4.4 Implications for technical operations of the grid

As assessed earlier, the main outcome of the reassignment was to designate a set of plants as being surplus to the needs of the system catering to the 'average energy demand' over the last 30-month period. In the process, nearly 50 GW worth of generation capacity was designated as being surplus (some to be decommissioned and some moth-balled, as detailed above). The overall PLF of the generating fleet increased by nearly 20 per cent in the process as expected. However, given that the reassignment did not really consider any network-related constraints, we make an assessment using high-level metrics to understand some key implications of such a reassignment exercise.

In the reassigned scenerio, the overall PLF improves to 79% from the baseline of 59%

A critical assessment is to see how the generation profile changes across the different regions of the country. We find that the Southern region would show a significant increase in overall generation by almost 11 per cent in the reassignment scenario. Concomitantly, the Eastern and Northern regions are expected to record a decrease in generation by 9 per cent and 6 per cent, respectively. The Western region would see a marginal increase of 3 per cent in generation (Table A3). While these changes in regional generation throw up concerns over the ability to move power between the regions, we see that over the course of the last 30 months, the individual regions have generated much larger amounts of thermal energy and also contributed a much larger thermal share to the grid than in the reassigned scenario (Table A8). At the day-level resolution, we see that these changes do not pose an operational challenge to the grid. However, the reassignment needs to be investigated at a higher temporal resolution to assess if such a shift in regional distribution of generation is likely to disrupt the system.

While regional considerations are important in system operations, from the perspective of individual discoms and states, exercising control over generation sources is perceived to be important. As there is a significant decrease in operational capacity (required) in the reassigned scenario, states across the board would see a reduction in their generation base. Nearly 60 per cent of the reduction in capacity in the reassigned scenario is attributed to the state-owned plants. Clearly, these plants were most inefficient in the stack and did not get requisitioned. In states like West Bengal and Rajasthan, this is most pronounced with more than 40 per cent decrease in overall installed capacity. Most states would witness a decrease in capacity between 20 and 30 per cent. However, states like Odisha, Haryana, Madhya Pradesh, and Assam are likely to experience lower levels of change (<20 per cent) to their capacity base. Further, state-owned plants are also likely to witness a 23 per cent reduction in generation from the base scenario. States such as Jharkhand, Chhattisgarh, Gujarat, Tamil Nadu, and Punjab may even experience a 40 per cent reduction in the generation from state-owned plants. Given that overall generation must remain constant across both scenarios (as they serve the same demand), for most states, the loss in generation from state-owned plants is made good by increased generation from private sector plants (Table A5). States like West Bengal would encounter a significant erosion (31 per cent) of overall generation within the state boundary, while Karnataka would notice a drastic rise in power generation (85 per cent). Barring these exceptions, overall generation changes within state boundaries are within ±20 per cent (Table A4).

Generation in the Southern region increases by nearly 11%, but a high level assessment does not suggest operational challenges from this

Over and above the split in generation across different regions, states, and ownership types, it is also important to address if some important attributes like system ramping capabilities change significantly as a result of this reassignment and consequent moth-balling of capacity. With the non-availability of many older units, it is expected that ramping capacity would decrease, as older units have published (and theoretical?) ramping rates that are higher than units of a newer vintage. We find that at the national and regional level, the ramping capacity changes may see a perceptible dip of nearly 26 per cent. At the national level, the ramping (up and down) capacity drops from 1,600 MW/min to 1,200 MW/ min

(Table A2). High temporal resolution dispatch data (15-minute time block) is available only for centrally owned inter-state generating stations (ISGS). We analysed the operations of the ISGS stations that are deemed surplus in our reassignment (~7.5 GW) and found that 3.5 GW of this capacity is used for ramping during peak hours to cater the peak demand[5]. The list of ISGS plants can be found in Table A10 of the annexure. However, it is worth mentioning that, for the most part, the observed peak ramping rates of the system over the last operational year saw the thermal fleet utilising only a fraction (5 per cent) of this ramping capacity (MERIT, n.d.). Importantly, most state-owned plants also do not contribute significantly to the ramping needs of the system presently and as a result, even in a reassigned scenario, we do not foresee a paradigm shift in the way the system ramping would be managed.

The discussion on ramping then brings us to the important question of what about contribution of thermal assets to the peak demand in the country? It is well known that, given the absence of 'peaker plants', we rely on our thermal coal plants to cater to the peak demand for several months. The demand surges typically during the evening and night hours and RE is not able to provide the matching supply. The system we are left with, in the reassigned scenario, has a total operational coal capacity of 143 GW. The actual peak contribution of thermal power plants, in the assessment period, is 140 GW. This clearly suggests that at the peak, the coal generation fleet has little slack to cater to any further increases in peak demand. However, the capacity considered in this assessment excluded nearly 6 GW of lignite-based capacity and 5.7 GW of coal assets that were in the early stages of commissioning over the assessment period. This again suggests that system would be able to cater to the peak load

4.5 Implications for supply and adequacy in future years (2020–2030)

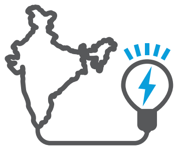
The final aspect of our evaluation is to assess how much of the demand in the later years of this decade will the retained plants be able to cater to? Here we consider future demand projections as envisioned in the NEP (CEA, 2018) and the CEA's Optimal Generation Mix Study for 2030 (CEA, 2019). As proposed earlier in this chapter, we envision that of the 50 GW of capacity identified as surplus, 30 GW must be primed for decommissioning at the earliest, while 20 GW of generation capacity is of a newer vintage that might still be beneficial to the system from an operations perspective or to cater to sudden (or gradual) growth in demand. While assessing system adequacy in catering to the overall demand (not necessarily from a network operations perspective), the retained fleet of 143 GW of capacity will be considered, in tandem with the proposed moth-balled capacity (20 GW) and any new capacity that will be added online from February 2020.

On new capacity that is under construction, we rely on existing data from CEA on the status of such plants. The latest report available suggests that a total capacity of 60 GW is under construction as of February 2020 (CEA, 2021). Of this 60 GW, specific timelines for construction and commissioning (acknowledging delays) have been proposed only for 36 GW of capacity. The construction of remaining 24 GW of capacity is either on hold, the assets are stressed, or there is uncertainty about the future progress of the construction or commissioning.

While theoretical ramping capacity (MW/min) sees a dip of 26%, only 3.5 GW of capacity that is actually used for ramping purposes is shelved in the reassigned scenario

5 The ISGS dispatch data is available in the public domain only from June 2020. Hence, the analysis was done for the period January – February 2021 and does not overlap with the analysis period (September 2017 – February 2020).

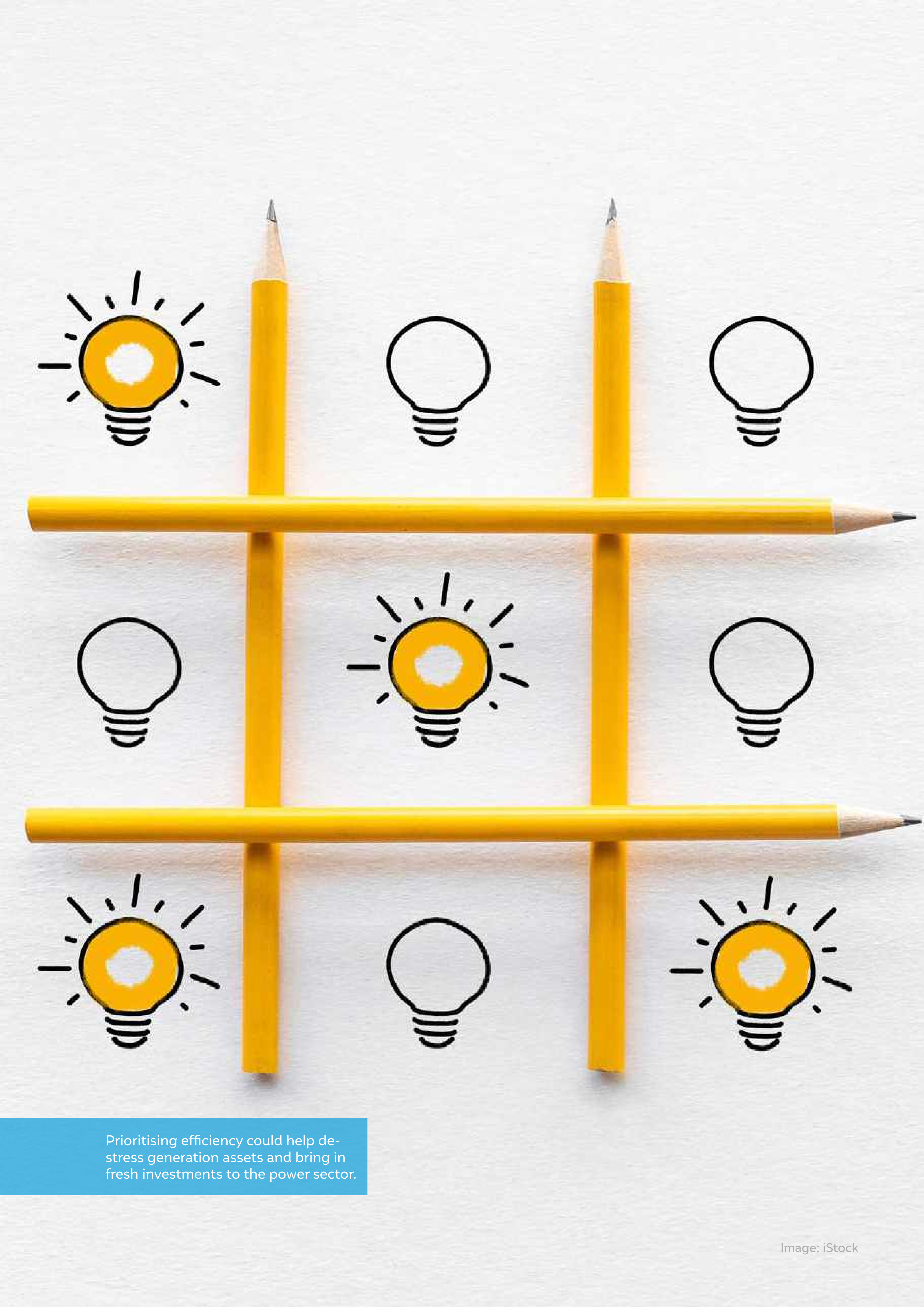
As mentioned earlier, in addition to the 143 GW of capacity retained in the analysis, there is an additional 12 GW of lignite and coal-based capacity (existing) that was not considered in the assessment. In total, we forecast 175 GW[6] of capacity as *potentially* available to supply to the system, through the rest of this decade, excluding any new capacity that might come on board from the projects under construction.



The retained thermal capacity and new generation capacity on boarded in this decade is sufficient to meet projected electricity demand

As per existing projections made in recent studies by the CEA, the share of coal in overall generation reduces from 68 per cent in 2022 to 62 per cent in 2027 and 58 per cent in 2030. In absolute terms, the generation from coal is expected to rise over the years. We find that, even by just considering the active 143 GW and moth-balled capacity (of 20 GW), the generation from this limited coal fleet is able to provide for 108 per cent of the average supply expected from all-coal assets in 2022 and 77 per cent of the supply expected from all-coal assets in 2030. If we consider days when the demand from coal is at its peak (winters and late monsoon period), we find that this limited coal fleet is able to provide 91 per cent of the peak supply expected from all-coal in 2022 and 66 per cent of the peak-supply expected from all-coal in 2030 (Table A6). With significant capacity of coal going to be made available to the system in the later years of the decade, we assess that the retained fleet is able to contribute disproportionately to the needs of the system. Experts are sceptical that the aggressive roll-out of 450 GW of RE by 2030 may not happen as the economy in the post-COVID scenario is likely to experience some teething issues, deflating some of the growth potential for all sources of energy generation. Equally, it can be expected that a sluggish economic growth would also dent the electricity demand as well in such a scenario. It is also more likely that the under-construction coal assets would see the light of day (given the significant resources already expended) at the expense of new RE capacity, the costs of which may not be justified (notwithstanding climate commitments). Under the various scenarios that could pan out in future, as explained, we are confident that the retained coal capacity would be sufficient and would contribute more than its fair share to the supply that would be expected from all coal assets over the course of this coming decade.

6 143 GW retained from the original starting point of 194 GW + 12 GW of capacity not considered in the assessment + 20 GW of capacity that is moth-balled (from the 194 GW).



Prioritising efficiency could help de-stress generation assets and bring in fresh investments to the power sector.

Image: iStock

5. Conclusions and recommendations

In this important study, we set out to examine the composition of the thermal (coal-based) generating fleet currently in use in the Indian power system, propose possible efficiency improvements, and the resulting financial and economic benefits from such improvements. We proposed a novel parametric estimation-based approach to characterise the efficiency of the thermal fleet and its variable cost structure. The parametrised functions further helped propose a dispatch stack that was based on energy efficiency of electricity generation and the costs associated with such a dispatch stack.

A reassigned scenario yields variable costs savings of ~INR 9000 crore a year

We found that at the aggregate level, an efficiency-based dispatch stack makes 50 GW of generation capacity redundant and surplus to the needs of serving the average demand over the analysis period (September 2017 to February 2020). The overall PLF of the fleet improves drastically from 59 to 78 per cent. The efficiency of the overall dispatch, in the reassigned scenario, is higher by about 6 per cent and the overall SHR falls to 2,719 kcal/kWh. In other words, the efficiency of the fleet improves from 29.7 to 31.6 per cent. A direct consequence of this efficiency improvement is that the overall coal consumption associated with generation drops (almost proportionately) and results in a coal savings of 42 MT of coal annually, on a base of 679 MT. This would translate to CO_2 emissions savings of to the tune of 42 MT annually and significant reduction in criteria pollutant loading as well. The financial implications of this efficiency-based reassignment of generation resulted in annual savings of INR 8,944 crore, primarily driven by avoided coal use in generation and savings in auxiliary consumption. There is also an opportunity for a one-time saving of INR 10,250 crore in avoided retrofit costs for plants that are part of the efficient generation stack.

On the critical question of what we propose to do with the identified surplus capacity, we arrived at a two-pronged solution. Around 30 GW of capacity, which overlaps with the plants identified in the NEP for retirement by 2027, must be considered for accelerated decommissioning, given the economic and environmental benefits associated with them not requiring to generate power. Each passing year of delay in letting them continue to generate implies that the system becomes more expensive and emission-intensive as a whole. Based on the financial solutions that we can come up with, decommissioning could also result in savings of the fixed cost outlays over the course of the remaining (contractual) life of these assets. For 20 GW of capacity that represents plants of a newer vintage and not identified for retirement in the NEP, we propose a temporary moth-balling of these facilities. Given that fixed cost payments are contractual obligations and must be made, we envision that these facilities will continue to be available for the system should the need arise. Given the uncertainty in demand outlook post-COVID and the trajectory of RE growth over the course of the decade (despite the aggressive target of 450 GW by 2030), the availability of these plants, over and above those that are under construction, provides a cushion for operational contingencies and supply adequacy. In the worst-case scenario, if they were to remain idle for the rest of their lives, it would still be a beneficial outcome, for the end-consumers and discoms, as they are anyway inefficient and the system is better off relying on other plants.

While the reassignment exercise did not consider any operational constraints associated with the grid, we performed an evaluation using high-level metrics that gave a glimpse of the operational disruptions that the reassignment exercise could pose. The slack in the system is obviously lower, with the fleet PLF going up to 78 per cent, which would require more efficient coordination on part of the system operator. State-owned generation assets account for 60 per cent of the capacity that is rendered surplus. The system is now more reliant on private sector plants and, as a result, the cushion of payment delays to state-owned plants that currently prevails would drastically come down. The impact of reassignment on states is uneven, with significant capacity reduction in West Bengal and Rajasthan. In generation terms, West Bengal is likely to experience a significant decline in overall generation of more than 40 per cent and Karnataka would witness a rise in generation by 85 per cent. The change in generation mix to a younger fleet also means that technical ramping capacity is also reduced. Given that the system today uses only a fraction of the capacity that is available in surplus, we conclude that this is not a significant barrier to the overhaul of the generation mix.

The NEP also identifies these 30 GW of capacity for decommissioning by 2027. This must be accelerated to realise these savings

On the two important questions of adequacy of such a system to cater to peak demand and for supply in the future years, we find a significant slack in the system by way of the additional capacity that we have not considered in the analysis—lignite plants (6 GW), newly commissioned coal-based capacity (5.7 GW), and plants under construction that are likely to come on board in this decade (36 GW). Over and above these capacity additions, the option to moth-ball 20 GW of capacity provides a ready breathing space for the system, should the need arise. However, rigorous assessment of the demand over the coming years and planning for operational dispatch bottlenecks would help ascertain the extent to which these redundancies would have to be made use of in case of an unexpected surge in demand.

The main takeaway from this exercise is that a unified electricity market, which treats the entire country as one dispatch region, is a desirable one. We echo the recommendations of Central Electricity Regulatory Commission (CERC) discussion paper on the redesigning of the day-ahead market for electricity and a focus on a shift to market-based economic dispatch (MBED) and move away from bilateral scheduling of generation (CERC, 2018). As India attempts to make a shift towards MBED, the need to assess efficient assets becomes even more important and the culling of surplus assets is implicit in the process. However, for this to happen, there is a fundamental change that is needed—the sanctity of variable costs in the Indian power system must be questioned. Given the distortions in the fuel market, lop-sided fuel availability and the unequal bargaining power of various actors in the system, we are unable to have a system where the lowest cost system is also the most efficient in terms of thermal efficiency.

India has made ambitious commitments to reduce GHG emissions on account of global agreements and the health emergency that our population faces on account of sustained levels of air pollution, to which thermal power plants contribute significantly, imply that it is in our interest to reduce coal use, in every way possible. While India's reliance on coal is likely to continue and rise over the course of this decade, there is a need to examine the opportunities that exist in the power sector today to rein in wasteful coal use. The overall generation efficiency of the fleet currently points to a lack of emphasis on efficiency, despite the power sector being strongly regulated with clear requirements for adhering to design efficiency standards.

Despite the increase in consumption of coal, this approach helps rein in coal dependence and eases financial pressure on the system