneously improved access to electricity, addressed energy security concerns, and laid the foundation for a clean energy transition. India's power system has evolved significantly since the 1990s (Figure ES1). India became the world's third-largest producer of electricity in 2019 (IEA 2021). By 2020, 96 per cent of the households were electrified (Agrawal et al. 2020). The country saw a fivefold increase in solar and wind power capacities between 2013 and 2022, making it amongst the top four renewable energy (RE) installers globally (PIB 2024a). Notwithstanding these achievements, India faces the unique and complex challenge of decarbonising its expanding power system while providing reliable and affordable electricity to meet rising demand.

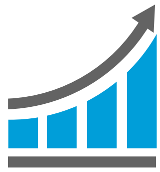
Figure ES1 India's power system has evolved significantly, since the 1990s



Source: Authors' compilation based on data from CEA (2024d) and Agrawal et al. (2020)

Note: ckm refers to the circuit kilometre for 66 kV and above transmission and distribution lines.

The Central Electricity Authority (CEA), in its 20th *Electric Power Survey (EPS)*, projects that India's FY30 electricity requirement and peak demand will both grow by 6.4 per cent per annum, from FY22 (CEA 2022a). However, recent trends show ~9 per cent annual growth in the electricity requirement since FY21, compared to an average of 5 per cent per annum in the decade before (CEA, n.d.-d). The EPS demand estimates for 2030 consider baseline projections for green hydrogen production, rooftop solar penetration, electric vehicles, and other sectors based on extant policies. One-third of this electricity demand is likely to be consumed by the industrial sector. Considering the push to decarbonise the industrial sector through electrification, the industrial electricity demand is expected to grow faster than anticipated. This would result in a higher electricity demand than that projected by the EPS. For instance, the impact of producing 5 million tonnes (MT) of green hydrogen in the context of an interconnected grid system could result in a 13 per cent higher electricity requirement than that projected in the EPS for 2030 (Pradhan et al. 2024). Additionally, economic growth, urbanisation, and climate–induced extreme weather events are likely to influence demand growth and make it more uncertain.



Since 2022, India's electricity demand has grown rapidly, at 8–10% every year

While the supply side has responded to the growing demand, capacity addition has been slow in recent years due to a combination of domestic and extraneous factors. For instance, as of August 2024, over 30 GW of coal capacity is under-construction, 19 GW of which was awarded before 2019 (CEA 2024c). Simultaneously, India has deployed only 3 GW of hydro and nuclear capacities and about 90 GW of RE capacities between 2019 and 2024, resulting in around 218 GW of total non-fossil based capacity (CEA, n.d.-b).[1] The country still needs to deploy around 56 GW of non-fossil based capacity every year between 2025 and 2030 to meet its 500 GW of non-fossil capacity target by 2030 (CEA, n.d.-b, PIB 2023d).

These trends raise a critical question: **how should India plan for adequate resources to meet its energy and peak power requirements by 2030**? Answering this question requires an assessment of alternative scenarios the country may face and be prepared for such possibilities. For instance, would India be able to reliably meet its 2030 power demand with its existing and planned generation and transmission capacities? If the country faces higher demand than that projected by the EPS, what might be some cost-effective strategies to enhance the capacities? Further, if India does not meet its 2030 non–fossil capacity target of 500 GW, how much new thermal capacity would be required? In choosing a desirable pathway to ensure energy security, how can India maximise the social and environmental outcomes while limiting the financial burden on its already strained electricity sector? Finally, what kinds of policy signals and market mechanisms are needed to achieve the energy trilemma of securing clean, affordable, and reliable electricity access by 2030?

A. Study methodology and model results

To answer these questions, we modelled India's power system and performed national-level despatch simulations. We conducted the exercise using Plan OS' production cost, a security-constrained linear optimisation model, in collaboration with GE Vernova's Consulting Services.[2]

1 Non-fossil capacity comprises RE (solar, wind, bioenergy, and small hydro), large hydro, and nuclear.

2 We modelled each state as a distinct node, connected via interstate and interregional transmission linkages. Plan OS' production cost is a security-constrained linear optimisation tool that minimises the total production cost of electricity while balancing the demand and generation at every 15-minute interval.

We simulated six scenarios for 2030, considering two major factors: i) uncertainty in growth and, therefore, total demand, and ii) uncertainty in the rate of non-fossil capacity deployment. For the first factor, we modelled moderate demand scenarios (5.8 per cent and 5.1 per cent growth in the energy requirement and peak demand respectively, between 2023 to 2030) and high demand scenarios (6.4 per cent and 6.0 per cent growth in the energy requirement and peak demand respectively, between 2023 and 2030); the latter assumes that the energy requirement and peak demand projections from EPS for FY32 will manifest early in 2030. For the second factor, we modelled varying non-fossil capacities – stated (500 GW), high (600 GW), and low (400 GW) – along with operating and under-construction thermal capacity,[3] assuming that the residual demand will be met with additional coal capacities and transmission enhancements. These simulations resulted in a combination of six scenarios, described in Figure ES2.

Figure ES2 Six scenarios accounting for varying demand and non-fossil deployment in 2030

Non-fossil capacity by 2030		Moderate demand 2,377 BUs, 343 GW peak	High demand 2,473 BUs, 365 GW peak
400 GW	Solar 229 GW Wind 98 GW Hydro 60 GW Nuclear 14 GW	*400 GW – mod demand*	*400 GW – high demand*
500 GW	Solar 302 GW Wind 123 GW Hydro 62 GW Nuclear 20 GW	*500 GW – mod demand*	*500 GW – high demand*
600 GW	Solar 377 GW Wind 148 GW Hydro 62 GW Nuclear 20 GW	*600 GW – mod demand*	*600 GW – high demand*

Source: Authors' representation of the scenarios modelled

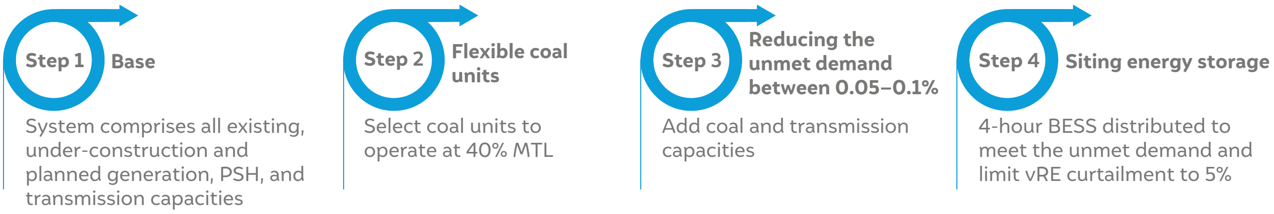
Notes: (1) All scenarios considered 207 GW of operational coal, 27 GW of under-construction coal, and 24 GW of gas capacity. The planned capacity varies across scenarios (400, 500, and 600 GW). (2) New coal, beyond the existing and under-construction capacity, is added in each scenario, if needed, to meet the demand. (3) For the 500 GW scenarios, we considered the operational and under-construction capacities for hydro and nuclear, as planned in CEA (2023a), and 325 GW of variable renewable energy (vRE), as per CEA (2022c) and the states' policy targets. (4) In the 400 GW scenarios, we assumed that 80 per cent of the stated target (500 GW) will be achieved by 2030. (5) In the 600 GW scenarios, we added another 100 GW of solar and wind capacity in a geographically diverse manner. We added this capacity exogenously, considering the energy-deficit profiles, interstate transfers, and vRE potential across all states.

To facilitate comparison across scenarios, we constrained the model to meet the reliability criteria: (i) normalised energy not served (NENS) between 0.05–0.1 per cent, and (ii) vRE curtailment less than 5 per cent in 2030 (CEA 2023c). We used a four-step approach to meet these reliability criteria across all scenarios, as illustrated in Figure ES3. We also assumed the system would follow a Market-based Economic Despatch (MBED) scheduling framework in 2030. Once the reliability criteria were met, we evaluated the system costs. We considered the annualised capital costs for new coal units and enhanced transmission networks, the levelised costs of storage, and the production cost of electricity from all generating sources.[4] Figure ES4 summarises the model results for all six scenarios.

3 Here, we consider 234 GW of coal (211 GW of existing [as of 31 December 2022] + 26.9 GW of under-construction capacity - 3.9 GW of perpetually under outage), along with 24 GW gas-based capacity.

4 The system-cost calculation does not include the fixed-cost component for existing and under-construction thermal units or the cost of the existing transmission network. This is considered a sunk cost, and will remain same across all scenarios.

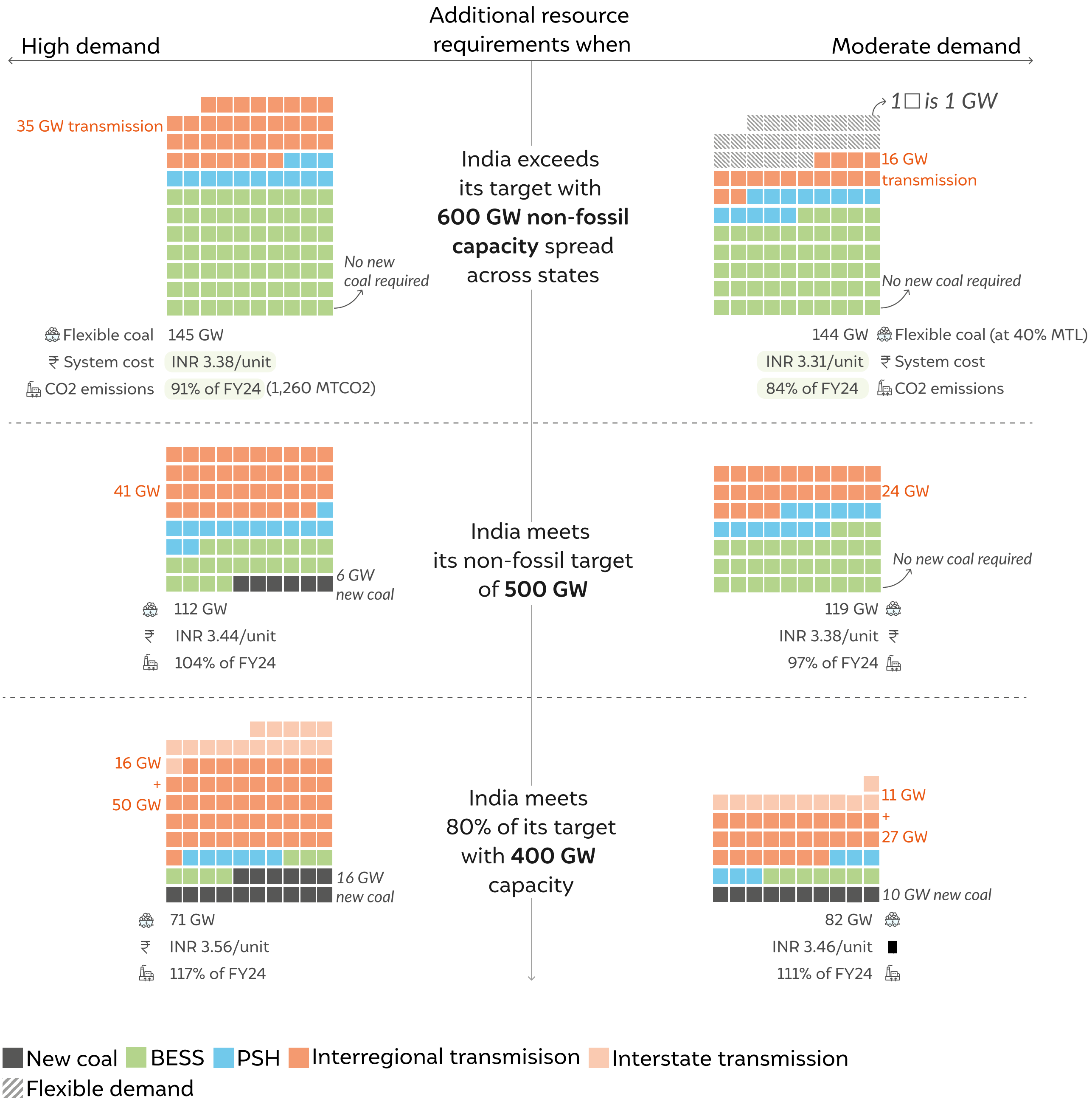
Figure ES3 We followed a four-step sequential approach for each scenario



Source: Authors' depiction of the approach

Notes: (1) MTL is the minimum technical loading of a thermal unit at which it can perform stable operation. (2) PSH is pumped storage hydropower and BESS is battery energy storage system.

Figure ES4 A high-RE pathway will help India meet its rising demand at lowest system cost and emissions with desirable social outcomes



Source: Authors' analysis

B. Key insights

- **India's existing, under-construction, and planned generation capacities will be adequate to meet its power demand, as per EPS projections for 2030.** In the *500 GW-mod demand* scenario, India will meet its demand reliably. To do so, it will use 776 GW of generation capacity, including 234 GW of coal, 230 GWh of storage, and 24 GW of additional interstate transfer capability enhancements.
- **Additional generation and transmission capacities will be needed to meet the EPS-projected demand for 2030 if India falls short of its non-fossil target.** If India only achieves 80 per cent of its planned non-fossil target (i.e., 400 GW), it will face a power deficit of 2 GW or higher for 10 per cent of the time, with likely shortages of 6 billion units (BUs) overall in 2030 (0.26 per cent of total demand, which is higher than the allowed reliability level). To meet the demand reliably (0.05–0.1 per cent), the system will need an additional 10 GW of coal capacity beyond the 27 GW under construction. The system will also require significant additional interstate and interregional transmission enhancements. There will be negligible scope to cater to uncertainties in demand and supply, as more than 90 per cent of the available coal fleet[5] will be despatched throughout the year.
- **In the high-demand scenarios, deploying an additional 100 GW of vRE capacity will help India meet the energy and peak demand reliably, cost-effectively, and with better social and environmental outcomes.** The country could meet the additional demand through more renewables (100 GW) or new thermal capacities. As compared to the *500 GW-high demand* scenario (with additional coal), the *600 GW-high demand* scenario (with high RE) yields better social, economic, environmental, and sectoral outcomes, in the following ways:

Creating new jobs	Around 53,000 additional full-time equivalent (FTE) jobs will be created between 2024 and 2030.
Lowering system costs	System costs will be reduced by INR 0.06 per unit of electricity, saving INR 13,000 crore (USD 1.5 billion) in 2030 alone, due to lower fossil fuel consumption.[6]
Adding capacities at speed to avoid shortages	Since RE, storage, and transmission capacities can be built much faster than new coal capacities, aiming for a high-RE scenario will increase our ability to meet the swiftly growing demand before 2030 and lower the risk of power shortages.
Mitigating the risk of uncertainties	In addition to the 5 per cent planned reserve margin, the system will have additional room of up to 4 per cent from coal, which can be tapped in case of uncertainties.
Decarbonising the grid	A 53 per cent clean grid,[7] with a vRE share of 39 per cent, will be achieved, in line with the country's targeted renewable purchase obligations (RPOs) (MoP 2022).
Improving air quality	Approximately 160 MTCO2 of emissions will be avoided in 2030.[8] A 13 per cent lower coal consumption will significantly decrease criteria pollutants (PM2.5, PM10, sulphur dioxide [SO2], and nitrogen oxides [NOx]), thus leading to better air quality and lower associated health burdens.

5. Available coal fleet refers to installed capacity excluding capacity under maintenance and outages.
6 We used the conversion of USD 1 = INR 83.77.
7 The share of generation from non-fossil capacity.
8 About 13 per cent of India's power sector emissions in FY24. Power sector CO2 emissions for FY24 amounted to 1,260 MT (Niti Aayog, n.d.).

- **A varied RE mix spread across states will help meet the demand reliably and at lower cost**. The additional 75 GW of solar could be distributed across more states, such as Kerala, Bihar, Punjab, West Bengal, Odisha, and Telangana. Similarly, 25 GW of additional wind capacity can be installed in states such as Madhya Pradesh, Maharashtra, Tamil Nadu, Karnataka, and Rajasthan. Diversified vRE deployment will halve the unmet demand in the *600 GW-high demand* scenario relative to the *500 GW-high demand* one.[9] Additionally, 6 GW of transmission enhancement across states could be avoided.[10]

In 2030, deploying 600 GW of non-fossil capacity will save up to INR 42,400 crore in system costs

- **Failing to meet the 2030 non-fossil target will lead to suboptimal outcomes**. If India achieves only 400 GW of non-fossil capacity by 2030, and the demand grows more than anticipated (as modelled in the *400 GW-high demand* scenario), the unmet demand will be 0.62 per cent, double of that projected in the *500 GW-high demand* scenario. To meet the demand reliably, 16 GW of new coal capacity will be needed, beyond the existing and under-construction assets. This will likely take more than five years to build. However, in addition to the need for more coal-based generation assets, we also observe the following:
  - Interstate and interregional import transmission limits will need significant enhancement (see Figure ES4).
  - Overall system costs will be higher by INR 30,000–42,400 crore in 2030, relative to the *500 GW-high demand* and *600 GW-high demand* scenarios.
  - Power sector emissions will go up by 17 per cent over FY24 levels.
  - About 90 per cent of the available coal capacity will be despatched for more than 60 per cent of the time, leaving little room beyond the 5 per cent planned reserve margin to manage uncertainties and contingencies.

- **The system's ramping requirements will increase multi-fold**. Between 2022 and 2030, the system's net load ramping requirements[11] will grow five to six times in the *500 GW-high demand* and *600 GW-high demand* scenarios, indicating the need for more flexible resources. All resources, including coal, gas, hydro, PSH, and BESS, will need to be leveraged to meet flexibility needs. Our simulations show that BESS will provide most support to meet steep ramping requirements followed by PSH, hydro, coal, and gas.

- **Making select coal units more flexible can help integrate RE cost-effectively in both moderate- and high-demand scenarios**. The CEA has published a plan to retrofit over 90 per cent of the installed coal-based capacity (191 GW) to operate at 40 per cent MTL by 2030 (CEA 2023d). However, our scenario modelling shows that selecting 71–145 GW of coal units to operate at 40 per cent MTL will be adequate and cost-effective for absorbing vRE during its peak generation hours.[12] For instance, in the *500 GW-mod demand* and *600 GW-high demand* scenarios, operating select coal units will reduce vRE curtailment by 3–4 per cent, thus lowering system costs by 5–6 per cent. This will help avoid up to ~150 GWh of BESS capacity that would have otherwise been needed to absorb the curtailed RE. A lower MTL will also allow coal units to operate more consistently, even during low-demand periods. This will allow them to continue generating revenues and mitigate the risk of becoming stranded. There will be negligible additional gains from retrofitting additional coal capacity beyond this quantum. This indicates the need to critically re-evaluate the selection and prioritisation criteria for retrofitting power plants to improve flexibility by 2030.

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9. This is based on the results of Step 1 of the four-step approach, for the *500 GW-high demand* and *600 GW-high demand* scenarios, which considered the existing and planned generation and transmission capacity to meet the demand.
10. In the *500 GW-high demand* scenario, limits were relaxed for Punjab (6 GW), Haryana (3 GW), Delhi (3 GW), Maharashtra (2 GW), Gujarat (1.5 GW), and Telangana (1 GW). These relaxations can be avoided to some extent in the *600 GW-high demand* scenario by distributing wind and solar additions across these states.
11. The net load is the residual demand to be served by sources other than must-run vRE capacity. The ramp rate is the difference between the net load corresponding to two consecutive time blocks (15 minutes).
12. A coal unit is considered for lowering its MTL to 40 per cent only when the corresponding production cost savings in 2030 are INR 20 crore or higher.

- **Effective maintenance of the existing coal fleet will help meet demand reliably and provide the desired flexibility**. In both the *500 GW-mod demand* and *500 GW-high demand* scenarios, coal comprises ~60 per cent of the generation during non-solar hours.[13] This share increases during the post-monsoon months of October and November, reaching 75–78 per cent. However, our assessment shows that 15–28 per cent of the installed coal capacity was unavailable in October and November in FY23 and F24 for non-statutory reasons. This indicates that the system can be made more reliable with timely maintenance and preventive measures to prevent technical outages.
- **Faster deployment of energy storage is needed to integrate the desired levels of RE by 2030**. In the *500 GW-mod demand* scenario, India will need 132 GWh of BESS, along with 100 GWh of PSH, to meet the demand reliably. However, in the *600 GW-high demand* scenario, the storage requirement will increase to 280 GWh of BESS and 100 GWh of PSH. This aligns with India's energy storage obligation for 2030 (MoP 2022). As of January 2025, the operational BESS capacity stands at 360 MWh (Sen 2025). The gap between existing and required storage capacity indicates the urgent need to fast-track investments in energy storage.
- **Harnessing demand flexibility will lower the need for battery storage and save costs**. In one of the scenarios – meeting moderate demand with high RE (*600 GW-mod demand*) – a 24 GW demand shift[14] in 10 states will help avoid 30 GW of 4-hour BESS capacity. This will lower system costs by ~INR 14,000 crore (USD 1.6 billion). RE-rich states, such as Rajasthan and Gujarat, will collectively contribute one-fourth of this shift. For instance, in Rajasthan, about 2–3 GW of early morning agricultural load in the winter will need to shift to solar hours.

Between 2022 and 2030, integrating 500-600 GW of clean energy capacity will increase the system flexibility requirement by 5-6 times

C. Challenges in RE deployment

Meeting the rising demand with a high-RE pathway is a reliable, affordable, and clean option. However, our analysis and stakeholder consultations reveal several challenges that can restrict the pace of RE deployment, integration, and offtake. These include the slow pace of transmission capacity addition, connectivity delays,[15] complexities in land procurement, and supply-chain constraints (Figure ES5). However, it is possible to overcome these challenges through continuous policy innovation and strategic interventions.

Figure ES5 Transmission connectivity, land procurement and supply chain problems are the key barriers constraining RE deployment at the required pace

Transmission connectivity	Land	Tariff viability	Supply chain
• Delays in granting connectivity • Right-of-Way (RoW) issues • Slow infrastructure augmentation and upgrades • Process and permitting delays	• Non-availability of land in resource-rich areas • Site accessibility issues • Complexities in land aggregation • Escalation of land prices	• Contract signing delays • ISTS waiver uncertainty • Shrinking profit margins due to commissioning delays	• Limited availability of specialised materials and components • Lack of investments in customising or standardising product designs • Limited domestic manufacturing capacity to meet DCR requirements • Lack of skilled workforce

Source: Authors' compilation based on stakeholder consultations

Note: ISTS and DCR refer to interstate transmission system and domestic content requirement

13. We considered 0700 to 1745 as solar hours, and the rest as non-solar hours.
14. We considered a top-down approach to shift the demand from peak net load hours to non-peak net load hours.
15. Delays in connecting RE systems to the grid

D. A seven-point agenda for India's power sector transition

Drawing from the results of the model simulations and extensive discussions with key stakeholders in India's power sector, we recommend a seven-point action agenda. This plan will facilitate realising the socio-economic benefits and the desired power system outcomes of cost-effectively integrating renewables at scale.

I. To give a strong policy signal to the market, **the Minister of Power (MoP) must embed the target of achieving a 50 per cent share in generation from non-fossil capacity by 2030 in the *National Electricity Policy***. To achieve this target, the states may be provided with the flexibility to identify clean energy technology choices best suited to their needs. This is to ensure that India meets its net-zero target by 2070 and to delineate a pathway for the electricity sector until 2030.

II. **The MoP must collaborate with the Ministry of New and Renewable Energy (MNRE) and other key institutions to build a technologically and geographically diverse RE portfolio**. Our analysis shows that a technologically– and geographically–diverse mix of RE will help reduce the need for new transmission infrastructure and lower the need for flexible resources to manage grid operations. Two interventions could support this objective:

   a. Identify innovative deployment models and contract frameworks to support the co-location of wind and storage projects with existing solar capacities. This can diversify and accelerate the RE mix, and, in turn, increase the utilisation of the existing transmission infrastructure. One example is the proposed splitting of *General Network Access (GNA)* into solar and non-solar hours (CERC 2024b). To enable such implementation, associated commercial arrangements must be identified.

   b. Ensure the implementation of the *Uniform Renewable Energy Tariff* (URET), currently notified for solar, and extend the mechanism to include wind power (MoP 2023). Adopting the URET will help expedite offtake and encourage RE developers to tap locations across more states, even if doing so slightly increases bid tariffs relative to those of resource-rich sites only in select states. Alongside, the state and centre must identify incentive mechanisms to attract developers to add capacities in the state.

III. **The MoP, in collaboration with the MNRE, must unlock new avenues for RE offtake**. To enhance the deployment of RE at scale, new offtake avenues, besides long-term contracts, must be explored. We propose two potential interventions:

   a. Introduce bid guidelines to enable more RE developers to participate in the power exchange. This will help meet multiple objectives: (i) rapidly improving supply-side liquidity in power exchanges, (ii) creating an enabling environment for future investments in RE capacities, and (iii) creating conditions for cost-effective variability management in a RE-rich system.

   b. Encourage renewable energy implementing agencies (REIAs) to build their own generation portfolios. This can be accomplished by encouraging these entities to invest in standalone storage assets, direct RE procurement, and market trading to offer desired services to distribution utilities, system operators, and buyers in the short- and medium-term markets.

IV. **The Central Electricity Regulatory Commission (CERC) and Grid Controller of India (Grid India), in collaboration with states, must ensure fast-tracked deployment of energy-storage solutions.** Our analysis shows that integrating high RE capacities will require 55–70 GW of 4-hour BESS and 12.5 GW of PSH. The current BESS capacity is only 360 MWh. Therefore, the CERC and Grid India must undertake the following:

   a. Conduct a robust analysis to identify strategic locations for siting BESS projects to optimise network operations.

   b. Evaluate short-term flexible contracts to allow shared capacity contracts among utilities and the system operator to maximise the utilisation of BESS assets.

   c. Publish a discussion paper on possible sharing and operations of BESS capacities to take advantage of arbitrage opportunities across utilities and to enable offtake and participation.

V. **The MoP and CEA must enable states to ensure robust resource planning to meet the growing demand reliably and cost-effectively**. This can be achieved through the following interventions:

   a. Institute a technical assistance programme for states to establish the necessary infrastructure, institutional frameworks for data management, and in-house expertise for simulation-based exercises.

   b. Earmark funds from the Power System Development Fund (PSDF) for states to strengthen capabilities to conduct planning studies.

   c. Constitute an expert group to publish informed inputs and assumptions for robust capacity expansion and resource adequacy planning exercises.

Centre and states must work collaboratively to raise the share of renewables in India's power generation mix and scale up storage solutions

VI. **The Forum of Regulators (FoR), with support from the Bureau of Energy Efficiency (BEE) and Grid India, should nudge state regulators to assess the value of and market for tapping demand flexibility**. Our analysis highlights the benefits of shifting the demand from peak non-solar hours to solar hours. Shifting 24 GW of demand daily can help avoid (i) 30 GW of 4-hour BESS, and (ii) the construction of 6 GW of additional interstate transmission infrastructure. Further, it would help the system save INR 14,000 crore (USD 1.6 billion) in 2030.

   The coordinated efforts from the FoR and BEE can spur discussions and advance initiatives, such as that introduced by Maharashtra, which was the first to notify demand-side management (DSM) regulations in October 2024 (MERC 2024).

VII. **Grid India and CERC must help states adopt improved maintenance and scheduling practices**. Our analysis of past data and simulations highlights that optimising the operational planning and scheduling mechanism has multiple benefits. Here, two interventions could be considered:

   a. FoR must conduct a knowledge-sharing programme for state, regional, and national load despatch centres (LDCs) to share best practices on operational planning and effective scheduling and promote the transition from MBED to Security Constrained Economic Despatch (SCED) as a uniform mechanism for despatch.

   b. CERC must revisit the existing merit order despatch (MoD) mechanism to enable the scheduling of flexible resources such as energy storage, hydro budgets, and flexible demand.

For the next phase of RE growth, the Centre and States must take concerted actions to ease land procurement, enable timely availability of evacuation infrastructure, facilitate new avenues for offtake, and strengthen supply chains.

Image: iStock

1. Introduction

India, the world's fastest-growing economy, envisions becoming a developed nation by 2047 (PIB 2023c). Notwithstanding this aspiration, the country is also committed to transitioning to a net-zero economy by 2070 (PIB 2023a). India's capacity to realise this economic transition will be determined by its ability to cost-effectively meet its swiftly rising electricity demand while decarbonising its power system. Therefore, in this study, we model India's power system despatch for 2030 to assess the grid's ability to meet the rising demand under varying levels of renewable energy (RE) capacity additions.

Robust planning and periodic dialogues on seminal policies would be the key to India's sustained progress towards a clean energy future

India has demonstrated ambition and action to ensure energy security and a clean energy transition. India's electrification programmes have enabled 800 million people to access grid electricity since 1990 (Agrawal et al. 2020). Simultaneously, the country has adopted a functional pathway to leapfrog to clean energy sources. Its non-fossil capacity has almost doubled from around 95 GW in FY16 to 199 GW in FY24, and it aims to install 500 GW of non-fossil capacity by 2030 (CEA 2016; 2024a; PIB 2023d).[16]

The country has allocated significant fiscal resources to support the deployment and manufacturing of RE technologies and expand the transmission infrastructure. Moreover, RE subsidies increased 1.6 times, while fossil fuel subsidies reduced to one-fourth, between FY14 and FY22 (Aggarwal et al. 2022). This has helped mobilise domestic resources for the power sector transition. More recently, the government allocated funds to promote decentralised solar under *PM Surya Ghar: Muft Bijli Yojana*; accelerate battery energy storage system (BESS) deployment via the *Viability Gap Funding* (VGF) scheme and the domestic manufacturing of batteries via the *Production Linked Incentive* (PLI) scheme; and facilitate retail RE procurement (PIB 2024b; 2023b; 2021). As a result, India's clean energy sector attracted investments worth INR 8.5 lakh crore (USD 102.4 billion) between 2014 and 2023 (GoI 2024).

Despite their enormous deployment potential and falling costs, RE technologies are still not the first choice for electricity sector planners and operators. India has a massive variable renewable energy (vRE) potential of over 24,000 GW, as estimated by a recent CEEW study (Mallya et al. 2024). Following concerted action, the share of vRE in India's electricity generation mix reached 13 per cent in FY24, up from 9 per cent in FY19 (CEA 2024b; 2020; 2019). It is expected to more than double, to 32 per cent, by 2030 (CEA 2023b).

16. Non-fossil capacity comprises solar, wind, hydro, bioenergy, and nuclear; fossil-based capacity includes coal, lignite, gas, and oil-based generation.

We expect a surge in the pace of RE and storage deployment following the sharp fall in the cost of BESS in 2024 as large-scale auctions for RE-coupled and standalone BESS since March 2024 have led to the discovery of record-low prices (INR 3.4–4.6/kWh) (Abhyankar et al. 2024). Market trends point to a further decline in RE and storage costs by 2030, potentially making RE coupled with storage the preferred choice for new investments (BloombergNEF 2023). However, there is not enough evidence to instil confidence among stakeholders that, as the share of RE increases, it is possible (i) to meet the rising electricity demand without causing shortages, (ii) to provide affordable power to consumers, and (iii) to enable consistent investments in new RE projects despite the possibility of higher curtailment levels, and (iv) to sustain employment prospects in the power sector.

Conducting granular studies will generate evidence to steer investments to build an optimal technology mix

Stakeholders' concerns stem from challenges in the current power system – such as difficulties in managing any unexpected growth in demand, utilising system flexibility to manage RE variability, deploying affordable storage solutions, and ascertaining the likely RE generation across seasons. Due to these concerns, policymakers tend to bet on new coal-based capacity (PIB 2024c). However, doing so entails risking fossil fuel lock-ins, shortages before 2030, and negative environmental impacts.

There is a need to examine alternative pathways to achieve power sector goals. This brings us to the critical need for careful and robust examination of all possible development pathways for the power sector. Evaluating such pathways, including their implications for important indicators, spanning economic, social, and environmental outcomes for the country, is necessary.

Image: SLDC Odisha

All female executives operating the control room at Odisha state load despatch centre (SLDC) on 27 January 2025

Building on recent studies, we examined multiple transition pathways, considering a combination of supply choices for possible demand growth trajectories. Relevant government and independent research studies, such as CEA (2023b), Abhyankar et al. (2021), and Spencer et al. (2020), estimate that India's power system will contain a significant share of RE in 2030. Here, we reflect on the granularity, approach, and scope of these key studies that model India's electricity future.

- **Granularity**: CEA (2023b) considers an interregional model, whereas the other two studies include interregional and interstate transmission constraints. The only study that carries out simulations at a sub-hourly level is Spencer et al. (2020) with specific sensitivity analyses for select weeks at the 15-minute level.
- **Approach**: CEA (2023b) and Abhyankar et al. (2021) took a two-step approach, i.e., capacity expansion followed by despatch optimisation. The third study performed a production cost simulation to identify the changes required in system operations to accommodate a 30 per cent share of vRE in the generation mix in 2030, but at lower demand levels.
- **Scope**: These studies highlight that integrating 450–500 GW of non-fossil capacity is feasible, but the associated flexibility-related challenges must be addressed by making additional investments in BESS, tapping additional flexibility from the existing coal fleet, and leveraging demand response interventions. Only Abhyankar et al. (2021) assess the demand response interventions, particularly for agricultural loads.

Building on the existing research, our study attempts to answer this key question: **how should India plan for adequate resources to meet the energy and peak power requirements by 2030?** To do so, we (i) assessed the system-level implications of the plans already in place, the actual progress, and the choices being made to meet the demand reliably; (ii) evaluated the feasibility and outcomes of surpassing the stated clean energy ambition in 2030; (iii) made granular assessments of the available flexibility options, such as coal units that must be prioritised for flexible operations, and optimisation of BESS and pumped storage hydro (PSH), based on system needs; and (iv) examined the role of demand-side resources at a daily level in 2030. We performed spatially and temporally granular despatch simulations at 15-minute intervals for the entire year, adhering to a uniform reliability level aligned with CEA guidelines. We also used recent information on demand patterns, the state-wise split of planned capacities, and transmission constraints.

Robust system planning studies are needed to ensure that unplanned demand surges are met through affordable generation options and optimised network expansion.

Image: iStock

2. Approach and methodology

This section describes the approach, methodology, and data used for the study. The supporting document (Section 1) covers the details of the scenarios modelled, the simulation tool and structure, inputs, assumptions, and data sources.

We model various scenarios with varying supply and demand combinations to understand how India should meet its energy requirements reliably, affordably and sustainably by 2030.

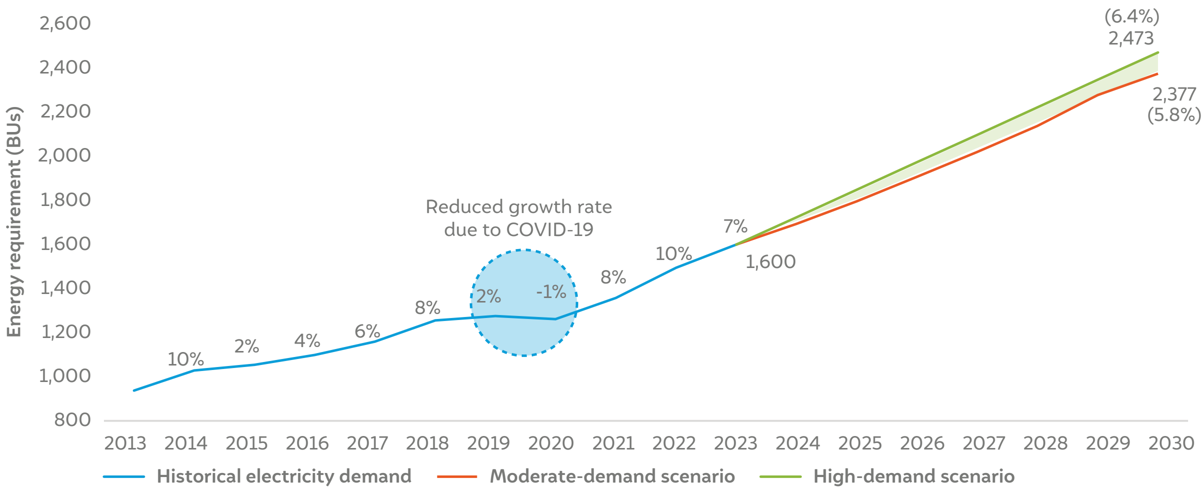
2.1 Projecting the electricity demand

The demand for electricity has grown faster in recent years, after FY21 than in the last decade (Figure 1). We considered two levels of electricity demand likely in 2030:

- **Moderate-demand scenario**: Consistent with the *20th Electric Power Survey* (EPS) projection for 2030, depicting a compound annual growth rate (CAGR) of 5.8 per cent between 2023 and 2030 (CEA 2022a).
- **High-demand scenario**: The demand is equivalent to the EPS projection for FY32, with a higher CAGR of 6.4 per cent between 2023 and 2030.

These two scenarios do not account for new demand drivers like green hydrogen. Our complementary assessments show that achieving India's green hydrogen target of 5 million tonnes (MT) by 2030 could result in the demand growing at a higher CAGR of 7.6 per cent (Pradhan et al. 2024).

Figure 1 India's electricity demand is growing faster than anticipated



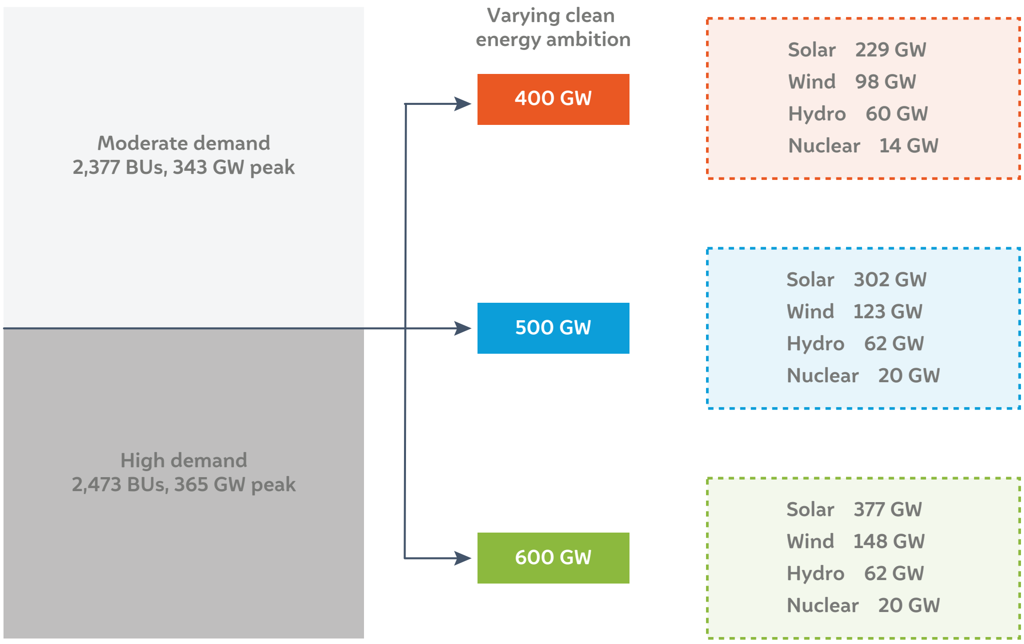
Source: Authors' analysis based on CEA (2022a; n.d.-d)

Note: The values in the parentheses represent the CAGR between 2023 and 2030.

2.2 Varying quanta of clean energy capacities

On the supply side, we assumed three levels of clean energy deployment for 2030: (a) low RE (400 GW of non-fossil),[17] (b) stated RE (500 GW of non-fossil), and (c) high RE (600 GW of non-fossil), with varying proportions of solar and wind (Figure 2). We simulated a system with varying levels of clean energy, in addition to all existing generation resources, to meet the demand reliably in the moderate- and high-demand scenarios.

Figure 2: Simulations for India's power system to meet the rising demand with varying clean energy ambitions



Source: Authors' representation of the modelled scenarios

2.3 Scenario descriptions

We modelled six scenarios based on the two levels of demand projections and three levels of clean energy penetration as discussed above:

- **Moderate demand, stated RE** (*500 GW-mod demand*): This scenario considers a demand level aligned with the EPS prediction (CEA 2022a). The energy requirement is 2,377 billion units (BUs) with a peak demand of 343 GW. The system has an installed non-fossil capacity of 500 GW. New coal capacity, beyond the existing and under-construction, is added if required to meet demand reliably.
- **Moderate demand, high RE** (*600 GW-mod demand*): Here, we assume that India will meet its EPS-projected peak and energy requirement for 2030. Beyond the 500 GW of non-fossil capacity, we model an additional 100 GW of solar and wind spread across more states.
- **Moderate demand, low RE** (*400 GW-mod demand*): The same EPS-projected energy requirement and peak occur in 2030, and India only achieves 80 per cent of its stated non-fossil target. To meet the demand reliably with 400 GW of non-fossil capacity, new thermal capacity is added beyond the existing and under-construction capacities.

17. This is assuming an annual deployment of 24 GW of solar and 8 GW of wind capacity between 2022 and 2030. Also, we consider that the capacity for nuclear and hydro will be delayed, and be equal to that planned for FY27.

- **High demand, stated RE** (*500 GW-high demand*): Here, the high demand corresponds to the peak and energy requirement projected by the EPS for FY32 to come in 2030. The energy requirement is 2,473 BUs, with a peak demand of 365 GW.[18] The system has an installed non-fossil capacity of 500 GW. New coal is added to meet the additional demand reliably.
- **High demand, high RE** (*600 GW-high demand*): The same EPS-projected peak and energy requirement for FY32 comes early in 2030. The system has an additional 100 GW of RE beyond the stated 500 GW of non-fossil capacity.
- **High demand, low RE** (*400 GW-high demand*): The 2030 peak and energy demand remain the same, aligning with the EPS projections for FY32. However, India only achieves 80 per cent of its stated non-fossil target and deploys 400 GW by 2030. New coal is added to reliably meet the incremental demand.

2.4 Model structure

We set up a 15-minute despatch optimisation model using a Plan OS' production cost tool[19] for the base year 2022. Our model considered each state as a distinct node in its regional pool.[20] All nodes and regional pools are connected through interstate and interregional transmission lines. Electricity is free to flow from one node to the other and it is constrained only by the actual power-carrying capabilities of the transmission links. We designed the model to emulate a Market-based Economic Despatch (MBED)[21] for 2030 to ensure efficiency in scheduling and despatch.

Image: CEEW

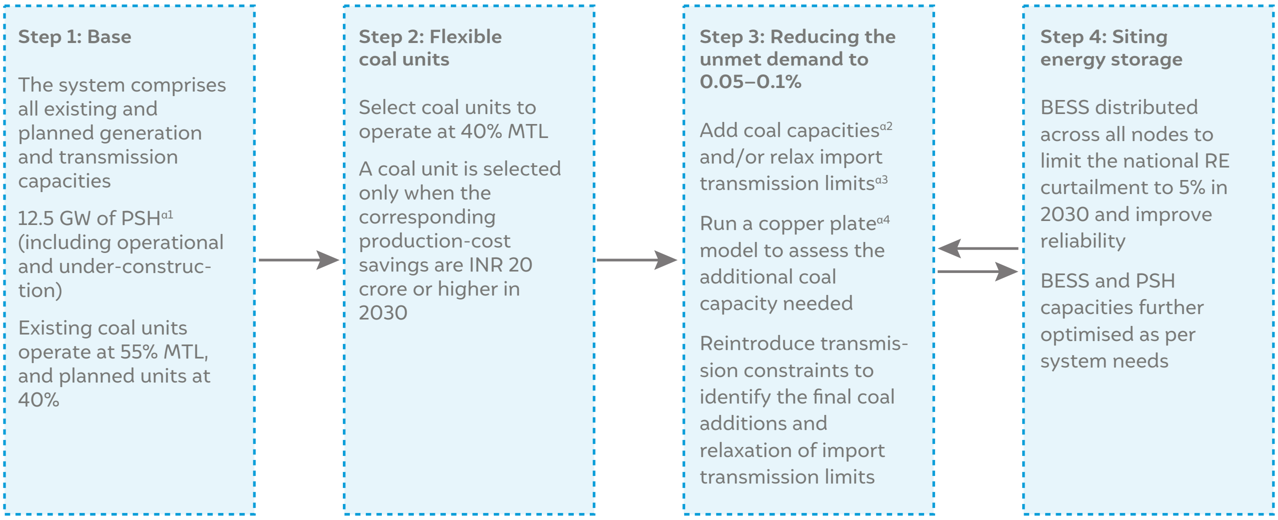
CEEW team gaining insights into the challenges of daily system operations at Rajasthan SLDC, April 2024.

18. In the high-demand scenarios, the energy requirement increases by 104 and peak demand increases by 106 per cent, respectively, as compared to the moderate-demand scenarios.
19. Plan OS' production cost is a security-constrained linear optimisation tool that optimises the cost to produce electricity from various sources in a power system to meet the demand, subject to various system constraints. We explain the model architecture, inputs, assumptions, and constraints in the supporting document (Section 1).
20. Except for the north-eastern states (pooled as a single node) and union territories (clubbed with their nearest states).
21. MBED is a scheduling mechanism through which all generation capacities are scheduled at the national level via a market mechanism (MoP 2021).

Simulating the scenarios to meet the system constraints

We ran each scenario in Plan OS' production cost model using a four-step approach (Figure 3) to optimise for system constraints: (i) normalised energy not served (NENS), also known as unmet demand, between 0.05 and 0.1 per cent (CEA 2023c), and (ii) vRE curtailment below 5 per cent.

Figure 3 For each scenario we followed a four-step sequential approach



Source: Authors' depiction of the scenario-simulation approach

Notes: (1) PSH refers to pumped storage hydropower projects and MTL to minimum technical loading levels. (2) α1: In the 500 GW and 600 GW scenarios, 12.5 GW of PSH comprises the existing capacity and capacity in different stages of construction. Only in the 400 GW scenarios did we consider 7 GW of PSH accounting for the existing capacity and capacity in the advanced stage of construction (considering the delays). (3) α2: Additional coal units are selected from the list of candidate coal units (CEA 2023a; 2024e). (4) α3: The import transfer limits are relaxed based on the transmission rolling plans (CTUIL 2023) or for the states where new generation capacity cannot be added, either due to the absence of a candidate coal plant or restricted RE potential. (5) α4: The copper plate model allows power to flow from one node to another without any transmission constraints. (6) Steps 3 and 4 are iterative. The need for additional coal, transmission relaxation, and battery storage is optimised to meet the constraints set for the unmet demand and vRE curtailment.

In one of the scenarios (*600 GW-mod demand*), we assessed the role of demand-side resources in meeting the flexibility requirements. We identified 10 states with high vRE curtailment.[22] In each of these states, we allowed a maximum of 10 per cent of the peak demand to shift, keeping the total daily demand for energy the same. The model shifted the demand in select states from peak net load hours to non-peak net load hours[23] only if the resultant cost benefit was higher than INR 0.8/unit (USD 10/MWh).

2.5 Approach to add 100 GW of solar and wind capacities

We added 100 GW of RE capacity beyond the planned 425 GW to meet the high demand (in the *600 GW-high demand* scenario). The 100 GW would comprise 75 GW of solar and 25 GW of wind capacity.[24] We selected the host states based on the temporal distribution and quanta of demand not met, and interstate transmission flows during solar and non-solar hours across seasons.[25] For instance, we added solar capacity in states that would likely face energy deficits during solar hours and/or would be heavily reliant on imports during solar hours. We then added the wind capacity considering the difference between states' wind potential and their wind capacity targets and solar capacity considering the difference between states' existing installation and their solar capacity targets. A detailed approach is discussed in the supporting document (Section 1).

22. Considering a threshold of 4 BUs of vRE curtailment for selecting the states.
23. The net load is the demand minus generation from solar and wind.
24. A solar to wind ratio of 3:1, according to the results of a long-term Global Change Analysis Model (GCAM), is needed for India to achieve its net-zero target by 2070 (Malik et al. 2023).
25. This is not based on an optimised capacity-expansion exercise. Instead, we analysed the temporal distribution of transmission flows and residual demand to identify state-wise capacities for additional solar and wind. This is one of the many solutions simulated to understand the need and value of diversified RE deployment.

2.6 Data inputs

To simulate the scenarios, we used publicly available data on existing and planned generation; actual and total transfer capacities across regions and states; cost trajectories for different generation technologies, storage, and transmission; RE and demand profiles for each node; and expected demand.[26] Details on data inputs, assumptions, data sources, and model architecture are available in the Annexure 1 and the supporting document (Section 1).

Power sector transition pathways must reflect a shared understanding of social, economic and environmental implications associated with technology choices

2.7 Output of the simulations

For each scenario, we identified additional coal capacities and/or additional transfer capabilities, assessed the system flexibility needs, and examined the quantum and role of different flexibility options required to meet the system constraints, based on the model output.

2.8 System-cost calculations

For each scenario, when the reliability criteria were met, we evaluated the system costs that would be translated into consumer tariffs. In the system-cost calculations, we considered the annualised capital cost for additional (new) coal plants, enhanced transmission networks, and a levelised cost of storage beyond the production cost of electricity from all generating sources (refer to Section 2 of the supporting document for details). The system-cost calculation does not include the fixed-cost component for existing and under-construction coal units or the cost of the existing transmission network. These are considered sunk costs across scenarios. We further conducted sensitivity analyses around assumptions for solar, wind, and energy storage to make the system costs reflective of possible cost trajectories.

2.9 Comparing pathways in terms of socio-economic and environmental outcomes

We quantified the opportunities and trade-offs for India as it chooses to pursue either of the envisioned pathways. We assessed the following aspects in addition to the system costs:

- **Creating new jobs**: The job creation potential across scenarios using available research on employment coefficients across technology sources.
- **Sector-specific outcomes**: Assessment of the ability of the system to deal with the risk of uncertainties in supply and demand and likely shortages.
- **Clean energy generation**: Compliance with renewable purchase obligation (RPO) targets.
- **Carbon dioxide (CO_2) emissions and air quality**: CO_2 emissions mitigation potential, along with sulphur dioxide (SO_2) and nitrogen oxides (NO_x) emissions across pathways, to assess alignment with India's commitment to reaching net-zero emissions by 2070.

We also undertook an assessment of the barriers that are slowing down the pace of RE deployment, integration, and offtake, and the opportunities that can help unlock jobs, growth, and sustainability benefits. In doing so, we evaluated sectoral trends, reviewed official reports and recent research publications, and consulted various stakeholders.

Finally, using the study design and approach, we suggest a seven-point action agenda for policymakers, power system planners, and operators to prepare the power system for the future.

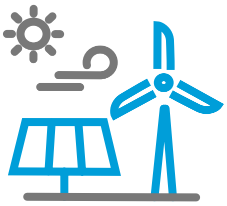
26. The 2022 demand profiles for each node projected for 2030 consider the CAGR and were adjusted to meet the projections for the annual energy and peak-demand requirement for all states as per CEA (2022a). In the high-demand scenarios, the same 2022 profiles were scaled to meet the peak-demand and energy requirements of the 20th EPS FY32 projection.

Deploying renewable energy projects across more states will help meet the demand reliably and cost-effectively.

Image: iStock

3. Model results and key insights

This section presents the results and key insights based on simulations of the scenarios discussed earlier. We assessed the resources requirements across scenarios to meet the demand reliably and address rising flexibility needs in a cost-effective manner.



A high RE pathway will be the most cost-effective in meeting higher demand despite increased flexibility requirements

3.1 Ensuring 600 GW of non-fossil capacity by 2030 will make India's grid reliable and clean

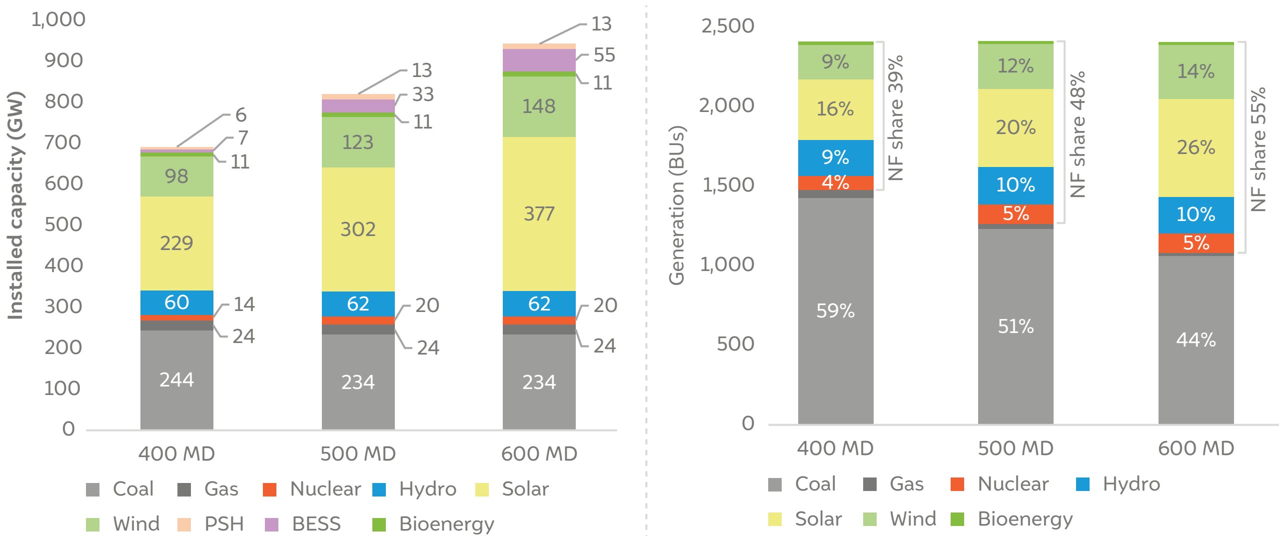
a. **Existing, under-construction, and planned generation resources will be adequate for India to meet its power demand as per the EPS projection for 2030**. Our analysis of the *500 GW-mod demand* scenario reveals that the existing, under-construction 258 GW of thermal capacity, and planned 500 GW of non-fossil capacity, along with the 33 GW of 4-hour BESS and 12.5 GW of PSH, will be sufficient to meet the demand of 2,377 BUs and a peak demand of 343 GW reliably (Figure 4). Coal will play a significant role, accounting for 51 per cent of the annual generation. During non-solar hours, dependency on coal will increase to 61 per cent, rising as high as 76 per cent in October and November.

b. **Additional generation and transmission capacities will be needed to meet the EPS-projected demand for 2030, if India falls short of its non-fossil target**. Installing 400 GW of non-fossil capacity by 2030 will lead to power shortages. For instance, the country will face a power deficit of 2 GW for more than 10 per cent of the time, with the likelihood of an overall 6 BUs of shortage in 2030. This will amount to 0.26 per cent, which is higher than the allowed reliability level. Therefore, we see a need to add 10 GW of new coal capacity, beyond what is under construction, to meet the demand within the reliability level. A 244 GW coal fleet will make up 60 per cent of the generation, with an annual load factor of 67 per cent. However, vRE will only comprise 25 per cent of the generation, which is much lower than the targeted RPO of 39 per cent in 2030.

c. **Meeting the EPS-projected demand for 2030 with a higher RE capacity is the most cost-effective pathway**. In the *600 GW-mod demand scenario*, India will be able to meet its projected demand – 2,377 BUs and a 343 GW peak, with 56 per cent clean energy.[27] Of these, vRE will contribute 40 per cent to the total generation mix. To integrate this high share of vRE, the system will need significant support from coal, hydro, gas, PSH, and BESS, and demand flexibility. Reliance on coal will remain high in non-winter months,[28] especially during non-solar hours. Additionally, the high-RE pathway will help save INR 16,000–35,000 crore (USD 2.0–4.2 billion), as compared to the *500 GW-mod demand* and *400 GW-mod demand* scenarios (discussed in Section 3.3).

27. Here, clean energy indicates generation from all non-fossil sources, including solar, wind, nuclear, hydro and bio-based sources.
28. Here, winter months include those from November to February.

Figure 4 **The share of coal in the generation remains high (44-59% across scenarios) to reliably meet the projected demand for 2030**



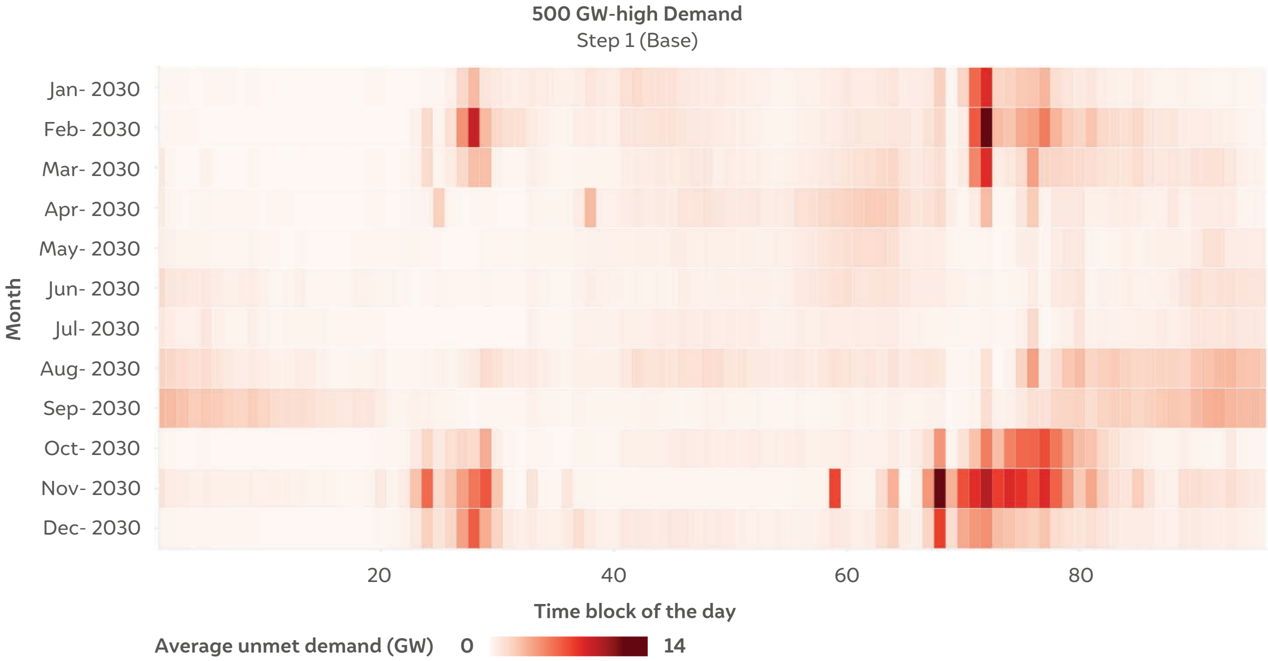
Source: Authors' analysis based on the moderate-demand scenarios

Notes: (1) Here, 400 MD, 500 MD, and 600 MD represent the 400 GW, 500 GW, and 600 GW moderate-demand scenarios, respectively. (2) Approximately 4 GW of coal capacity has been perpetually non-operational since FY18, and is not considered part of the system in 2030. (4) 4.5 GW of hydro imports are considered in the 62 GW of hydro. (5) The non-fossil (NF) share indicates the share of generation from nuclear, hydro, solar, wind and bioenergy capacities.

d. **If the demand exceeds the EPS estimates, India will face shortages even with existing, underconstruction and planned capacities.** In the *500 GW-high demand* scenario, nearly 8 BUs (0.32 per cent) of India's demand in 2030 will remain unmet with the existing targets and capacities in the pipeline.[29] These deficits will be uniformly distributed across solar and non-solar hours.[30] However, the deficits during non-solar hours will be higher in magnitude (Figure 5). Moreover, the northern region will experience nearly half of the total deficits, and two-thirds of those are likely to occur during non-solar hours. Using the four-step approach, we added 6 GW of new coal capacity and enhanced the interstate transmission capability by 41 GW to meet the demand reliably.[31]

29. This is based on the results of Step 1 of the four-step approach, for the *500 GW-high demand* scenario, which considers the existing, under-construction, and planned generation and transmission capacity to meet the demand.
30. We considered 0700 to 1745 as solar hours, and the rest as non-solar hours.
31. With 264 GW of thermal and 500 GW of non-fossil-based generation capacity, along with 22 GW of 4-hour BESS, 12.5 GW of PSH, and 41 GW of transmission-limit enhancements, the system is able restrict NENS to 0.08 per cent. To further restrict NENS to 0.05 per cent, the interstate transmission system will need an enhancement of 68 GW.

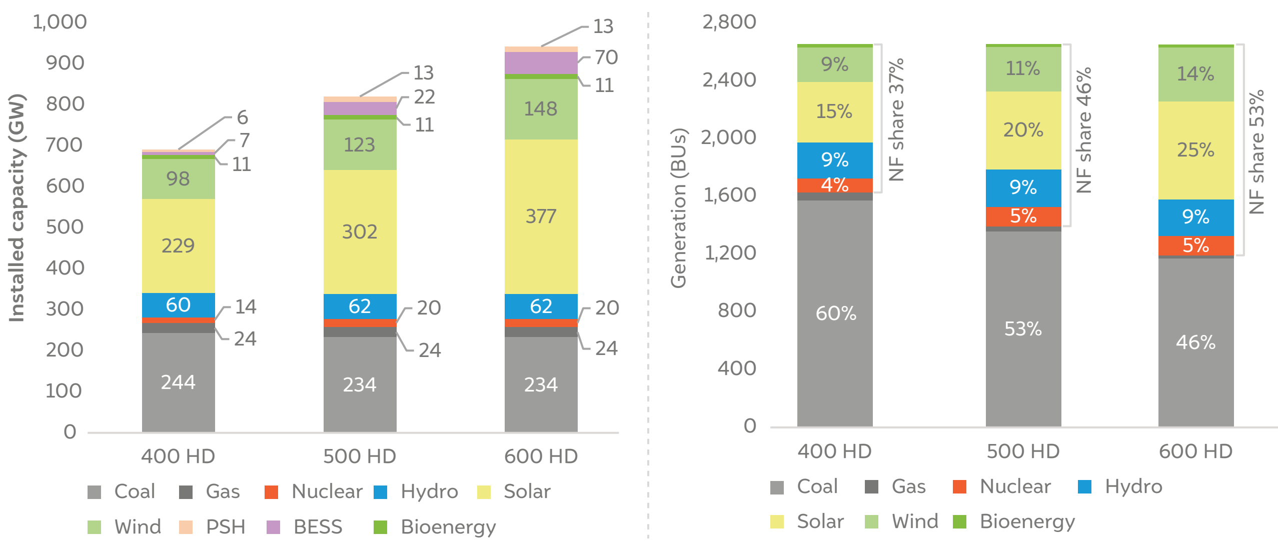
Figure 5 Even with the current and planned capacities, India will face consistent shortages in 2030



Source: Authors' analysis based on the results of Step 1 (Base) for the 500 GW-high demand scenario

e. **The system will need additional generation, transmission, and storage capacities to reliably meet the electricity and peak demand,** in case the demand grows faster than anticipated. For instance, in the *600 GW-high demand* scenario, the demand can be reliably met by deploying 525 GW of RE, 20 GW of nuclear, 62 GW of hydro, 70 GW of 4-hour BESS, 12.5 GW of PSH, and 234 GW of coal (Figure 6). With this combination, the share of vRE in the generation will rise to 39 per cent in 2030, up from 13 per cent in FY24.

Figure 6 876 GW of generation capacity can help reliably meet the demand in 2030



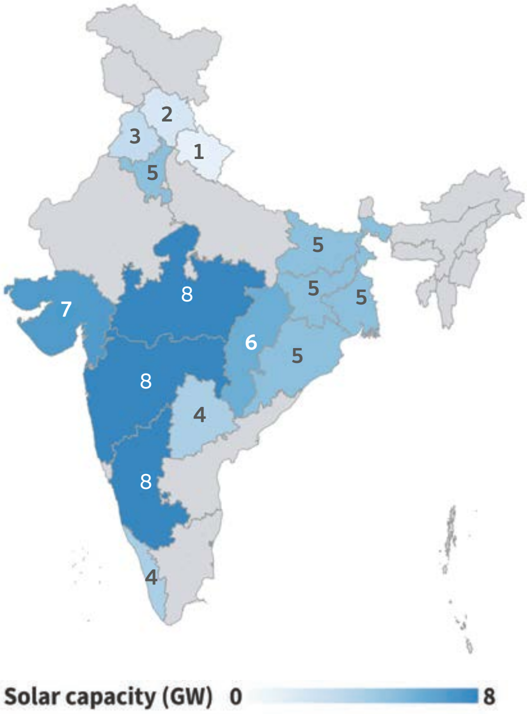
Source: Authors' analysis based on the high-demand scenarios

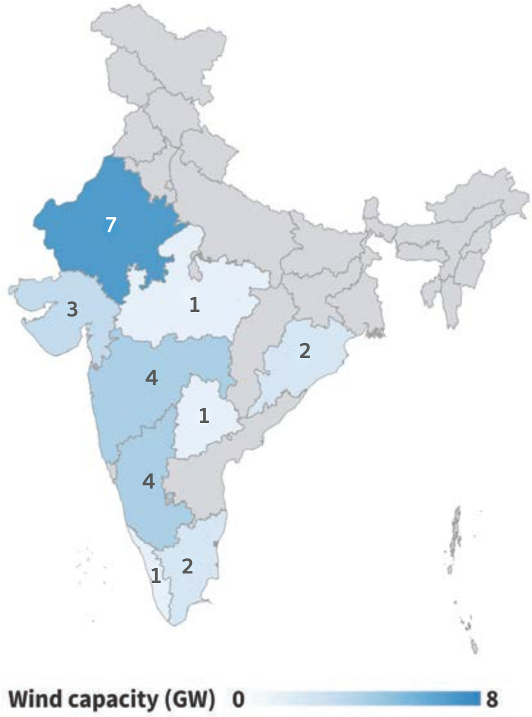
Note: Here, 400 HD, 500 HD, and 600 HD represent the 400 GW, 500 GW, and 600 GW high-demand scenarios, respectively.

f. **Ensuring cost-effective integration and enhanced reliability will need a geographically diverse and balanced RE mix**. In the *600 GW-high demand* scenario, adding 100 GW of RE (75 GW of solar and 25 GW of wind) in more states, such as Madhya Pradesh, Kerala, Bihar, and Odisha (Figure 7), will halve the overall unmet demand relative to the *500 GW-high demand* scenario (Step 1). This will aid in increasing the system's reliability. For instance, Karnataka and Kerala will face significant shortages with the existing, under-construction, and planned capacities, in case the demand grows higher, due to insufficient in-house generation and limited import capabilities.[32] In Karnataka, 37 per cent of these shortages will occur due to import congestion. Installing 7.5 GW of solar and ~4 GW of wind within the state will thus significantly reduce the instances of import congestion and electricity shortages.

Further, diversified deployment of solar and wind in select states will prevent the need to enhance import limits by 6 GW[33] relative to the *500 GW-high demand* scenario. States such as Rajasthan, Telangana, and Punjab will see significant reductions in their import transfer capacity enhancement requirements, which are time-sensitive to be built between 2024 and 2030.

Figure 7 Additional RE capacity beyond the targeted 500 GW must be diversified across states





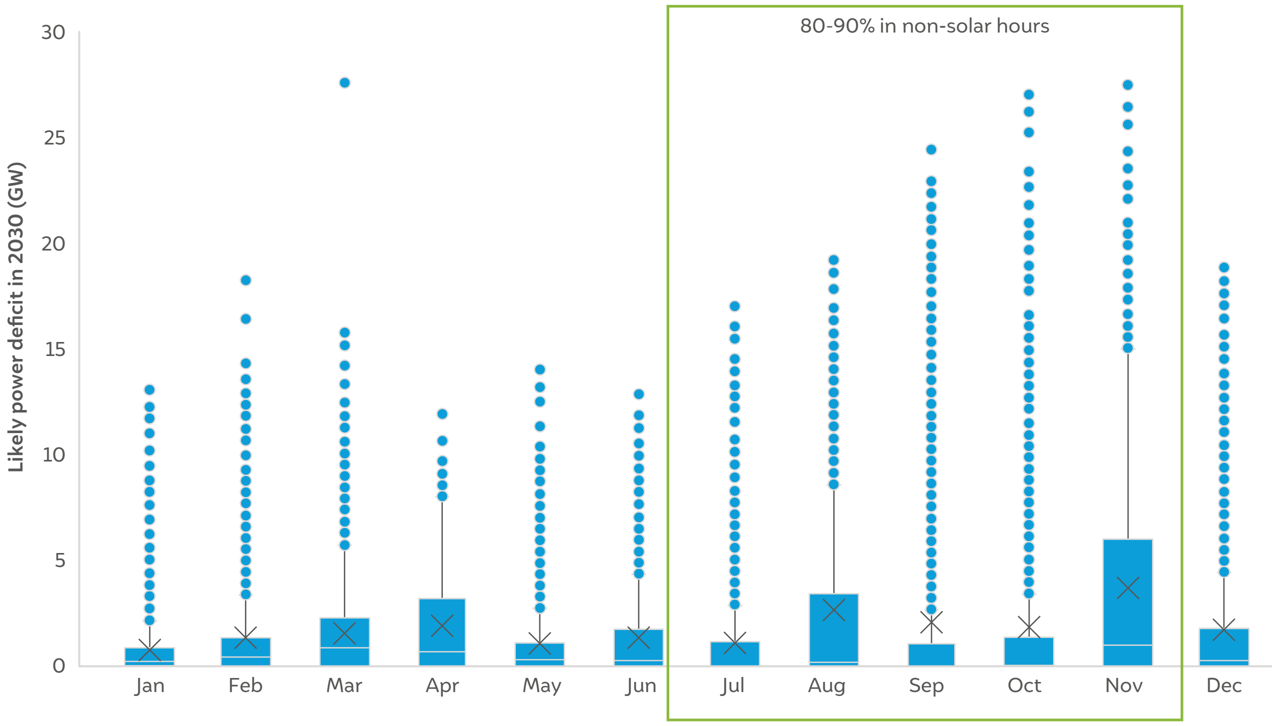
Source: Authors' analysis

32. This is based on the results of Step 1 of the four-step approach, for the *500 GW-high demand* scenario, which considers the existing, under-construction, and planned generation and transmission capacity to meet the demand.
33. In the *500 GW-high demand* scenario, the import limits will require an enhancement (41 GW), for Punjab (6 GW), Haryana (3 GW), Delhi (3 GW), Maharashtra (2 GW), Gujarat (1.5 GW), and Telangana (1 GW). These enhancements are avoided to some extent (35 GW) in the *600 GW-high demand* scenario by distributing wind and solar additions across these states.

g. **If RE deployment remains slow, meeting the demand reliably through thermal assets will yield suboptimal outcomes.** Our assessment of the *400 GW-high demand* scenario shows that if India achieves only 400 GW of non-fossil capacity by 2030, the unmet demand will be double that in the *500 GW-high demand* scenario, resulting in persistent daily shortages of 1–2 GW (Figure 8). These shortages are likely to peak during the late- and post-monsoon months, especially during non-solar hours. To meet the demand reliably, India must add 16 GW of new coal capacity,[34] beyond the existing and under-construction assets. This will likely take more than five years to commission. However, in this case

- The northern region will continue to face more than half the remaining shortages.
- 50 GW of the interstate and 16 GW of the interregional import limits will need to be enhanced.
- The system costs will be 4–5 per cent higher (discussed in Section 3.3).
- The power sector emissions will go up by 17 per cent over FY24 levels.[35]
- More than 90 per cent of the available coal will be despatched through the year, leaving little room beyond the 5 per cent reserve margin to manage uncertainties and contingencies.

Figure 8 India will see persistent shortages of 1–2 GW on a daily basis in 2030 if the planned non-fossil and new coal capacities are delayed



Source: Authors' analysis

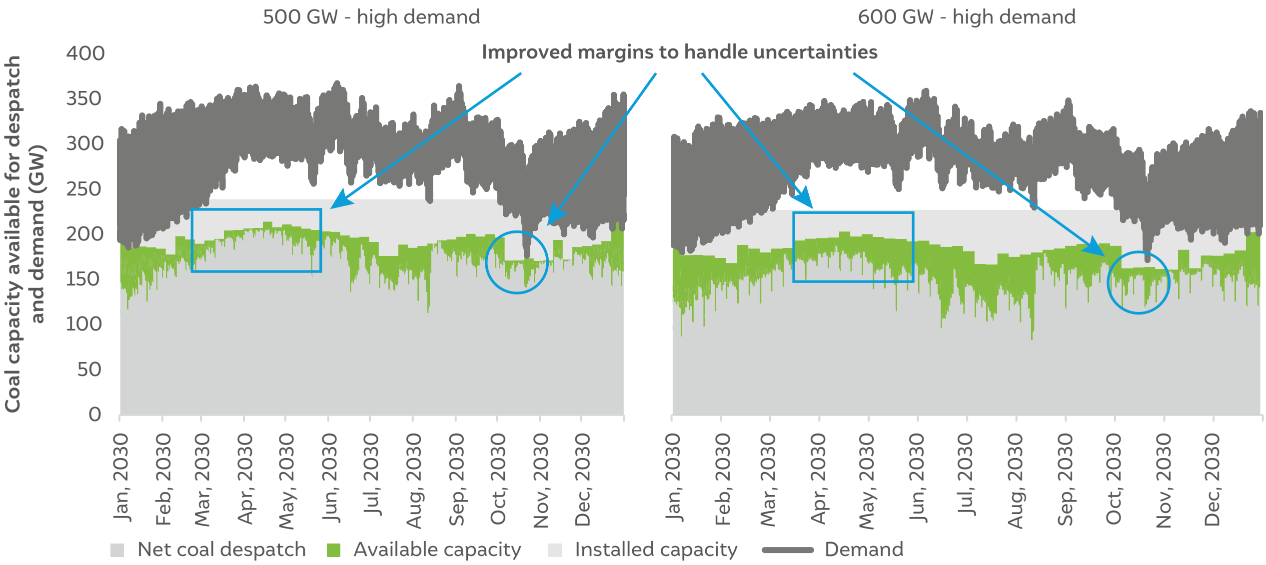
Note: The figure represents a box plot of power shortages in each hour across all months for Step 1 (Base) of the four-step approach in the 400 GW-high demand scenario.

34. The 16 GW of new coal capacity will operate at 71 per cent plant load factor (PLF), meeting 4 per cent of the demand.
35. There were 1,260 MTCO2 of emissions in FY24 (Niti Aayog, n.d.).

h. **The existing coal fleet must be maintained well to meet the demand reliably**. Across all scenarios (*400 GW-high demand*, *500 GW-high demand*, and *600 GW-high demand*), the capacity value of coal will be significant, in the range of 45–63 per cent for the top 10 per cent of the peak demand hours in 2030.[36] It will serve nearly 180 GW, 105 GW, and 85 GW, respectively, of the demand for 90 per cent of the time in each scenario. For instance, in the *500 GW-high demand* scenario, coal will comprise ~60 per cent of the generation during non-solar hours. This share will increase to 78 per cent during the post-monsoon months of October and November, when the unmet demand is also high (Figure 5). However, our assessment of the reported data for FY23 and FY24 on daily outages shows that 15–28 per cent of coal capacity was unavailable in October and November for non-statutory reasons (CEA, n.d.-a). More than 80 per cent of these were state- and privately owned coal units. Research shows that conducting regular scheduled maintenance lowers the incidence of technical outages (CEA 2024h).

i. **Deploying 600 GW of non-fossil capacity by 2030 will help create an additional reserve margin to manage unexpected surges in demand.** In October and November, when the unmet demand will likely be high, and in the high-demand months of March to June, almost all the available coal capacity will be despatched, leaving little margin to manage uncertainties (see the green area in Figure 9). However, the reserve margin from coal will improve in the *600 GW-high demand* scenario, compared to the *500 GW-high demand* scenario. We find that, on average, 14 GW of additional coal could be available for despatch during these months if the system experiences any demand- or supply-side uncertainties.

Figure 9 The 600 GW-high demand scenario will provide an additional 4% margin to handle uncertainties



Source: Authors' analysis based on the simulation results for the 500 GW-high demand and 600 GW-high demand scenarios

Note: Available coal capacity refers to installed capacity excluding capacity under maintenance and outages.

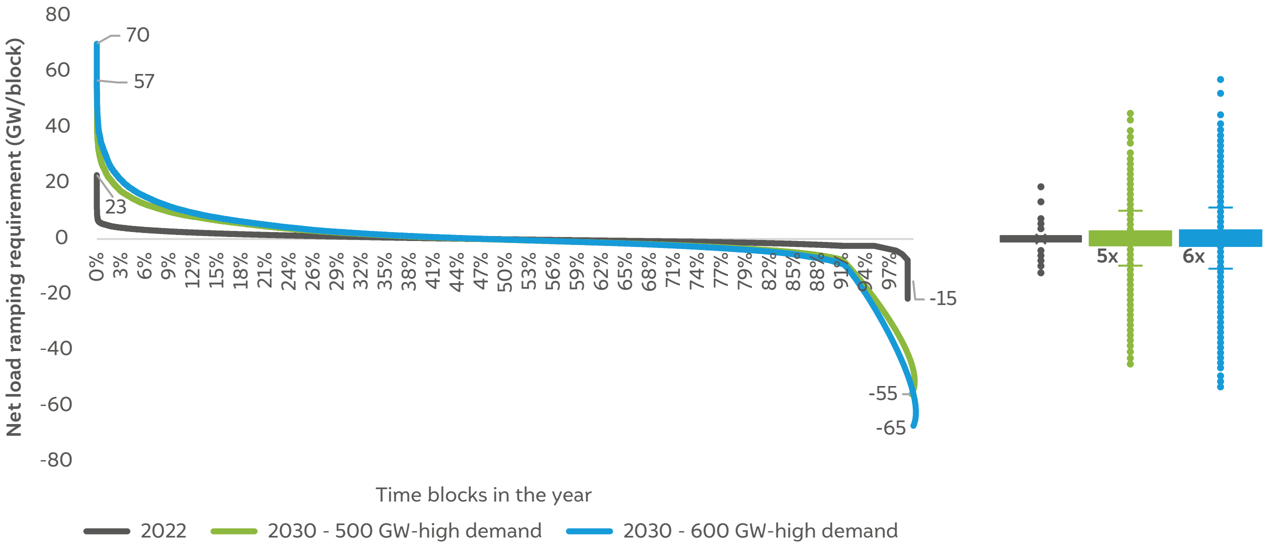
36. The capacity value represents the capacity-utilisation factor of coal in meeting the demand for the top 10 per cent of the demand hours.

3.2 To integrate 600 GW of non-fossil capacity by 2030 successfully, the system must become more flexible

In the *500 GW-high demand* and *600 GW-high demand* scenarios, the daily potential electricity generation[37] will be about 120 per cent higher than the daily energy requirement. However, part of the demand will remain unserved due to unavailable transmission and/or operational constraints of resources. For instance, in the *500 GW-high demand* scenario, for 30 per cent of the hours in 2030, which coincides with likely shortages, 51 GW of coal capacity will be available, yet be undespatched due to such constraints. Meeting the reliability norms will require more flexibility in the system. Our assessment of the simulation results reveals the following:

a. **Ramping requirements will grow significantly by 2030**. Between 2022 and 2030, the system net load ramping requirements[38] at the 15-minute level (also known as a time block), will grow five to six times in the *500 GW-high demand* and *600 GW-high demand* scenarios.[39] This indicates the need for more flexible resources (Figure 10). In 2030, a steep ramping requirement (±10 GW per time block or higher) is likely to occur 20 per cent of the time, primarily in the winter months (November to February). Additionally, continuous ramping needs will rise drastically, mainly in the northern region. The system will thus require fast-response resources.

Figure 10 The ramping requirements will increase by five to six times the current requirement in the 500 GW-high demand and 600 GW-high demand scenarios

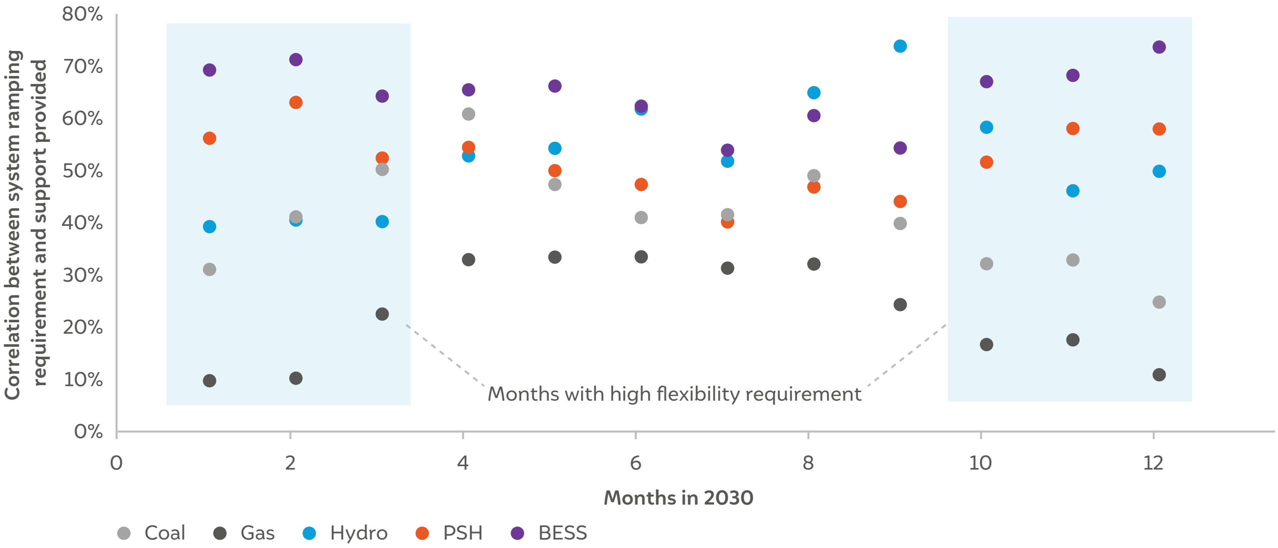


Source: Authors' analysis

37. The potential daily generation includes the available coal capacity (beyond the capacity under outage and auxiliary consumption), potential (available) solar and wind generation, hydro energy budget for the day, and energy unit scheduled from nuclear and gas.
38. Here, the net load is the residual demand to be served by sources other than the must-run RE capacity. The ramp rate is the difference between the net load corresponding to two consecutive time blocks.
39. We considered the ramp rates beyond ±10 GW per time block.

b. **Frequently occurring steep ramping requirements will be best served by BESS.** Across scenarios, we observe that all resources, including coal, gas, hydro, PSH, and BESS, will contribute to meeting the flexibility needs. Our analysis of the *600 GW-high demand* scenario shows that due to its limited flexibility, the coal fleet will ramp to a maximum of ±10 GW per time block.[40] We analysed the correlation between the system's block-level ramping needs and the ramping support provided by various resources. The correlation is a statistical representation of the linear relationship between the requirement and the support provided by the given resource in 2030 (Figure 11).[41]

Figure 11 BESS supports high system ramping requirements



Source: Authors' analysis based on the simulation results for the 600 GW-high demand scenario

Note: Months with a high flexibility requirement are those in which the system needs ±10 GW per time block of ramping support for more than 20 per cent of the time.

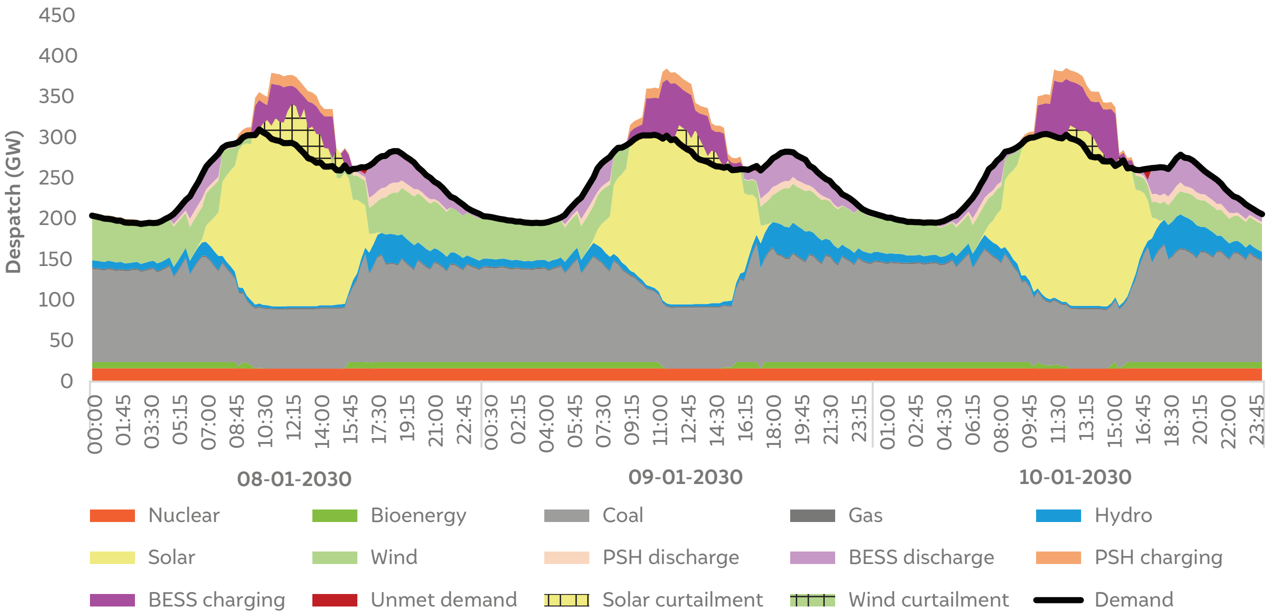
BESS will best correlate with the system ramping needs (65 per cent), followed by PSH (52 per cent), hydro (48 per cent), coal (40 per cent), and gas (22 per cent) (Figure 11). Other scenarios show similar trends. Storage is likely to be utilised for (i) energy shifting by charging from excess generation during solar hours, filling the valley in non-solar hours, and (ii) meeting the steep ramping requirements in the early morning and evening hours, when solar generation dips significantly (Figure 12).

40. In the 600 GW-high demand scenario, coal will provide ramping support of ±10 GW per time block for 93 per cent of the time.

41. The linear relation represents both the direction and magnitude between the support provided by various resources at a time-block level, corresponding to the system's ramping requirement (Orcutt and James 1948).

In the moderate- and high-demand scenarios, the system will need 55–70 GW of 4-hour BESS, along with 12.5 GW of PSH, to integrate 600 GW of non-fossil capacity. Deploying a lower BESS capacity will increase RE curtailment. For instance, in the 600 GW-high demand scenario, for every 5 GW reduction in BESS capacity, curtailment will increase by 0.5 per cent, but with negligible impact on the system costs. Refer to Section 3 of the supporting document for details.

Figure 12 **BESS will meet the steep ramping requirement during the early morning and evening hours**



Source: Authors' analysis based on the simulation results for the 600 GW-high demand scenario

Note: The figure represents some sample days.

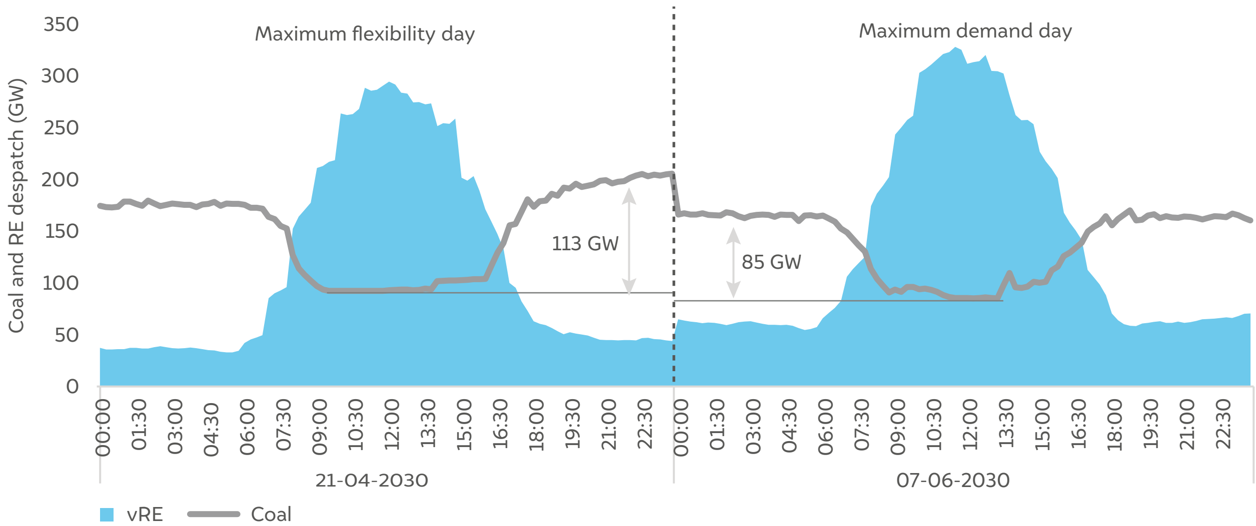
c. **Select coal units will need to be made more flexible to reduce RE curtailment and lower the need for cold starts**. In the *500 GW-high demand* and *600 GW-high demand* scenarios, we observe an excess RE generation (also, known as curtailment) of 11 and 19 per cent, respectively. Using our simulation approach and the selection criteria (as illustrated in Figure 3), we identified that 112–145 GW of coal units will need to operate at 40 per cent MTL. This will help reduce curtailment levels by 3–4 per cent, thus saving INR 22,000–27,000 crore in terms of production cost.[42] In both the scenarios, 12–32 GW of coal capacity will operate at a PLF of less than 35 per cent. This indicates that the system has spare capacities that can be utilised while the targeted coal units undergo retrofitting.

42. Additionally, this will help prevent the installation of 150 GWh of diurnal BESS capacity, considering 88 per cent round-trip efficiency and a 90 per cent depth of discharge.

Across all scenarios, selecting 71–145 GW of coal units to operate at 40 per cent MTL will be adequate and cost-effective to absorb RE during peak-generation hours. However, the CEA has published a plan to retrofit over 90 per cent of the installed coal-based capacity (191 GW) to operate at 40 per cent MTL by 2030 (CEA 2023d). A lower MTL will enable coal units to operate more consistently, even during low-demand periods, thereby generating revenues and mitigating the risk of being stranded. There will be negligible gains from retrofitting additional coal capacity beyond this quantum. This indicates the need to critically re-evaluate the selection and prioritise criteria for retrofitting power plants to meet the flexibility requirements by 2030.

On average, during solar hours, the coal fleet will ramp down by 77 GW daily in the *600 GW-high demand* scenario. On a maximum vRE penetration day, which coincides with the maximum demand day, it will ramp down by 85 GW (Figure 13). We also observe that by reducing the MTL for 334 units in the *600 GW-high demand* scenario, the number of cold starts will decrease. This will thus reduce the thermal stress, lower the system costs, and enhance the life of the unit.

Figure 13 Coal serves as a flexible resource throughout the year



Source: Authors' analysis based on the simulation results of the 600 GW-high demand scenario

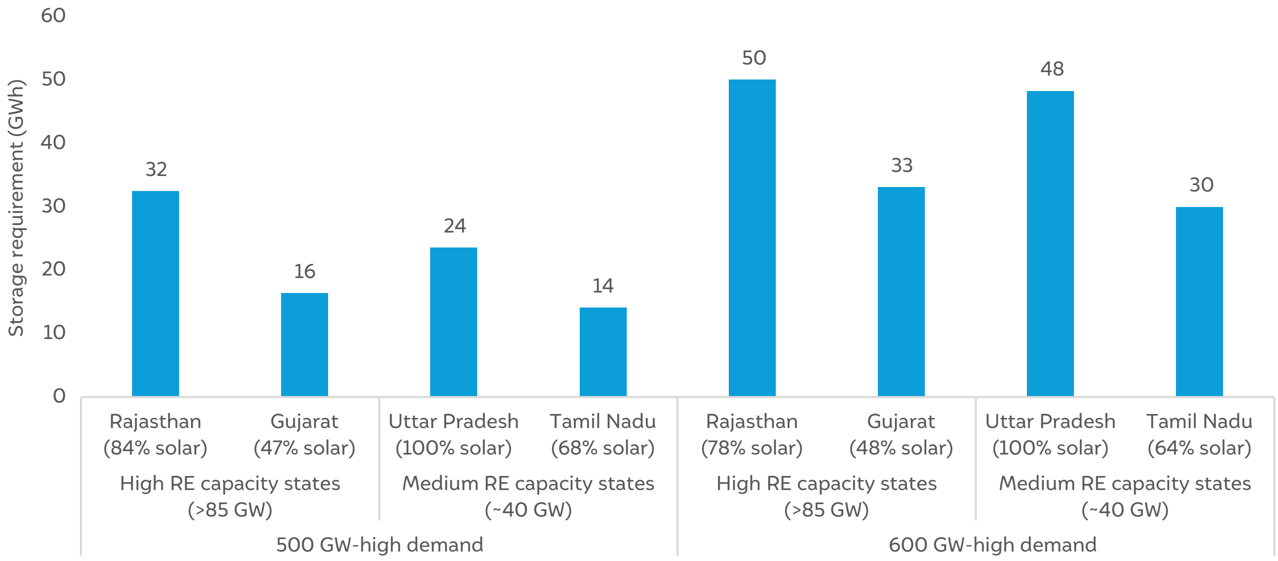
Note: The figure represents the maximum flexibility and maximum demand day.

d. **A varied mix of clean energy technologies spread across states will lower the need for flexibility**. In the *500 GW-high demand* scenario, both Gujarat and Rajasthan will house large RE capacities. While Rajasthan will be solar-rich (with 85 per cent solar capacity), Gujarat will have almost equal shares of solar and wind. Consequently, the storage need in Rajasthan will be double that of Gujarat (Figure 14).[43] Rajasthan will integrate this in-house RE capacity and contribute to meeting the system's demand with 32 GWh of storage (17 per cent of the national storage requirement) and 4.6 GW of transmission expansion.

43. We considered the storage requirements of a 4-hour BESS and 8-hour PSH.

However, with a relatively more balanced RE mix (an additional 6.6 GW of wind in the *600 GW-high demand* scenario), the state will meet the demand with 50 GWh storage (13 per cent of the national storage requirement) and a 3 GW enhancement of the transmission limits.

Figure 14 A balanced RE mix will reduce the requirement for energy storage



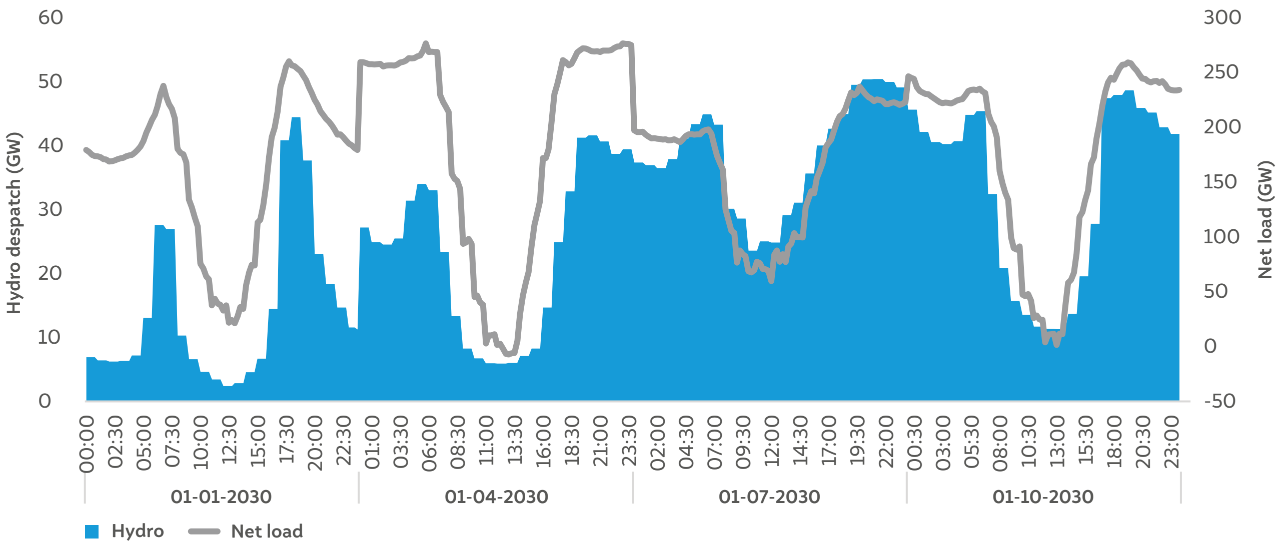
Source: Authors' analysis based on the simulation results for the 500 GW-high demand and 600 GW-high demand scenarios

Notes: (1) The requirement for flexible resources is also dependent on the RE and demand profile of the state. (2) Only four states are represented here, as examples, because similar patterns are observed in other states.

e. **Scheduling hydro resources at the national level will help meet flexibility requirements cost-effectively**. Hydro comprises about 10 per cent of the total generation mix across all scenarios, with the highest contribution during July–October (16 per cent). We scheduled daily and monthly hydro energy budgets at the regional level, not considering hydro as a base load resource but to meet peak demand and steep ramps. We find that following storage solutions, hydro is best placed to meet the steep ramping requirement with high vRE penetration (Figure 15).

In the *500 GW-mod demand* scenario, we conducted a sensitivity analysis to schedule hydro energy at the state versus the regional level. Scheduling hydro energy at the regional level, as compared to the state level, will help lower the vRE curtailment by nearly 8 per cent. This will facilitate avoiding nearly 11 GW in BESS capacity. This indicates that such benefits will be further enhanced if hydro resources are scheduled at the national level.

Figure 15 Hydro generation mimics the net load requirement, especially during and post-monsoon months

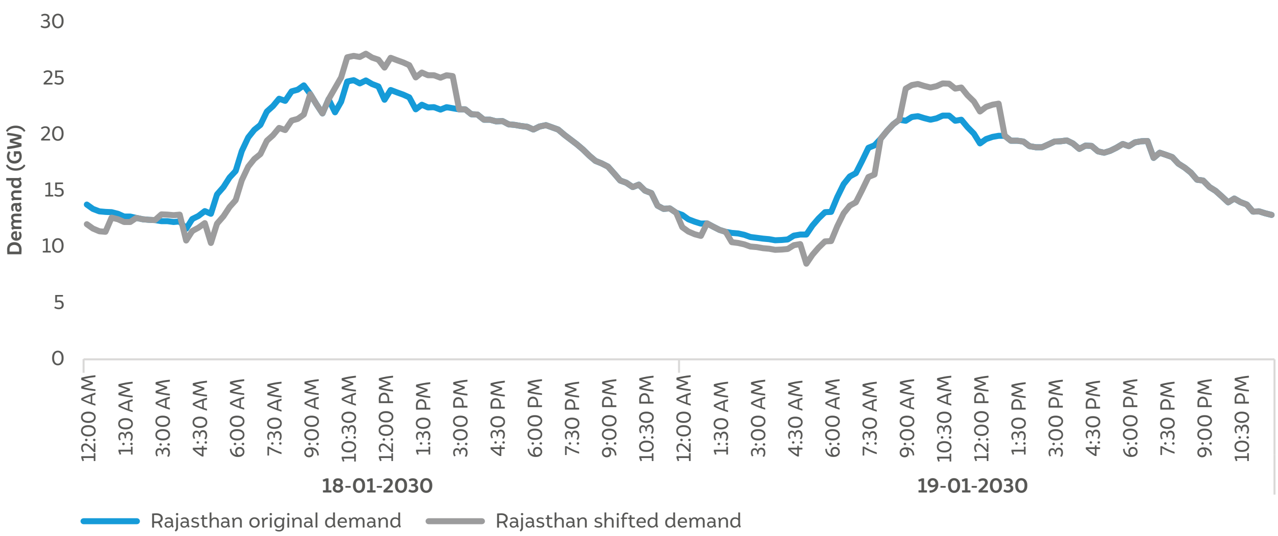


Source: Authors' analysis based on the simulation results for the 600 GW-high demand scenario

Note: The figure represents one day in a quarter.

f. **Harnessing demand flexibility (DF) will lower the need for BESS and save costs.** In the *600 GW-mod demand* scenario, shifting 10 per cent of the peak demand across 10 states,[44] equivalent to a total of 24 GW, will prevent the need for 30 GW of 4-hour BESS capacity at the national level. This will also lower the need to relax interstate transmission import limits by 6 GW. These outcomes will lower the system costs by ~INR 14,000 crore (USD 1.6 billion). RE-rich states such as Rajasthan and Gujarat will collectively contribute one-fourth of the total demand shifted. In Rajasthan, on average, 13 MUs of energy will need to shift daily. In the winter, about 2–3 GW of the required early morning load shift could be mobilised by moving the agricultural load to solar hours (Figure 16). Utilising demand flexibly in the winter months will be useful because this will also be when the flexibility requirement at the state, as well as the national level, is the maximum (Agrawal et al. 2023).

Figure 16 2–3 GW of the early morning agricultural demand can be shifted to solar hours



Source: Authors' analysis to assess the role of DF in the 600 GW-mod demand scenario

44. Uttar Pradesh, Gujarat, Tamil Nadu, Madhya Pradesh, Rajasthan, Telangana, Andhra Pradesh, Karnataka, Odisha, and Jharkhand are the 10 selected states.

3.3 A high RE pathway will help deliver affordable electricity

Having 600 GW of non-fossil capacity will lead to a 53–55 per cent clean (non-fossil generation) grid in the high- and moderate-demand scenarios. In both scenarios, the system will be the most cost-effective (Table 1). With high RE in the high-demand scenarios, the savings in the system costs will be in the range of INR 13,000–42,400 crore (USD 1.5–5.0 billion),[45] as compared to the low- and stated-RE scenarios. Similarly, in the moderate-demand scenarios, integrating high RE will save INR 16,000–35,000 crore (USD 2.0–4.2 billion).

In the *600 GW-mod demand* scenario, we utilised the demand-side resources as an additional flexibility option to lower the need for BESS and realise greater cost savings. However, the system will still be cost-effective in the absence of this intervention.[46]

Table 1 Raising the non-fossil target to 600 GW is a cost-effective way to meet India's electricity demand in 2030

System cost (INR/kWh)	Moderate demand	High demand
Low RE (400 GW)	3.46	3.56
Stated RE (500 GW)	3.38	3.44
High RE (600 GW)	**3.31**	**3.38**

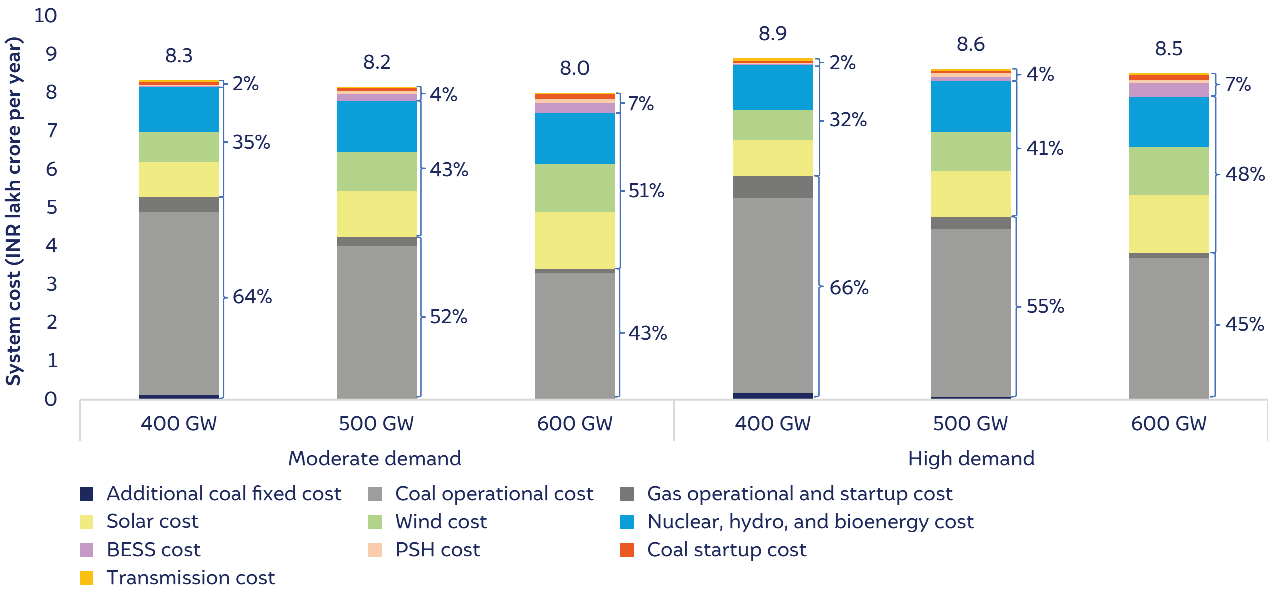
Source: Authors' analysis

Notes: (1) The system-cost calculation does not include the fixed-cost component for existing and under-construction coal units and the cost of the existing transmission network. This is considered a sunk cost across scenarios. (2) All cost numbers expressed as 2022 real values.

45. We used the conversion of USD 1 = INR 83.77.
46. When the demand flexibility is not tapped, the requirement for BESS and relaxations in transfer capacity increase. This results in a per-unit cost of INR 3.37, which is still lower than the stated-RE (INR 3.38/unit) and low-RE (INR 3.46/unit) scenarios.

Integrating high RE shares will increase flexibility needs (as discussed in Section 3.2), but the impact of the corresponding solutions on the system costs will be low. Increasing the energy storage, frequently switching coal units, and relaxing interstate transmission limits will only make up 2–7 per cent of the total system costs (Figure 17).

Figure 17 Flexible options only make up 2–7% of the system costs



Source: Authors' analysis

We also conducted sensitivities for future cost trajectories. We considered a 10 per cent increase in the capital cost for solar, wind, BESS, and new supercritical and ultra-supercritical coal units. We find that a high-RE system will still be cost-effective in meeting the demand, even if the costs do not fall as per the anticipated trends (Table 2).

Table 2 A high-RE pathway will remain cost-effective, even if the technology costs are 10 per cent higher than anticipated

10% higher capital expenditure considered for	400 GW-high demand	500 GW-high demand	600 GW-high demand
	(INR/kWh)		
Solar and wind	3.63	3.53	3.50
BESS	3.56	3.44	3.40
Coal	3.56	3.44	3.38
All four technologies (solar, wind, BESS, and coal)	**3.63**	**3.53**	**3.51**

Source: Authors' analysis

Note: No additional coal capacity is needed in the 600 GW-high demand scenario.

We compare all the moderate- and high-demand scenarios in Table 3. We summarise the additional generation, storage, transmission and flexibility requirements, and the socio-economic and environmental benefits of each scenario.

Table 3 The high-RE scenarios can reliably meet both the moderate and high demand with lower system costs

	Moderate demand (2,377 BUs, 343 GW peak)				High demand (2,473 BUs, 365 GW peak)		
	Low RE (400 GW)	Stated RE (500 GW)	High RE with DF (600 GW)	High RE without DF (600 GW)	Low RE (400 GW)	Stated RE (500 GW)	High RE (600 GW)
Capacity requirements and share in generation							
Additional RE capacity, beyond the 500 GW target (GW)	–	–	100	100	–	–	100
Additional coal (GW)	10	–	–	–	16	6	–
Non-fossil/vRE share in generation (%)	39/25	47/32	55/40	55/40	36/24	45/31	53/39
Coal share in generation/PLF (%)	59/67	51/61	44/52	45/53	60/69	53/63	47/57
System flexibility requirements							
Interstate transmission relaxation (GW)	27	24	16	22	50	41	35
Interregional transmission relaxation (GW)	11	–	–	–	16	–	–
Flexible coal at 40% MTL (GW)	82	119	144	144	71	112	145
4-hour BESS (GW)	7	33	55	85	7	22	70
PSH (GW)	6.0	12.5	12.5	12.5	6.0	12.5	12.5
Demand flexibility (GW)	–	–	24	–	–	–	–
System benefits							
System cost (INR/kWh)	3.46	3.38	3.31	3.37	3.56	3.44	3.38
Full-time equivalent (FTE) jobs	134,096	182,471	240,049	240,049	138,914	187,289	240,049
Emissions in 2030 ($MTCO_2$)	1,401	1,225	1,064	1,064	1,474	1,307	1,149
SO_2 in 2030 (MT)	5.89	5.10	4.42	4.44	6.20	5.46	4.78
NO_x in 2030 (MT)	3.11	2.69	2.33	2.34	3.27	2.89	2.52
Investments (INR lakh crore)	13.30	18.64	23.38	23.44	14.16	18.99	24.11

Source: Authors' compilation of the results across all scenarios

Notes: (1) FTE jobs include jobs generated by solar, wind, and coal capacity addition between 2024 and 2030. (2) Investments include potential investments needed to deploy fossil and non-fossil generation, energy storage, and transmission capacities between March 2024 and 2030.

Investing in a cleaner, flexible, and resilient power grid will help our economy grow sustainably, create new jobs, and improve health outcomes.

Image: Shalu Agrawal/CEEW

4. Evaluating transition pathways: Socio-economic and environmental performance

This section discusses socio-economic opportunities unlocked with the high-RE pathway. It also highlights key barriers in meeting the demand reliably across all scenarios.

4.1 The ambitious clean energy pathway offers enormous benefits

India's ambitious clean energy pathway will enable it to meet its rising energy and peak requirements cost-effectively, in a timely manner. This pathway will impact lives and livelihoods by creating new jobs, alleviating the health burden associated with environmental pollution, attracting investments, and mitigating carbon emissions at a low cost. We quantify the benefits as follows:

- **Job creation**: The high-RE pathway (*600 GW-high demand*) will create 53,000–101,000 additional FTE jobs, as compared to the stated-RE (*500 GW-high demand*) and low-RE (*400 GW-high demand*) pathways.[47]
- **Reduced reliance on coal imports**: With the high-RE pathway, India's coal requirement for thermal power will reduce to 700–766 MT in both the moderate- and high-demand scenarios, as compared to 950–1,000 MT in the low-RE scenarios.[48] The Ministry of Coal projects a requirement of 1,034 MT of coal in FY30 for the power sector, with an overall domestic supply of 1,511 MT and an import of 170 MT (CIL 2022).[49] Meeting the demand with high RE will help prevent imports to some extent.
- **Investment attraction**: Between FY24 and FY30, additional investment of around INR 13–24 lakh crore (USD 160–290 billion) is likely to flow into the economy across generation (86 per cent) and storage capacities (14 per cent).[50] Beyond this, there is potential for investments in interstate and intrastate transmission infrastructure development.

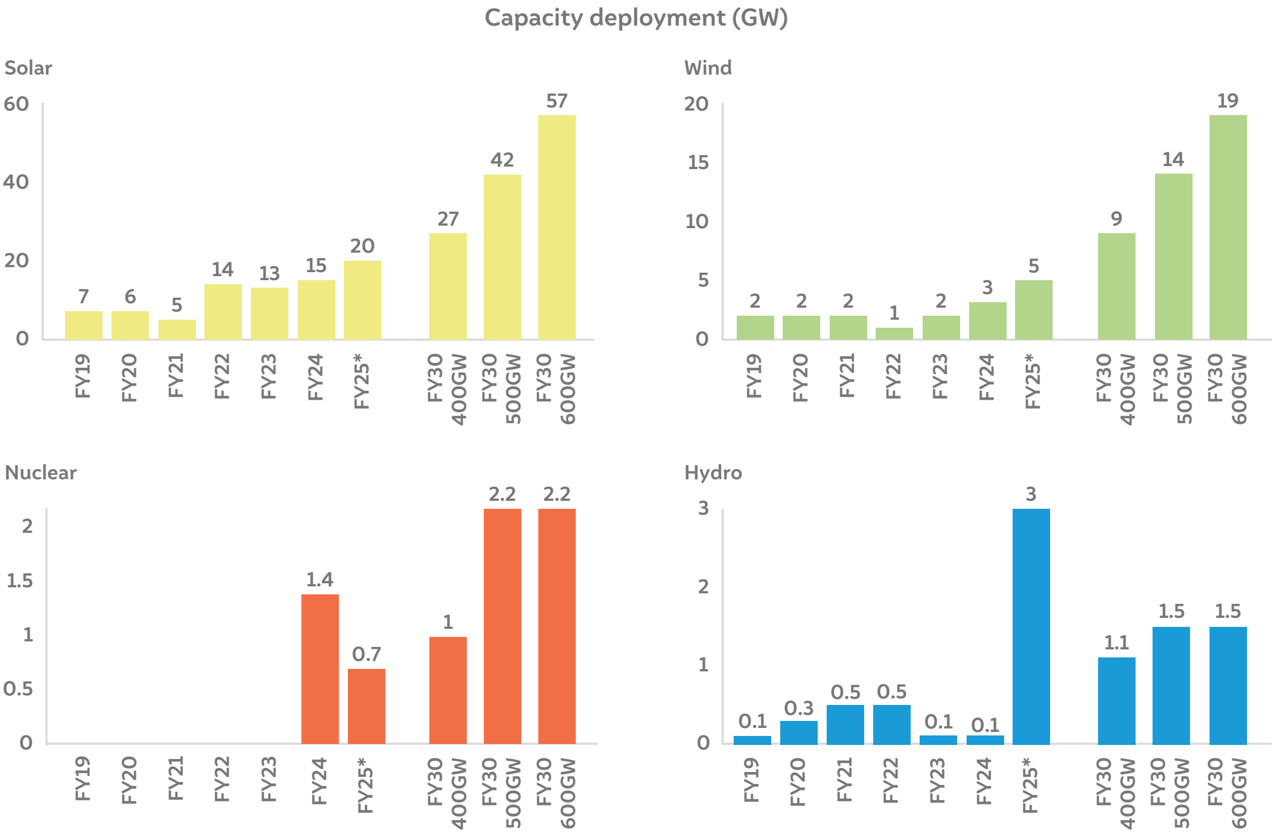
47. Here, we evaluated the FTE estimates for solar, wind, and coal for 2025, as per Malik et al. (2021), with initial estimates for solar and wind as per Kuldeep et al. (2017) and coal as per CEA (2022b). The analysis did not consider the employment offered by deploying new storage, transmission, nuclear, and hydro capacity. Refer to Section 2 of the supporting document for details.
48. We considered 0.66 g/kWh specific consumption, as per historical trends (CEA, n.d.-c).
49. Here, overall coal requirement implies both power and non-power coal demand.
50. We evaluated the investments for all technologies, including coal (super and ultra-supercritical), nuclear, hydro, solar, wind, PSH, 4-hour BESS and transmission. Refer to Section 2 of the supporting document for details.

- **Emission savings**: With the ambitious RE pathway (*600 GW-high demand*), India will avoid 160–325 MTCO2 emissions from the power sector in 2030 without adopting expensive mitigation options,[51] thus paving the way for an accelerated net-zero trajectory. This will ease the burden on other sectors – for which mitigation options are more expensive (Elango et al. 2023; Patidar et al. 2024; Sripathy et al. 2024), thereby achieving the Nationally Determined Contribution (NDC) targets cost-effectively.
- **Better air quality**: With high-RE generation (*600 GW-high demand*) in 2030, SO2 and NOx emissions will be 23 per cent lower, as compared to the *400 GW-high demand* scenario.[52] This will lead to improved air quality and health outcomes.

4.2 Realising the socio-economic benefits will require overcoming barriers to RE deployment and integration

Despite past efforts to add RE capacity, the share of RE in India's electricity generation mix is only 13 per cent as of FY24 (CEA 2024b). To ensure a reliable power supply while meeting its 500 GW target, the country will need to deploy 42 GW of solar and 14 GW of wind power capacities every year between FY25 and FY30. (Figure 18). Our stakeholder consultations and literature review revealed that this is because of multiple barriers (Box 1).

Figure 18 At the current pace of RE capacity addition, achieving the stated-RE target would be difficult



Source: Authors' analysis based on CEA (n.d.-b)

Notes: (1) The FY30 bars indicate the annual rate of deployment needed between FY25 and FY30 to reach 400, 500, and 600 GW. (2) FY25* indicates the capacity expected to be installed in FY25.

51. This is as compared to the *500 GW-high demand* and *400 GW-high demand* scenarios. We considered 90 gCO2/million joules (MJ) for coal, 49.4 gCO2/MJ for gas, and 71.9 gCO2/MJ for oil (CEA 2024g). Refer to Section 2 of the supporting document for details.
52. We considered 4.12 and 2.17 gSO2 and gNOx/kWh (Cropper et al. 2021), respectively, for coal-based generation. Refer to Section 2 of the supporting document for details.

Box 1 **Barriers to deploying RE at a faster rate**

Challenges in land procurement: The limited availability and high cost of land in the vicinity of substations with transmission connectivity margins have limited the addition of new projects. For example, the Solar Energy Corporation of India (SECI) Tranche X, 1,200 MW ISTS-connected wind power project had to drop 300 MW of capacity due to lack of land availability (CERC 2024a). This is one of many such examples of central bids that have been delayed, undersubscribed, or cancelled due to land allocation issues (GWEC 2023). Our consultations indicate that the share of the land cost in the overall project cost has more than doubled and is expected to increase further in areas with connectivity and RE potential.

Transmission-related bottlenecks: As of May 2024, nearly 100 GW of vRE is connected to the intrastate transmission system (InSTS). The interstate transmission system (ISTS) hosts about 31 GW, and another 119 GW has been granted connectivity under a complete ISTS charge waiver (MNRE 2024b). The country aims to establish 6.48 lakh circuit km (ckm) and 2,342 giga-volt-amperes (GVA) of transmission and transformation capacity by 2032 (PIB 2024d). This would require an annual addition of ~21,000 ckm and 136 GVA of capacity. However, capacity additions have been relatively muted, with 14,200 ckm and 71 GVA in FY24 (CEA 2024f). Rapid RE addition is restricted by insufficient ISTS capacity availability in the near term, and challenges in variability management and expansion of InSTS. Moreover, building new ISTS infrastructure from states such as Rajasthan and Gujarat to distant load centres is becoming more expensive.

Constrained supply chains for equipment and services: In 2024, 25 GW of solar and wind energy was expected to come online, of which about 14 GW was carried over from the previous year. The delay can be attributed to manufacturing limitations, a shortage of balance-of-plant vendors, and challenges in timely procurement of equipment. The introduction of certification requirements for copper products (MoCI 2024) and restrictions on solar module imports (MNRE 2024a) have further constrained the supply chain.

Tariff reductions making projects unviable for developers: The tariff for renewable tenders has declined sharply over the years, with recent auction results declared in October 2024 clearing at 2.74 INR/kWh (falling from 3.1 INR/kWh in 2022). Meanwhile, cost and execution related uncertainties continue to increase, leaving little room for risk budgeting.

Financially stressed distribution companies: The total debt of discoms stands at INR 6.87 lakh crore as of FY23 (which is 11 per cent higher than FY22), despite multiple financial reform packages (PFC 2024). This is due to non-cost-reflective tariffs, mounting government subsidy dues, inefficiencies in power procurement, and gaps in metering, billing, and revenue collection. These factors restrict discoms from meeting RPO targets and investing in planning and network strengthening.

Restricted offtake avenues: Discoms continue to be the bulk procurers of RE through long-term contracts. However, distribution sector challenges impede the pace of offtake, in turn, slowing down the deployment. Current market structures and regulatory frameworks do not adequately support diverse business models for short-term or corporate procurement of RE.

Gaps in demand–supply forecasting and resource planning: Inconsistent approaches across states, combined with inadequate consideration of non-linear factors affecting consumption patterns and limited accounting for potential demand-side resources, have resulted in inaccurate demand projections and significant variations in sectoral demand estimates.

Inefficiencies in electricity procurement and operations: Discoms rely on long-term power purchase agreements (PPAs), with fixed capacity charges, for nearly 90 per cent of their requirements. Merit order despatches (MoDs) are not always based on real-time cost information, and further, there may be gaps in compliance. These practices restrict the availability and scheduling of the cheapest resources, increase power procurement costs, and limit the ability to harness the inherent flexibility of the system.

Absence of retail markets for flexibility services: Cost-effective RE integration requires enhanced system flexibility, with significant contribution from demand-side resources. Despite demand-side management (DSM) regulations existing since 2010, DSM programmes are not regulator-approved in the absence of proper impact evaluation guidelines (Aggarwal et al. 2024). Further, the absence of distribution-level markets has held back aggregator business models despite Central Electricity Regulatory Commission (CERC) regulations permitting aggregators to provide ancillary services in the wholesale market.

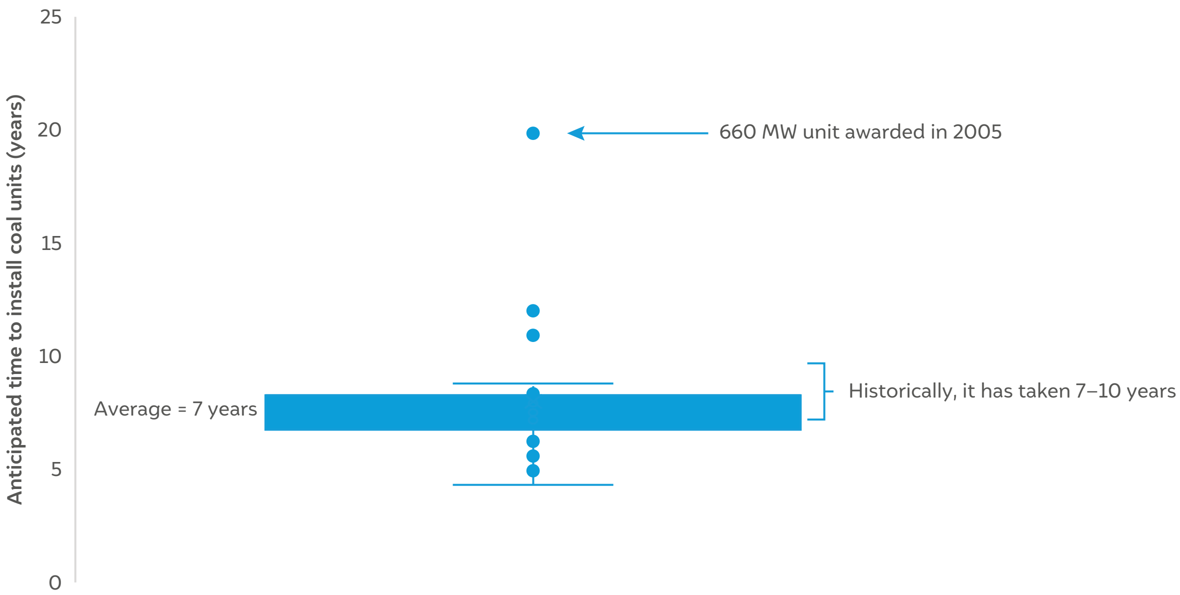
Low liquidity on wholesale market platforms: Despite the existence of power exchanges since 2008, only 6.3 per cent of electricity was procured through power exchanges in FY23 (CERC 2023). Such low trade volumes increase price volatility, force continued reliance on long-term PPAs, and limit the country's ability to integrate RE cost-effectively and at scale.

Source: Author's compilation based on secondary research and stakeholder consultations

4.3 Coal-based power plants face delays in commissioning

Recently, policymakers have been considering coal-based power plants to augment generation capacities to meet the rising demand. As of August 2024, 30 GW of coal capacity is under construction (CEA 2024c). Of this, 19 GW, awarded before 2019, is yet to be commissioned. We also observe an average delay of three to four years. Indeed, coal units have historically taken 7–10 years to become operational. This suggests that coal units may be a risky proposition for mitigating likely shortages in 2030 (Figure 19).

Figure 19 Coal units have historically taken 7–10 years to commission



Source: Authors' analysis based on CEA (2024c)

5. Policy recommendations

Image: Anoop Radhakrishnan/CEEW

As India pursues its economic growth aspirations and net-zero goals, it must be prepared to meet the rising electricity demand by establishing a reliable, affordable, and clean power system. This trilemma brings a new and unique set of challenges associated with maintaining reserves to manage unexpected spikes in demand, ensuring swift deployment of RE and energy storage, and meeting peaks reliably, particularly during non-solar hours.

Our study highlights the need to rigorously evaluate alternate transition pathways for the country's energy system. Doing so will enable India to establish a cost-effective power system that drives resilient and accelerated economic growth. In the study, we compare multiple pathways and observe that the high RE pathway will help India be prepared to deliver reliable and cleaner supply cost-effectively under moderate and high-demand growth scenarios. We also emphasise that systemic approaches are needed to ensure accelerated deployment and integration of RE and other flexible solutions. Extensive collaborative efforts involving the centre and states are essential to develop robust plans for generation and transmission expansion, remove barriers restricting fast-track deployment, rethink market design and operations, and create new market-based mechanisms to attract investments in flexible resources.

5.1 A seven-point action agenda

We call on policymakers, planners, system operators, and utilities to take the following actions:

I. To give a strong policy signal to the market, **the Minister of Power (MoP) must embed the target of achieving a 50 per cent share in generation from non-fossil capacity by 2030 in the *National Electricity Policy***. To achieve this target, the states may be provided with the flexibility to identify clean energy technology choices best suited to their needs. This is to ensure that India meets its net-zero target by 2070, and to delineate a pathway for the electricity sector until 2030.

II. **The MoP must collaborate with the Ministry of New and Renewable Energy (MNRE) and other key institutions to build a technologically and geographically diverse RE portfolio**. Our analysis shows that a balanced mix of solar and wind will help reduce the need for new transmission infrastructure and flexible resources to manage grid operations. Two interventions could support this objective:

   a. **Identify innovative deployment models and contract frameworks** to support the co-location of wind and storage projects with existing solar capacities. This can diversify and accelerate the RE mix, and, in turn, increase the utilisation of the existing transmission infrastructure. One example is the proposed splitting of *General Network Access* (GNA) into solar and non-solar hours (CERC 2024b).[53] Associated commercial arrangements will need to be devised to enable its implementation.

   b. **Ensure the implementation of the *Uniform Renewable Energy Tariff* (URET)**, currently notified for solar, and extend the mechanism to include wind power (MoP 2023). Adopting the URET will help expedite offtake and encourage RE developers to tap locations across more states, even if that could slightly increase generation costs relative to those in resource-rich sites in select states. Alongside, the state and centre must identify incentive mechanisms to attract developers to add capacities in the state.

III. **The MoP, in collaboration with the MNRE, must unlock new avenues for RE offtake**. To enhance the deployment of RE at scale, new avenues for offtake, besides long-term contracts, must be explored. We propose two potential interventions:

   a. **Introduce bid guidelines** to enable more RE developers to participate in the power exchange. This will help meet multiple objectives by (i) rapidly improving supply-side liquidity in power exchanges, (ii) creating an enabling environment for future investments in market-driven RE capacities, and (iii) creating conditions for cost-effective variability management in a RE-rich system.

   b. **Encourage renewable energy implementing agencies** (REIAs) to build their own generation portfolios. These entities can be encouraged to invest in standalone storage assets, direct RE procurement, and market trading to offer the desired services to distribution utilities, system operators, and buyers in the short- and medium-term markets.

53. A mechanism to enable multiple generators to access the same transmission network during solar and non-solar hours. This will enable granting network access during non-solar hours to BESS or wind capacities, co-located with existing solar.

IV. **Central Electricity Regulatory Commission (CERC) and Grid India, in collaboration with states, must ensure fast-tracked deployment of energy storage solutions**. Our analysis shows that integrating significant RE capacities will require 55–70 GW of 4-hour BESS and 12.5 GW of PSH. The current BESS capacity is only 360 MWh. Therefore, CERC and Grid India must undertake the following:

   a. **Conduct a robust analysis** to identify strategic locations for siting BESS projects to optimise network operations.

   b. **Evaluate short-term flexible contracts** to allow shared capacity contracts between utilities and the system operator to maximise the utilisation of BESS assets.

   c. **Publish a discussion paper on possible operations and the sharing** of BESS capacities to take advantage of arbitrage opportunities across utilities and enable offtake and participation. Leveraging the diverse demand profile and requirement amongst states and utilities, and sharing BESS capacity for a particular season or time of day will maximise its utilisation.

V. **The MoP and CEA must enable states to engage in robust resource planning to meet the growing demand reliably and cost-effectively**. This can be achieved through the following interventions:

   a. **Institute a technical assistance programme** for states to establish the necessary infrastructure, institutional frameworks for data management, and in-house expertise for simulation-based exercises.

   b. **Earmark funds from the Power System Development Fund** (PSDF) for states to strengthen capabilities to conduct planning studies.

   c. **Constitute an expert group** to publish informed inputs and assumptions for robust capacity expansion and resource adequacy planning exercises.

VI. **The Forum of Regulators (FoR), with support from the Bureau of Energy Efficiency (BEE) and Grid India, must nudge state regulators to assess the value and market for tapping demand flexibility**. Our analysis highlights the benefits of shifting the demand from peak non-solar hours to solar hours. Shifting 24 GW of demand daily can help avoid (i) 30 GW of 4-hour BESS, and (ii) the construction of 6 GW of interstate transmission infrastructure. Further, it would help the system save INR 14,000 crore (USD 1.6 billion) in 2030.

   The coordinated efforts from the FoR and BEE can spur discussions and advance initiatives, such as that introduced by Maharashtra, which was the first to notify demand-side management (DSM) regulations in October 2024 (MERC 2024).

VII. **Grid India and CERC must help states adopt improved maintenance and scheduling practices**. Our analysis of past data and simulations highlights that optimising operational planning and scheduling mechanism has multiple benefits. Here, two interventions could be considered:

   a. **FoR should conduct a knowledge-sharing programme** for state, regional, and national load despatch centres (LDCs) to share best practices on operational planning and effective scheduling and promote the transition from MBED to security-constrained economic despatch (SCED) as a uniform mechanism for despatch.

   b. **CERC must revisit the existing merit order despatch** (MoD) mechanism to enable the scheduling of flexible resources such as energy storage, hydro budgets, and flexible demand.

A host of continuous innovations, backed by a systemic approach, would be essential to integrate an increasing share of renewables in an expanding and modernising grid.

Image: iStock

6. Limitations and future scope

This study considers varying demand projections and supply mix for 2030, highlighting the system needs. For instance, the need to build new generation, transmission and storage capacities to meet electricity and flexibility requirements. Such assessments would be more reflective of possible scenarios with the following considerations:

- **Capacity expansion plus despatch optimisation for multiple years to generate evidence around strategies to help eliminate shortages cost-effectively**. This study optimises the despatch for predetermined capacity mixes based on targets and plans. A capacity expansion exercise, along with despatch optimisation for multiple years, can be a valuable next step to identify strategies to eliminate shortages over the next 2–3 years and identify the utility of investments made in the next 10–15 years.
- **Robust demand forecasts**. Uncertainties in demand projections are made evident by the wide variation seen across published estimates. Such studies do not capture intraday and seasonal variations in demand, leaving much to be desired. The impact of peak shifts, skewed growth in demand across sectors, and regional variations are not completely incorporated in this study, primarily due to a lack of disaggregated data across time and consumer categories.
- **Stochastic approaches**. Studies covering all ranges of supply and demand scenarios can provide an idea of the minima and maxima. Conducting studies with likely variations to evaluate various probabilistic simulation scenarios would help bring the forecast situations closer to what may be expected in reality.
- **Treatment of transmission network different from the geographical boundaries of the state**. Our report documents the benefits of geographically diversifying and sharing capacities among states, along with relevant recommendations. While the geographical distribution of capacity offers a diverse perspective on the capacity profile, it would not address the evacuation constraints based on the electrical network layout. Mapping capacities to electrical network layout would provide a clearer understanding of power flows and constraints.

Annexure 1: Input and assumptions

RE profile and capacity assumptions

We assumed 327 GW, 425 GW, and 525 GW of vRE capacity in 400 GW, 500 GW, and 600 GW scenarios, respectively. We considered five profiles each for solar and wind for each state using the NREL database (NSRDB, n.d., Draxl et a.l 2015). We distributed the RE capacity across states (see Table A1) considering (CEA 2022c) and the states' policy targets (Govt. of Rajasthan 2023; KREDL 2022; UPNEDA 2022; Energy Department Odisha 2022; JREDA 2022; Invest Uttarakhand 2023; Government of Tamil Nadu, 2023; FICCI-MNRE 2022). For existing solar and wind capacities (as of December 2022), we considered the actual PLFs performed in 2022, and for the additional solar and wind capacities, we considered 20 and 30 per cent annual PLFs, respectively. The additional solar capacity located in Rajasthan is considered to operate at 23 per cent annual PLF, and the 3 GW offshore wind capacity (2 GW in Tamil Nadu and 1 GW in Gujarat) is considered to be operating at a PLF of 37 per cent.

Table A1 State-level RE capacity addition across low, stated and high RE scenarios

State	2022		2030 - 400 GW		2030 - 500 GW		2030 - 600 GW	
	Solar	Wind	Solar	Wind	Solar	Wind	Solar	Wind
Rajasthan	15	5	57	12	75	15	75	21
Karnataka	8	5	10	8	13	10	20	14
Gujarat	8	10	31	36	40	45	48	49
Uttar Pradesh	2	0	28	0	36	0	36	0
Jharkhand	0	0	3	0	4	0	9	0
Odisha	1	0	8	0	11	0	15	2
Tamil Nadu	6	10	20	11	26	13	26	15
Uttarakhand	1	0	2	0	3	0	5	0
Andhra Pradesh	5	4	29	18	38	22	38	22
Telangana	5	0	10	2	14	3	18	4
Madhya Pradesh	3	3	8	5	11	6	19	7
Maharashtra	3	5	9	7	12	9	20	13
JK & Ladakh	0	0	9	0	12	0	12	0
Himachal	0	0	1	0	1	0	3	0
Kerala	1	0	1	0	1	0	5	1
Bihar	0	0	0	0	0	0	5	0
Chhattisgarh	1	0	1	0	1	0	6	0
Delhi	0	0	0	0	0	0	0	0
Goa	0	0	0	0	0	0	0	0
Haryana	1	0	1	0	1	0	6	0
North East (Aggregated)	0	0	0	0	0	0	0	0
Punjab	1	0	1	0	1	0	4	0
Sikkim	0	0	0	0	0	0	0	0
West Bengal	0	0	0	0	0	0	5	0
India	**61**	**42**	**229**	**98**	**302**	**123**	**377**	**148**

Source: Authors' compilation

Operational and economic constraints

We considered the following operational and cost-related constraints across all scenarios.

- We considered 1 and 3 per cent per minute ramp rates for coal and closed-cycle gas plants, respectively.
- Each unit is available 85 per cent of the time in the year. The planned maintenance and forced outages vary depending on the technology and capacity of individual units.
- We considered cold start assumptions for coal units, including 24 hours of minimum downtime, 72 hours of minimum uptime, and startup costs as per (CEA, 2022d).
- All gas units will operate at 40 per cent MTL, and coal units will operate at 55 per cent MTL, except the select units in each of the scenarios (Section 2) will operate at a lower MTL of 40 per cent.
- We modelled all hydro projects as reservoir-based hydro with monthly budgets, based on their despatch in 2022.
- We considered 1 per cent fuel cost escalation for domestic and imported coal, every year between 2022 and 2030.
- We projected gas prices based on the Annual Energy Outlook (EIA 2022).
- We considered INR 20 per kWh as a penalty for unserved energy.
- The production cost model of PlanOS considers fuel cost and heat rate to model the variable cost. We benchmarked this based on data available on the MERIT portal and daily coal reports from the national power portal (CEA, n.d.-c).

Assumptions for system cost calculations

Along with the production cost for conventional sources, we calculated the resultant system cost exogenously, across scenarios based on the assumptions described in Table A2. More detailed methodology along with assumptions is discussed in the supporting document (Section 2).

Table A2 Cost assumptions for system cost calculations

Parameters	Unit	Cost (INR/kWh)
Solar LCOE	INR/kWh	3.29
Wind LCOE	INR/kWh	3.63
Battery LCOS	INR/kWh	4.5
PSP LCOS	INR/kWh	4.6
800 MW coal capex	INR crore / MW	9.64
600 MW coal capex	INR crore / MW	8.97
Transmission cost	INR crore/MW	1
Debt	%	70
Equity	%	30
Return on equity	%	9
Interest rate	%	12 (wind, solar) 15 (Coal, BESS, transmission)

Source: Authors' compilation of the assumptions considered based on stakeholder discussions

Note: LCOE stands for levelised cost of energy and LCOS stands for levelised cost of storage.

Additional model output

Table A3 16-65 GW transmission limits are needed to be relaxed to meet the demand reliably, across scenarios

State	2022	Projected (MW)	Transmission enhancements (MW)					
			Moderate demand			High demand		
			400 GW	500 GW	600 GW with DF	400 GW	500 GW	600 GW
Rajasthan	3,400	7,000	3,000	4,500	400	6,000	4,600	3,000
Punjab	6,500	8,900	6,100	5,000	4,800	10,100	11,100	9,100
Haryana	5,000	8,500	6,500	3,500	1,900	9,000	6,500	6,500
Uttarakhand	2,500	2,500	500	1,000	1,000	1,500	1,500	1,500
Delhi	4,500	6,800	5,200	2,500	1,200	7,200	5,750	5,750
Maharashtra	9,904	9,904	2,096	2,000	-	5,096	4,096	4,096
Telangana	7,200	7,200	1,800	3,000	2,500	4,800	4,000	2,800
Kerala	2,812	2,812	1,188	1,500	988	2,238	2,238	2,188
Gujarat	10,568	12,450	-	-	118	1,550	1,550	-
Himachal Pradesh	1,400	1,400	-	500	-	600	-	-
Karnataka	3,500	3,500	500	-	3,000	1,500	-	-
Uttar Pradesh	8,420	14,500	-	-	-	-	-	-
Madhya Pradesh	10,924	10,924	-	-	-	-	-	-
Chhattisgarh	3,448	3,448	-	-	-	-	-	-
Andhra Pradesh	6,000	6,000	-	-	-	-	-	-
Tamil Nadu	10,450	10,450	-	-	-	-	-	-
West Bengal	2,612	6,991	-	-	-	-	-	-
Bihar	7,721	7,721	-	-	-	-	-	-
Jharkhand	1,820	2,443	-	-	-	-	-	-
Odisha	2,675	3,743	-	-	-	-	-	-
Sikkim	109	175	-	-	-	-	-	-
North-East	600	1,290	-	-	-	-	-	-
Inter-state relaxation			**26,884**	**23,500**	**15,906**	**49,584**	**41,334**	**34,934**
Northern region	15,500	24,400	10,600	-	-	15,600	-	-
Western region	-	-	-	-	-	-	-	-
Southern region	7,000	16,300	-	-	-	-	-	-
Eastern region	-	-	-	-	-	-	-	-
North-eastern region	600	1,470	-	-	-	-	-	-
Inter-regional relaxation			**10,600**	-	-	**15,600**	-	-

Source: Authors' analysis

Acronyms

BEE	Bureau of Energy Efficiency
BESS	battery energy storage system
BUs	billion units
CAGR	compound annual growth rate
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
ckm	circuit kilometre
CO_2	carbon dioxide
DF	demand flexibility
DSM	demand side management
EPS	*Electric Power Survey*
FoR	Forum of Regulators
FTE	full-time equivalent
GCAM	Global Change Analysis Model
GE	General Electric
GNA	*General Network Access*
GVA	giga-volt-ampere
InSTS	intrastate transmission system
ISTS	interstate transmission system
LCOE	levelised cost of energy
LCOS	levelised cost of storage
LDCs	load despatch centres
MBED	market-based economic despatch
MNRE	Ministry of New and Renewable Energy
MoD	merit order despatch
MoP	Ministry of Power
MT	million tonnes
MTL	minimum technical loading
NDC	nationally determined contribution
NENS	normalised energy not served
NF	non-fossil
NO_x	nitrogen oxides
PLF	plant load factor
PLI	*Production Linked Incentive*
PM	particulate matter
PPA	power purchase agreement
PSDF	Power System Development Fund
PSH	pumped storage hydropower
RE	renewable energy
REIAs	renewable energy implementing agencies
RoW	right of way
RPO	renewable purchase obligation
SCED	security-constrained economic despatch
SO_2	sulphur dioxide
URET	*Uniform Renewable Energy Tariff*
VGF	*Viability Gap Funding*
vRE	variable renewable energy

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