MAHARASHTRA'S ELECTRICITY SUPPLY MIX BY 2030

Cost and reliability insights from a GridPath production cost modelling exercise.

Prayas (Energy Group)

Energy Modelling Series

Maharashtra’s Electricity Supply Mix by 2030

Cost and Reliability Insights from a GridPath Production Cost Modelling Exercise

Prayas (Energy Group), Pune

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Summary

The electricity sector is undergoing several changes, key among them is the increasing share of renewables driven by low and long-term fixed prices and lower socio-environmental impacts. Simultaneously, coal-based capacity addition is under scrutiny due to its environmental impacts and diminishing generation cost competitiveness. The variable nature of renewable generation coupled with uncertainties in demand growth and load profiles necessitate the use of sophisticated and analytically robust approaches to power procurement planning.

Around the world, production cost simulation and capacity expansion optimisation tools are increasingly being used by utilities, regulators and system operators to inform supply strategies for meeting demand reliably and cost-optimally. Commercial tools, though popular and feature-rich, are unaffordable to a wide range of stakeholders in India. In addition, the black box nature of these closed-source tools makes them unsuitable for public consultation processes such as regulatory proceedings.

In this study, a production cost simulation model has been set up for the state of Maharashtra in GridPath—an open source, feature-rich and extensible power sector modelling platform. We use this model to investigate the feasibility of 50% renewable penetration in energy terms in the fiscal year 2029–30 under different coal-based capacity scenarios. Further, we compare these scenarios to a reference scenario with 30% of the demand being met through renewables.

A summary of the findings follows:

- Without considering transmission constraints, it is possible to meet demand in 2030 without any 'net addition to coal fleet' and with 50% energy contribution from RE, while coal plants are operating within currently acceptable technical limits (technical minimum, ramp rates, etc.). It should be noted that the high demand growth rate considered for this analysis is unlikely to materialise, which further strengthens this finding.

- It is possible to meet system demand reliably and cost-effectively in 2030 while retiring coal-based power generation capacity that is older than 40 years. It is also possible to meet system demand while retiring capacity older than 30 years, though this leads to greater short-term power procurement and intermittent stress conditions in the operation of the system. To ensure reliability, maintenance events of the remaining capacity need to be planned carefully, and a nimble approach needs to be adopted to adjust for unexpected changes in demand and renewable generation. This approach may involve reviewing maintenance plans on a month-ahead or week-ahead basis and exploring opportunistic short-term power purchase options. Better forecasting of demand and RE generation will contribute crucial inputs to this process.

- Availability and flexible operability of the coal fleet such as intra-day ramping and part load operation are important for reliability across all scenarios. Coal plants are assumed to be available for 85% of the time in this analysis. In the past, coal power plants have not been available to generate when needed at times, due to outages or fuel unavailability. If the availability reduces, reliability of power supply is severely affected even with a lower share of renewables in the system. With an increased penetration of renewables, coal plant availability becomes all the more critical.

- Shifting of agricultural load to day times through tail-end solar plants attached to agriculture feeders significantly helps in absorbing solar generation. Ensuring near universal coverage of the solar agriculture feeder programme, in addition to improving quality of power supply to farmers, also greatly aids the integration of cost-effective renewable electricity generation.

- Agile and innovative power procurement strategies will yield full benefits of cost-competitive renewable energy sources without compromising the reliability of supply. Such strategies would include short-term seasonal procurement, procuring 'peak energy' from exchanges or 'peaking capacity' such as open cycle gas, and importantly, grid-scale battery storage systems (BESS). As our analysis demonstrates, on a per-unit, standalone basis, though the cost of such resources may be higher than conventional base-load resources or RE resources, they lower the overall system cost by aiding a greater uptake of cheaper RE sources.

Given these findings, we suggest that the following policy and regulatory initiatives be undertaken in addition to expanding ongoing initiatives such as solarisation of agriculture feeders and renewable purchase obligations:

- The time-of-day tariff regime in the state should be expanded to cover more consumers, and the peak tariff slot should eventually be adjusted automatically according to the demand-supply balance. In addition, seasonal tariffs need to be introduced.

- A more rigorous and structured RE procurement approach should be adopted, taking into account parameters such as the location and generation profile in assessing the value to the system, rather than just a least-cost approach.

- Grid-scale battery storage should be procured on a pilot basis in order to better understand the value to the grid.

- Given that a 50% RE scenario is both feasible and desirable by 2030, intra-state transmission should be planned to prepare for a high RE scenario. This is especially important given the long gestation times for transmission strengthening.

We compared the results from the GridPath model to those from a similar model set up using a popular, commercial market simulation platform called PLEXOS. We found that the results are comparable between the two models and similar insights are drawn from both exercises, thus increasing confidence in the models and findings. The Maharashtra GridPath model is publicly available for download at https://github.com/prayas-energy/gridpath-mh.

Finally, there is a fair degree of uncertainty in future cost trajectories, demand growth, changes in the demand profile, weather conditions, and the feasibility of capacity addition. Carefully designed scenario analysis using sophisticated models can aid more rational decisions given the uncertainty. Such exercises should be conducted in a transparent manner with adequate public consultation. Given that modelling tools are increasingly becoming accessible, a diverse set of stakeholders are likely to engage in a public process, leading to more informed decisions. As solar, wind and battery storage systems are more modular in nature, and have shorter gestation periods, capacity addition decisions involving these technologies can be made closer to when such capacity is needed (that is, 3–4 years in advance). Thus, there is a need for iterative and periodic analyses to adapt to the changes unfolding in the sector.

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1 The context

1.1 Challenges in the Indian power sector

Over several decades, distribution companies (DISCOMs) in India have faced chronic problems of financial viability, poor planning, high cost of supply, inadequate access, poor supply quality and non-competitive tariffs for large consumers. A number of initiatives were undertaken to address these issues, but only with limited success. A large addition of base load capacity has resulted in a sustained surplus power situation in many states. (PEG, 2018)

The situation is not very different in the state of Maharashtra. The state-owned distribution utility, the Maharashtra State Electricity Distribution Company Limited (MSEDCL), serves the state of Maharashtra except the Mumbai area. The average cost of supply has been steadily rising at an average rate of approximately 4% each year, to reach 7.9 Rs/kWh in FY19 (PEG, 2021). The burden on cross-subsidising commercial and industrial consumers is growing, with average tariffs including fixed charges in the range of 9–10 Rs/kWh (MERC, 2020).

While new coal capacity prices are in the range of 4–5 Rs/kWh and rising each year, wind and solar PV levelised costs are in the range of 2.5–3 Rs/kWh and fixed for a period of 25 years. However, wind and solar PV are characterised by variability, thus increasing the need for balancing sources. Battery storage prices are falling rapidly, making them a potential cost-effective option for managing variability. Thus, alternative supply options are becoming increasingly cost-competitive, leading to rising open access and captive consumption. (PEG, 2018)

With commercial and industrial consumers migrating to open access and captive options, the MSEDCL is unable to rely on cross subsidies from such consumers to meet the demand of small residential and agricultural consumers. Migration of sales is leading to uncertainty in the demand to be met by the distribution utility. These varied dynamics, along with the uncertainty regarding future trends, have added to the complexity of power purchase planning for the utility. (PEG, 2021)

1.2 Critical importance of power procurement planning

Since power purchase costs account for about 75% of the annual revenue requirement (ARR) of the distribution utility (MERC, 2020), power procurement planning and strategy is of critical importance in order to address the challenges mentioned above. The planning process must take into account the following considerations:

- The cost of marginal power procurement could be less than the average cost of contracted capacity.
- The focus should switch from a baseload-based approach to a variable renewables-based approach. This implies recognising variability and valuing flexibility in the system.
- A more robust approach with higher temporal granularity is needed, which in turn requires more sophisticated tools.
- Renewable projects require shorter gestation periods and are modular compared to coal-based generation projects. Thus, power procurement decisions can happen at more frequent intervals in order to adapt to evolving changes with respect to demand growth, demand profile, technology and generation cost.

- It is advantageous to shift flexible loads within the day to match solar generation, since it would be the cheapest source of power.
- Electricity can be stored diurnally with increasing ease and affordability.

As a result of the slow-down in demand coupled with the excess baseload capacity, as well as owing to renewable purchase obligation targets (e.g., 25% RPO by 2025 in Maharashtra), there is a growing consensus among policy makers in various states that new coal-based capacity should not be added (PTI, 2021) (Roy, 2020) (Rathi & Singh, 2019) (Express News Service, 2019). This was suggested by the union power minister as well in a recent interview (Kumar, 2020).

The extent of renewable energy that can be absorbed by the power system without adversely impacting reliability and overall costs, and the role of coal in facilitating this integration, are important aspects that should be analysed to inform the power procurement strategies of the DISCOMs. Specifically, in the case of Maharashtra, the following aspects need to be better understood:

- Can MSEDCL demand in 2030 be served without any net coal capacity addition?
- What are the reliability and cost implications of an MSEDCL system with a high share of renewables by 2030?
- What are the implications of retiring some of the aging coal power plants contracted by MSEDCL?

1.3 Increasing complexity in power system planning

Traditionally, baseload capacity addition played an important role in power procurement planning, which involved a rule-of-thumb and intuition based approach to ensure that adequate capacity was available to meet projected peak load and annual energy requirements. Such an approach is inadequate in the situation of an increasing share of intermittent renewables and the high uncertainty in future demand and technology trends. In particular, the following aspects must be dealt with during power procurement planning:

- Social and environmental imperatives driving a shift towards clean energy policies.
- Availability of cheap, near-zero variable cost generation from solar and wind characterised by intermittency and temporal variability which will increase the need for flexible resources.
- Open access consumption, distributed generation collocated with load, the advent of prosumers and the prospect of peer-to-peer trading (IRENA, 2020) (Powerledger, 2021), leading to uncertainty in demand to be served by the utility.
- Increasing penetration of the electricity market and the introduction of new market products (RTM, G-TAM and G-DAM in future) to address various bottlenecks in the system, which provide alternative avenues for need-based power procurement.
- Growing viability of battery storage systems and their role in diurnal balancing.
- Electrification of sectors such as transport and industry resulting in uncertainty in load shapes.
- Demand-side measures to provide balancing and flexibility support to the system.

Given these considerations in the context of a changing sector, planners and regulators need to employ sophisticated models that can provide clarity on the complex challenges facing the sector.

2 Power system modelling tools

A variety of models are available for various stages of the planning cycle, from identifying optimal resource addition to simulating dispatch to optimal power flow and stability analysis (Boyd, 2016). These tools are now accessible in terms of cost, usability and computing requirements.

Capacity expansion models help in identifying optimal investments in generation, storage and transmission resources from a set of candidate capacities. Total (i.e., fixed and variable) costs are minimised over a period of several years, even decades. The models can be set up to take into account technical, policy, feasibility and environmental constraints, although the extent of constraints taken into account varies from model to model. Due to the size of the problem, capacity expansion models are typically set up with simplified specification of temporal granularity as well as generation, storage and transmission resources. The optimal generation capacity mix study for 2029–30 by the Central Electricity Authority is based on a capacity expansion model (CEA, 2020).

Production cost simulation models are used to simulate grid operation (i.e., unit commitment and dispatch) while minimising system costs given exogenously specified generation, storage and transmission resources. The simulation is set up to adhere to operational constraints such as technical minimum, start-up trajectories and costs, ramp rates and minimum up/down times. These models are typically run for a period of a year, although the duration is flexible and can be run for a few days or a few years depending on the analysis at hand. These models are used to assess the impact of various capacity mix strategies on reliability, system operation and operating costs. The Security Constrained Economic Dispatch (SCED) pilot conducted by POSOCO to minimise production costs of inter-state generating stations is implemented using an in-house production cost simulation model (POSOCO, 2020).

Load flow models are used to estimate voltages, currents and power flows through a steady state analysis of the system, and to determine optimal power flow to minimise costs. The generation and load conditions are specified for the time at which the power flow is simulated. In addition, **transient stability models** are used to examine the system response to a contingency such as a generator or transmission line outage.

These are typically run in the order specified. That is, capacity expansion models are run to determine optimal resource addition. These resources are exogenously specified in the production cost simulation to examine reliability and system operation. The specific times of interest identified from the production cost simulation are then simulated in the load flow and the transient stability models to assess bottlenecks in the transmission system and the impact of contingencies on stability.

2.1 GridPath

GridPath is a versatile simulation and optimisation platform for power system planning and operations that is useful for production cost simulation, capacity expansion and resource adequacy studies. The definition of the temporal span and resolution is flexible, and the temporal granularity, optimisation steps and balancing periods can be customised for each model instance. In addition, GridPath supports flexible specification of representative periods to simplify the size and complexity of the problem. GridPath's architecture is modular and easily scalable to adapt to new modelling requirements.

In the production cost simulation mode, detailed operations of the specified power system are simulated over a short period, e.g., a year, while minimising the system operation cost. The simulation of unit commitment and economic dispatch of generation units can be set up to run multiple stages, e.g., on a day-ahead, hour-ahead and real-time basis, with inputs such as demand and generation profiles and outages varying across these stages. Generator operations such as ramp rates, heat-rate curves, minimum up/down times and start-up trajectories, and transmission operations such as DC power flow are simulated at high fidelity, along with simplified formulations and the ability to relax some of the constraints at a penalty. Spin-up and look-ahead functionalities are provided to increase the hindsight and foresight within the optimisation step.

In the capacity expansion mode, the platform can be set up to evaluate investments in new infrastructure over a longer period of time, say 5 years or more. To limit the size of the problem, lower temporal resolution can be specified, and system operations can be modelled in a simplified manner along with aggregated representation of generation and transmission resources. Reliability requirements such as planning the reserve margin or local capacity requirements can be specified.

More information about GridPath can be found at https://www.gridpath.io. GridPath is available for download at https://github.com/blue-marble/gridpath, along with detailed documentation.

3 Modelling approach

The Maharashtra state utility (MSEDCL) system is modelled using the GridPath platform. The MSEDCL system covers the entire state of Maharashtra except Mumbai. MSEDCL's power system is the largest in India, accounting for roughly 10% of the national demand.

The following questions are sought to be analysed using the model:

- Can MSEDCL demand in 2030 be served without any net coal capacity addition?
- What are the reliability and cost implications of an MSEDCL system with a high share of renewables by 2030?
- What are the implications of retiring some of the aging coal power plants contracted by MSEDCL?
- How do the results from the GridPath model compare with PLEXOS—a popular, commercial market simulation platform?

The policy/regulatory instruments considered in the model are limited to decisions that can be taken at the state level, with less dependence on interstate and central initiatives or regional/national level optimisation. Only investments within the state domain are considered.

Conservative assumptions with respect to input costs and operational constraints are considered to account for uncertainties in the pace of technological change as well as the policy and regulatory environment. Slightly higher costs than expected are considered for RE generation and battery storage. Coal-based plants are considered to operate according to the current regulatory norms for technical minimum and ramp rates (MERC, 2020), with slightly higher ramp rates for central generating stations. Diffused demand side measures such as demand response have not been considered.

Given the possibility of sales migration away from the utility, the utility demand growth rate is likely to be subdued in the coming years. Yet, aggressive demand growth rate was considered for this analysis in order to understand the feasibility of reliably meeting such demand without net coal capacity addition.

Transmission is not modelled. Hence, it is assumed that the transmission system will be augmented as needed by 2030.

The model is set up as a production cost simulation, i.e., generation and storage capacities are input exogenously to the model. Scenarios are defined with the intent of assessing the appropriateness of a 'high' RE scenario, rather than finding the 'maximum' amount of RE that can be absorbed by the system.

The exercise is focussed on gleaning high level insights about system operation, understanding the importance of various inputs and assumptions, and identifying the policy and regulatory approaches needed for a high renewables scenario.

The following parameters have been considered for the analysis:

- Reliability: shortage quantum and profile
- System operation in stress hours and months
- Operation of the thermal fleet: plant loading factors, part-load operation, starts and ramp requirements
- Curtailment of renewables
- System costs: variable costs, start costs etc.; and total costs: including fixed costs

Year-ahead, perfect foresight of the demand and variable generation profiles is assumed. This is acceptable given the questions we set out to analyse, listed above. The modelling approach considered here is relevant for medium to long-term power procurement planning where decisions need to be taken several years in advance. Such exercises need to be repeated every couple of years or so to incorporate changes in the sector. Once the model is set up and a methodology adopted, undertaking such repeated exercises is not an onerous task.

The model is set up in a way similar to that in an earlier study by the authors using the commercial power system modelling platform, PLEXOS (PEG, 2019) (Dukkipati, Dixit, Gambhir, & Chitnis, 2019), with some minor differences in input assumptions and definition of scenarios. The earlier PLEXOS model is modified with the same inputs as the GridPath model, and the results from both these models are compared. The versions of these platforms used for this analysis are version 0.8.2 of GridPath and version 7.500R04 of PLEXOS. The commercial solver CPLEX (version 12.8.0.0) was used with both platforms.

4 Modelling the MSEDCL power system

4.1 Model setup

The base year for the model is 2017–18 (or FY18), i.e., input data such as demand, generation capacity, and demand and generation profiles are taken from FY18. The year 2029–30 (henceforth denoted as FY30) is modelled. As indicated earlier, it is a single-node, copper plate model, i.e., transmission is not modelled. Contracted capacity from out-of-state is adjusted to account for interstate transmission losses. Table 4.1 refers to the technology wise capacity contracted in MW by MSEDCL in FY18.

Table 4.1: Capacity contracted by MSEDCL in FY18

Coal	Gas	Hydro	Nuclear	Wind	Solar	Other RE
20,218	672	2,843	748	3,641	654	1775

Demand profile is based on the MSEDCL busbar demand as reported by the Maharashtra State Load Despatch Center (MSLDC) in FY18 (MahaSLDC, n.d.). The base year profile is adjusted to account for open access, and an estimated combined capacity of 1000 MW of wind and bagasse that is not monitored by MSLDC. The annual energy demand considered is as approved by the Maharashtra Electricity Regulatory Commission (MERC) in MSEDCL's retail tariff order (MERC, 2016). The demand for FY18 is then scaled up by 5% every year up to FY30—a higher rate than the 3.85% growth rate approved by MERC for the multi-year tariff period ending FY20.[1] A higher demand growth rate was considered to ensure robustness of the findings. The impact of the Covid pandemic on demand has not been considered.

The FY30 demand profile is modified to shift 4000 MW of non-monsoon night-time agricultural load to day time. This is done to account for Maharashtra's agriculture solar feeder policy, under which 2–10 MW grid-connected solar PV capacity is installed in the proximity of the distribution substation to supply power to farmers during the day time (GoM, 2021). The Maharashtra agriculture solar feeder program is already underway after a successful pilot implementation (PEG, 2021).

It should be noted that the MSEDCL demand profile is likely to change significantly in the coming years. Industrial and commercial demand is likely to increasingly shift to times when cheaper renewable generation is available, encouraged by time-of-day tariffs, own generation, etc. However, only the agriculture load shift to day time has been incorporated in this exercise.

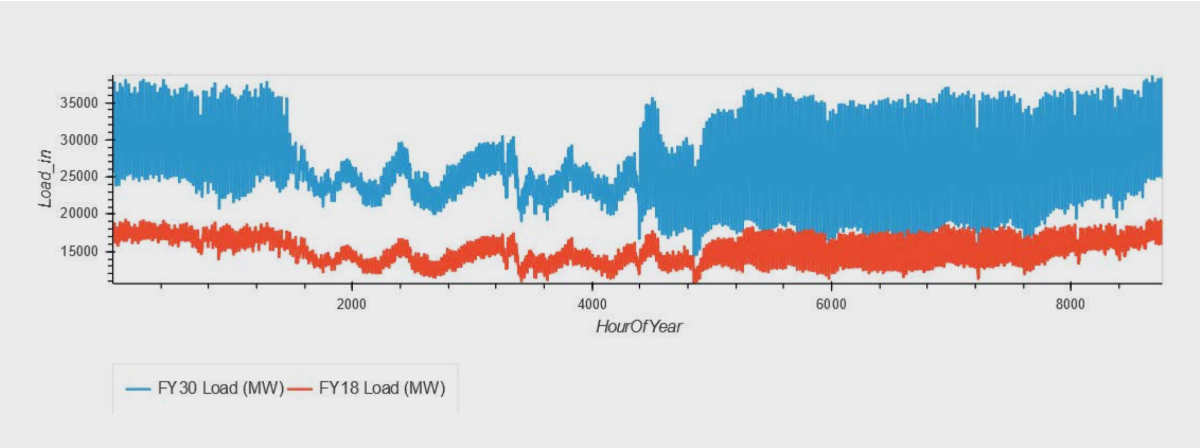
Table 4.2 refers to the annual demand in GWh and the average, peak and trough load during FY18 and FY30. The load profiles in FY18 and FY30 are depicted in Figure 4.1.

1. Subsequent to this analysis, the MERC also approved the demand for the multi-year tariff period ending FY25 at a CAGR of 2.51%. This occurred prior to the onset of the Covid pandemic. This was done to ensure robustness of the findings.

Table 4.2: MSEDCL busbar demand in FY18 and FY30

Year	Annual (GWh)	Average (MW)	Peak (MW)	Trough (MW)
FY18	129,605	14,795	19,077	10,393
FY30	232,750	26,750	38,119	14,705

Figure 4.1: MSEDCL Hourly demand profile in FY18 and FY30



Generation profiles of existing solar and wind capacity are the same as reported in the MSLDC daily reports. The generation profile of new wind capacity is derived from the existing wind profile by scaling it up to ~28% capacity utilisation factor (CUF). Generation profile of new solar capacity is generated using the System Advisor Model (SAM) (NREL, n.d.) for a few locations in Maharashtra, and for both fixed tilt as well as single axis tracking type installations.

4.2 Operational constraints

As mentioned earlier, generator operations can be simulated with high fidelity in GridPath. Individual generating units of coal, gas and hydro projects are modelled along with the following operational constraints. These constraints are based on operational practices followed by many generating units in the year 2021. It is likely that these constraints are conservative, especially for the 2030 timeframe given the increasing focus on enhancing the flexibility of the coal-based generation fleet in the context of an increasing share of renewables in the system.

- Coal
  - Technical minimum is specified as 55%.
  - Ramp up and down rates vary between 1 and 1.5 % of rated capacity per minute.
  - Min up/down time is considered to be 24 hours.
  - Start costs are taken as per CEA's 2019 report on 'Flexible Operation of Thermal Power Plants for Integration of Renewables'.
  - Coal-based units are assumed to be available 85% of the time — approximately 8% under planned maintenance (single event) and 7% under unplanned outage.

- Hydro
    - o Yearly energy budget and monthly minimum energy based on generation data from past few years for Koyna, Sardar Sarovar and Pench.
    - o For the rest of the hydro plants, generation profile is provided based on the past few years' data.
- Open Cycle Gas ramp rate is assumed to be 4% per minute.

4.3 Maintenance planning and hydro optimisation

An important aspect of the optimised unit commitment and economic dispatch at an annual scale is the coordination of planned maintenance and seasonal scheduling of storage-based hydro projects with the annual demand and generation profiles. In GridPath, this can be achieved through a multi-pass approach where unit maintenance is scheduled in high reserve periods (such as the monsoon when demand is low and wind generation is high), and reservoir based hydro generation is budgeted so that it is available when its value is highest while adhering to other constraints such as minimum/maximum flows. Run-of-the-river hydro generation is input exogenously to the model based on data from past years, and hence not optimised in this way.

Annual maintenance inputs are provided in terms of duration and frequency of the events. Hydro budgets are provided at annual and monthly granularity. In the first pass, the model is set up to co-optimise maintenance events and daily generation schedules in one optimisation step for the whole year. In the second pass, the model is set up to optimise generation at a daily level for each month of the year using the maintenance schedules and hydro budgets from the first pass. The second pass provides the daily hydro budgets for the third pass.

In the third pass, the maintenance schedule from the first pass is combined with unplanned outages (generated outside GridPath) to form the exogenous availability input for third pass. The daily hydro generation output from the second pass is converted to daily hydro budgets for the third pass. Based on these, the final production cost simulation is run, resulting in unit commitment and economic dispatch optimised on a daily basis at 15-minute resolution and one-day look-ahead visibility, provided as exogenous inputs to the third pass. Operational constraints such as ramp rates, minimum up/down times and start-up costs and ramps are enforced in pass 3.

Note that this approach does not consider intra-day variations as far as planned maintenance is concerned. For example, if demand is especially peaky in a certain month such that the total energy demand is low but peak load is high, maintenance could get scheduled in that month, resulting in shortages due to reduced dispatchable capacity. The model could be improved in the future in this regard.

4.4 Generation cost assumptions

Coal variable cost is assumed to be constant in real terms, whereas wind levelised cost is assumed to decline at 1% in real terms and solar levelised cost is assumed to decline at 2% in real terms. An inflation rate of 5% has been assumed. Thus, coal variable costs grow at 5%, and wind and solar levelised costs grow at 4% and 3% respectively in nominal terms. The cost trajectory assumed for wind and solar levelised costs is conservative as compared to recent trends and projections for utility-scale projects (PEG, 2021) (NREL, 2021).

Table 4.3 shows the variable cost assumptions in the model. The open cycle gas variable cost is Rs 7.37/kWh in FY30. Day-ahead market purchase in stress hours (18:00–23:00) depends on the season. Coal start costs are as per the Central Electricity Authority's (CEA) report on flexible operation of thermal power plants for integration of renewables (CEA, 2019).

Table 4.3: Variable costs in FY30 (Rs/kWh)

	Nominal Rs	Real (in 2020 Rs)
New Coal	4.49	2.76
Open Cycle Gas	12	7.37
Market Peak	7.5–10	4.50–6.14
Market Non-Peak	6.5	3.99

Wind and solar levelised costs are assumed to be 2.86 and 2.76 Rs/kWh respectively in FY20, and reduce by 1% and 2% respectively in real terms each year. Table 4.4 has the details. Costs are levelised in nominal terms, hence are decreasing in real terms. Battery costs (weighted average cost of storage added until FY30) are Rs 14,450/kWh for a 6-hour battery, and Rs 17,425/kWh for a 4-hour battery.

Table 4.4: Levelised costs[2] in FY30 (Rs/kWh)

	Nominal Rs	Real (in 2020 Rs)
New Wind Levelised in FY30	4.23	2.60
New Solar Levelised in FY30	3.71	2.28
Cumulative New Wind	3.72	2.28
Cumulative New Solar	3.35	2.06

Even though fixed costs do not affect unit commitment and dispatch, these are considered in the model for comparing total costs across scenarios, since the scenarios represent different power procurement choices. For existing capacity, fixed costs are as approved by MERC with appropriate escalation, depending on whether the project falls within the loan repayment period or not. Fixed costs of new coal capacity are derived based on recently-added capacity (Koradi Units 8, 9 & 10). The cost for complying with the environmental norms for coal plants is assumed to be a constant at 0.3 Rs/ kWh in nominal terms (this includes capital costs as well as operational costs owing to pollution control equipment).

4.5 Scenarios

The Maharashtra state power generation company (MSPGCL) has proposed adding efficient, supercritical coal-based capacity at Bhusawal, Koradi and Nashik in lieu of retiring older units that are 25+ years of age. Two such 660 MW units are added across all scenarios. In addition, new renewables are dominated by solar PV and wind across all scenarios, in the ratio of 60% solar and 40% wind. The scenarios represent alternative power procurement strategies

2. Cumulative costs are weighted average costs in FY30 for capacity added from base year to FY30.

involving the addition or retirement of coal-based generation capacity, procurement of peaking power from the market, and addition of battery storage.

In the reference case, it is assumed that 30% of the demand is met through renewables. To meet the growing demand, an additional four 660 MW supercritical coal-based units are added. In addition, 2000 MW of open cycle gas-based capacity is available as fast ramping capacity at Rs 12/kWh (FY30 Rs). 30% generation from renewables by FY30 is likely to be achieved fairly easily given that MERC has mandated 25% generation from renewables by FY25 (MERC, 2019). No battery storage is added. This scenario is henceforth referred to as the RPO30 scenario.

Three scenarios are run with 50% of the demand being met through renewables. These scenarios have different levels of retirement of existing coal-based capacity, and have either open cycle gas or market procurement for peaking support. In addition, 3000 MW of 6-hour battery storage and 2500 MW of 4-hour battery storage are added by FY30 in all the RPO50 scenarios, primarily for diurnal balancing. These scenarios are titled RPO50S1, RPO50S2 and RPO50S3.

In the RPO50S1 scenario, it assumed that six 210 MW units are retired by FY30, resulting in a near flat coal-based generation capacity compared to FY18, after considering the 1320 MW added across all scenarios. The six units that are retired, located at Bhusawal, Chandrapur and Nasik, would all complete over 40 years of operation by FY30, with the Nasik units in operation for 50 years by then. These units are already on the brink of being retired as of 2021. As in the RPO30 scenario, 2000 MW of open cycle gas-based capacity is available for peaking and balancing support.

In the RPO50S2 scenario, it is assumed that an additional six 210 MW units are retired by FY30, all of which would complete 40 years of operation by FY30, resulting in a net reduction of 1200 MW in coal-based capacity compared to FY18. In lieu of open cycle gas, it is assumed that power is procured from the market up to 2000 MW at 6.5–10 Rs/kWh (FY30 Rs) depending on the season and time of day. Market procurement happens in two blocks: evening peak hours (6–11pm) and non-peak hours (rest of the day). This is done to simulate a strategy to procure necessary peaking support from the market on a day-ahead basis. This can be a more cost-efficient strategy, if implemented carefully, as compared to contracting open cycle gas capacity.

The RPO50S3 scenario is the same as the RPO50S2 scenario with aggressive coal retirements including NTPC capacity and capacity that will complete 30 years of operation by FY30. This is close to the likely retirements as per the CEA's National Electricity Plan 2018 (CEA, 2018), and results in retirement of over 5000 MW coal-based capacity by FY30. When compared to FY18 coal-based contracted capacity, there is a net reduction of 3735 MW by FY30 in the RPO50S3 scenario.

Table 4.5 summarises the key difference between the scenarios. Table 4.6 summarises the technology-wise capacities across scenarios, and Table 4.7 lists the units that are retired in the different scenarios.

Table 4.5: Comparison of scenarios

	RPO30	RPO50S1	RPO50S2	RPO50S3
Change in coal-based capacity (MW)	+ 6x660	+2x660 - 6x210	+2x660 - 12x210	+2x660 - 5,055
RE generation share	30%	50%	50%	50%
Open Cycle Gas or Market	Gas	Gas	Market	Market
Battery storage	-	Yes	Yes	Yes

Table 4.6: Generation and storage capacity across scenarios

Contracted Capacity (MW) in FY30	RPO30	RPO50S1	RPO50S2	RPO50S3
Coal	24,832	20,932	19,672	17,137
State Genco Hydro	2,102	2,102	2,102	2,102
Wind	12,940	21,215	21,215	21,215
Solar	19,675	28,640	28,640	28,640
Others[3]	4,909	4,909	4,909	4,909
Generation Capacity	64,458	77,798	76,538	74,003
Flexible Gas/Market	2,000	2,000	2,000	2,000
Pumped Storage	574	574	574	574
Battery Storage	-	5,500	5,500	5,500

Table 4.7: Retirement of coal-based units across scenarios

Station/Unit	Capacity (MW)	Vintage*	RPO50S1	RPO50S2	RPO50S3
Bhusawal Unit 3	210	1982	Y	Y	Y
Chandrapur Units 3 & 4	420	1985–86	Y	Y	Y
Chandrapur Units 5 & 6	1000	1991–92			Y
Khaperkheda Units 1 & 2	420	1989–90		Y	Y
Khaperkheda Units 3 & 4	420	2000–01			Y
Koradi Units 6 & 7	420	1982–83		Y	Y
Nasik Units 3, 4 & 5	630	1979–81	Y	Y	Y
Parli Units 4 & 5	420	1985–87		Y	Y
KSTPS (NTPC)	656	1983–89			Y
VSTP Stage I (NTPC)	459	1987–91			Y
Retirement (MW)			1,260	2,520	5,055

* Refers to the year in which commercial operation began

3. Others includes combined cycle gas, nuclear, biomass (cogeneration) and small hydro

5 Results and observations

As indicated in Senction 2.1, the scenario results are compared for system reliability, curtailment of renewables, thermal plant load factors (PLFs), starts and ramp requirements, and costs. To begin with, let us look at the generation mix across scenarios.

5.1 Generation mix

Corresponding to the 30% and 50% generation from renewable sources across scenarios, coal accounts for 64% of the generation in the RPO30 scenario, and 44–47% of the generation in RPO50 scenarios, as seen in Figure 5.1.

Figure 5.1: Generation share by fuel across scenarios

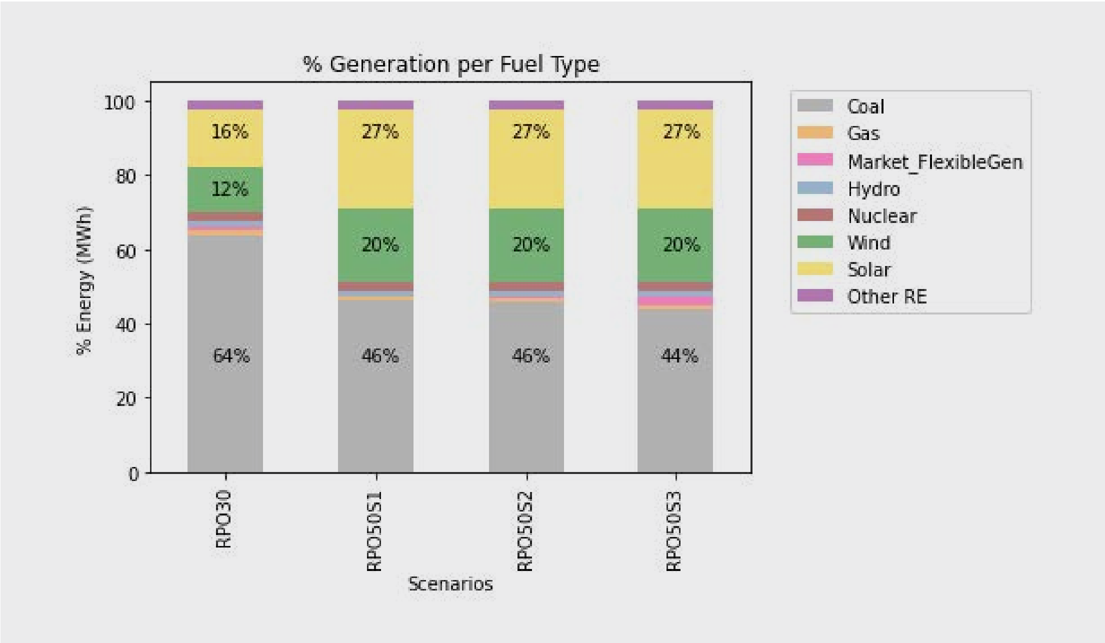
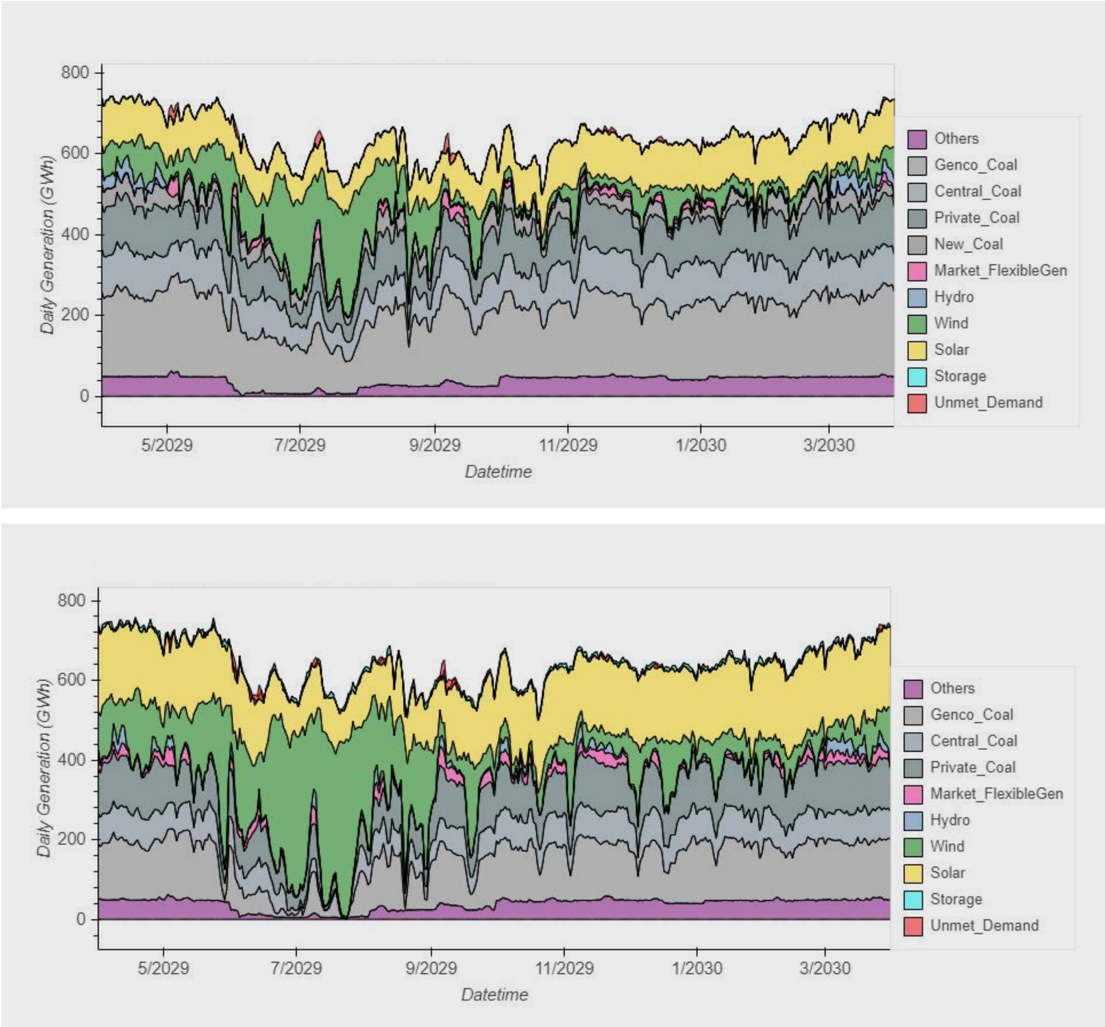


Figure 5.2 shows the daily generation stacks in the RPO30 and RPO50S3 scenarios. Coal generation (different shades of grey) dominates most of the year in the RPO30 scenario. In the RPO50 scenarios, solar (yellow) and wind (green) play a larger role, accounting for the entire demand during some periods in the monsoon months.

Figure 5.2: Daily generation stacks in RPO30 and RPO50S3 scenarios



5.2 Unmet demand

Shortages occur when demand cannot be met with the available generation sources at a point in time. This can happen due to operational constraints, outages or because it is cost economical to not meet demand. The value of lost load (VoLL) input to the model is used to determine whether the costs incurred to meet demand are justified. A VoLL of 20 Rs/kWh (nominal in FY 30) has been assumed. In addition, the simulation assumes perfect foresight with respect to demand and generation profiles on a day-ahead basis.

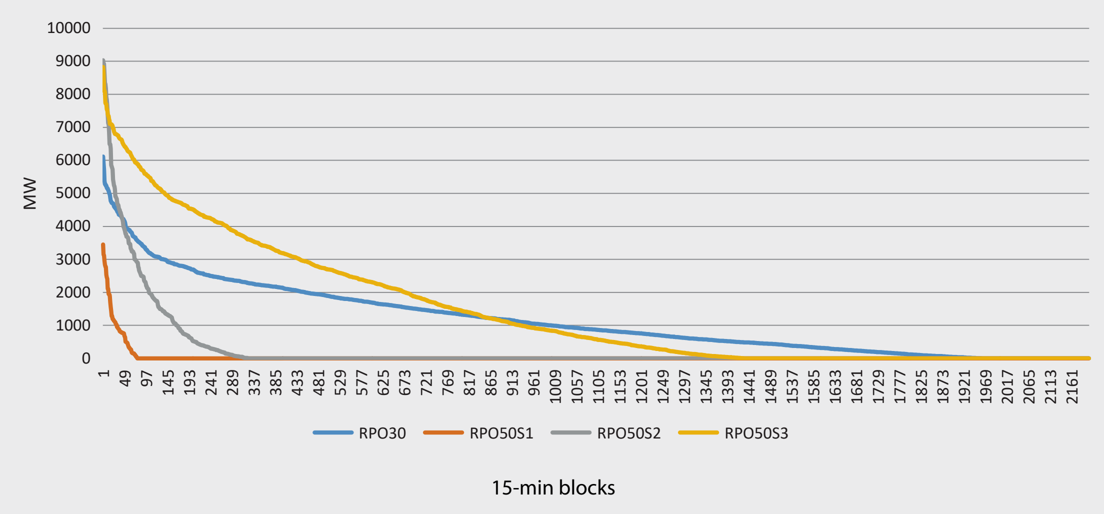
Minimal unmet demand is observed across all scenarios, ranging from 0.01% of the load in the RPO50S1 scenario to 0.34% of the load in the RPO50S3 scenario (see Table 5.1). These shortages are small enough that a combination of short-term purchases and demand response measures can cost-effectively address them, but long-term capacity addition cannot. For reference, the loss of load probability (LOLP) assumed for planning studies in India is 0.2% (CEA, 2018). In the rest of this section, we explore the underlying dynamics that lead to some of this unmet demand.

Table 5.1: Comparison of unmet demand across scenarios

Parameter	RPO30	RPO50S1	RPO50S2	RPO50S3
Unmet demand (GWh)	633	20	147	800
Unmet demand (% of demand)	0.27%	0.01%	0.06%	0.34%

Peak demand curtailment varies from 3446 MW in the RPO50S1 scenario to 9030 MW in the RPO50S2 scenario. Days on which peak unmet demand occurs are different in different scenarios and the underlying causes are different. While the peak unmet demand is high, the number of hours when this occurs is small. This can be seen in the duration curves of unmet demand in Figure 5.3.

Figure 5.3: Duration curves of unmet demand for all scenarios



The number of hours where unmet demand is above 5000 MW is highest in the RPO50S3 scenario, at about 35 hours (0.39%) in the entire year. It is worth noting that the profile of unmet demand is not very different in the RPO30 and RPO50S3 scenarios representing two extremes—one with significant coal addition and the other with significant coal retirements. This underscores the fact that having more coal-based capacity does not automatically avoid shortages. The number of hours where unmet demand is above 1000 MW is similar in the RPO30 and RPO50S3 scenarios (see Table 5.2).

Table 5.2: Number of hours* of unmet demand by magnitude

Magnitude of unmet demand	RPO30	RPO50S1	RPO50S2	RPO50S3
> 1000 MW	250	8	41	233
> 3000 MW	34	1	18	110
> 5000 MW	4	0	7	35

* Rounded to the nearest hour

The seasonal and diurnal distribution of unmet demand in the RPO30 scenario is shown in Figure 5.4, with days of the year on the y-axis and 15-minute blocks within the day on the x-axis. As can be seen, shortages happen in a few days of the year, predominantly during evening and early morning hours.

Figure 5.4: Heatmap of unmet demand for the RPO30 scenario

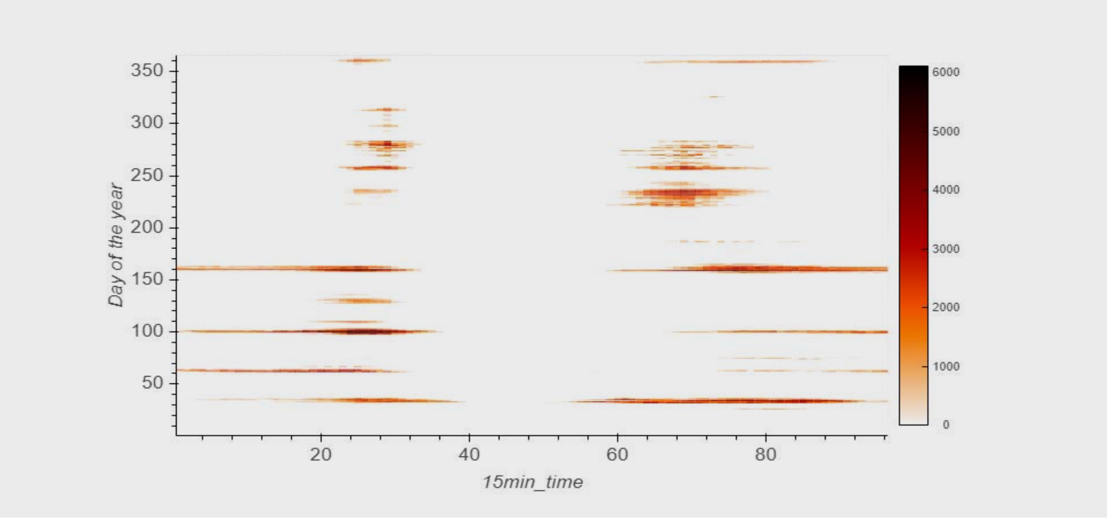
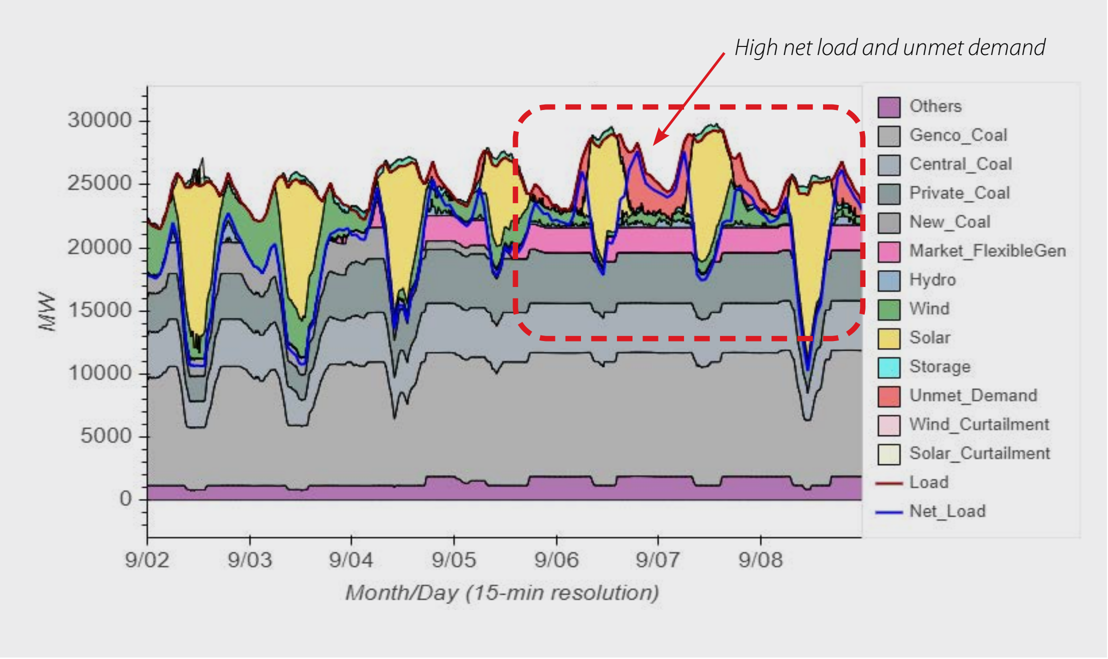


Figure 5.5 looks more closely at the week during which the unmet energy demand is highest in the RPO30 scenario. From the chart, it can be seen that during this week, there is a dip in wind generation and a simultaneous increase in demand, resulting in an unmet demand of over 5 GW at some times.

Figure 5.5: Maximum unmet demand week in the RPO30 scenario



A significant amount of coal-based capacity (~6 GW) is also unavailable during this time due to planned maintenance or unplanned outages, resulting in the high evening and night time shortages. This can be seen in Figure 5.6.

Figure 5.6: Unmet demand and unavailable coal capacity during the high shortage period in the RPO30 scenario

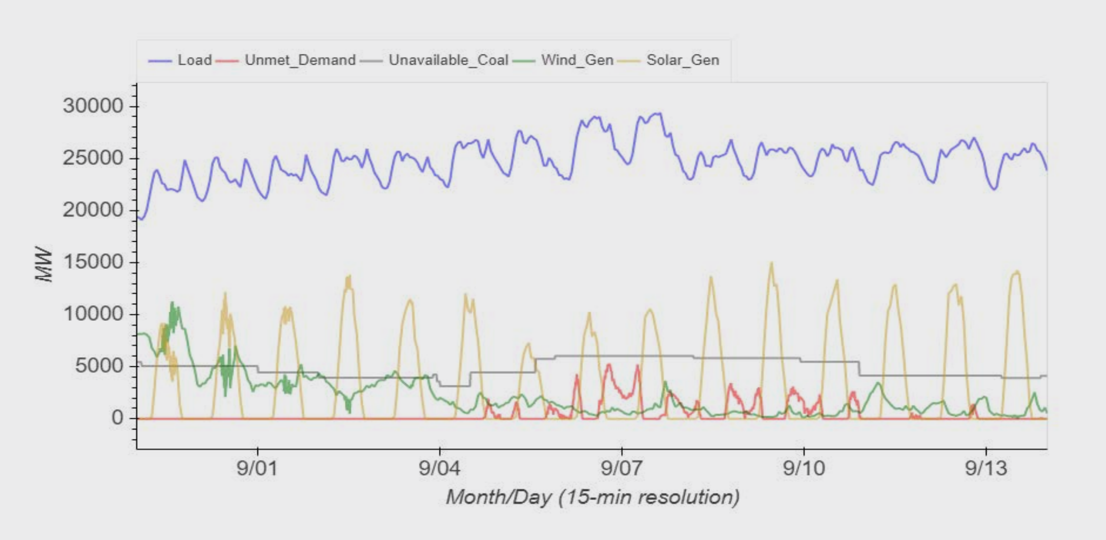


Figure 5.7 shows the unmet demand in the RPO30 scenario along with coal unavailability throughout the year. In this simulation, the planned maintenance is scheduled on a year ahead basis and unchanged afterwards, assuming perfect foresight. In real operation, either the maintenance plan could be reviewed on a month-ahead or week-ahead basis or short-term purchases and deployment of demand response may be made to avoid the shortages. This requires a nimble approach, something that's already followed to some extent, but which becomes even more critical with increased penetration of renewables in the system. Better forecasting of demand and RE generation are crucial inputs to this process.

It is important to note that while the specific date on which these shortages occur is a result of the demand and generation profiles considered based on the base year (2017–18) data, the analysis is still useful as it gives some insight into the underlying dynamics that one could expect under different scenarios.

Figure 5.7: Unmet demand and unavailable coal capacity in FY30 in the RPO30 scenario

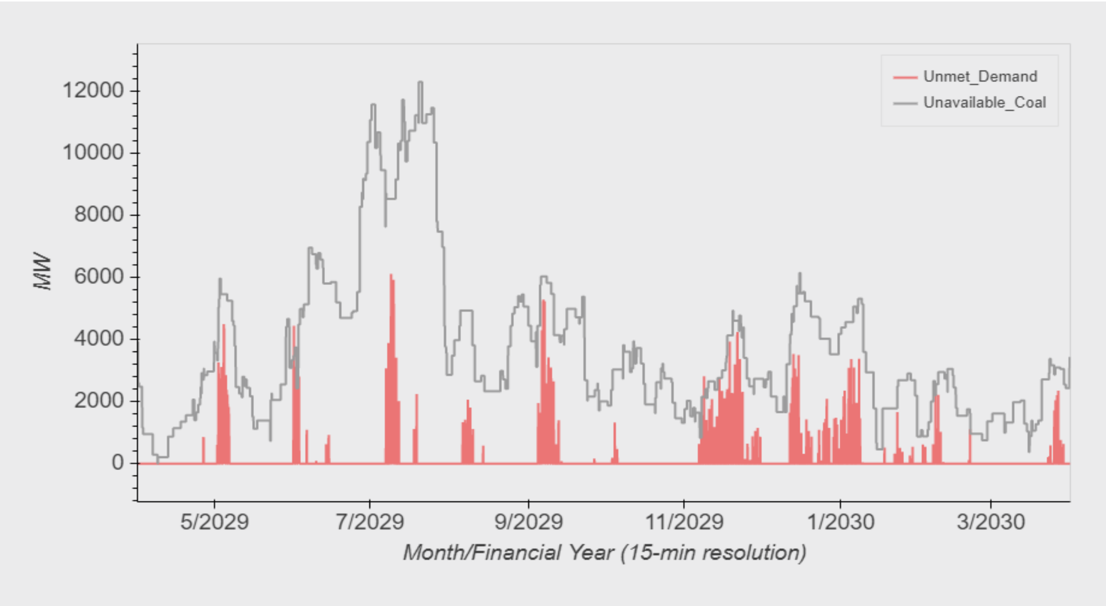
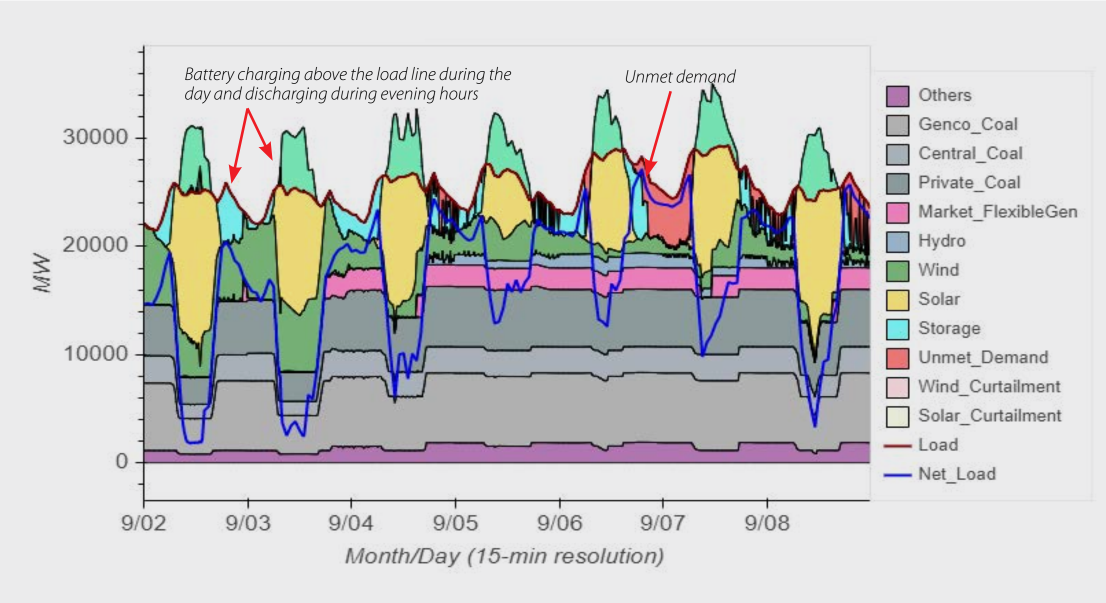


Figure 5.8 shows the generation stack for the same week in the RPO50S3 scenario. Solar and wind generation is higher compared to the RPO30 scenario, and battery storage helps in diurnal balancing by shifting some of the day time generation to evening and early morning hours. Power is procured from the market as well to help tide over this stress period. Nevertheless, some unmet demand is observed.

Figure 5.8: Generation stack in a high unmet demand week in the RPO50S3 scenario



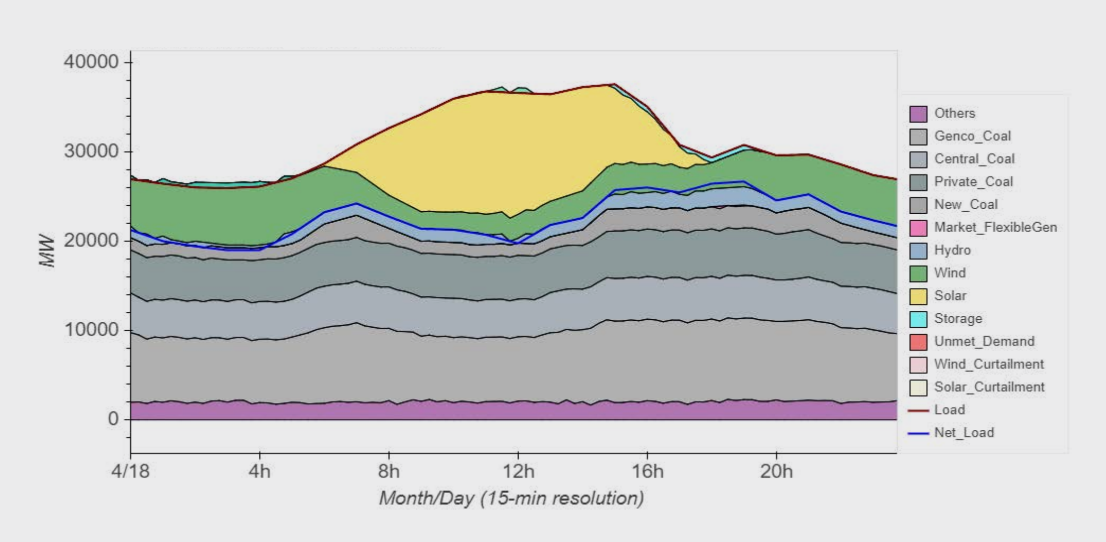
It is important to note that in all the scenarios, a few hours of high magnitude unmet demand is observed. Long-term capacity addition cannot address these types of shortages in a cost-effective manner. Opportunistic power purchase from the market or demand side initiatives such as demand response can help address such issues.

5.3 Dispatch on high demand days

Given the demand profile of the base year (2017–18) and the growth rate considered, March, April and May are the high demand months, and a peak demand of a little over 38 GW is projected to occur between 1 and 4 pm in April in FY30.[4] No shortages are observed on the day of peak demand across all the scenarios, as there is sufficient contracted capacity to meet the demand, and planned maintenance is scheduled in periods where reserves are higher. On this day, close to 22 GW (out of about 25 GW) of coal-based contracted capacity is dispatched in the RPO30 scenario during the peak net load hours (Figure 5.9).

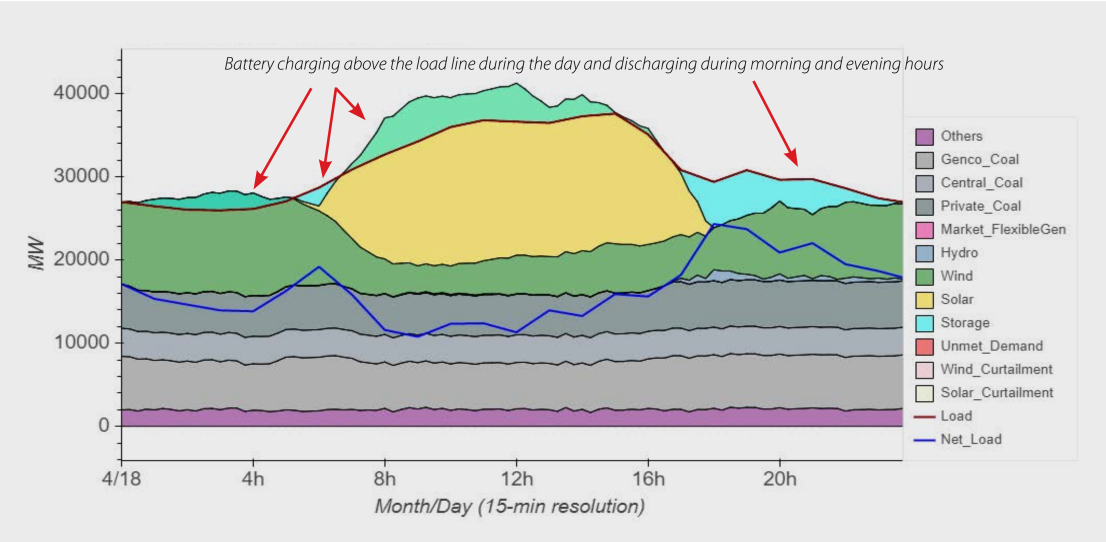
4. The actual peak demand in FY30 and the day on which it occurs is likely to be different from what is seen in this model as it is dependent on the weather, changes in demand and RE generation profiles, growth in demand over the years, etc. Even so, the insights gained using this model are useful in understanding the dynamics in the system.

Figure 5.9: Dispatch stack on maximum load day in the RPO30 scenario



In the RPO50S3 scenario, a little over 15 GW (of about 17 GW) of coal-based contracted capacity is dispatched on the high load day. The remaining demand is met predominantly with wind and solar generation (see Figure 5.10). Excess generation during the day and early morning is absorbed by battery (appears above the load line) and dispatched during evening and morning hours when there is no sun (appears below the load line).

Figure 5.10: Dispatch stack on maximum load day in RPO50S3 scenario



5.4 RE curtailment

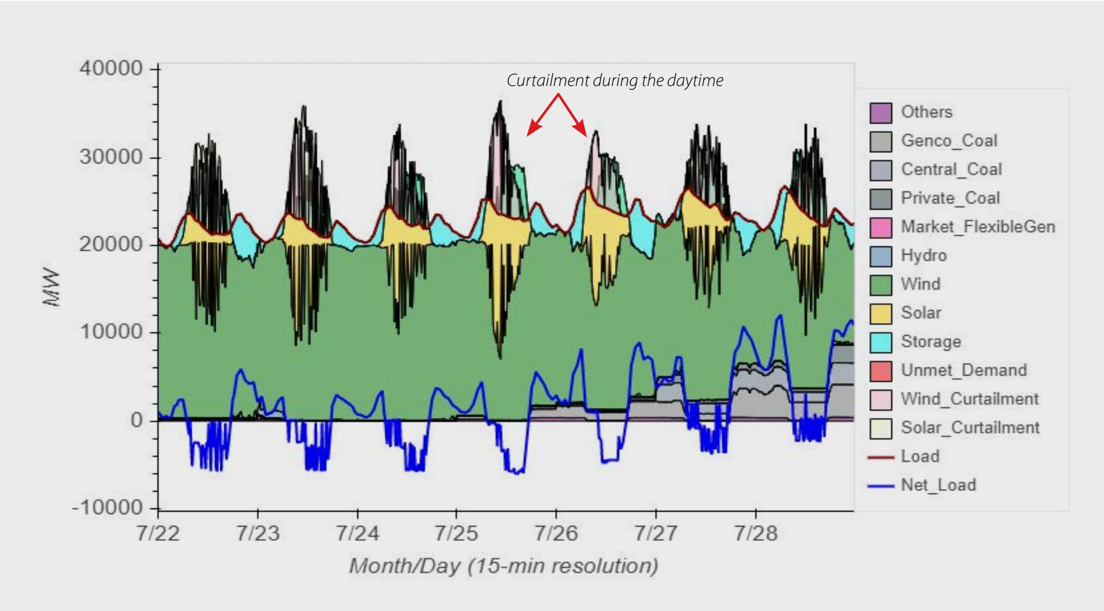
Curtailment of solar and wind generation, which have zero variable cost, happens when it is technically not feasible to absorb the generation into the grid due to reasons such as generation in excess of demand, and operational constraints like technical minimum and ramp rates. As the share of renewable generation increases, the chances of curtailment go up, especially if the generation profiles of newer capacity are similar to those of the existing capacity. RE curtailment is expected in a system with a high share of renewables, and is the most cost-effective option at some times of the year. Hence, curtailment is acceptable up to a certain share of renewable generation.

Across scenarios, 0.9% to 2.42% of the renewable generation is curtailed on an annual basis (see Table 5.3). As one would expect, curtailment is higher in the RPO50 scenarios, especially during some monsoon days when net load is negative due to both wind and solar generating at full capacity (see Figure 5.11).

Table 5.3: RE curtailment across scenarios

Parameter	RPO30	RPO50S1	RPO50S2	RPO50S3
RE curtailment (GWh)	799	2647	2555	2379
RE curtailment as % of RE generation	1.24%	2.42%	2.33%	2.17%

Figure 5.11: Dispatch stack during week with maximum curtailment in RPO50S3 scenario

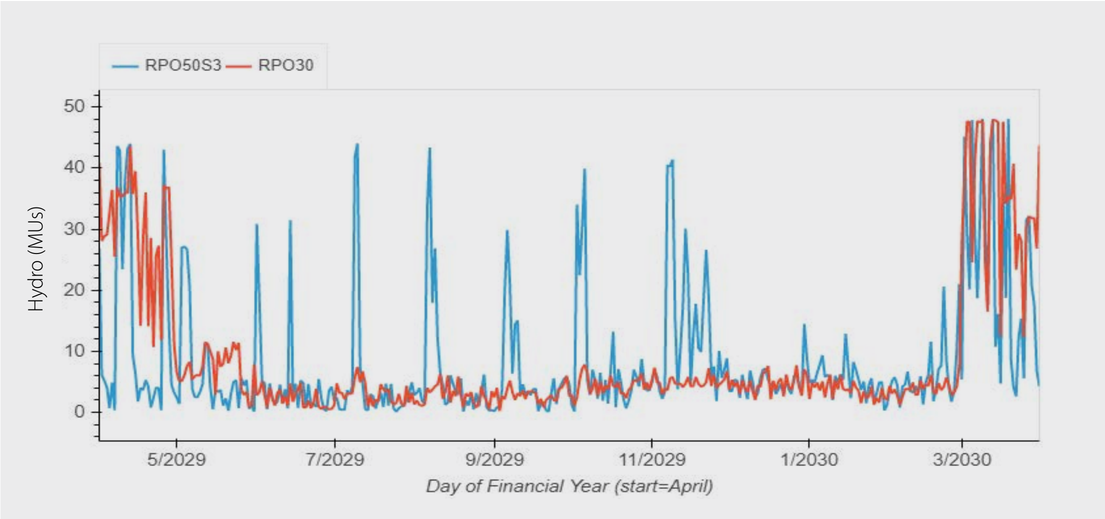


5.5 Role of hydroelectric generation

MSEDCL has contracted about 2000 MW of storage-based hydroelectric capacity at Koyna that can be scheduled based on power generation needs. Monthly minimum generation constraints are specified for these hydro projects based on past generation data, but no maximum generation constraints are specified. As specified in Section 4.3, generation from hydro plants is scheduled using a three-pass approach, where the annual budget is first divided into daily budgets during the first two passes, and then optimised within the day during the final pass at 15-minute resolution.

Across scenarios, hydropower is used as a seasonal storage, generally reserved for the summer months, though there are significant differences in the schedule across scenarios. In the RPO30 scenario, hydro generation is predominant during the summer months, whereas it is more distributed across the year in the RPO50S3 scenario (see Figure 5.12) due to increased net load variability, and maintenance is also scheduled differently.

Figure 5.12: Daily hydro generation for RPO30 and RPO50S3 scenarios



5.6 Role of storage

Pumped hydro and battery storage systems are assumed to be available in FY30. Two existing pumped hydro stations are assumed to be operational in all scenarios. The 250 MW Ghatghar Pumped Storage Scheme (PSS) has been operational since 2008, and the 324 MW Sardar Sarovar Right Bank Powerhouse (RBPH) Station is assumed to operate in pumped storage mode. In addition, as mentioned in Section 4.5, 3 GW of 6-hour and 2.5 GW of 4-hour battery storage is assumed to be deployed by FY30 in the RPO50 scenarios.

As expected, storage plays an important role in diurnal balancing of generation sources, i.e., charging during the day and discharging during evening and early morning hours, thus avoiding both shortages and RE curtailment in the RPO50 scenarios (see Figure 5.10). Table 5.4 shows the energy dispatched from storage across the different scenarios.

Table 5.4: Energy dispatched from storage (in GWh) across scenarios

Parameter	RPO30	RPO50S1	RPO50S2	RPO50S3
Storage energy dispatched (GWh)	791	10016	10069	10380

5.7 Procurement of flexible power

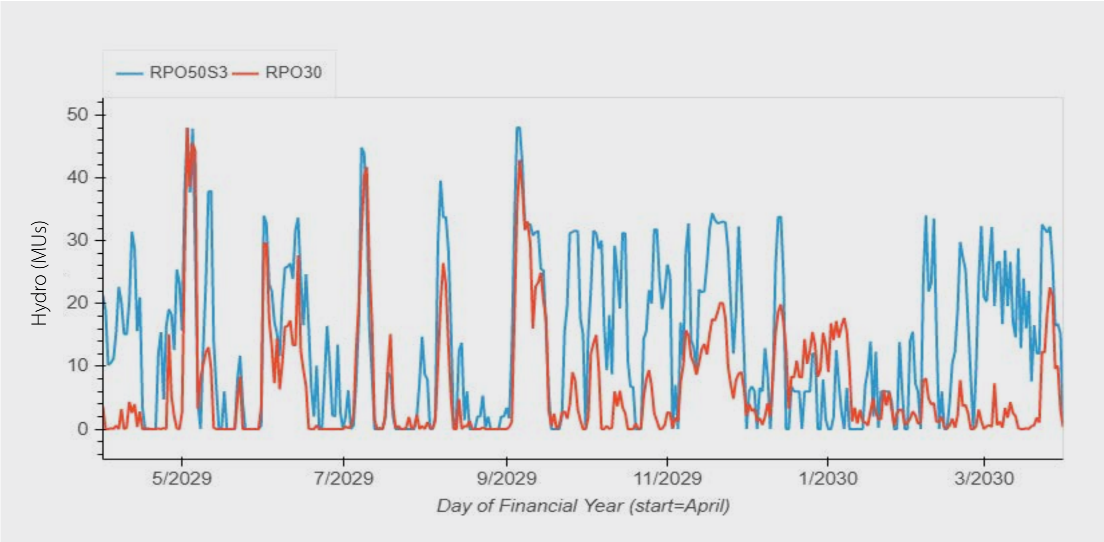
Across all scenarios, 2000 MW of flexible power is assumed to be available for peaking support. In RPO30 and RPO50S1 scenarios, this is available in the form of open cycle gas at Rs 12/unit. In RPO50S2 and RPO50S3 scenarios, this is available in the form of procurement from market at 6.50–10 Rs/unit depending on the season and time of day.

It is seen that peaking power is scheduled throughout the year (see Figure 5.13) predominantly during the stress hours, i.e., evening and early morning, and plays an important role in avoiding shortages especially in the RPO50S3 scenario with an annual capacity utilisation factor of 29% (see Table 5.5). Thus, aggressive retirement of old capacity could result in increased procurement through opportunistic short to medium term contracts or market purchases, which could be costly on a per-generation unit basis given that there may be a significant need during stress hours.

Table 5.5: Procurement of flexible power across scenarios

Parameter	RPO30	RPO50S1	RPO50S2	RPO50S3
Market/Open Cycle Gas (GWh)	2415	613	1881	5109
Market/Gas annual CUF (%)	14%	3.5%	11%	29%
Share of demand met (%)	1.04%	0.26%	0.81%	2.20%

Figure 5.13: Daily procurement of flexible generation (in GWh) in RPO30 and RPO50S3



5.8 Coal fleet operation

An important aspect of integrating higher renewables into the system is its impact on the scheduling and operation of the coal fleet. Coal-based capacity is the predominant dispatchable capacity in the system, but has also not been traditionally designed for flexible operation. Increased renewable penetration results in increased variability in the system, resulting in the need for part-load operation, fast ramping and increased number of starts of coal units. All these factors lead to more wear and tear in coal power plants, resulting in higher operation and maintenance (O&M) costs and increased downtime for O&M operations (Sinha, 2020) (GtG, 2020). The impact of increased cycling and part-load operation of coal plants on costs, efficiencies and outages are not considered in this analysis, but start costs are accounted for in the model during unit commitment.

In this section, we take a look at different aspects of coal fleet operation such as their PLFs, number and distribution of starts, loading levels and cycling. These dynamics may be different at the unit level when transmission constraints are taken into account, but the broad insights from this copperplate simulation would be valid at the fleet level. We also find that the broad insights are in line with what would be intuitively expected, but the simulations help quantify some of the impacts, and these provide useful pointers for future coal plant operations.

As mentioned in Section 5.1, the coal-based capacity accounts for 64% of the generation in the RPO30 scenario, and 44% in the RPO50S3 scenario. While the plant load factor (PLF) is around 72% in RPO30 and RPO50S3 scenarios, it is 62% and 66% in the RPO50S1 and RPO50S2 scenarios respectively (see Table 5.6).

Table 5.6: Coal PLFs and starts/unit across scenarios

Parameter	RPO30	RPO50S1	RPO50S2	RPO50S3
Coal-based capacity (MW)	24,832	20,932	19,672	17,137
Coal-based generation (GWh)	156,881	114,474	112,466	106,986
Gross Coal PLF (%)	72%	62%	66%	72%
Annual coal starts/unit	8.5	12.6	16.3	14.3

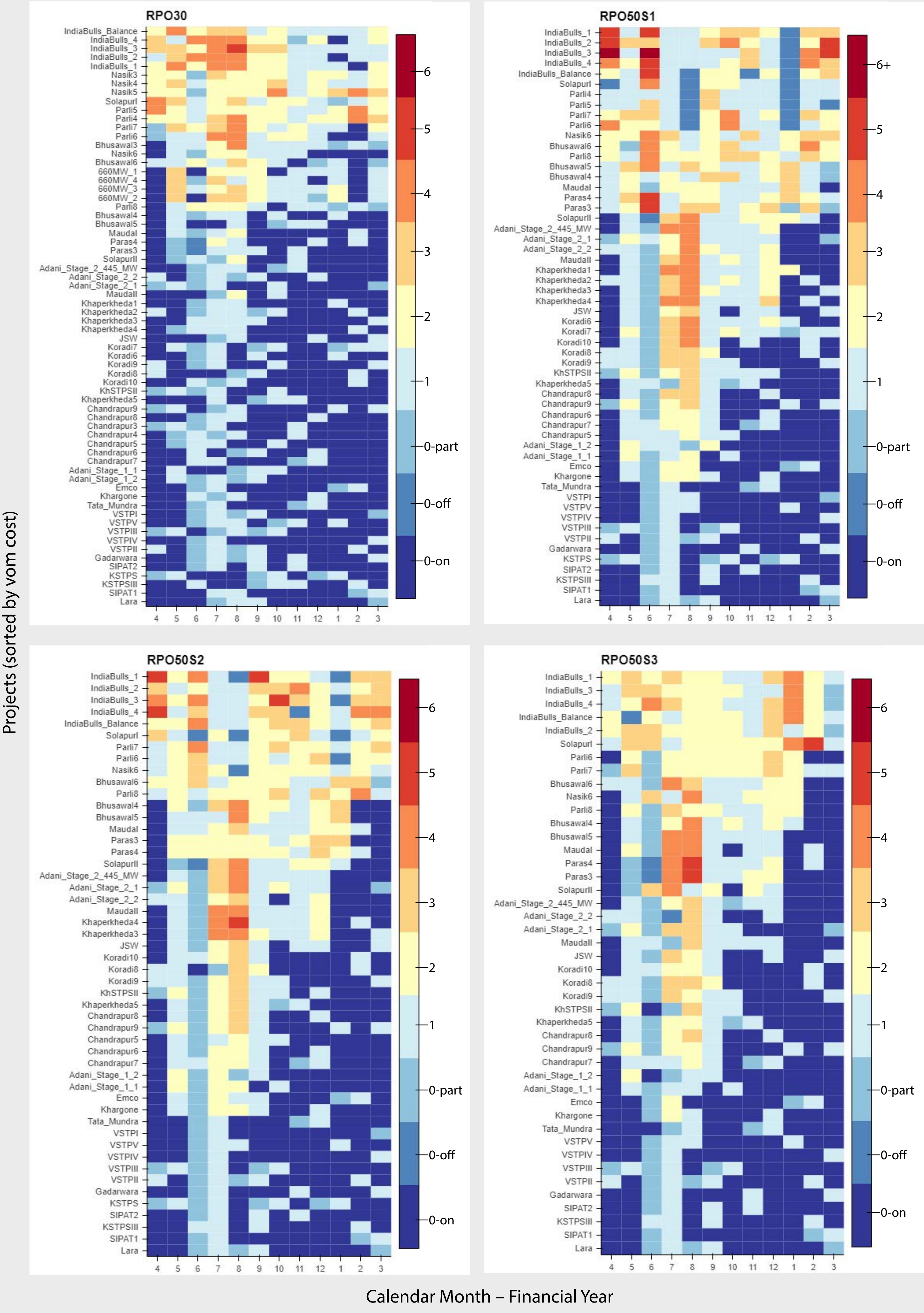
5.8.1 Coal unit starts

Coal-based power plants are stopped and started due to planned and unplanned outages, and in response to fluctuations in demand and intermittent generation sources. When a unit is started, an additional cost is incurred due to liquid fuels used for support during start up. Frequent starts/stops correlate with higher heat rates, higher O&M costs and lower PLFs, adding to the costs per unit of generation.

As seen in Table 5.6, the number of starts per generating unit is higher in the RPO50 scenarios. The number of annual starts per unit in the RPO50S2 scenario is almost double that of the RPO30 scenario. Figure 5.14 shows the month-wise unit-wise distribution of starts across scenarios. The months on the x-axis refer to the calendar year and not the financial year, i.e., 1 stands for January and 12 stands for December. The generating units are listed on the y-axis in increasing order of variable cost. Note that the variable costs considered in this analysis do not reflect change-in-law related changes. The colour of each cell (unit-month combination) represents the number of starts as shown by the legend. All the cells with different shades of blue, corresponding to values 0-part, 0-off and 0-on, represent zero starts during the month with the units being partially off, off throughout and on throughout respectively.

As expected, the number of starts is higher during the monsoon months (6, 7 and 8) when wind generation is high, demand is low and net demand to be met through dispatch-able sources is sometimes negative. It can be observed that the number of starts is higher for units that are higher up in the merit order stack.

Figure 5.14: Month-wise unit-wise coal starts across scenarios

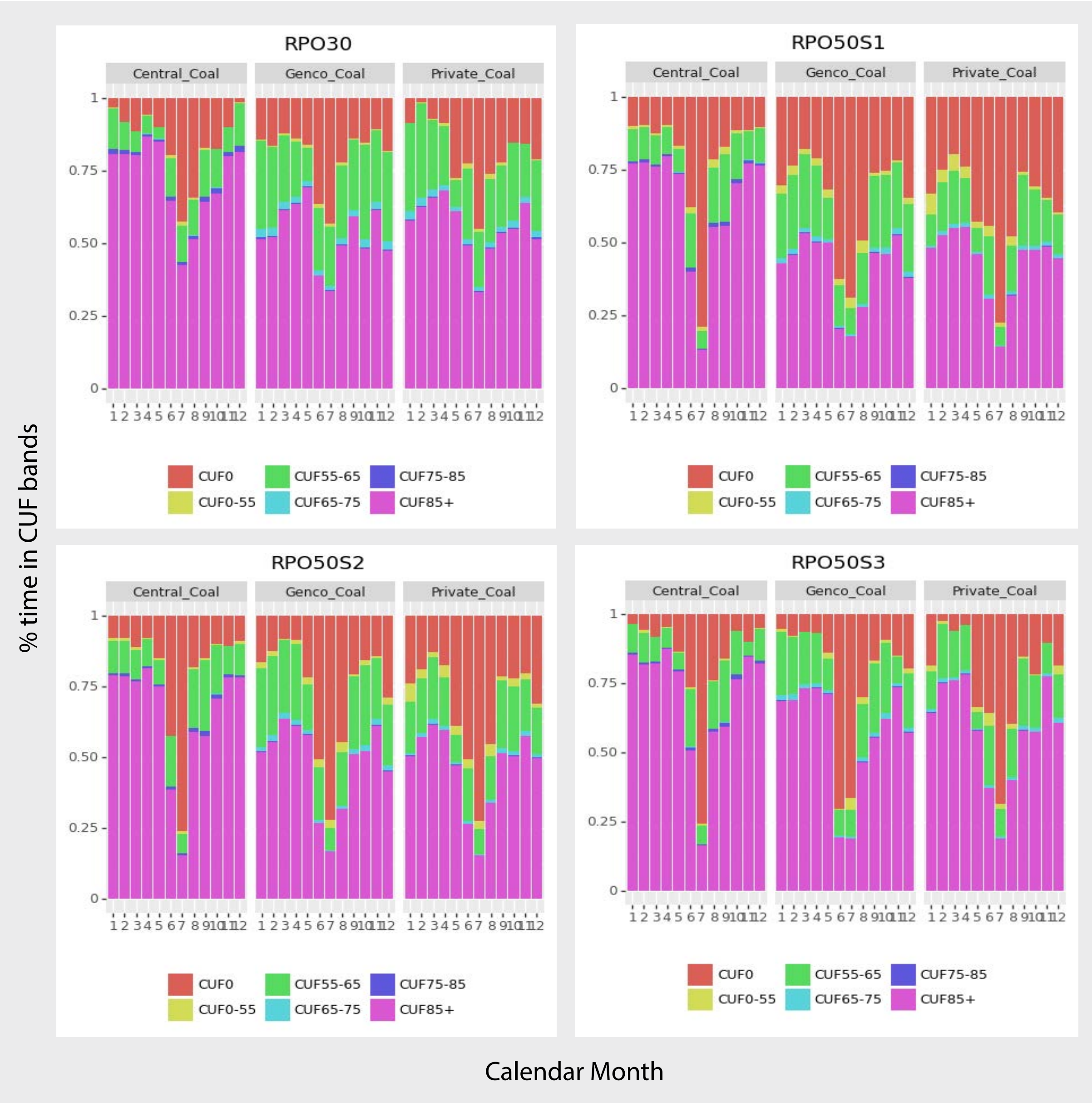


5.8.2 Partial load operation of coal-based generating units

An important aspect of coal-based unit operation especially in the context of integration of renewables is the loading level. The higher the loading level, the better the heat rate or conversion efficiency of the unit. Lower loading levels result in higher variable costs.

Figure 5.15 shows the percent of time spent by the coal fleet in different loading level bands—85%+, 75-85%, 65-75%, 55-65%, 0-55% (during starts and stops) and at 0%. In the RPO50 scenarios, coal capacity is turned off (depicted in red) 50-75% of the time during monsoon months due to lower demand and higher RE generation. This is due to maintenance being scheduled during those months as well as due to backing down. Also, it is important to note that these units are in part load operation, i.e., 55-65% loading level, for about 25% of the time, in the RPO30 as well as the RPO50 scenarios. This implies lower efficiency (or higher heat rates) and the resulting impact on variable costs, as well as the need to adapt operational practices to effectively deal with part load operation.

Figure 5.15: Time spent at different loading levels by coal fleet category



5.8.3 Ramp requirement from coal units

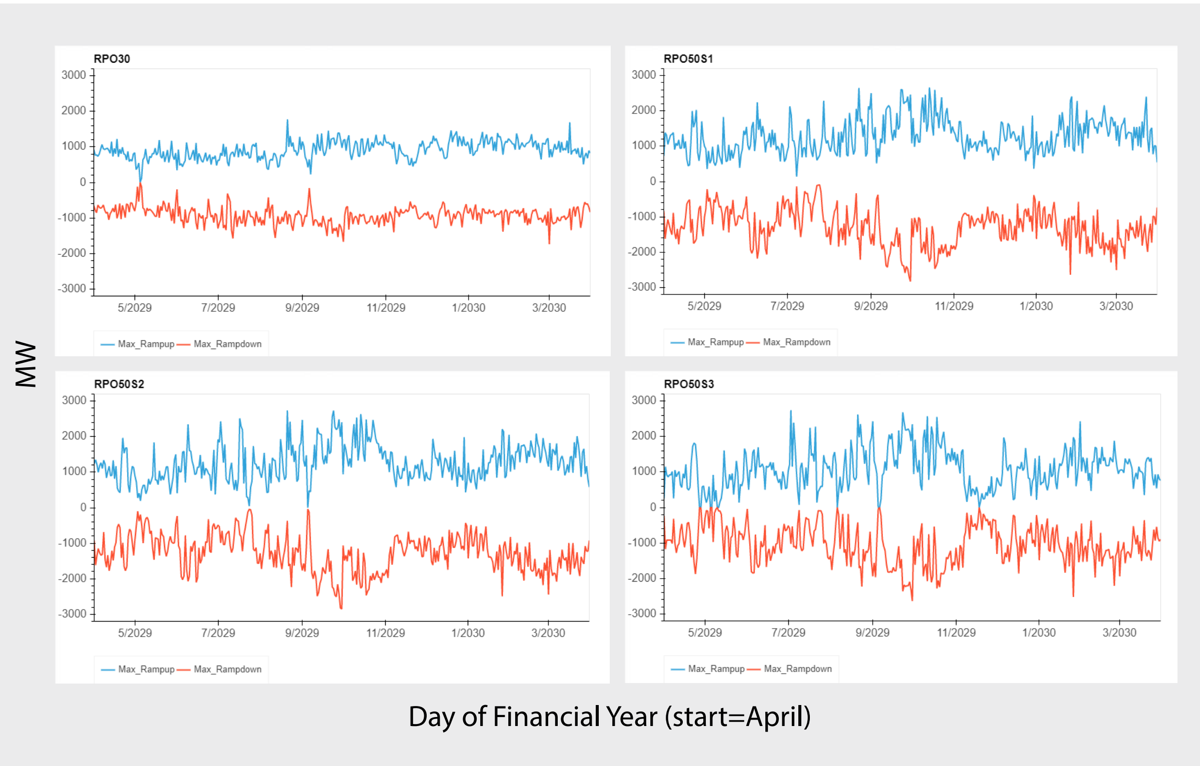
Being the predominant dispatch-able capacity, the coal fleet provides important balancing support on the grid in response to fluctuations in demand and RE generation. As renewable penetration increases, there is likely to be a greater need for ramping up and ramping down coal-based generation. These ramps are limited by the ramp rates specified, i.e., 1–1.5% of rated capacity per minute.

First, we look at the maximum ramp that the entire coal fleet has to undergo across all 15-min blocks within each day of the year. As would be expected, the ramp requirement is higher in the RPO50 scenarios. However, the simulation helps to quantify the increase.

In the RPO30 scenario, the average maximum ramp between two 15-minute blocks is around 900 MW (60 MW/min), with a peak ramp of around 1700 MW or 113 MW/min (see Figure 5.16). In the RPO50 scenarios, the maximum ramps average around 1100 MW (73 MW/min) and have a peak of around 2900 MW (193 MW/min).

It is important to note that the total coal capacity is close to 25 GW in the RPO30 scenario, whereas it is about 17 GW in the RPO50S3 scenario. So the peak ramp as a percentage of the coal fleet capacity is around 17% over a 15-minute period (or over 1% per minute) in the RPO50S3 scenario, about 2.5 times that in the RPO30 scenario.

Figure 5.16: Maximum coal fleet-wide ramps within a 15-minute period on each day

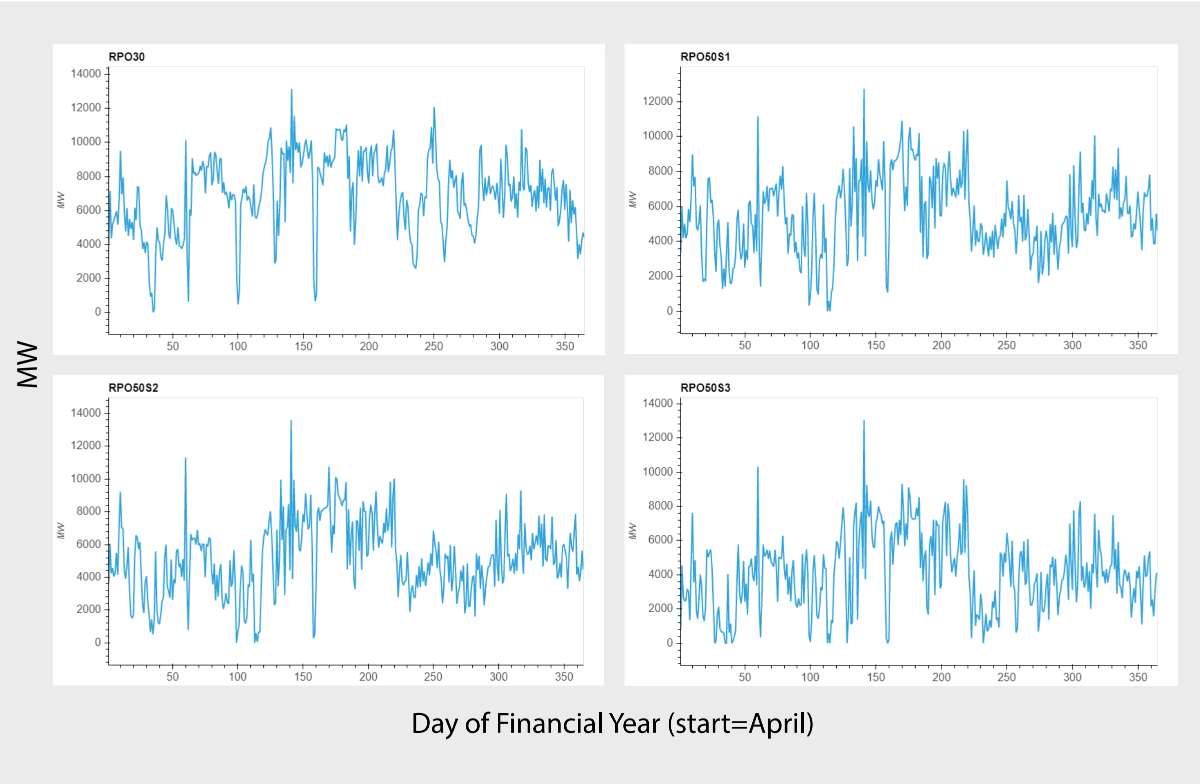


5.8.4 Intra-day cycling of coal units

In addition to ramps within a 15-minute period, it is also useful to understand the impact of increased variability on the extent to which coal generators need to cycle during a given day. This has implications for part load operation as well.

Figure 5.17 illustrates the difference between the minimum and maximum generation level across the coal fleet during each day of the year. The average cycling[5] within a day varies between 4 GW in the RPO50S3 scenario and 7 GW in the RPO30 scenario, with the maximum cycling at around 13 GW across all scenarios. The lower average daily cycling in the RPO50 scenarios is due to the presence of battery storage that absorbs a significant portion of the diurnal variation. Among the RPO50 scenarios, average cycling is highest in the RPO50S1 scenario at about 5.5 GW. This is consistent with the higher number of starts in RPO50S1 as seen in Section 5.8.1.

Figure 5.17: Coal fleet-wide difference between min and max generation during each day



The daily cycling seen in FY30 is significantly higher than the average daily cycling of approximately 2.5 GW and a maximum of approximately 5 GW that was observed in FY18. This points to the need for system operators and generating companies to prepare for increased flexibility in dispatch-able capacity.

5.9 Comparison of generation costs across scenarios

Total costs, including fixed, variable and start costs, as well as market purchases are similar across all scenarios, with the RPO50 scenarios having 2% to 3.5% lower cost as compared to the RPO30 scenario (see Table 5.7). A few caveats apply here. Transmission costs have not been estimated during this study. In addition, costs due to part load operation have not been incorporated, although we don't expect them to add significantly to the costs reported here.

5. This is the average of the daily difference between minimum and maximum generation for the entire coal fleet.

In any case, if incorporated, part load costs would impact all scenarios (as seen in Figure 5.15), and hence are unlikely to alter the conclusions with respect to relative costs across scenarios. Finally, as indicated in the Section 4.4, future solar and wind cost reductions (in real terms) assumed in this analysis are conservative as compared to recent trends.

Table 5.7: Nominal generation costs (in Rs/kWh) across scenarios

Parameter	RPO30	RPO50S1	RPO50S2	RPO50S3
System cost[6]	2.89	1.99	2.02	2.16
System cost + solar and wind costs	3.93	3.76	3.79	3.94
Total cost	5.22	5.10	5.05	5.11

5.10 Comparison between GridPath and PLEXOS model runs

The GridPath model described thus far was replicated in PLEXOS, a popular electricity market model (Energy Exemplar, n.d.) used by regulators, system operators, utilities and researchers across the world. The results from the GridPath model are benchmarked against the results from the PLEXOS model. The parameters for comparison are the same as those considered for the above analysis, i.e., reliability, operation in stress periods, renewable curtailment, coal fleet operation, and costs. The versions of these platforms used for this analysis are **0.8.2** for GridPath and 7.500R04 for PLEXOS.

Table 5.8 summarises the comparison between the GridPath and PLEXOS runs for the RPO30 and RPO50S3 scenarios. The results are similar between the two platforms, and the broad insights drawn from the analysis of GridPath results are corroborated by the PLEXOS results.

Table 5.8: Comparison of scenario results between GridPath and PLEXOS

	RPO30		RPO50S3	
Parameters	GridPath	PLEXOS	GridPath	PLEXOS
Unmet demand (GWh)	633	430	800	1837
Unmet demand (% of load)	0.27%	0.18%	0.34%	0.79%
RE curtailment (GWh)	799	1176	2379	3132
RE curtailment (%)	1.24%	1.84%	2.17%	2.88%
Market/Gas (GWh)	2415	3401	3735	7482
Storage (GWh)	789	673	10380	9373
Gross Coal PLF (%)	72%	72%	73%	69%
Coal starts/unit	8.5	6.1	14.3	9.1

6. System cost is operations cost which includes variable costs, start costs and market purchases.

Nevertheless, there are some important differences between the GridPath and PLEXOS results across all the parameters. As compared to the GridPath runs, unmet demand is lower in the RPO30 scenario, and higher in the RPO50 scenarios in the PLEXOS runs. Curtailment of renewables and procurement from flexible sources (open cycle gas or market) are higher in the PLEXOS runs, while coal unit starts as well as energy dispatched from storage are higher in the GridPath runs. System costs are similar between the two platforms. These differences are small in comparison to the size of the system and can be explained by the differences in methodology for maintenance and hydro scheduling. This is further explained in Appendix A.

6 Summary of results and insights

The high-level insights from this analysis are summarised below:

1. Without considering transmission constraints, it is possible to meet demand in 2030 without any 'net addition to coal fleet' and with 50% energy contribution from RE, while coal plants are operating within currently acceptable technical limits (technical minimum, ramp rates etc.). It should be noted that the high demand growth rate considered for this analysis is unlikely to materialise, which further strengthens this finding.

2. It is possible to meet system demand reliably and cost-effectively in 2030 while retiring coal-based power generation capacity that is older than 40 years. It is also possible to meet system demand while retiring capacity older than 30 years, though this leads to greater short-term power procurement and intermittent stress conditions in the operation of the system. To ensure reliability, maintenance events of the remaining capacity need to be planned carefully, and a nimble approach needs to be adopted to adjust for unexpected changes in demand and renewable generation. This approach may involve reviewing maintenance plans on a month-ahead or week-ahead basis and exploring opportunistic short-term power purchase options. Better forecasting of demand and RE generation will contribute crucial inputs to this process.

3. Availability and flexible operability of the coal fleet such as intra-day ramping and part load operation are important for reliability across all scenarios. Coal plants are assumed to be available for 85% of the time in this analysis. In the past, coal power plants have not been available to generate when needed due to outages or fuel unavailability. If the availability reduces, reliability of power supply is severely affected even with a lower share of renewables in the system. With an increased penetration of renewables, coal plant availability becomes all the more critical.

4. Shifting of agricultural load to day time through tail-end solar plants attached to agriculture feeders significantly helps in absorbing solar generation. Ensuring near universal coverage of the solar agriculture feeder programme, in addition to improving quality of power supply to farmers, also greatly aids the integration of cost-effective renewable electricity generation.

5. Agile and innovative power procurement strategies will yield full benefits of cost-competitive renewable energy sources without compromising the reliability of supply. Such strategies would include short-term seasonal procurement, procuring 'peak energy' from exchanges or 'peaking capacity' such as open cycle gas, and importantly, grid-scale battery storage systems (BESS). As this paper demonstrates, on a per-unit, standalone basis, though the cost of such resources may be higher than conventional base-load resources or RE resources, they lower the overall system cost by aiding greater uptake of RE sources.

Given that it is possible to reliably meet demand in the MSEDCL system with 50% of the generation from renewables, and since this is accompanied by economic and environmental benefits, we suggest that the following policy and regulatory initiatives be implemented in addition to expanding ongoing initiatives such as solar feeder and renewable purchase obligations:

1. The time-of-day tariff regime in the state should be expanded to cover more consumers, and the peak tariff slot should eventually be adjusted automatically according to the demand-supply balance. In addition, seasonal tariffs need to be introduced.

2. A more rigorous and structured RE procurement approach should be adopted, taking into account parameters such as the location and generation profile in assessing the value to the system, rather than just a least-cost approach.

3. Grid-scale battery storage should be procured on a pilot basis in order to better understand the value to the grid.

4. Given that a 50% RE scenario is both feasible and desirable by 2030, intra-state transmission should be planned to prepare for a high RE scenario. This is especially important given the long gestation times for transmission strengthening.

The scenarios set up in the GridPath Maharashtra model have been replicated in PLEXOS. The high-level results are comparable between the GridPath and PLEXOS runs with respect to the questions we set out to answer (see Section 2.1). This strengthens confidence in the insights derived from our analysis. There are some minor differences between the two models in terms of reliability, especially in the RPO50S3 scenario. These differences can be attributed to the difference in scheduling of maintenance events and hydro generation between the two models.

Finally, there is a fair degree of uncertainty in future cost trajectories, demand growth, changes in the demand profile, weather conditions, and the feasibility of capacity addition. Carefully designed scenario analysis using sophisticated models can help make more rational decisions under such uncertainty. Such exercises should be conducted in a transparent manner, with adequate public consultation. Given that modelling tools are increasingly becoming accessible, a diverse set of stakeholders are likely to engage in a public process, leading to more informed decisions. As solar, wind and battery storage systems are more modular in nature, and have shorter gestation periods, capacity addition decisions involving these technologies can be made closer to when such capacity is needed (that is, 3–4 years in advance). Thus, there is a need for an iterative and periodic analyses to adapt to the changes unfolding in the sector.

7 Conclusion

It is possible to reliably and cost-effectively meet Maharashtra's demand in FY30 with 50% generation from renewables and no net addition of coal-based capacity. Battery storage, opportunistic procurement from the market, and demand-side solutions such as solarisation of the agricultural energy demand play an important role in helping integrate higher renewables in the grid and managing stress situations. Retirements of depreciated, low fixed-cost coal plants should be carried out after a careful consideration of future demand and supply trajectories.

Key insights from our results are the same for both the GridPath and PLEXOS models, increasing confidence about the modelling tools and the insights gained. Full-featured, open-source tools are available, and high-performance computing power is now accessible. Regulators should mandate that utilities perform such studies as part of periodic, public consultations on resource planning. It is equally important that all input data and assumptions used for these studies are placed in the public domain so that all stakeholders can provide informed inputs.

The GridPath model used for this study is publicly accessible and available for download at https://github.com/prayas-energy/gridpath-mh.

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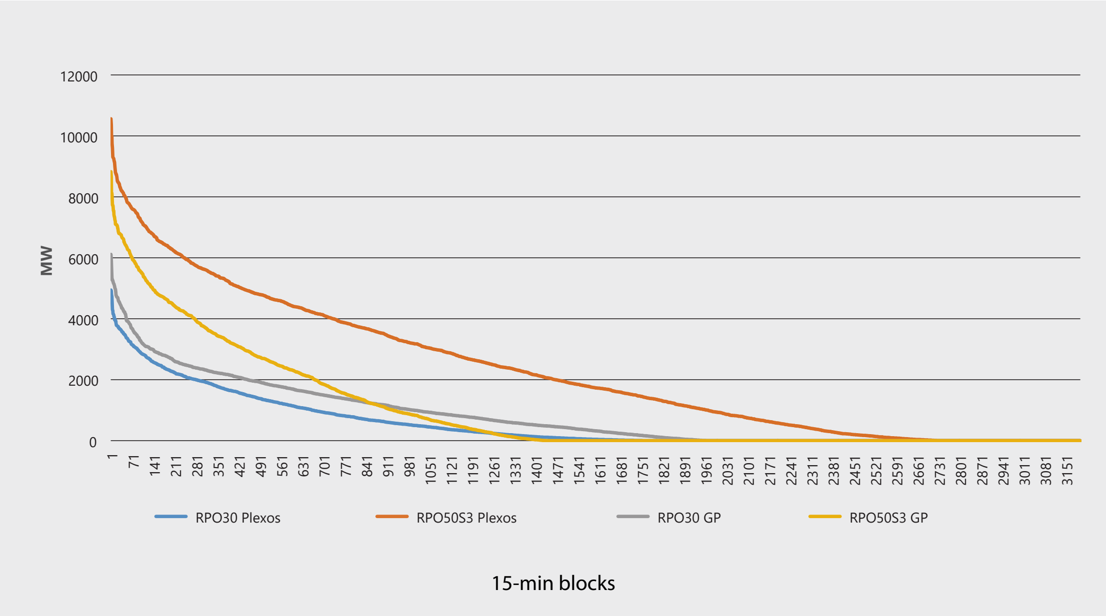
A Annexure: Difference in dispatch between GridPath and PLEXOS models

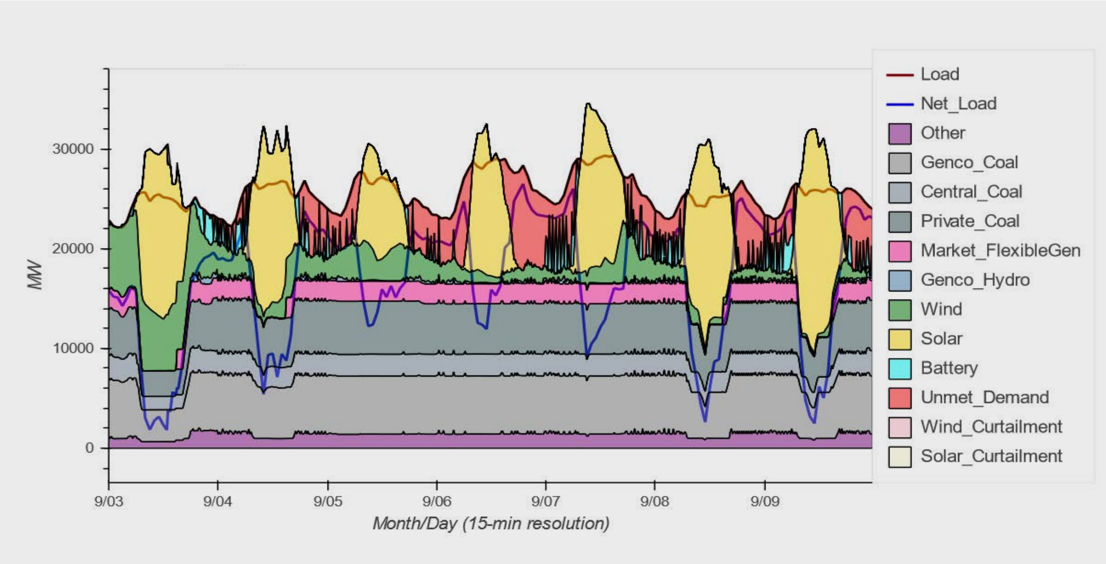
The dispatch stack for the week in which unmet demand is high (in both models) is compared in detail in this section. Figure A.1 shows the 15-minute shortages arranged in descending order (duration curves). As can be seen, the unmet demand duration curve for the RPO50S3 scenario run in PLEXOS is an outlier, and the magnitude of shortages is quite high.

Figure A.1: Duration curves of unmet demand in GridPath and PLEXOS



We take a closer look at the week during which maximum shortages occur. This is the same week that was discussed in Section 5.2 on unmet demand. As indicated, this is a period when wind generation falls dramatically, accompanied by a slight increase in demand. Figure A.2 shows the generation stack for this week in the PLEXOS RPO50S3 run. Very high shortages are seen during the week, coinciding with simultaneous reduction in wind and solar generation and an increase in demand as seen in the net load curve (blue line). Coal-based generation is flat and at full load throughout the week, and additional power is procured from the market. On some days, very little generation in excess of demand is observed, so the battery also does not get fully charged.

Figure A.2: Maximum unmet demand week in the RPO50S3 scenario in PLEXOS



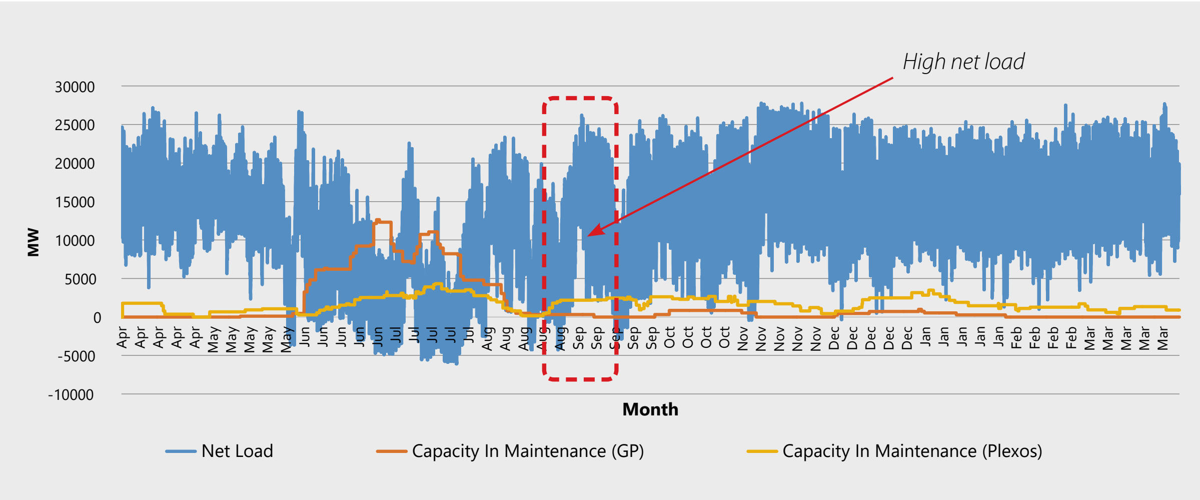
Two things stand out in the above chart. In spite of high shortages, state hydro generation (almost 2 GW capacity) is not scheduled, and coal-based generation is capped at slightly below 15 GW out of over 17 GW contracted capacity. These observations point to differences in the scheduling of outages and hydro generation between the two platforms, which are explored further below.

A.1 Scheduling of maintenance events

Outages can be due to planned maintenance events or unplanned outages. Maintenance events are known in advance and are typically scheduled during high reserve periods, i.e., during monsoon when demand is lower. In PLEXOS, maintenance events are scheduled as part of the Projected Assessment of System Adequacy (PASA) stage. In GridPath, maintenance events are distributed over the year in a separate run prior to the actual production simulation (as described in Section 4.3). In this step, the model is set up with a daily resolution and dispatch is optimised for the entire year in one step. Unplanned outages need to be specified exogenously in GridPath, whereas in PLEXOS, they are randomly generated based on the specified distribution. In order to make the two runs comparable, the unplanned outages generated in PLEXOS for each scenario are input exogenously in the GridPath model. In both cases, unplanned outages are not known in the earlier stages/passes, that is, they are not known until the day-ahead unit commitment and economic dispatch. Thus, any differences in outages between the two platforms are due to differences in scheduling of maintenance events.

Figure A.3 shows the differences in the maintenance schedule between PLEXOS and GridPath runs for scenario RPO50S3 along with the net load curve, i.e., demand minus generation from non-dispatchable capacity such as solar, wind, bagasse and nuclear. During the first ten days of September (which is the period when unmet demand is the highest), a significant increase in the net load is seen. During this time, capacity is under maintenance is over 2 GW in the PLEXOS run, and around 300 MW in the GridPath run. This higher unavailability of coal-based capacity partly explains the difference in the shortages between the two runs.

Figure A.3: Net load and maintenance in the RPO50S3 scenario



A.2 Hydro generation schedule

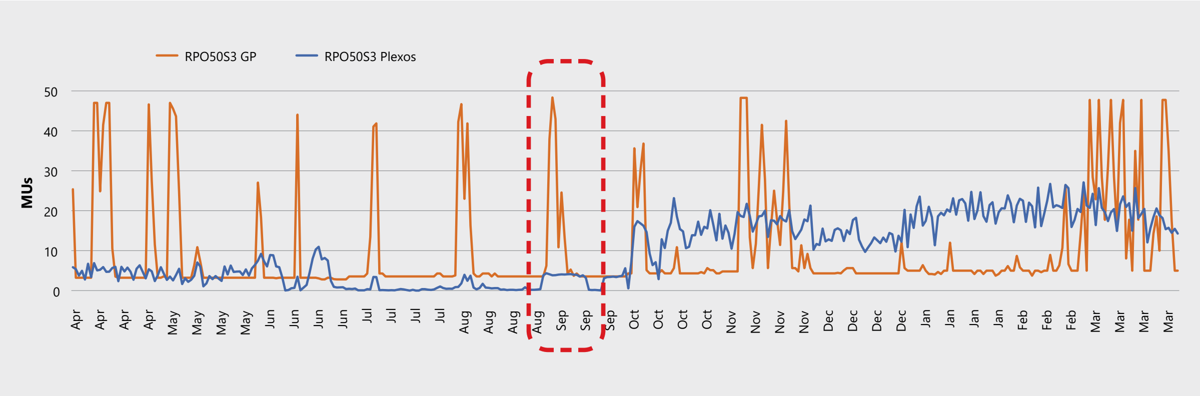
Hydroelectric projects, if scheduled efficiently, can be invaluable for system operation since they provide fast ramping capability. However, they are constrained by varying water flows due to different weather conditions as well as competing uses. Thus, hydroelectric projects have annual energy budgets based on the generation potential in a typical weather year. In addition, depending on the available storage and alternative uses for the water such as irrigation and environmental flows, hydro projects can have minimum and maximum generation by season and hour of day. The variable cost of hydro generation is typically low as there are no fuel costs. Given this, the hydro generation schedule forms a critical part of optimised dispatch operations.

In GridPath, daily hydro budgets are determined using a three-pass approach, as described in Section 4.3. In Plexos, the Medium Term (MT) Schedule is run with a reduced temporal detail and with partial chronology using a load duration curve approach, to determine hydro budgets on a quarterly basis.

In Maharashtra, there is over 2000 MW of storage-based hydroelectric generation (most of it at the Koyna project) that is available largely for power generation purposes. An annual energy budget along with monthly minimum generation based on past year data are specified, and hydro generation is optimised to reduce system costs in both the GridPath and PLEXOS models.

Figure A.4 shows a comparison of daily hydro generation between the GridPath and PLEXOS runs for scenario RPO50S3. As can be seen, hydro generation is scheduled throughout the year in the GridPath model, whereas in PLEXOS, hydropower is used as a seasonal resource. Note that this schedule varies from scenario to scenario.

Figure A.4: Hydro generation in the RPO50S3 scenario

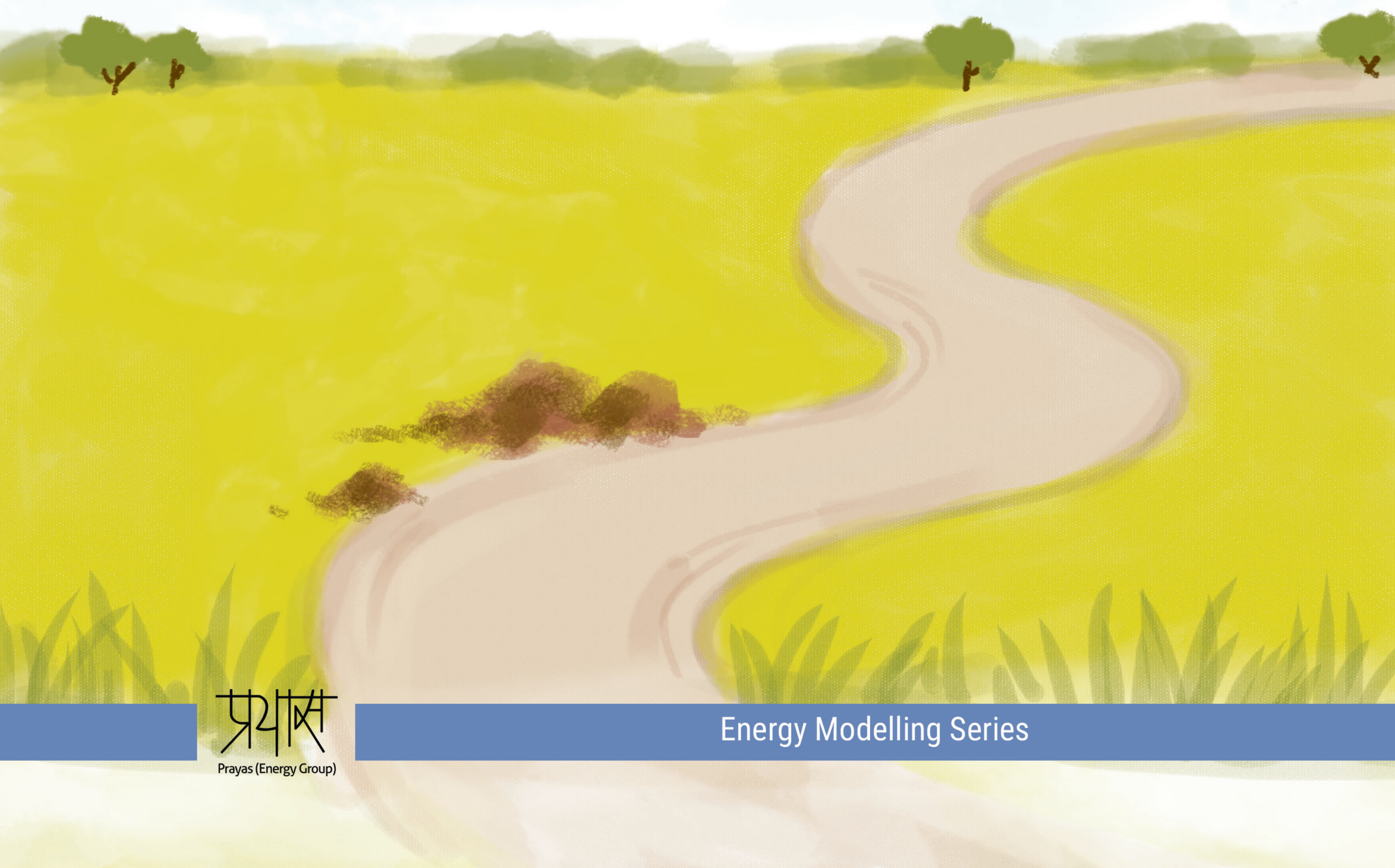


During the first 10 days of September when unmet demand is high, it can be seen that up to 40 GWh are generated from hydro sources on some of the days in the GridPath run, whereas less than 5 GWh per day come from hydro sources in the PLEXOS run. This results in higher shortages during this week in the PLEXOS run as compared to the GridPath run.

The results of the PLEXOS run could have been different if the hydro budgets are generated in the MT Schedule over a week instead of a quarter, or if the full chronology is used. This has not been investigated further since the overall insights remain the same in both the GridPath and PLEXOS models.

Over the last decade, renewable electricity (RE) generation, mostly from wind and solar, has displaced coal-based generation as the cheapest source of electricity in generation cost terms. It is also desirable to add as much renewables as the system can absorb, for environmental reasons. As the share of RE increases in India's energy mix, a closer look at its impact at the state level is needed to understand the implications for power procurement planning and grid operation.

This study investigates whether it is feasible to reliably and cost-effectively meet Maharashtra's power demand with no net coal capacity addition. This is done by analysing two sets of scenarios for 2030 - one with 30% RE generation share and additional coal capacity, and the other with 50% RE and battery storage. The analysis was done using GridPath, an open source modelling platform, as well as PLEXOS, a commercial power system simulation software.



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