Integrating Wind and Solar in the Indian Power System

An Assessment with a Unit Commitment and Dispatch Model

Neshwin Rodrigues, Raghav Pachouri, Shubham Thakare, G. Renjith and Thomas Spencer

Abstract

India's coal contribution to the total electricity generation mix stood at 73% in 2018. To meet India's NDC ambitions, the federal government announced determined targets to integrate 450 GW Renewable Energy in the grid by 2030. This paper explores the pathways to integrate high RE generation by 2030 with

N. Rodrigues (✉) · R. Pachouri · S. Thakare
The Energy and Resources Institute (TERI), New Delhi, India
e-mail: n.rodrigues@teri.res.in

N. Rodrigues
School of Public Policy, Indian Institute of Technology (IIT), New Delhi, India

R. Pachouri
e-mail: shubham.thakare@teri.res.in

S. Thakare
e-mail: raghav.pachouri@teri.res.in

G. Renjith
The Energy and Resources Institute (TERI), Kerala, India
e-mail: g.renjith@teri.res.in

T. Spencer
International Energy Agency (IEA), Paris, France
e-mail: spencer.thomas885@gmail.com

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effective balancing of supply and demand and associated challenges of flexibility requirements. A Unit commitment and economic dispatch model, which simulates the power system operation was used. The overall share of variable renewables reaches 26% and 32% in the Baseline Capacity Scenario (BCS) and High Renewable Energy Scenario (HRES) respectively. Improved ramp rates and a minimum thermal loading limit induce flexibility in the thermal fleet. In the HRES, more than 16 GW of coal plants are required for two-shift operations in April and more than 50% of days see an aggregate all-India ramp from the coal fleet in excess of 500 MW per minute. Battery Storage provides daily balancing while reducing VRE curtailment to less than 0.2% in the HRES. Nationally Coordinated dispatch shows increased power transfer from high VRE regions to export power during high VRE generation periods. It is thus found that high RE penetration is possible by 2030 at no extra system costs.

Keywords

Power Systems Modelling · Unit Commitment and Economic Dispatch · Power System Flexibility · Renewable Integration System Costs · Energy Storage

1 Introduction

1.1 Indian Policy Context

Providing affordable and reliable electricity is essential to the achievement of India's goals of poverty eradication and economic growth. At the same time, the electricity sector is responsible for the largest share of India's energy-related CO_2 emissions, at 43.4% as of 2018, due to the high share of coal in the electricity mix (Enerdata, 2020). As part of its Nationally Determined Contribution (NDC) to the Paris Agreement to reduce its emission intensity per unit of GDP by 33–35% till 2030, the Government of India has set an ambitious goal of achieving 175 GW of installed capacity of renewable energy by 2022 later revising the target to 450 GW of renewable energy generation capacity by 2030 (Central Electricity Authority, 2020d). These targets are driven by the financial competitiveness of wind and solar, which have achieved auction-based tariffs substantially lower than the cost of new coal (Spencer et al., 2018).

As of October 2020, India had an installed capacity of 373 GW, excluding captive power (Central Electricity Authority, 2020b). Of this, 55% was coal and lignite, 7% gas and diesel, 12% large hydro, 10% wind, 10% solar, 2% nuclear, and the remainder consists of small hydro and biomass (Central Electricity Authority, 2020a). Total generation from variable renewable energy (VRE), i.e. solar and wind, comprised of 9% of the total generation in fiscal year 2019–20 (Central Electricity Authority, 2020b). Thus, at one fifth of total capacity and almost 10% of total generation, wind and solar already play a significant role in the Indian power system. However, given the targets mentioned above, by 2030, the share of VRE could be expected to be above 25% of total generation (J. D. Palchak et al., 2019). Increasing the share of VRE in the electricity mix brings additional challenges of grid integration. Even at the relatively low penetration achieved today, Indian system operators are already experiencing some challenges of grid integration. These range between insufficient power evacuation capacity, regulated scheduling and dispatch within Inter-state balancing areas. In spite of having a well-developed transmission infrastructure with 432,785 circuit kilometres of transmission network (Central Electricity Authority, 2020c), curtailment issues in VRE rich states are rising due to the inadequacy of interstate transmission infrastructure (Buckley & Shah, 2019).

1.2 Flexibility in the Indian power system

In addition to scheduling and transmission infrastructure concerns, the integration of VRE faces challenges due to inflexible coal fired generation. India has 198 GW of coal-fired generation capacity, of which 30% are centrally owned, 33% are state-owned, and 37% are privately owned (Central Electricity Authority, 2020a). The majority of state-owned coal generators have limited ramping capabilities and a high declared technical minimum of 65–75% (Central Electricity Authority, 2019). In a recent report, the Central Electricity Authority (CEA) had emphasized the requirement for thermal power plants to facilitate VRE integration by improving ramping rates, technical minimum, and two shift operation capabilities (Central Electricity Authority, 2019). Adhering to which, these coal plants can assist in energy transition to accommodate high shares of solar and wind in the Indian grid.

Currently, however, India mostly relies on its existing hydro and gas fleets to meet its peak demand and fast ramping requirements. India has 46 GW of large hydro power capacity (Central Electricity Authority, 2020a), which consists of run of river hydro and reservoir hydro. Due to its fast ramping capability and negligible startup time, the national system operator (POSOCO) proposed that centrally-owned hydro stations provide fast response ancillary services (FRAS) through regulated up and down services in five-minute time blocks (POSOCO, 2019). India also has about 5.6 GW of pumped storage capacities under operation, and another 3.1 GW under construction (Standing Committee on Energy, 2019). However, limited utility from pumped hydro has been realized as of date. This is due to adequate spinning reserves availability from coal fleet and moderate ramp requirements. As the share of variable renewables will increase, the fast ramping requirement and intermittent generation will aid to pumped storage requirements. Gas power plants in India have provided a higher degree of ramping support to peak demand; however due to the lack of sufficient domestic gas supply and expensive imported gas, this has left a 14.3 GW gas fleet stranded in India (IEEFA, 2019).

1.3 Power System Modelling studies in India

In India, the Central Electricity Authority (CEA) of the Ministry of Power is the technical body responsible for power system planning. As per the 2003 Electricity Act, the omnibus legislation governing the power sector, the CEA prepares a National Electricity Plan every five years. In a recent study, the CEA studied the least cost optimal generation capacity mix required to meet the projected peak electricity demand and energy requirements for 2029–30 (Central Electricity Authority, 2020d). However, the study neglected the spatial aspect of grid integration by considering a single balancing area and neglecting other aspects of VRE integration in terms of power transfers between balancing regions, and impacts due to coal fired power plants flexibility which is a requisite for operational studies.

Energy system models such as that used by de la Rue du Can et al. (2019) are useful for assessing the sectoral and fuel interactions of different pathways, but face limitations in adequately assessing options for VRE integration and use simplified heuristics to proxy integration constraints on VRE penetration. Lawrenz et al. (2018) proposed an energy systems model that represents six sub-annual time slices to explore issues related to VRE grid integration. These studies disregard the operational aspects of power systems at hourly or sub-hourly temporal scale which is necessary to understand VRE integration, particularly in a high coal system where unit commitment constraints may be substantial.

To model high VRE integration in the power system, it is essential to incorporate operational level detail in the modelling exercise (Balachandra & Chandru, 2003), in particular at least hourly time resolution in order to explore generator cycling, start up, and minimum output levels. Deshmukh et al. (2017) used a mixed-integer unit commitment and dispatch model to model the costs of integrating high VRE in the Indian Power system by 2030, finding additional costs of 0.25–0.56 Rs/kWh for integrating more than 300 GW of VRE. Palchak et al. (2017) provides one of the most comprehensive assessments of VRE grid integration in India using an hourly unit-commitment and dispatch model with individual representation of each Indian state and the interstate transmission system. The study assessed the achievement of the 175 GW target by 2022, and found that reducing the technical minimum of coal-based plants from 70 to 40% would result in RE curtailment to reduce from about 3.7% to 0.76% by 2022. Likewise, coordinating dispatch at national level would lead to 4% annual savings in production costs. However, this study assessed the year 2022 and a level of VRE capacity by that year which now seems unachievable. In contrast, Palchak et al. (2019) used the same modelling framework to study the impact of integrating a 22% share of VRE in total generation by 2030. However, this study looked at a limited number of scenarios.

To address these limitations, this paper presents the results of a detailed modelling exercise using a unit commitment and economic dispatch (UCED) model to assess the least production cost scenario for integrating high shares of VRE in the Indian power system by 2030. A mixed integer linear programming (MILP) formulation was used with few modifications in the source code to adjust aspects relevant to represent the Indian power system. An open source modelling framework 'Python for Power Systems Analysis (PyPSA)' developed by Brown et al. (2017) was used. PyPSA has been used in a growing number of studies of power system planning and VRE integration (Hörsch & Calitz, 2017; Dedecca et al., 2017; Markus & Alexandre, 2017).

The paper is structured as follows. Section 2 provides a modelling approach and scenarios description. Section 3 elucidates modelling results with recommendations and Sect. 4 concludes the paper.

2 Modelling approach

2.1 PyPSA-India Model Description

PyPSA is a partial equilibrium model that can optimize both short-term operation and long-term investment in the electricity system as a linear problem using linear power flow equations. Short term operation optimization computes optimal generation of all generating units to meet the time varying load for a given snapshot. Since long term investment optimization has not been considered in this paper, build-up from current year 2019 to 2030 has not been assessed endogenously to the problem formulation.

The model minimises the total annual system costs as per Eq. 1.

$$\min_{\substack{g_{n,r,t},\\ h_{n,s,t},\\ suc_{n,r,t},\\ LS_{n,t}\\ sdt_{n,r,t}}} \left[\begin{array}{l} \sum_{n,r,t} w_t \cdot o_{n,r} \cdot g_{n,r,t} + \sum_{n,r,t} suc_{n,r,t} + \sum_{n,r,t} sdt_{n,r,t} + \sum_{n,s,t} w_t \cdot o_{n,s} \cdot \\ h_{n,s,t} + \sum_{n,r,t} w_t \cdot o_{n,ls} \cdot LS_{n,t} \end{array} \right] \quad (1)$$

The model consists of the capacities at each bus n for generation technologies r and storage technologies s, while $o_{n,r}$ and $o_{n,s}$ are the variable costs of generation technologies r and storage technologies s. The start-up cost and shut-down cost for generator technologies r connected to bus n and at time t are given as $suc_{n,r,t}$ and $sdt_{n,r,t}$ respectively. Unserved load at time t and bus n is given by $LS_{n,t}$ with a very high associated variable cost $o_{n,ls}$.

The dispatch of conventional generators $g_{n,r,t}$ is constrained by their capacity $G_{n,r}$ and time-dependent availabilities $\overline{g}_{n,r,t}$ and $\tilde{g}_{n,r,t}$, as per Eq. 2.

$$u_{n,r,t} \cdot \tilde{g}_{n,r,t} \cdot G_{n,r} \leq g_{n,r,t} \leq u_{n,r,t} \cdot \overline{g}_{n,r,t} \cdot G_{n,r} \, \forall \, n, r, t \quad (2)$$

Time-dependent availabilities $\overline{g}_{n,r,t}$ are used to model time series resource profiles for solar and wind. The binary variable $u_{n,r,t}$ is not applicable for generators that are not committable. For conventional generators such as coal and gas based generating units, $\overline{g}_{n,r,t}$ and $\tilde{g}_{n,r,t}$ are considered to be 1 and 0 respectively, while the binary variables are used to incorporate unit commitment constraints such as minimum and maximum generation levels of committable generators, as well as minimum up and down times for committable generators. The cost of generator start-ups prevent frequent generator starts and stops, while minimum up times and minimum down times constraints ensure that a given generator is on for at least a minimum number of time stamps (minimum up time) after start-up and off for at least a minimum number of time stamps (minimum down time) after shut down. These binary values help incorporate start-up and shut down costs within the objective function.

Limit on the maximum active power increase or decrease that thermal generating units are capable of from one snapshot to the next is captured by two parameters $rd_{n,r}$ and $ru_{n,r}$, the ramp down limit and the ramp up limit as percentage of rated generator capacity is elucidated in Eq. 3:

$$-rd_{n,r} \cdot G_{n,r} \leq \left(g_{n,r,t} - g_{n,r,t-1}\right) \leq ru_{n,r} \cdot G_{n,r} \, \forall \, n, r, t > 0 \quad (3)$$

Similarly, the dispatch of storage units $h_{n,s,t}$ for energy storage units, connected to bus n at time t is constrained by a similar equation to that for generators in Eq. 4, where $H_{n,s}$ is the maximum power capacity of energy storage s.

$$-H_{n,s} \leq h_{n,s,t} \leq H_{n,s} \quad \forall n, s, t \tag{4}$$

The energy levels $e_{n,s,t}$ in Eq. 5 for energy storage *s* and time *t* has to be within limits such that:

$$Min_{SOC} \cdot E_{n,s} \leq e_{n,s,t} \leq E_{n,s} \cdot 1 \quad \forall n, s, t \tag{5}$$

where Min_{SOC} is the minimum possible state of charge of energy storage s and $E_{n,s}$ is the energy capacity of storage s. The energy level $e_{n,s,t}$ at time t has to be constrained consisting of the energy level in the previous time stamp $e_{n,s,t-1}$, dispatch of storage units during charging $\lfloor h_{n,s,t} \rfloor^{+}$ and discharging $\lfloor h_{n,s,t} \rfloor^{-}$ and charging and discharging efficiency $(\eta_{n,s,+}, \eta_{n,s,-})$ as indicated in Eq. 6.

$$\begin{aligned} e_{n,s,t} = e_{n,s,t-1} + \left(Timestamp * \eta_{n,s,+} * \lfloor h_{n,s,t} \rfloor^{+}\right) - \\ \left(Timestamp * \eta_{n,s,-} \cdot \lfloor h_{n,s,t} \rfloor^{-}\right) \forall\ n, s, t \end{aligned} \tag{6}$$

Linearized power flow equations for AC networks (Ringkjøb et al., 2018) are used for the power flow constraints. This has proved useful in solving for optimal power flow (Brown et al., 2017; Hörsch et al., 2018).

The Kirchhoff formulation was used in this study to model power flow. The power balance equations are applicable for each node *n* and time *t*. This is assuming that the load is inelastic.

$$\sum_{r} g_{n,r,t} + \sum_{s} h_{n,s,t} + \sum_{l} \alpha_{l,n,t} \cdot f_{l,t} = d_{n,t} \forall n, t \tag{7}$$

Here the electrical load at bus n at time t is $d_{n,t}$ and the power flow on line joining to buses is $f_{l,t}$. The term $\alpha_{l,n,t}$ is used to incorporate the direction of the flow i.e. $\alpha_{l,n,t} = -1$ if line l starts at node n and $\alpha_{l,n,t} = 1$ otherwise. The power flow on any given line is also constrained by the line rating and equivalent reactance (through the power flow constraints).

2.2 Technical Constraints

Table 1 provides the baseline generator constraints used in this study, which were derived drawing on the technical literature (Agora Energiewende, 2017), similar

Table 1 Baseline generator constraints. (Source: Own depiction)

Constraint	Unit	Coal	Gas	Biomass and Waste	Hydro
Technical Minimum	% Nominal Power	55%	40%	30%	10%
Ramp rate up and down	% Nominal Power/ Hr	60%	100%	100%	100%
Minimum Up Time	Hrs	4	3	3	0
Minimum Down Time	Hrs	6	4	3	0
Start-up Costs	INR/MW	14,100	6690	14,100	0

production cost modelling exercises (D. Palchak et al., 2017), and operational data of Indian power plants (Central Electricity Authority, 2019). The model works on hourly resolution and hence ramping constraints are denominated in percent of nominal capacity per hour. The scenarios assessed in this study vary from the baseline constraints given in Table 1. More detail on scenario design is given in Sect. 2.3 below.

2.3 Scenario Description

As noted above, PyPSA-India was used to simulate power system operation with highly detailed representation of unit commitment and economic dispatch. Without substantial adjustments to model structure, combining detailed representation of unit commitment and new investment decisions would make the model problem computationally intractable (Palmintier & Webster, 2011). For this reason, scenarios are defined exogenous to the model for 2030, drawing on the available literature as described below. The scenarios analyzed in this paper have been designed across three different parameters, namely production capacities, transmission system, and power system flexibility.

2.4 Production capacities

This refers to the assumptions regarding future capacities of different generation technologies, such as coal, gas, hydro, nuclear, wind, and solar. The capacity assumptions are defined exogenously from the model, based on recent studies by the Central Electricity Authority. Two contrasting scenarios are analyzed in this study. First, the Baseline Capacities Scenario (indicated in the scenario name by the notation B) assumes a mix of coal and renewables by 2030, and reflects broadly the assumptions of the 2018 National Electricity Plan, developed by the Central Electricity Authority (2018a). In the second scenario, the High Renewable Energy Scenario (indicated in the scenario name by the notation H), has a higher level of renewable energy production capacity of 450 GW by 2030, reflecting the assumptions of the CEA's more recent capacity expansion study (Central Electricity Authority, 2020d). Table 2 depicts the scenarios. (Table 2).

2.4.1 Transmission system

Two contrasting transmission scenarios are developed. In the Unconstrained Transmission Scenario, the power transfer capacities of each interstate transmission line have been expanded sufficiently by 2030 such that power can flow around the country in an unconstrained manner. A corollary – but implicit – assumption here is that the electricity market 'infrastructure' is likewise developed by 2030 to allow seamless interstate scheduling and dispatch of power. In the Expanded Transmission Scenario, the transmission system has been expanded by 2030 in line with existing plans, such as the National Electricity Plan, such that there will still be some capacity constraints in power transfer (Central Electricity Authority, 2018b). This scenario reflects a more fragmented electricity

Table 2 Installed capacities in the two scenarios for the year 2030. (Source: Own depiction)

Technology source	Installed Capacity (GW)	
	Baseline scenario (B)	High RE Scenario (H)
Thermal	263	263
Nuclear	17	17
Large Hydro	74	74
Wind	129	169
Solar	189	229
Biomass and waste	23	23
Small Hydro	10	10
Total	**705**	**785**

Note: Thermal refers to coal, lignite, imported and domestic gas, and liquid fuel plants. Large hydro refers to dispatchable pondage and reservoir hydro and run-of-river hydro above 25 MW. Wind refers to only onshore wind

Table 3 Description of transmission scenarios. (Source: Own depiction)

Notation	Transmission Scenario	Description
E	Extended Transmission	Interstate transmission capacities extended to 2030 as per the National Electricity Plan
U	Unconstrained Transmission	Interstate transmission capacities extended such that there are no physical constraints on power transfer between states

market, where power transfer is constrained by some infrastructural bottlenecks. Table 3 describes the transmission scenarios.

2.4.2 Power system flexibility

This refers to the capacity of the power system to flexibly integrate VRE, through supply-side, demand-side, and storage flexibilities (transmission flexibility is dealt with previously). In particular, two aspects are studied. First, the impact of lower or higher technical minimum for coal-based power plants is assessed. State Coal fleet has currently inflexible technical minimum of 70%. In this regard a more flexible fleet is analyzed pertaining to its high contribution in coal capacity mix. Further, in a less optimistic scenario a low flexible thermal fleet is foreseen if retrofits would be undertaken slowly by 2030. This is a crucial parameter for the grid integration of VRE in India, as it allows the coal fleet to back down output when VRE is high (for example, at midday for solar) and ramp it up quickly when VRE output falls (for example, in the evening). Second, the impact of integrating battery storage in the power system by 2030 is foreseen. Table 4 provides a description of the flexibility scenarios.

2.4.3 Nomenclature of Scenarios

This paper follows a specific nomenclature to define various scenarios under this study. The name of the scenario consists of 4 letters. The first letter defines the capacity type, the second letter defines the transmission network system, and the remaining two letters define the power system flexibility type. For example the nomenclature HEHT indicates High Renewables, Expanded Transmission, High Thermal Flexibility scenario. After taking all the above parameters of production capacities, transmission system, and power system flexibility, seven scenarios have been prepared. Table 5 provides an overview of the seven unique scenarios analyzed in this paper. BEBF and BELT scenarios were selected to assess if a fairly expanded transmission and a moderate to limited coal flexibility

Table 4 Description of power system flexibility scenarios. (Source: Own depiction)

Notation	Flexibility Type	Description
BF	Baseline flexibility	All coal-fired stations can achieve a technical minimum of 55%
LT	Low thermal flexibility	Centrally owned and privately owned coal-fired stations can achieve a technical minimum of 55%. State owned coal-fired stations can only achieve a technical minimum of 65%
HT	High thermal flexibility	Centrally owned and privately owned coal-fired stations can achieve a 40% technical minimum from current 55%. State owned plants can achieve a 55% technical minimum from current 70%
BS	High battery storage flexibility	All coal-fired stations can achieve a technical minimum of 55%, additional battery capacity of 120 GWh/60 GW

Table 5 Final scenarios analysed in this paper. (Source: Own depiction)

Capacity Scenario	Transmission Scenario	Flexibility Scenario	Notation
Baseline Capacity Scenario	Expanded Transmission Scenario	Baseline Flexibility Scenario	BEBF
		Low Thermal Flexibility Scenario	BELT
	Unconstrained Transmission Scenario	Baseline Flexibility Scenario	BUBF
High Renewable Energy Scenario	Expanded Transmission Scenario	Baseline Flexibility Scenario	HEBF
		Battery Storage Flexibility Scenario	HEBS
		High Thermal Flexibility Scenario	HEHT
	Unconstrained Transmission Scenario	Baseline Flexibility Scenario	HUB

could manage the fair transition to a renewable energy trajectory by mid-term. Similarly with BUBF, an assessment with baseline flexibility and unrestricted transmission corridor was carrier out to assess maximum transfer capacities between the Inter-state transmission corridors. In HRES scenario family, a high degree of flexibility is assessed through HEBS, HEHT and HUB. This was predominantly identified to investigate the integration of battery storage with expected augmentation of transmission corridor and a high level of thermal flexibility across all thermal fleets.

3 Aggregate Scenario Results

3.1 Results Summary

This section provides a brief overview of the key results of the scenarios analyzed (Table 6). The results include key indicators such as unserved load, wind and solar curtailment and plant load factor (PLF). Note that each of the scenarios analyzed has same energy requirement (2260 TWh) and peak load (304 GW).

Across scenarios, unserved load was nearly zero. Some of the variance in the small amounts of unserved load was driven by stochastic generator outages rather than the dynamics of the scenarios themselves. For example, the Baseline Capacities, Expanded Transmission, Low Thermal Flexibility scenario (BELT) had lower unserved load than the Baseline Capacities, Unconstrained Transmission, Baseline Flexibility (BUBF), despite having less transmission and less thermal flexibility. This also suggests that the capacities envisaged in both capacity scenarios are broadly robust to a range of power system flexibility outcomes.

Table 6 Key scenario results. (Source: Own depiction)

Scenario Name	Unserved Load	Solar Curtailment	Wind Curtailment	Gas PLF	Hydro PLF	Coal PLF
	MWh	%	%	%	%	%
BEBF	0.00	0.41	0.27	16.75	36.15	65.48
BELT	2.00	0.53	0.34	16.70	36.04	65.55
BUBF	38.74	0.34	0.01	16.66	36.03	65.55
HEBF	39.19	2.73	1.29	16.47	35.32	58.77
HEBS	0.00	0.10	0.08	16.55	36.05	57.77
HEHT	21.16	1.16	0.73	16.62	35.68	58.34
HUBF	214.00	3.00	0.92	16.41	35.06	58.92

3.2 Curtailment

Annual VRE curtailment ranges from 0.2% in the High Renewables, Expanded Transmission, Battery Storage Flexibility scenario (HEBS) to 4% in High Renewables, Expanded Transmission, Baseline Flexibility scenario (HEBF). The high curtailment in the HEBF scenario is mostly due to the operational constraints of dispatchable sources during the times of excess solar injection in mid-day and excess wind injection during monsoon. The similar curtailment issues in HRES, Transmission Flexibility and low curtailment in HRES, Storage Flexibility scenario confirms that the curtailment is largely driven by inadequate additional flexibility options rather than the transmission availability.

Figure 1 shows monthly solar and wind curtailment by scenario. Solar curtailment is more intense in the months of March, April, May, June. This is because, particularly in April, the evening peak load requirement is high and the availability of wind and hydro resources are relatively low, as it is before to the start of monsoon. This leaves the daily ramping burden to coal. Given the inadequate flexibility of coal to shut down at mid-day and turn on to support evening peak, solar has to curtail to make the coal available on standby and to contribute to peak load. For wind, the curtailment concentrates in monsoon where its output is

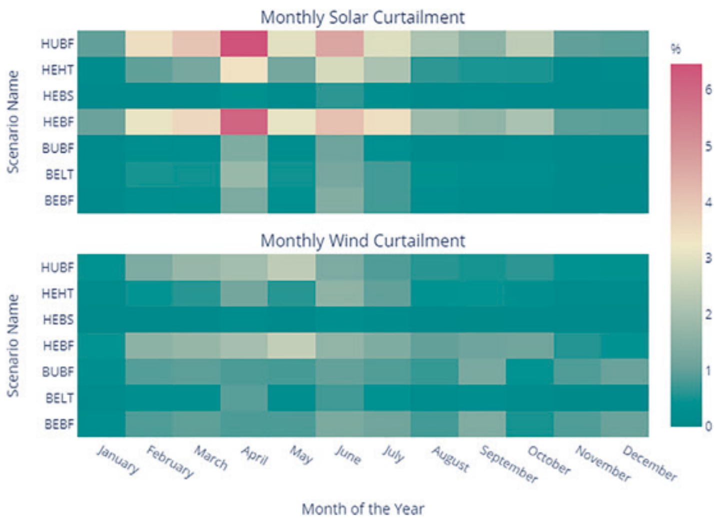

Fig. 1 Monthly wind and solar curtailment by scenario. (Source: Own depiction)

highest. Adding the hydro output which is high during the monsoon forces coal to shut down. As the sufficient coal capacity is required to meet the variation in net-load, the model is curtailing wind output. However, the peak monthly curtailment is low compared to solar with maximum value of 2.5%, occurring in the month of July in the High Renewable, Expanded Transmission, and Baseline Flexibility scenario. Curtailment is substantially reduced in the High Renewable, Expanded Transmission, Battery Storage Flexibility Scenario (HEBS) and the High Renewables, Expanded Transmission, High Thermal Flexibility Scenario (HEHT). This is due to the ability of storage to absorb high solar injection and contribute to evening peak (HEBS), or the lower technical minimum facilitating higher solar injection (HEHT). Curtailment is not substantially reduced in the High Renewables, Unlimited Transmission, Baseline Flexibility Scenario, indicating that it is the aggregate flexibility of the dispatchable fleet which determines curtailment, not localized transmission bottlenecks.

3.3 Plant Load Factor

The coal fleet PLF varies marginally in Baseline Capacity scenarios between 68.48% and 68.55%. In High Renewable scenarios, this declines significantly to the range of 57.77% and 58.92% in Transmission Flex and Storage Flex respectively. In the last four fiscal years, the coal PLF averaged 59%, indicating that if renewables and coal capacity and demand evolve as per the Baseline Capacity scenarios in this paper, the current situation of low coal PLF will continue. The hydro PLF is relatively stable throughout all the scenarios, reflective of its zero marginal costs and high operating flexibility which helps in balancing VRE whenever required. Hydro is thus constrained by energy availability determined by the seasonal flow of India's river systems, not marginal cost. The gas PLF is consistently low at around 17% across all scenarios due to the limited availability of cheap domestic gas, and high cost of imported gas.

3.4 System Costs

This section summarises the implication of scenarios in terms of total system generation cost, which is further broken down to fixed and variable costs. Here, the per unit system-wide fixed cost in the High Renewable scenarios is higher than in the Baseline Capacity scenarios as the total installed capacity is substantially higher. In the HEBF scenario, the system–wide fixed cost increases to

2.63 INR/KWh compared to the HEBF scenario with 2.37 INR/KWh. Further in the HEBS scenario, this again increases to 2.77 INR/KWh, driven by additional investments in battery storage facilities. However, High Renewable scenarios result in lower variable cost compared to Baseline Capacity scenarios due to the large share of zero marginal cost renewables in the system. In the BEBF scenario per unit variable cost is higher by 0.23 INR/KWh than in HEBF scenario. This gap further raises to 0.29 INR/KWh in HEBS scenario, as storage outcompetes high marginal cost sources of generation and reduces the need for expensive starts and stops. The total system-wide generation costs in BEBF scenario is 4.8 INR/kWh and 4.83 INR/kWh in the HEBF scenario. The total system cost is highest in the HEBS scenario at 4.92 INR/kWh. In effect, the total system-wide generation costs between two broad capacity scenarios are almost identical, and certainly within the uncertainty margin of these calculations (Fig. 2).

3.5 Operation of the Coal Fleet

With an increasing VRE share in the generation mix, coal fleet contribution is reducing. In base line and high RE scenarios generation share of coal power plants and annual PLFs are varying from 57% to 50% and 66% to 58%

Fig. 2 System generation costs by scenario. (Source: Own Depiction)

respectively. Impacts on plant performance due to integration of VRE will be discussed in subsequent sections in detail.

3.5.1 Unit-Wise PLF by Scenario

In the Baseline Capacity scenarios, the coal fleet PLF is around 66%. It increases from today's levels of 58%-60% (56% in fiscal year 2019–2020), because load grows faster than the addition of new coal-based generating resources. By contrast, in the High Renewables scenario the coal fleet PLF remains in the order of 57%–58%. Figure 3 shows the unit-wise distribution of the coal fleet PLF in scenarios analysed in this paper. An important conclusion emerging from Fig. 3 is the large variation on annual PLF across the coal fleet. On one end there are a number of plants operating at close to 85% annual PLF, notably pit head coal plants with very low variable costs, and on the other end of the extreme, there is a group of plants, which, regardless of the scenario, never start. The relationship between unit-wise PLF and marginal costs is analysed further in Fig. 4 below.

Another important conclusion relates to the impact of the different flexibility scenarios on the coal fleet PLF. From Fig. 3 it can be seen that the spread of unit PLF is higher in High Renewables scenarios, particularly in the HEBS scenario. In this scenario, the model substitutes discharge for the high marginal cost coal units that are used to meet peak demand in other scenarios. In the HEBS scenario, the median coal plant PLF is four percentage points lower than the median coal

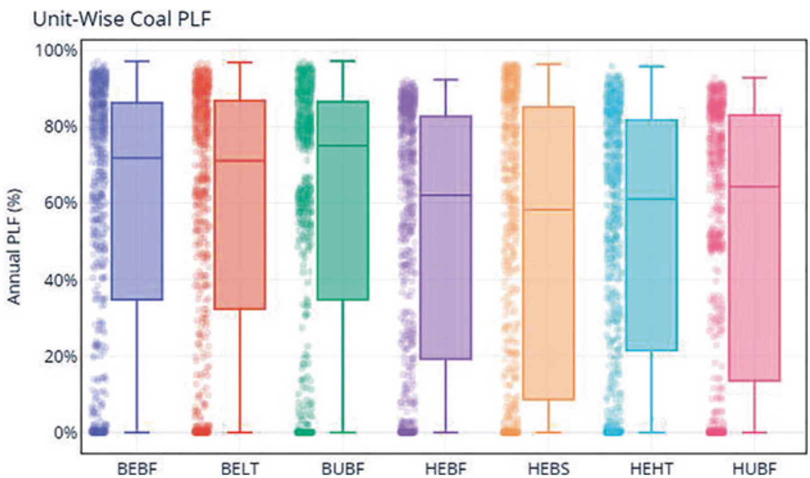

Fig. 3 Unit-wise coal PLF by scenario. (Source: Own Depiction)

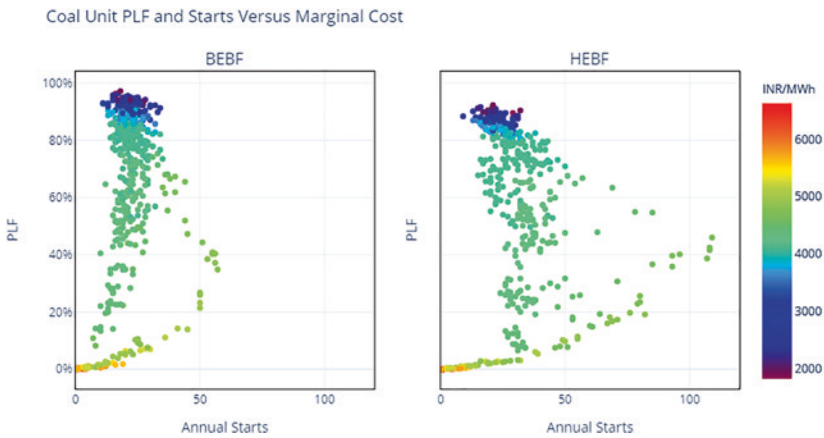

Fig. 4 Unit-wise PLF and starts as a function of marginal costs. (Source: Own Depiction)

plant PLF in the HEBF scenario without storage, while the PLF of the bottom quartile of plants is a full ten percentage points lower in the HEBS compared to the HEBF scenario. This result shows that there is significant scope for battery storage to compete against the higher marginal cost coal plants.

3.5.2 Unit-Wise Coal PLF and Unit Starts Versus Marginal Cost

Figure 4 shows unit-wise coal PLF on the y-axis versus unit-wise annual starts on the x-axis. Marker colour represents the unit-wise marginal cost. Two scenarios are selected for representation, the BEBF and HEBF scenarios. As expected, PLF is inversely correlated with marginal cost. As the level of renewables increases between the BEBF and HEBF scenarios, unit-wise PLFs are reduced, and the number of unit-wise annual starts is increased substantially. The growth in annual starts is particularly noticeable for the plants at the right end of the distribution, with annual starts for the most aggressively cycled plants doubling between the scenarios.

3.5.3 Two-Shift Operation of the Coal Fleet

Two-shifting refers to coal unit operation in which the unit is switched on and off again within a short period of time, and on a regular basis. Due to operational constraints of technical minimum and minimum shut down time, at times of high evening peak demand some coal plants are required to operate in two-shifting mode, even if some solar is curtailed and considering high start-up costs. For analysing the two-shift operation by coal stations, for the purposes of this paper two shifting is defined as four or more unit starts within a week.

Figure 5 displays a heatmap of the coal unit capacities on two-shifting operation per scenario across the months of year. According to the dispatch results, about 3–4 GW of coal capacity runs on two shifting operation throughout the year in Baseline Capacity scenarios. This capacity will increase to a maximum of 20 GW, with a range between 5–20 GW for several months of the year, in the High Renewable capacity scenarios particularly in March and April. In the HELT scenario, the higher technical minimum of state-owned plants (65%) forces more plants to operate on two-shifting in order to accommodate the injection of VRE at midday. Similarly, the improvement of thermal flexibility in the HEHT scenario decreases the requirement for two-shifting. The lower technical minimum achievable by central and IPP plants allows the coal fleet to turn down to a lower level to accommodate renewables injection at midday, without the necessity of plants operating on two-shifting.

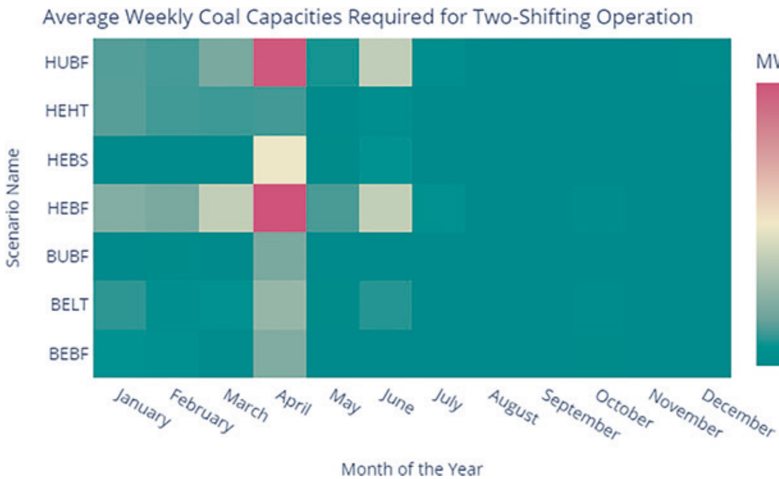

Fig. 5 Monthly coal capacity on two-shift operation by scenario. (Source: Own Depiction)

3.6 Insights in the Operation of Gas and Hydro

The hydro fleet offers low cost and substantial supply side flexibility by quick ramp up and down support in order to cater peak power demand requirements (in morning and evening). Considering this advantage, hydro can ramp down quickly during midday to accommodate more solar in the grid. However, the power output varies based on monsoon and non-monsoon seasons as seen in Fig. 6.Therefore, ensuring a high degree of flexibility and coordinated dispatch from India's hydro fleet is critical to the integration of high levels of VRE.

The gas fleet also offers higher operational flexibility as compared to coal. However, the dispatch of imported gas is limited by its high marginal cost (considered delivered price of $10-$12/mmbtu). The results suggest that the non-competitiveness of imported gas based power with other existing options makes it an unattractive option to dispatch in an hourly resolution. However, in a sub-hourly (15 min) baseline capacity scenario, the result suggests the role of imported natural gas based fleet as a peaking power option as seen in Fig. 7 due to the stringency of ramping resources in the system.

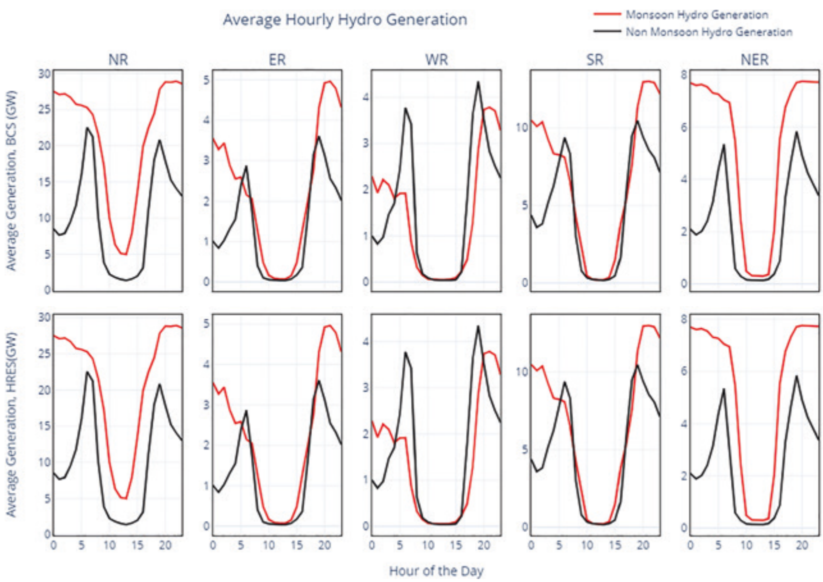

Fig. 6 Average hourly region-wise hydro generation. (Source: Own Depiction)

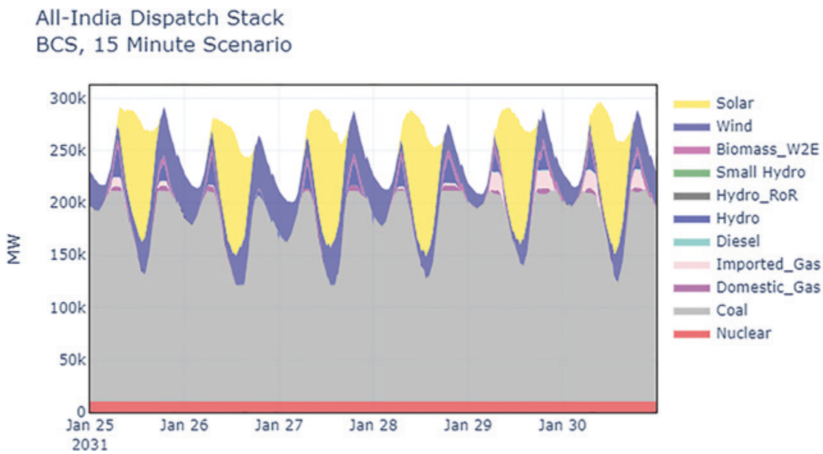

Fig. 7 All-India dispatch stack, BCS, 15-min scenario. (Source: Own Depiction)

3.7 Role of Battery Storage

In the HEBS Scenario mentioned in Sect. 3, the model includes 60 GW, 120 GWh of battery storage. Here the sizing and allocation of Battery capacities is examined through state-level solar and wind curtailment in the HEBF and BEBF scenarios in form of the curtailment duration curves. Accordingly looking at steep curtailment curves, the size of battery facilities is calculated to ensure sufficient operating hours in the year and to make each battery unit a worthwhile investment. Given the steepness of the curtailment duration curves in the HEBF and BEBF scenarios, a power to energy ratio of 2 was most effective at reducing curtailment while minimizing the investment in storage.

Figure 8 below shows the average hourly state of charge (SoC) of the battery facilities in the power system, by hour of the day and month of the year. The battery facilities tend to begin the day with a zero SoC, indicating that they have discharged the previous day and have not charged in the final hours of the day. SoC tends to increase towards the midday, as the batteries assist with the integration of solar energy into the grid and reduce the need for solar curtailment, or coal plant cycling. By evening the SoC of the battery facilities reduce, as they discharge power to provide peak support and thus reduce the need for committed coal generation to be online to meet the evening peak.

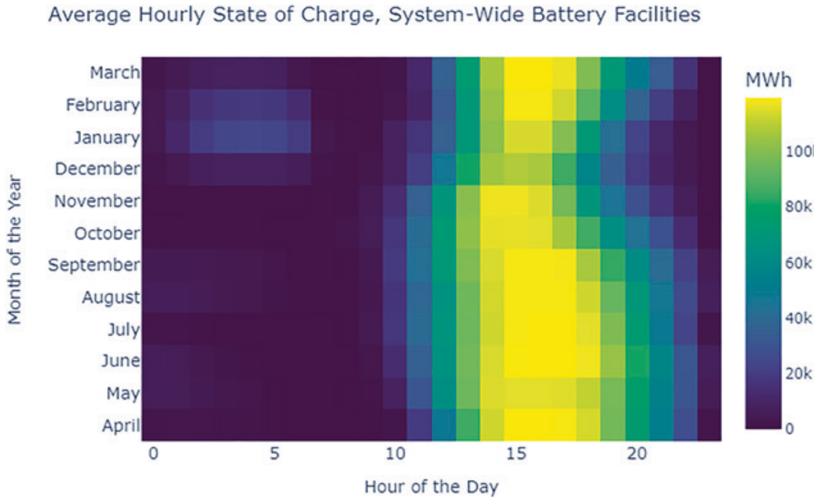

Fig. 8 Average hourly state of charge. (Source: Own Depiction)

4 Conclusion

The aforementioned analysis based on the unit commitment and economic dispatch model indicates a clear pathway to attain a moderate to high level of renewable energy grid integration in India by 2030. This pathway is subject to a robust policy and regulatory interventions at national and sub-national level. It envisages a massive change in supply and demand side interventions to impart operational flexibility and demand shift to manage the peak demand.

Power System Flexibility: The Analysis suggests that substantial flexibility will come from the coal fleet. The BCS, Low Thermal Flexibility scenario showed a substantial increase in the risks of curtailment with decreasing thermal plant flexibility. Increasing the transparency around state-level scheduling and dispatch, and plant performance, can increase the understanding of how the burden of supply-side flexibility is being shared among different players in the system. The degree of flexibility required from the coal fleet is potentially challenging to meet, and perhaps the real advantage of battery storage in the next few years will be in reducing the operational stress on the power system. The analysis presented here suggests that an aggregate energy capacity of about 120 GWh, with a relatively low power to energy ratio of 2, would have benefits in terms of reducing curtailment and the aggressive cycling required of the coal system. The analysis also suggests that the requirement for storage would really begin to value more in HRES. In the BCS, curtailment and metrics such as maximum hourly ramp rate or capacity required for two-shifting appear more manageable. This suggests that the development of battery capacities should be seen as a mid-term investment, preparing the power system for greater shares of VRE thereafter.

Policy for Planning: The electricity sector is driven by the requirement to balance supply and demand. The sector encompasses a very long value chain, from generation, transmission, distribution, and consumption, along which different players respond to different incentives and physical constraints. The analysis shows that the median trade intensity (the sum of imports and exports over the sum of imports, exports, and load) among Indian states is almost 50%, implying a high level of interstate power transfer and coordinated scheduling and dispatch. Thus, Planning should be seen as a mechanism for coordinating the expectations of players across the whole value chain.

Future work in the context could be focused towards a more robust power system modelling with scenarios detailing uncertainties due to COVID shocks and changing demand. An ever changing economic growth and disruptive technologies have changed the way of generating electricity to end consumption. Hence, future models need to be elaborate on limitations of deterministic approaches towards power system planning. Although an operations model can detail the level on RE integration, the actual essence of future power system planning can be enhanced by integrated capacity expansion and unit commitment models working in tandem.

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