BROOKINGS INDIA

THE FUTURE OF INDIAN ELECTRICITY SUPPLY

SCENARIOS OF COAL USE BY 2030

BY | **SAHIL ALI & RAHUL TONGIA**

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SCENARIOS OF COAL USE TILL 2030

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Executive summary

- Coal represents approximately three-quarters of electricity generation in India today. This study aims to examine coal-based electricity generation (grid and captive) in light of the ongoing demand and supply side transformations in the electricity sector, especially the rise of Renewable Energy (RE). This is the supply focussed companion paper of the Brookings report on the bottom up analysis of India's 2030 electricity demand.

- The authors' analyses of 2030 end-use electricity demand from grid and captive generation ranges from 2,075 to 2,785 TWh (5.4-7.4% CAGR, with the mid-scenario CAGR of 6.2%), compared to 949 TWh in 2015. The analysis spans GDP growth rates of 6.5, 7.0 and 7.5% CAGR, each associated with its respective high, medium and low scenarios for energy efficiency and conservation.

- For the purpose of this analysis, demand scenarios ranging from 5.4-6.5% CAGR are shortlisted as lower and upper bounds based on historically prevalent rates of and outlook on energy efficiency, after accounting for own (auxiliary) consumption and technical grid losses. A range of scenarios of non-fossil capacity growth and technological improvements are developed and coal-based generation is modelled as a residual to balance supply with end-use electricity demand.

    - The modelling platform used is Analytica, which allows simultaneous n-dimensional analysis and sensitivity treatments—an alternative to endogenous pricing equilibrium models. This enables the examination of the Indian electricity system under more relevant contexts and evolutionary frameworks, where the least-cost optimised solution may not necessarily be the socially preferred pathway. Such arithmetic balancing also avoids complications of attempting to examine economic trade-offs in supply options—an area fraught with uncertainty, especially around RE, fossil and battery prices.

    - We find that electricity generation from coal continues to rise through 2030 in virtually all scenarios, albeit at much lower growth rates than the past. This has profound implications not just for Coal India Limited (CIL) but also the Indian Railways, which is dependent on carrying coal to meet its revenue and cross-subsidy mandates.

- Other relevant model details are as follows:

    - The base and terminal years for the analysis are 2017 and 2030. While 2017 is the most recent year for available data for disaggregated official baseline, 2030 fits with a number of strategic objectives, including India's climate change commitments. Base year results are calibrated and synced with data from the Central Electricity Authority (CEA), Ministry of Coal (MoC), and other relevant sources.

    - Of the possible 81 cases in the model [nine demand, three renewable energy (RE), and three Other Non-Fossil (ONF, including hydro and nuclear)], nine are shortlisted and presented here based on the range of plausible outcomes. All cases of generation capacity presented have a non-fossil mix of well over 40%, as mandated in the Nationally Determined Contribution (NDCs).

    - Coal-based generation and coal demand (domestic and imported) is calculated as a residual, after deducting generation from other sources, subject to multiple constraints. RE is modelled across a range of capacities with a 'must-run' equivalent status. Gas is viewed as a modest source of supply given pricing constraints. Nuclear and hydro are modelled to grow in absolute terms, but the share of hydropower in generation falls across scenarios. The efficiency of coal-based generation rises with the growth in the share of super-critical plants. We also assume the phase-out of older (sub-critical) plants, for end-of-life as well as environmental reasons.

  - While coal has been the bedrock of electricity supply in India's top-down planning model focused on self-sufficiency, present evidence and our analysis indicates that the days of double-digit coal power capacity growth as witnessed in the previous decade are over. In fact, the additional planned coal capacity under various stages of construction by 2022 could suffice until 2030.

  - Significantly, while the analysis does not directly factor in time of day, it does account for mid-day demand and its link to RE and coal output (including implied PLFs) to examine any curtailments in high RE situation.

- Based on electricity demand scenarios and transmission and distribution (T&D) loss trajectories till 2030, grid supply requirement at bus-bars is likely to grow to 2,057-2,341 TWh (4.6-5.6% CAGR) compared to 1,149 TWh in 2017.

  - Of this, sources except coal may contribute between 611-1,007 TWh based on non-fossil capacity deployment scenarios, which vary between 262 GW and 436 GW (196-350 GW RE) by 2030. Based on recent policy announcements, we also provide a sensitivity analysis of a 'very high' scenario of 500 GW RE by 2030.

  - This implies that the maximum generation requirement from grid-based coal plants in 2030 is not to be more than 1,753 TWh, yielding 5.6% CAGR growth from 2015. This stands in stark contrast to the decadal trend of 7.4% CAGR of coal generation, compounded by the fact that the actual requirement will likely be much lower than the maximum (derived on a pessimistic scenario of RE and ONF deployment). Coal-based power generation in the mid-scenario grows at 4.6% CAGR. Growth of coal demand will likely be even lower due to improving power plant efficiency and increased penetration of advanced technologies in the mix.

  - Captive generation (> 1MW) on the other hand will likely witness higher growth rates in line with past trends which have led to a secular increase in its share of total generation. Net generation from captive is projected to grow to 318-361 TWh (5.5-6.5% CAGR) from 159 TWh in 2017, with coal contributing approximately 66%, down from over 80% in 2017.

- Grid coal generation will become increasingly efficient by 2030 with a higher super-critical capacity (45%) and even some ultra-super-critical capacity in the mix (5%).

  - Sub-critical capacity is set to fall from 82% to 50% of the mix on account of retirements, pollution control measures, etc. This will likely improve the overall generation efficiency by at least 2.5 percentage points to 36.2%.

- The domestic coal demand and actual generation from coal power plants is calibrated in 2017 at a GCV value of 3958 kcal/kg (corresponding to G12 grade).

  - This includes 80% raw non-coking coal, and 20% lignite, coking and washed coal.

  - While future analysis takes place with constant domestic GCVs, falling GCVs based on historical trends could lead to approximately 75 million tonnes (Mt) of greater domestic coal demand.

- Lower specific coal consumption (SCC) in the future will be driven by two key factors: improved generation efficiency and increasing shares of imports due to technological, logistical and locational reasons.

- Average grid SCC is set to drop from 0.62 kg/kWh to 0.57 kg/kWh in 2030.
- However, with falling domestic, the drop could be much lower (0.60 kg/kWh at 3,650 kcal/kg), or SCC may even increase (0.63 kg/kWh at 3,450 kcal/kg).

- In the absence of major interventions, imported coal's share in (grid and captive) generation could grow from 12.2 to 15.5%, reaching 129-198 Mt by 2030.
  - Using washed coal (20-25% of domestic consumption) for imported can reduce the share of imports to below 12.2%.
  - This comes with a need to mine (at existing yield ratios) at least 42-65 Mt of additional raw coal, aside from the environmental implications of washing.
- With no major incentive for technology upgradation, captive coal plants are likely to continue using sub-critical capacity, with average efficiency improving from 32% to 34%.
- Coal will remain a dominant fuel source in India's electricity mix, with over 50% share in generation by 2030 under different demand and non-fossil scenarios.
  - Accordingly, aggregate coal demand for electricity (including domestic and imported coal for grid and captive generation) may grow from 672 Mt in 2017 to 827-1,277 Mt by 2030 (1.6-5.1% CAGR).
  - A capacity of 260 GW of grid-based coal plants (already planned or in some stage of construction) is likely to suffice till 2030.
  - If the 175 GW RE target is achieved by 2022, 210 GW of coal capacity will suffice with adequate PLF headroom; likewise, 210 GW will suffice by 2030 if the recent policy announcement of 500 GW RE materialises by then (with appropriate storage and load shifting options available).
- There is no 'peak coal' situation in the power sector by 2030, unless the 500 GW RE scenario materialises (with adequate grid-level storage), electricity demand growth is at its lowest and GCVs of domestic coal going to power are no worse than 2017 levels.
  - While coal generation growth will continue to fall as RE keeps gaining shares beyond 2030, the median RE capacity addition between 2030 and 2040 will need to be over 60 GW per annum for the absolute generation from coal to stabilise (or decline).

Figure A: Scenarios of net generation (billion units) from coal, RE and other sources

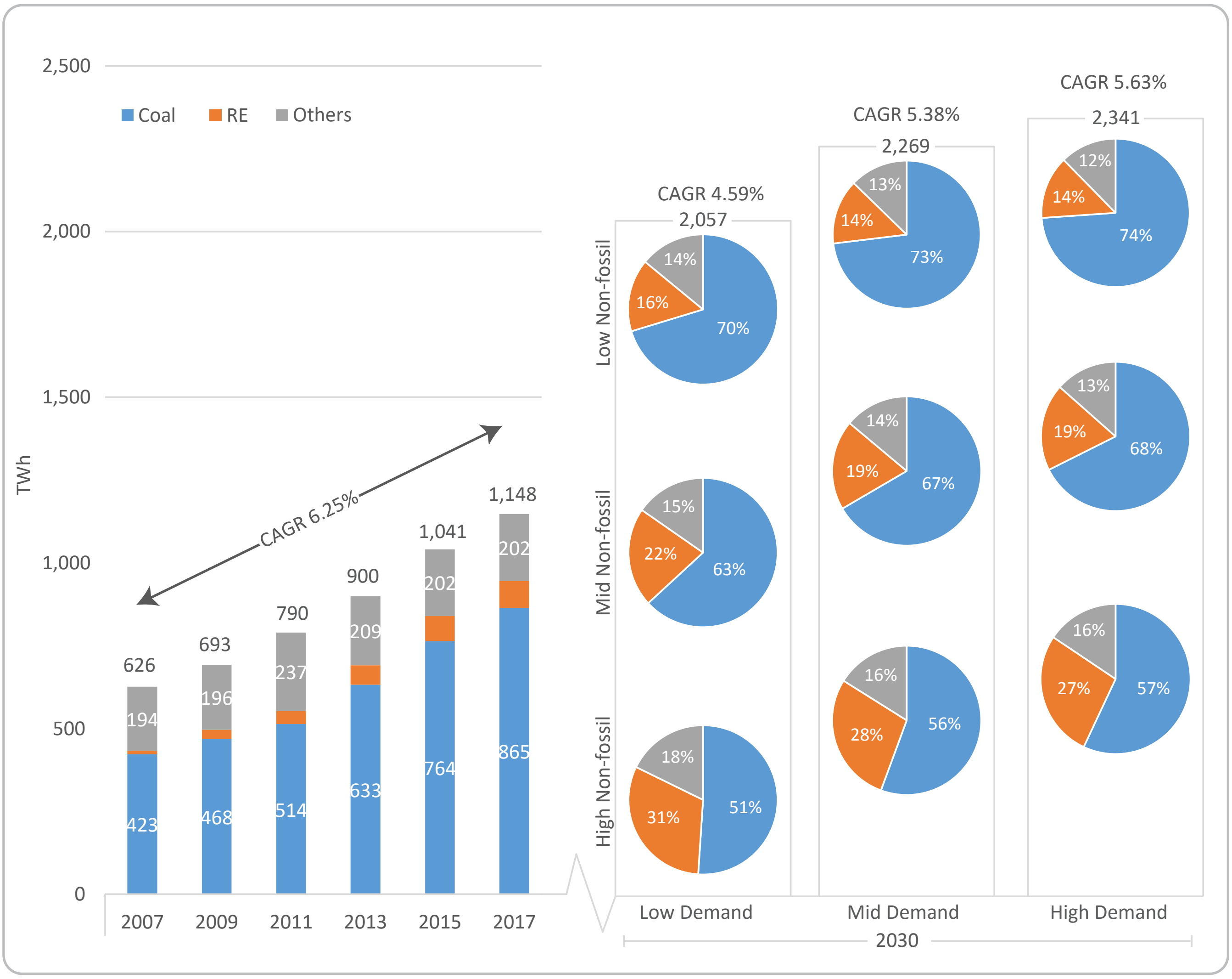


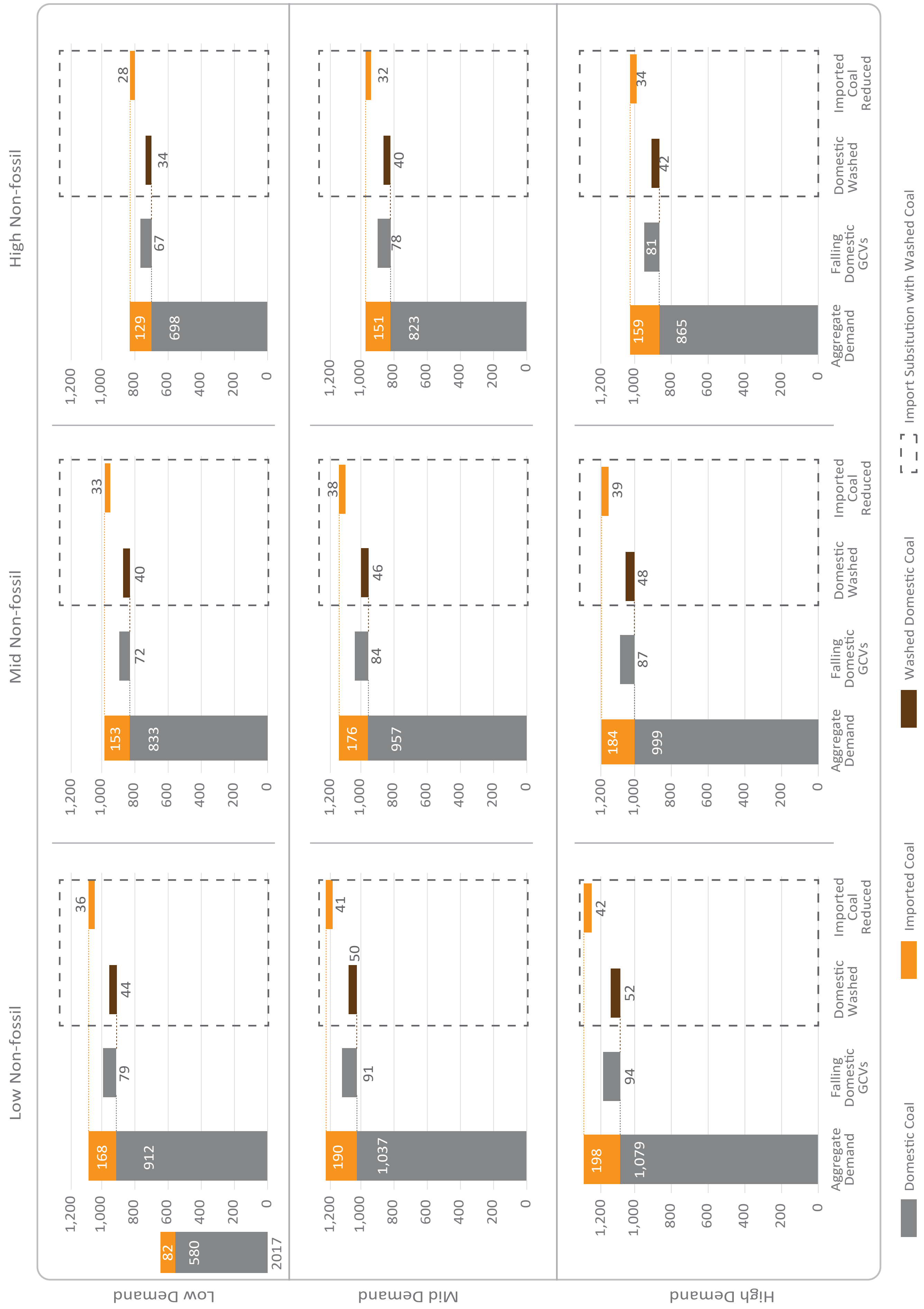
Fig. A (above) shows the historical trend and future scenarios of grid-based net generation (availability at bus-bars) from coal, RE and all other sources. The nine scenarios consist of three electricity demand and three non-fossil scenarios.

Fig. B (next page) shows the aggregate demand of domestic and imported coal from grid and captive sources and two sensitivities based on:

I) *Falling domestic GCVs:* The aggregate demand is obtained at constant domestic coal GCVs. However, if the domestic GCVs were to continue falling as in the past, the additional domestic coal required to meet energy input requirement is represented.

II) *Import substitution:* The amount of washed domestic coal required to substitute some of the imported coal, such that the share of imported coal in electricity does not increase from 2017 levels.

Figure B: Scenarios and sensitivities of coal demand (million tonnes) by 2030



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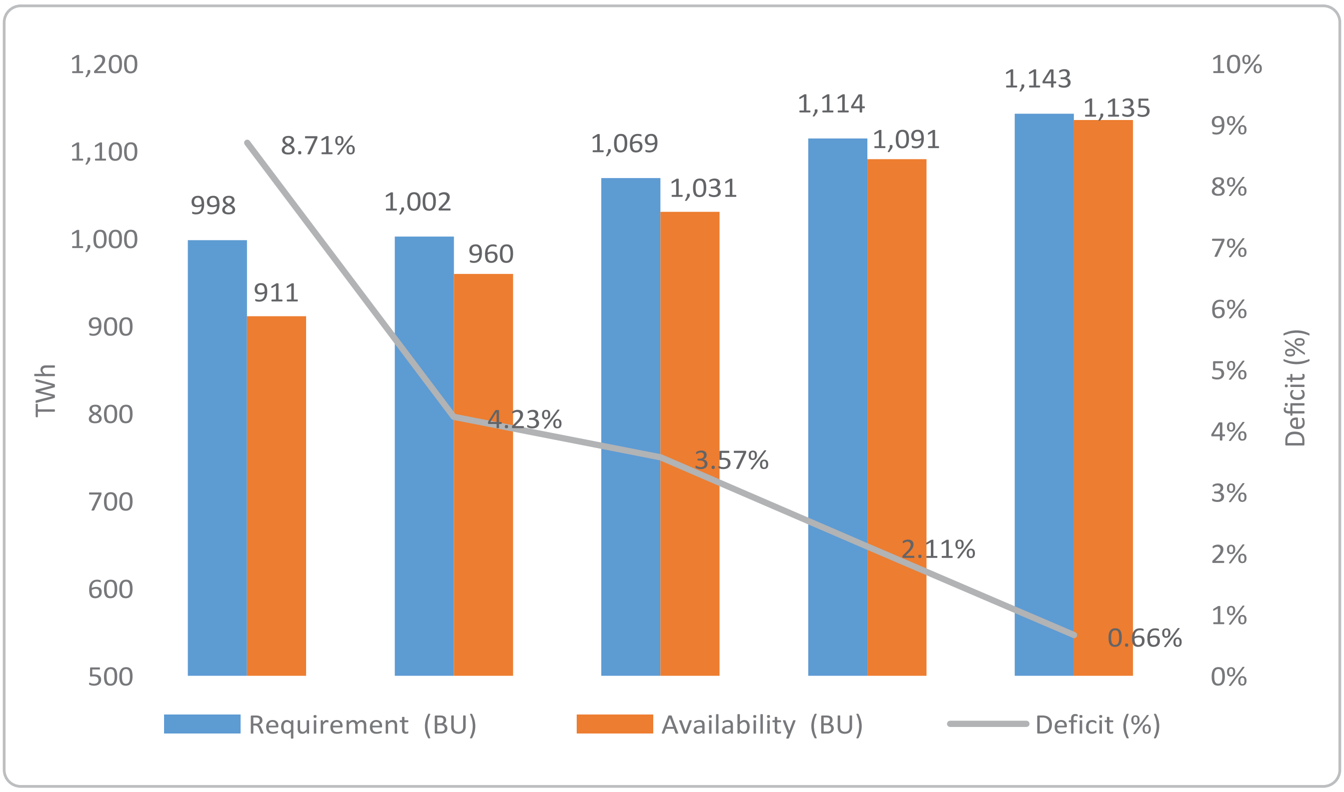
1. Introduction and rationale

For various reasons, India's electricity supply has been influenced by a target-driven and top-down planning process. Owing to vast latent demand; growing industrialisation; pump-set energisation; and household and railway energisation with electricity, on the one hand, and sizeable gestation lags and infrastructure lock-ins on the other, the capacity additions have been oriented towards fuelling development needs. India's per capita end-use electricity consumption remains at under 1,000 kWh per annum[1] which is much lower than the world average. However, its transmission and distribution (T&D) losses remain amongst the highest in the world, accompanied by arguably high levels of commercial losses owing to theft, non-billing and/or non-collection. This, among other issues, has created persistent liquidity issues in India's electricity distribution utilities (Discoms), which many would argue is slowing the pace of India's electricity reforms.

In the recent past, persistent efforts to augment supply coupled with slowdowns in demand have resulted in a reduction of both energy and peak deficits[2], as demonstrated in Figure 1 and Figure 2.

Figure 1: Recent trends in grid-based energy requirement, availability and deficit

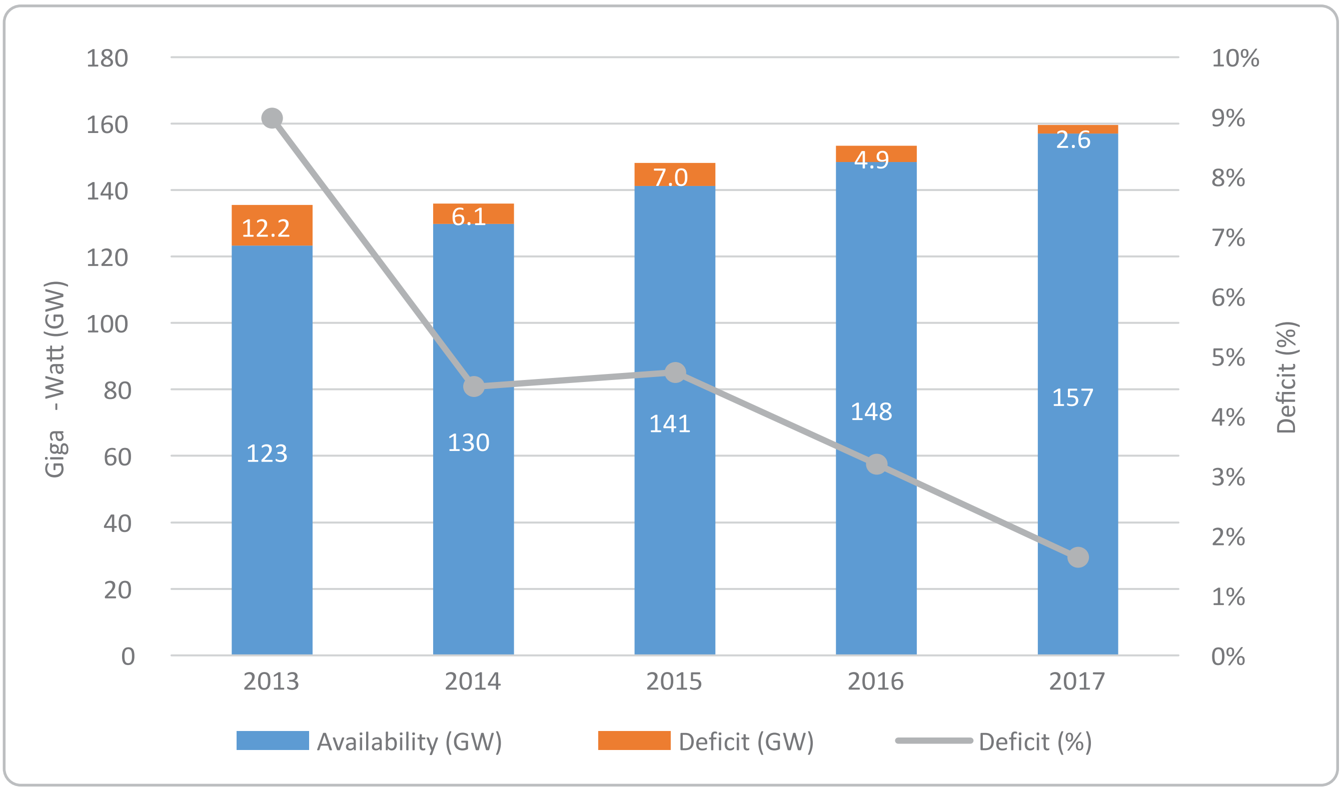


Source: CEA Load Generation and Balancing Reports.

[1] This was 724 kWh in 2017, after accounting for end-use consumption from utilities and captive plants (non-utilities > 1 Mega-watt (MW)).

[2] Official methodologies as adopted in CEA's Load Generation and Balancing Reports understate the shortfall in supply because of reporting shortfall at a notional peak time instead of actual or instrumented shortfall, but also due to other accounting issues (Tongia, Re-thinking Access and Electrification in India: From Wire to Service, 2014). However, the overall trend remains positive.

Figure 2: Recent trends in peak availability and deficit



Source: CEA Load Generation and Balancing Reports.

Further, the technical T&D losses have also been reducing owing to concerted efforts in the form of government policies like Ujjwal Discom Assurance Yojana (UDAY), Restructured Accelerated Power Development and Reforms (R-APDRP) and various state-level initiatives at strengthening the distribution infrastructure. Over the past 15 years, T&D losses have been reduced by over a third to less than 22% in 2016 (Central Electricity Authority, 2017). This has further checked the growth of electricity demands at bus-bars. However, there is significant room for improvement: world average losses are less than 10% and countries like Japan, South Korea, and Germany have reached less than 5%. This indicates that the growth of electricity generation in the future will be lower than that of electricity demands owing to an improved T&D loss situation.

With these general trends in mind, this report focuses on the future scenarios of electricity generation, with an emphasis on the supply mix, particularly the share and growth of coal-based power by 2030. In 2017, coal contributed to nearly three-fourths to the 1149 TWh of electricity generated. Further, over four-fifths of the total domestic coal despatch (633 Mt) in 2016 was used for electricity by grid and captive power plants (Ministry of Coal, 2017). Taxes, cesses, and royalties from coal contribute as much as two to three% to central government revenues[3] (Ministry of Coal, 2017; Coal India Ltd., 2018). A recent study at Brookings India shows how the coal's interlinkages with the Indian Railways results in a tariff pass-through of INR 0.14 per each unit of coal-based electricity generated in 2017 to cross-subsidise consumer fares (Kamboj & Tongia, 2018).

[3] In states such as Chattisgarh and Jharkhand, this is as high as 7%.

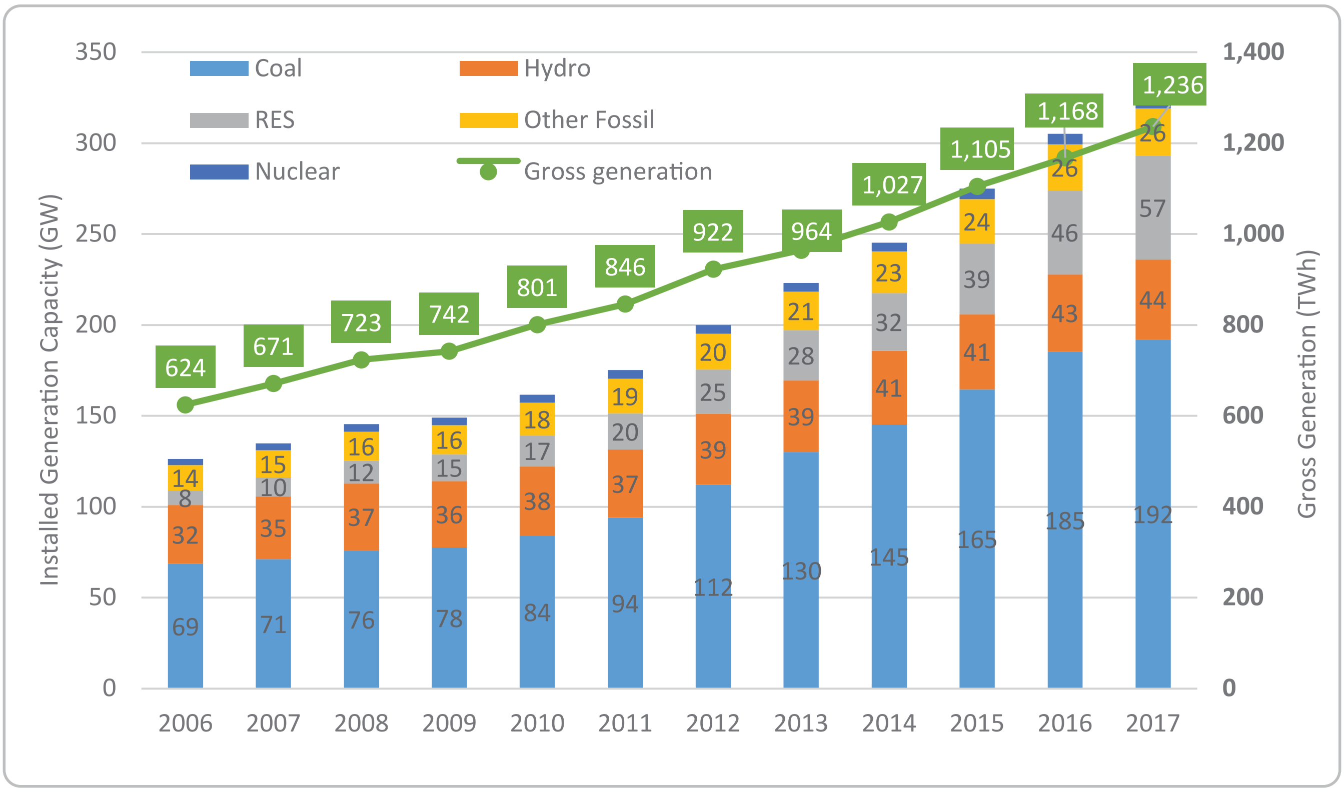
More recently, the slowdown in electricity demand growth and the ongoing push towards 175 GW RE by 2022 is likely to have significant implications for coal generation in the future, based on likely growth in electricity demand. The author's bottom-up analysis of end-use electricity demand shows this in the range of 5.4-7.4% compounded annual growth rate (CAGR), with a plausible growth of 6.2% CAGR through 2030[4] (Ali, 2018). Therefore, whereas multiple research questions are examined, they are analysed from the perspective of the required generation from coal to meet the electricity demand by 2030 and its implications.

1.1. Trends in electricity generation

Figure 3 shows how installed capacity of grid-connected power plants has almost doubled from 2006 to 2017, growing at 9.1% CAGR over the past decade. Coal-based capacity has achieved 10.4% CAGR in the same period, with an almost 60% share in installed capacity indicating the significance of coal as the bedrock of India's supply-mix. RE capacity has grown at 19% CAGR since 2010 with the launch of the then National Solar Mission, whereas hydro's share in capacity has reduced from over a quarter in 2006 to 13.5% in 2017.

Grid-based gross generation has grown at 6.3% CAGR for the entire mix and 7.4% for electricity from coal, with the latter reaching three-quarters share in gross generation. Coupled with the fact that India's load curve has remained fairly flat with relatively small peaks compared to developed nations, coal-based power being the cheapest base-load choice has helped its dominance in India's electricity sector.

Figure 3: Trends in grid-based installed capacity (source-wise) and gross generation

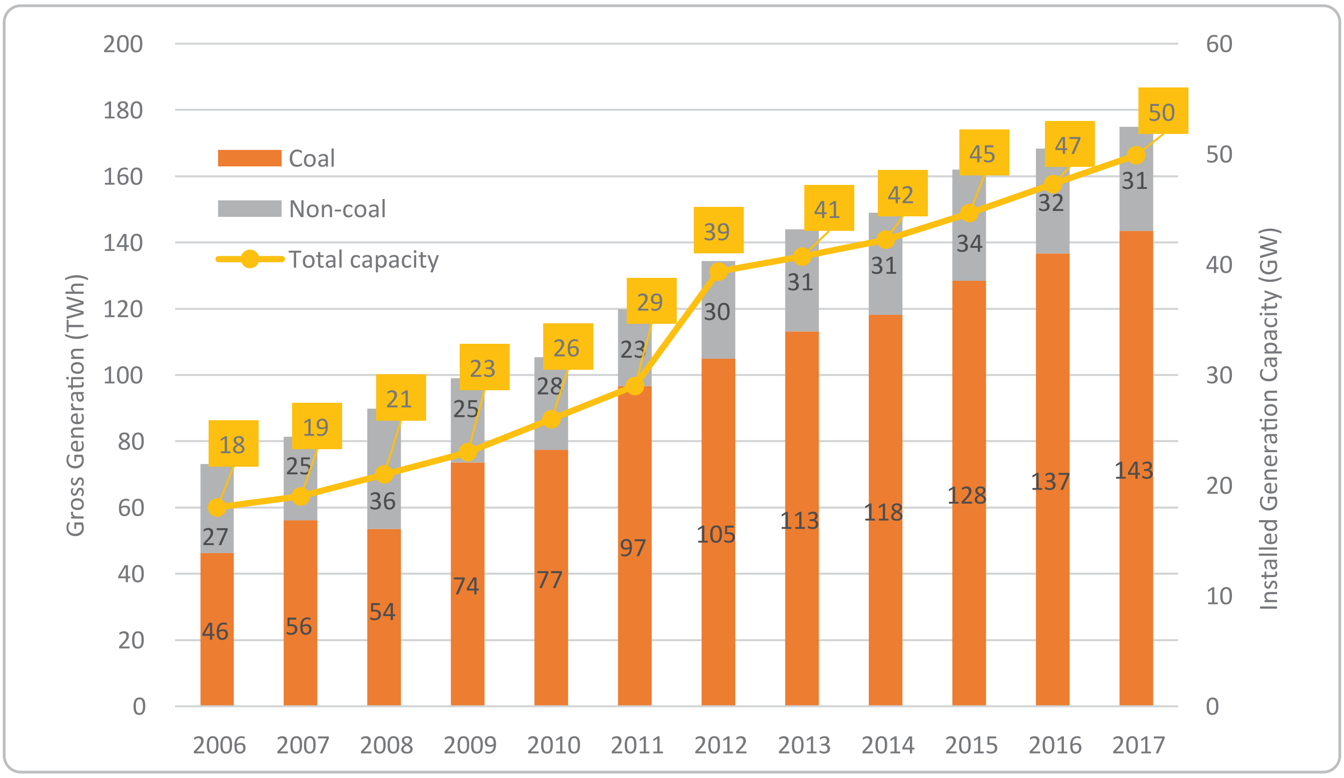


Source: CEA General Reviews and author's calculations.

[4] The cases of electricity demand are derived under different scenarios of macroeconomic growth, energy efficiency and conservation measures; and policies affecting end-use demand for all grid and captive users.

On the other hand, Figure 4 indicates that captive generation capacity has grown at 10.1% CAGR in the last decade. Coal forms 60% of the generation capacity in captive plants as well. Similarly, generation CAGR from captive is higher than the grid's by 2 percentage points at 8.3%. The primary motivation for growing captive consumption is the need for reliable power for industry, which is why the coal component of captive generation has grown at almost 10% CAGR in the given period.

Figure 4: Trends in generation (coal and non-coal) and installed capacity of captive plants



Source: CEA General Reviews and author's calculations

Taking Figure 3 and Figure 4 together, while total installed capacity and generation have grown at 8.4 and 6.5% CAGRs respectively between 2007 and 2017, the same from coal have grown at 10.4% and 7.4% CAGRs, indicating the growing share of coal in supplying India's electricity needs. However, as discussed earlier several factors indicate that a reversal in this trend is on the cards. The following section discusses the approach followed to estimate India's future electricity generation, fuel-mix and its implications.

2. Scope and methodology

To analyse the aforementioned questions, a spectrum of likely generation from coal-based on growth in electricity demand and non-fossil sources is estimated. From a total of nine electricity demand scenarios, three are shortlisted to represent the upper and lower bounds and mid values. The lower bound is derived as 5.4% CAGR (low economic growth and end-use demand with high efficiency) and the mid value is 6.2% CAGR (mid economic growth with mid-efficiency)[5]. However, the upper bound at high economic growth is taken at medium levels of efficiency (rather than low), which comes to 6.5% CAGR (Ali, 2018). This is because historical experience in India and around the world demonstrates how market transformations in energy efficiency goes hand-in-hand with higher economic growth (Planning Commission, 2014; Ali, 2018).

These are coupled with three cases each for renewable energy (RE) and other non-fossil (hydro and nuclear) sources. Plausible penetration of coal generation technologies such as sub, super and ultra-supercritical are modelled for a range of efficiencies and domestic-imported coal mix[6]. The (net) generation requirement from coal is derived as a residual after netting out captive's share[7] in demand and generation, generation from other grid sources and rooftop PV (RTPV), technical (T&D) losses and auxiliary consumption.

Technology costs are not explicitly modelled here, since capacities under different scenarios are fixed and PLFs constrained. The decision to signal investment in a particular capacity type versus another is based on a number of factors aside from costs, as discussed later. The logic followed attempts to model the implications of this decision-making process in terms of different cases of deployed capacity. Instead of optimising the mix, we are interested in the role that coal will play under different cases of demand and generation from other fuel sources that combine to form scenarios. Lots of bets in the power sector have already been made, and intentions signalled via regulatory provisions or policy announcements; all under different stages of progress. We do not aim to examine if these policies or levels of achievements are least cost or price optimal. Instead, we attempt to examine them based on their cumulative.

We treat RE as a must-run resource with improving PLFs, and assume hydro PLFs as being constrained by historical factors that continue despite capacity growth, modest growth in gas capacity and PLFs due to dual issues of availability and prices that render it uncompetitive vis-à-vis coal, and nuclear as a base-load with stable PLFs due to technological reasons. Coal plant PLFs are endogenously calculated based on exogenously specified future capacities that are triangulated based on scenarios[8].

[5] The low, mid and high levels of GDP growth are taken as 6.5, 7 and 7.5% CAGR.

[6] While some plants currently use blended coal, certain supercritical boilers are designed to accept only imported varieties with lower ash content compared to domestic coal.

[7] Electricity and coal requirement from captive is calculated separately since it operates on different weighted efficiencies and has a more limited scope of future improvement compared to grid-based coal plants. Also, it does not carry the technical losses associated with distribution of supply.

[8] As an example, a low demand and high non-fossil scenario will need less coal capacity than other scenarios. Our aim is to achieve coal PLFs between 60 and 75%, which leaves adequate headroom for adjustment in either direction.

A full examination of supply to meet the demand consists of three levels of increasing sophistication:

1) Meeting the aggregate energy demand.
2) Meeting instantaneous demand at all points of the day.
3) Meeting other systemic constraints on transmission, generator ramping etc.

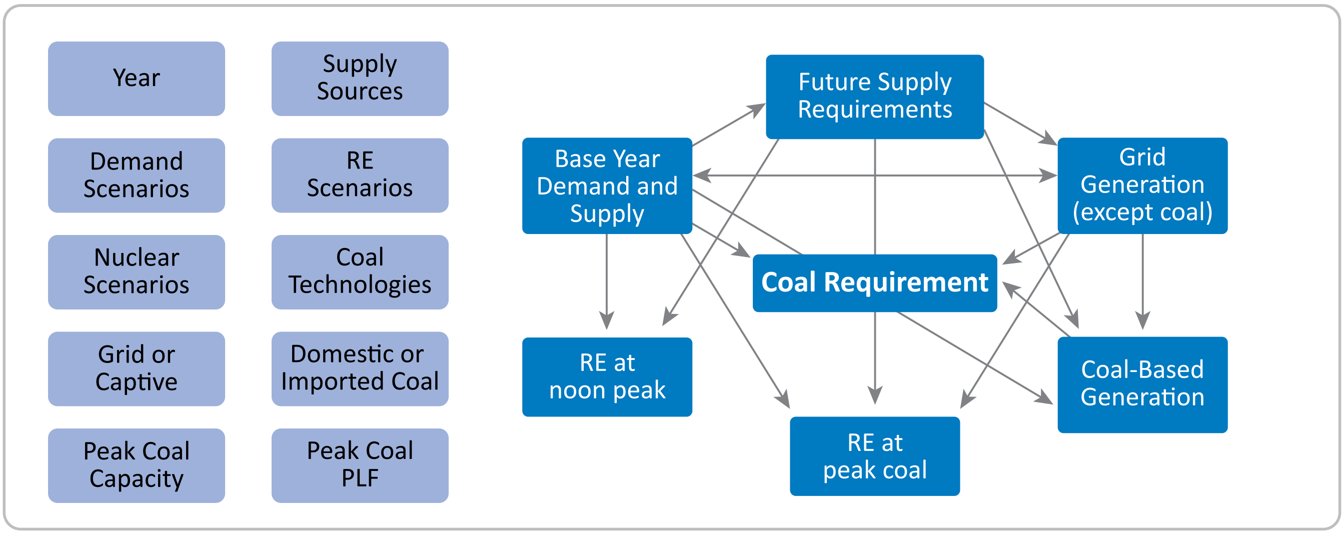
This analysis is only for the first level but provides insights that feed into (2) and (3). Without adequate energy to meet the demand, all other options and constraints become moot. For example, no amount of demand shifting to solar hours can ensure all demand is met if total energy generated is less than what is required. In such a case, the need to explicitly model storage technologies is also avoided but can be factored into the analysis by including an additional 'efficiency factor' into solar generation that accounts for storage losses. As a rudimentary measure to ensure no curtailment from solar, we check that the solar capacities under all scenarios are less than mid-day peak at bus-bars[9].

2.1. Model specification

The supply-side modelling is carried out on the *Analytica*[10] platform. Analytica allows for stochastic and parametric (scenario) analyses, but is advantageous for its flexibility, transparency, and visual and intuitive interface. Figure 5 provides a snapshot of how the electricity supply and coal demand model is set-up in Analytica.

Each module contains a set of sub-modules, and relationships between variables and modules are indicated by arrows that represent dependence. The parallelograms on the left side not linked by arrows represent the indices and scenarios specified in the model to develop vectors or matrices associated with the model variables.

Figure 5: Modelling setup in Analytica



[9] As a conservative measure of mid-day peak, we assume it grows at the rate of aggregate energy demand. However, in practice we will see load shifting to day-time for certain applications like irrigation pump-sets and EVs as solar penetration grows.

[10] For more information on Analytica, please visit http://www.lumina.com/

The modules consist of:

1) Base-year information—end-use electricity demand to fuel-wise gross generation.
2) Future supply requirements—obtained from the demand scenarios above and separated by grid and captive.
3) Grid-based generation— scenarios of future supply capacity (fuel-wise) and PLFs for all sources except coal.
4) Coal-based generation requirement—calculated as a residual between electricity demand and generation from other fuels (at bus-bars) and RTPV.
5) Coal requirement— derived on the basis of future mix of technologies (sub, super and ultra-supercritical) including efficiencies, import-export mix, and calorific content of domestic and imported coal.

These comprise the core of electricity modelling exercise elaborated in this paper. In addition, two modules—RE at noon peak and RE at peak coal—seek to offer insights on the maximum and minimum RE capacity respectively under specific conditions. The first module constrains the aggregate solar capacity to less than or equal to noon peak load since solar output is at the maximum when the sun is directly overhead. This implicitly assumes no large-scale grid-level battery storage in the next five years (at least). The constraint is relaxed for a longer time horizon when minimum RE requirement is derived in the event of zero coal-based generation growth (peak coal) after 2030, which constitutes the second module.

2.2. Base-year calibration of demand and supply

The total end-use consumption (grid and captive) of electricity in India in 2017 is calculated as 1049 TWh[11] (Ali, 2018; Central Electricity Authority, 2013-2018). The fuel-wise capacity, gross generation and auxiliary consumption (grid) in 2017 is used to arrive at net generation in 2017[12]. This is shown in Table 1.

Table 1: Base year capacity and generation

2017	Capacity (GW)	PLF*	Gross Generation (TWh)	Auxiliary Consumption	Net Generation (TWh)
Coal	192	56%	945	8.5%	865
Hydro	44	31%	122	1.0%	121
Wind	31	17%	46	1.0%	46
Solar Grid	11	14%	14	0.5%	13
Solar Rooftop	1	0.8%	0.1	0.5%	0.1
Other RE	14	18%	22	1.0%	22
Other Fossil	26	22%	49	3.4%	48
Nuclear	7	63%	38	10.0%	34
Total/ Wtd. Avg.	327	43%	1,236	7%	1,149

** Note that the PLF of roof-top solar appears very low – this is a reporting artefact (annual rather than monthly weighted average), as it is presently not well captured in any official statistics. Actual steady-state PLFs in future may hover around 14%, still lower than grid-scale solar, owing to a variety of constraints.*

The PLFs for each source are calculated on a gross generation basis and used to validate the capacity and generation (gross and net). Next, T&D losses (technical) are calculated as the% difference between net generation and grid-based electricity consumption in 2017. These come to 21.85%, and compare well with the historical trend of T&D losses as reported earlier. Thus, the electricity demand and supply in the base-year are balanced.

[11] Of this, 897.7 TWh is consumed from the grid and 151.1 TWh via captive sources (>1 MW).

[12] 'Net generation' is the generation available at the bus-bar (grid) level, and removes auxiliary consumption from the gross generation typically reported by CEA. All years mentioned are in financial and not calendar year terms. So year 2017 refers to FY 16-17 in this paper, unless expressly stated otherwise.

3. Assumptions and results

3.1. Grid supply projections

Based on the end-use demand growth scenarios, RTPV penetration and future T&D losses[13] , supply (net generation) requirement is calculated at the grid level. For captive generation, very low technical losses are assumed due to on-site generation[14]. Table 2 shows the supply (net generation) requirement in 2030 for grid and captive users under the three end-use demand scenarios described earlier[15].

Table 2: Supply requirement by 2030

TWh (CAGR)	2017	2030 High	2030 Mid	2030 Low
Grid (TWh)*	1,149	2,341 (5.6%)	2,269 (5.4%)	2,057 (4.6%)
Captive (TWh)	159	361(6.5%)	350 (6.3%)	318 (5.5%)
Total (TWh)	1,308	2,702 (5.7%)	2,619 (5.5%)	2,375 (4.7%)

**Note: Grid demand excludes the amount generated via RTPV (assuming full self-utilisation).*

Table 2 shows that growth in supply requirement for grid power (netting RTPV consumption) may range from 4.7 to 5.7%, which is lower than that described for end-use electricity demand (5.4-6.5%). This is owing to the improvement in T&D loss situation by 2030.

Table 3 shows the range of capacities for non-fossil fuels considered for this analysis, informed by government policies and targets, historical rates of achievement, and subjective assessments of scholars and experts of likely future deployment[16]. The results are calculated for the years 2022 and 2030 to account for government's 175 GW RE target in the high RE scenario, and its consequent impact on coal generation uptake. CEA's National Electricity Plan projects the 2027 RE capacity as 275 GW, and total non-fossil capacity as 362 GW, which sits comfortably within the ranges considered for this study (Central Electricity Authority, 2018).

Table 3: Range of future non-fossil capacities

Non-fossil Scenarios (GW)			
	2017	2022	2030
Solar grid	11	40-60	90-150
Solar rooftop	1	8-40	20-70
Wind	31	45-55	70-100
Other RE	14	15-16	16-30
Total RE	*57*	*108-171*	*196-350*
Nuclear	7	9-12	13-23
Hydro	44	47-55	53-63
Total non-fossil	*108*	*153-241*	*262-436*

[13] T&D losses are assumed to fall to 17.5% by 2022 and 15% by 2030.

[14] Approximately 91% of gross generation from captive sources is available for end-use consumption after netting out auxiliary consumption (~8%) and technical losses (~1%).

[15] These are derived keeping the grid and captive end-use consumption share constant at 2017 levels (85% grid share). In practice, however, with encouragement to open access and captive generation as with the recent amendments to 2016 Tariff Policy, the growth of consumption from captive generators may actually be higher (Ministry of Power, 2018).

[16] These assumptions were chosen based on multiple rounds of expert (academic, policy, business) reviews, as have other key future assumptions on technological parameters and penetration.

In the high non-fossil (NF) scenario, while capacity deployment for RE doubles between 2022 and 2030[17], total non-fossil capacity reaches 436 GW. In the low NF scenario, total NF capacity still crosses 250 GW[18]. As will be clear later, in both these situations the aggregate capacity will contain well over 40% fossil-free share committed in India's NDC's. Other fossils (mainly gas) are likely to continue playing a side role, reaching 30 GW in 2030 from 26 GW in 2017, purely on account of expansion in gas capacity, likely for peaking or RE balancing[19].

3.1.1. Uncertainty over future non-fossil capacity deployment

Constituting hydro and nuclear power, other non-fossil (ONF) sources contributed 13.5% to electricity supply in 2017 (Table 1). In hydropower, the installed capacity and generation is at about a fifth of the estimated potential (Central Electricity Authority, 2018)[20]. However, with only a 0.7% CAGR in installed capacity over the last decade and over 16% fall in PLF, hydro's share in gross generation has reduced from 16.3% to 10%. Moreover, while CEA envisages capacity additions of 15 GW by 2022 and 27 GW by 2027, it is unlikely that this will materialise owing to a number of factors, broadly:

1. Downward re-estimation of future electricity demand by CEA
2. Emphasis on RE capacity addition
3. Underutilisation of existing assets (stranded capacity), especially in coal and gas
4. Looming electricity surplus
5. Social, ecological and environmental concerns

This last point is unique to hydro-power at a generation plant level, and is a major reason that 'planned' or 'under-construction' capacity has found low progress over the years. In the last decade, hydro capacity has grown at 2.5% CAGR, but generation by only 1.7%. For a mid-scenario, we assume that the future capacity grows by historical growth in generation, therefore assuming PLFs don't worsen further. This yields a mid-scenario capacity of 55.5 GW by 2030, which is more conservative than expressed by the CEA.

On the nuclear front, only about 4 GW have been added in the past ten years, and owing to the reasons mentioned above (except that in nuclear, sitting and safety concerns are more important), the government revised its target to 23 GW capacity by 2032, two-thirds lower than the previous target set by the Department of Atomic Energy (Financial Express, 2018). However, experts feel that this is not a 'scaling down' but a realistic shift towards delayed capacity addition, reflective of historical achievement and domestic ambitions[21].

Accordingly, high hydro and nuclear scenarios have an upper bound of 63 and 23 GW respectively.

[17] While there is no official target, the Chief Economic Advisor to GoI in 2017 has suggested this as a likely aspiration for RE in 2030. There are very recent pronouncements (but not official policy) suggesting even 500 GW of RE by 2028, which we examine as a specialised case of 'very high' RE in this study.

[18] In the mid-scenario, total NF capacity reaches 310 GW with 235 GW of RE by 2030.

[19] It has been suggested that a viable low-carbon strategy may have a larger role for gas than previously envisaged (Frank, 2014), but owing to numerous short-medium term constraints and competing demands, gas still plays a relatively minor role in this model.

[20] Pumped-storage hydropower, which can play a significant role in RE integration, is only at 4.8 GW against the 96 GW estimated potential across seven sites. Further, only 2.6 GW of this is operational in pumped storage mode (Central Electricity Authority, 2018).

[21] The domestic ambitions indicate a shifting emphasis on quality (technology development) over quantity (adding capacity)—scaling up domestically designed Pressurised Heavy Water Reactors along the lines of the CANDU model, and successfully commissioning the long-awaited prototype Fast-Breeder Reactor (Sundaram, 2018).

3.2. Supply requirement from coal power plants

Table 4 shows the aggregate net generation excluding coal under different combinations of RE and other non-fossil scenarios (including generation from RTPV).

Table 4: Total net generation (except coal) in various grid-based non-fossil scenarios

Net Generation (TWh) except coal		Other Non-fossil Scenarios		
		Min	**Mid**	**High**
Renewable Energy Scenarios	**Min**	611	637	687
	Mid	732	758	808
	High	931	957	1,007

From the above, RTPV generation is netted out, and the remainder (net generation from other grid-based sources) is used for calculating net generation requirements from coal plants until 2030 under high (H), mid (M), and low (L) scenarios of electricity demand[22]. The results are presented in Table 5.

Table 5: Net generation required from coal in demand and non-fossil scenarios

Net Generation Required from Coal (TWh (CAGR)		Non-fossil Scenarios		
		Min	**Mid**	**High**
Demand Scenarios*	**High**	1,779 (5.7%)	1,629 (5.0%)	1,374 (3.6%)
	Mid	1,708 (5.4%)	1,557 (4.6%)	1,302 (3.2%)
	Min	1,495 (4.3%)	1,345 (3.5%)	1,090 (1.8%)

**In 2017, approx. 85% of captive supply was via coal, assumed to fall to 66% by 2030.*

The above results reflect the range of possibilities of net generation growth that will be required from coal-based plants under upper and lower bounds of demand and non-fossil scenarios. These correspond to CAGRs of 5.7% in high demand and low non-fossil scenario to less than two% (1.8%) in the low demand and high non-fossil scenario.

However, this case-building approach provides a range of theoretical possibilities[23]. In the real world, considerations of future growth and development and consequently end-use electricity demands affect planning and decisions to invest in capacity addition. In that sense, the results along the anti-diagonal of the above matrix are more intuitive, whereby aggregate capacity addition in non-coal sources follow the directionality of demand. Viewing this way, we obtain CAGRs of 4.0%, 4.2% and 2.7% in the min, mid and high scenarios respectively of both the electricity demand and non-fossil growth.

3.2.1 Industrial captive supply

Apart from grid-based plants, a number of captive power plants run on coal and are operated by industrial captive users. These are used to assure steady, on-demand power to run production assembly lines that require uninterrupted power to ensure smooth operation. The share of captive generation in overall generation increased

[22] Net gen. requirement from coal= Net generation from all grid sources except coal (Table 4-RTPV generation)—total net generation requirement from Grid (Table 2)+ Captive net generation requirement from coal.

[23] However, these possibilities (bounds) are derived from an assessment of realistic assumptions based on the prevailing state of knowledge.

steadily from around 10.5% to over 12.5% over the last decade. The CAGR of electricity generation from captive power plants has been around 8.3% compared to 6.3% from the grid during the same period (Central Electricity Authority, 2007-2017).

Captive coal plants are known to be more polluting due to lower efficiency than grid-based power plants for sub-critical technology. Part of the reason is the partial utilisation of captive generation capacities, and lack of incentives to improve efficiency. In 2017, approximately 85% of the captive generation is estimated to have come from coal, with a net generation of 135 TWh at 8.6% auxiliary consumption (Ministry of Coal, 2017; Central Electricity Authority, 2016-2018; Central Electricity Authority, 2017; Central Electricity Authority, 2007-2017).

Based on the historical rate of penetration of RE and other fuels (particularly gas) in the captive supply mix, the share of coal used for captive generation is assumed to fall to 75% in the future. Further, India's prospects in expanding and diversifying its manufacturing base together with the scope and role of fuel-switching and energy efficiency will dictate the pace of captive supply growth. By 2030, coal captive (net) generation may contribute 239 and 271 TWh in the lower and upper bounds respectively of electricity demand, representing CAGRs of 4.5% and 5.5% respectively.

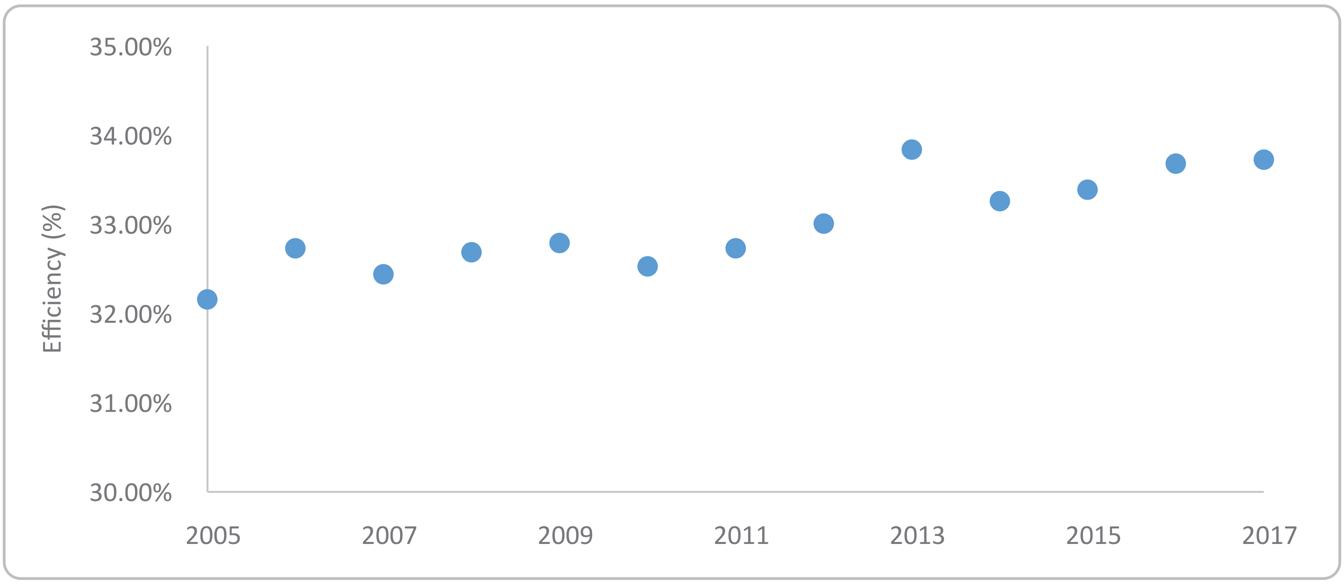
4. Coal requirement for electricity generation

Once coal-based generation requirements from grid and captive plants are calculated as a residual between demand and generation from other sources at the bus-bar level, the coal requirement for this generation is calculated. This is done by characterising fuel properties and conversion technology parameters in the base-year and for the future and working backwards to arrive at the tonnage of coal required.

4.1. Base-year coal technologies and consumption

The first step in this exercise is to validate model assumptions with the official database from CEA and MoC. This involves specifications of technology shares (sub, super and ultra-supercritical), and conversion efficiencies and the domestic-imported coal mix associated with each. In 2017, about 18% of the 192 GW coal capacity was supercritical, rest being sub-critical (Central Electricity Authority, 2018b). At efficiencies of 33% and 37% respectively, the weighted efficiency obtained is 33.72%, corresponding to the trends in efficiency of coal power plants as reported by the CEA. Figure 6 illustrates these trends.

Figure 6: Historical generation efficiencies of coal power plants (grid)



Source: CEA General Reviews (pre 2017) and author's calculations (2017).

The coal consumption for grid-based plants in 2017 is reported by CEA as 574.9 Mt, of which 66 Mt was imported (Central Electricity Authority, 2016-2018). This yields a specific consumption of 0.61 kg/kWh of gross generation[24]. Among the sub-critical and super-critical plants, the average percentage blending of imported coal in energy terms works to be 11% and 30% respectively[25]. This is based on the reported tonnage of imports received by each unit as per CEA's monthly fuel reports (Central Electricity Authority, 2016-2018).

It is well understood that super and ultra-supercritical boilers require a certain quality of coal (composition and calorific value) to achieve stated efficiencies and minimise boiler damage. Consequently, Indian coal which is low in calorific value but high in ash content is often blended with imported coal from Indonesia, Australia, etc. to

[24] In 2017, gross generation from grid-connected power plants was 945 TWh.
[25] Assuming a calorific value of 5,200 kcal/kg for imported coal.

match boiler requirements. In fact, as shown above, there is on average three times higher blending in super-critical plants as opposed to sub-critical plants at present[26]. Accordingly, the blending percentage for future ultra-supercritical capacity is assumed at 40%.

Following from above, the only missing part of the puzzle is the average calorific value of domestic coal, which balances the reported coal generation with domestic and imported coal consumption. Given the multiple grades of Indian coal, each spanning a GCV range of 300 kcal/kg, and the uncertainty and variance around the quality of coal received versus contracted[27], there is no single truly representative number of the average calorific value of Indian coal used for electricity generation. Various studies have used GCVs ranging from 3700 to 4200 kcal/kg, which correspond to G12 and G11 grades respectively. Following from these considerations, GCV for domestic coal is derived as an equilibrating factor between electricity generation and coal consumption and is calculated as 3958 kcal/kg, which corresponds to the higher end of the G12 grade[28]. In this way, the base year coal-based generation and coal consumption by grid-connected plants are balanced.

4.2. Future coal requirement scenarios

4.2.1. Future coal capacity mix

Based on the module setup described in Figure 5, the future capacity shares of the three coal technologies will primarily determine the future conversion efficiency, and therefore the quantum of coal energy required[29]. CEA reports that about 67 GW of coal capacity is currently under construction and expected to come up by 2022. Of this, 52 GW of plants have definite commissioning dates, while the others remain uncertain. Further, 42 GW of the 67 GW will be super-critical capacity, leaving about 25 GW for sub-critical plants.

To arrive at the future capacity mix, the currently constructed capacity with uncertain commissioning dates are assumed to be commissioned after 2022. Further slippage of 25% is assumed on the 53 GW for which the expected commissioning dates are mentioned. Old, inefficient and/or polluting sub-critical capacity of 40 GW is expected to retire by 2030 and assumed to be replaced by super and ultra-supercritical capacity, latter constituting one-third of the replacements (Central Electricity Authority, 2018b). Further, the ultra-supercritical capacity assumed to be operational only after 2022. The results obtained are shown in Table 6.

[26] There is some uncertainty as to how much the need for imported coal is driven by technology versus locational issues. Newer plants are super-critical and many are located far from coal mines; especially coastal plants find it cost-effective to use higher blend rates of imported coal.

[27] Last year, the Coal Controller Organisation downgraded 41% of 871 sidings across 386 mines for FY 18 (Indo Asian News Service, 2017).

[28] This includes 38 Mt of lignite (2200 kcal/kg) and 20 Mt of washed non-coking coal (4500 kcal/kg) we estimate as being utilised in the power sector. It also includes 38 Mt of domestic coking (non-metallurgical) coal (4900 kcal/kg) that is calculated as being used for power. The remainder (80% of total domestic coal in grid and captive generation) is thermal non-coking coal with its calorific value derived as 4011 kcal/kg (within G11).

[29] Improvements in overall efficiency will also come from the junking of old subcritical capacity and the building of new plants with better efficiencies. Moreover, efforts and investments are needed to retrofit existing coal plants to meet notified emissions norms. While these may raise costs by a INR 0.25-0.75/kWh (CSTEP, 2018), this is a worthwhile cost compared to the likely environmental and health benefits.

Table 6: Present and future coal capacities

Coal Capacity (Share)	2017	2022	2030
Sub-critical (GW)	158 (82%)	161 (70%)	143 (55%)
Super-critical (GW)	34 (18%)	69 (30%)	104 (40%)
Ultra super-critical (GW)	0	0	13
Total (GW)	192	230	260

The process of arriving at future capacity mix (and therefore total future capacity) is iterative and based on the range of generation requirement from coal under different scenarios described earlier. In this case, the decision to fix capacity is based on the PLFs obtained under different cases.

The extreme cases (very high or low PLFs) are tested for capacity sufficiency or surplus. The results of this analysis are discussed in section 5.2. Irrespective of the aggregate capacity levels, efficiency, and environmental considerations require that such capacity unfit for future generation be upgraded with newer technologies. The choice between retrofitting and junking or replacement is not modelled in this study, as it would be made on a case-basis for individual plants/units. However, suffice to say there will be some additional capacity beyond what is already planned to compensate for what is lost from retired plants, except in the extreme scenario of very high RE (section 5.5), low energy demand and high energy efficiency.

4.2.2. Compliance with NDC capacity targets

As detailed in section 5.2, coal capacities of 260 to 300 GW are tested for sufficiency and surplus using the PLFs obtained. From Table 6, we find that non-fossil capacity grows from 108 GW in 2017 (33% share in total capacity of 327 GW) to between 262 and 436 GW in 2030. This gives the minimum possible share of non-fossils as 44% (262 GW non-fossil and 300 GW coal), and maximum as 62% (436 GW non-fossil and 230 GW coal). India has targeted 40% non-fossil capacity by 2030 as a means to fulfil its NDCs. Therefore, every capacity mix contained in this analysis beats the NDC target on fossil-free share in the capacity mix.

4.2.3. Operating efficiencies and fuel quality

The efficiencies of the weighted mix of sub and supercritical plants are assumed to improve to 34% and 38% respectively by 2030, while ultra-supercritical is taken to operate at 42% efficiency. An analysis at Brookings India reveals a weighted average reduction of up to 20% between an average calorific value coming from various subsidiaries of CIL and SCCL between 2007 and 2017[30]. This trend is likely to continue as the subsidiaries with declining grade continue to assume a greater share of CIL production (Coal India Limited, 2018). On the other hand, while SCCL has also witnessed a small decline in GCV in the given period, its share in total production continues to decline.

Against this trend, greater washing of domestic coal along with substitution of non-coking with surplus non-metallurgical coking coal may be required to maintain plant performance, especially in light of advanced coal technologies. Washing coal results in generation of rejects, with a yield rate of around 80% as reported by the CCO (Coal Controller's Organisation , 2018). The implications of these are discussed in section 5.4.1.

[30] Much of this is due to growing output from the most-cost effective subsidiaries (with low stripping ratios meaning less overburden removal) that happen to have lower grade coal. Among the growing subsidiaries, the key ones are CCL, SECL and MCL.

Accordingly, based on the trends and efficiencies reported above, the base-case assumes internal substitution between various types of domestic coal to maintain base-year GCV of the mix. In addition, two sensitivities of falling GCVs are examined to ascertain the impact on domestic coal demand by 2030. The results of this exercise are discussed in section 5.3.1.

For captive power plants, the average efficiency of sub-critical units is assumed to improve from 32% in 2017 to 34% in 2030[31]. For other variables (GCV and domestic-import mix), the values derived above for the grid-based power plants are used.

Table 7 provides an account of the domestic and imported coal consumption across grid and captive power plants in 2017.

Table 7: Electric coal consumption in 2017

2017 Coal Consumption (Mt)	Grid	Captive	Total
Domestic	508	81	590
Imported	67	15	82
Total	575	96	672

From 672 Mt in 2017, the coal demand is calculated across scenarios of grid electricity demand, industrial growth and efficiency, and penetration of non-coal sources as described earlier. Table 8 gives an aggregate picture of coal demand, represented similarly as Table 5, but inclusive of captive demand.

Table 8: Aggregate electric coal demand in 2030

2030 Coal Demand (Mt (% CAGR))		Non-fossil Scenarios		
		Min	**Mid**	**High**
Demand Scenarios	**High**	1,277 (5.1%)	1,183 (4.5%)	1,024 (3.3%)
	Mid	1,227 (4.7%)	1,133 (4.1%)	974 (2.9%)
	Min	1,080 (3.7%)	986 (3.0%)	827 (1.6%)

The table above shows how overall electric coal demand CAGRs can vary from 1.6 to 5.1% between 2017 and 2030. However, as the discussions on the results in Table 5 elucidate, these are extreme outcomes and most likely will not materialise. Similarly, the results are better illustrated via the anti-diagonal, where decisions to add capacity take the cue from historical, prevailing and future assessments of macroeconomic and electricity demand situation. The CAGRs so obtained are 3.3%, 4.1% and 3.7% across the min, mid and high scenarios of demand and non-fossil generation. This suggests a moderate, although non-trivial growth in coal demand from the electricity sector.

[31] Super and ultra-supercritical technologies are not considered for captive plants.

5. Coal for electricity: Additional results and implications

While key results pertaining to coal demand for electricity have been presented so far in this chapter, a number of intermediate (or granular) insights from this analysis help to shed light on big-ticket questions in India's energy economy. A few of these are summarised in this section.

5.1. Dominance of coal in the electricity sector

Table 9 shows that in the mid-scenario across all variables, the share of coal in electricity generation shows some decline, but remains over two-thirds of total generation (net)[32]. Hence, coal still remains the bedrock of base-load generation, even with no more capacity addition than already under construction. Table 10 demonstrates this point across different demand and non-fossil scenarios.

Table 9: Fuel shares in generation mix in the mid-scenario

Share (%)	2017	2022	2030
Coal	73.7%	68.6%	68.4%
Hydro	10.5%	8.7%	6.2%
Wind	4.4%	7.1%	8.3%
Solar grid	1.7%	6.2%	7.5%
Solar rooftop	0.1%	0.8%	2.0%
Other RE	2.0%	1.7%	1.4%
Other fossil	4.0%	3.3%	2.5%
Nuclear	3.5%	3.6%	3.8%
Total	100.0%	100.0%	100.0%

Table 10: Coal's share in net generation in 2030

Coal's Share in Net Generation (2030)		Non-fossil Scenarios		
		Min	Mid	High
Demand Scenarios	High	74.4%	68.3%	57.7%
	Mid	73.6%	67.3%	56.4%
	Min	71.0%	64.0%	52.0%

From Table 10, even in the extreme scenario of high demand and low non-fossil capacity addition, coal's contribution does not change by much. This is a powerful and instructive insight and confirms that even in a business-as-usual (BAU) case[33], coal's share could potentially drop by 10 percentage points. But even in the opposite extreme (low demand, high-non fossil), it continues to be the overwhelmingly dominant source in the mix[34].

[32] From Table 1, it becomes clear that its share in gross generation will be higher due to higher auxiliary consumption than the weighted average, especially RE.

[33] BAU technology-policy scenario in energy modelling studies generally denotes moderate success in energy efficiency, conservation and RE. Given that this is a bounding exercise with an additional mid/bounding pathway, the BAU would lie between mid and high cases.

[34] The next most significant is solar with a share of 18%.

5.2. Capacity adequacy and PLFs

Table 11 shows the coal plant PLFs based on the capacities defined in Table 6. While 260 GW 'technically' suffices in all cases, in the extreme (and as described earlier, extremely unlikely) cases, there may emerge the need for some capacity headroom or rollback. By and large, the capacity already under construction seems to suffice for 2030—an important lesson emerging from this study, and coinciding with CEA's projections for 2027 (Central Electricity Authority, 2018).

Table 11: Coal plant PLFs at 260 GW capacity in 2030

Coal Plant PLFs (2030)		Non-fossil Scenarios		
		Min	**Mid**	**High**
Demand Scenarios	**High**	85.4%	78.1%	65.9%
	Mid	81.9%	74.7%	62.4%
	Min	71.7%	64.5%	52.3%

At low non-fossil scenarios, there emerges some stress on existing capacity to fulfil the electricity demand[35]. Additional sensitivities constraining PLFs to below 80% and 75% across all scenarios yield coal capacity requirements of around 280 and 300 GW respectively.

However, with the recent policy announcements of increasing RE capacity to 500 GW by 2028, the push for RE has been reinforced. In the event of 500 GW RE scenario materialising by 2030 (discussed in detail in section 5.5), a coal capacity of 230 GW would be sufficient across all demand scenarios. With the kind of coal capacity expansion that is already in the works, it is increasingly important that the MoP and MNRE approach planning in a coordinated way to reduce the risk of build-up of stressed assets in the future.

Table 12 shows the mid-scenario PLF trends in the three coal technologies modelled. PLFs show a reduction from current levels by 2022 (at 230 GW capacity), thereafter recovering to healthy levels by 2030. To achieve minimum PLFs of 60% across technologies, the maximum capacity that should be deployed by 2022 is 210 GW.

Table 12: Trends in technology-wise coal PLFs (mid-scenario)

Tech-wise Coal PLFs	2017	2022	2030
Sub-critical	53.8%	51.7%	65.5%
Super-critical	60.3%	57.9%	73.2%
Ultra super-critical	-	-	80.6%

PLFs for more efficient technologies are higher, which is an intuitive result. The reason becomes clearer as higher RE shares require coal to share the burden of 'flexing' its output, a function that will likely be performed by the older and less efficient sub-critical plants, depressing the overall sub-critical PLFs compared to other technologies[36]. There are also industry concerns that super-critical plants have technical limits on output reduction, lest they lose their super-critical operations.

[35] In the low demand scenario however, 230 GW of coal suffices.

[36] Actual decisions on which coal plants should reduce output based on grid conditions is a complex process based not just on marginal fuel requirements (efficiency) but broader economics as well, which vary by location, contracts, etc. This is before considering technical constraints, e.g., some older plants cannot flex below 70% output without requiring expensive oil support (Tongia, Harish, & Walawalkar, Integrating Renewable Energy Into India's Grid-Harder than it looks, 2018).

5.3. Specific consumption of coal plants

Specific Coal Consumption (SCC) of coal plants is something that is closely followed and reported as a measure of generation efficiency across time. Table 13 and Table 14 show the technology-wise as well as average (weighted based on generation) SCC derived through 2030.

Table 13: Trends in technology-wise specific coal consumption

Tech-wise SCC (kg/kWh)	2017	2022	2030
Sub-critical	0.64	0.63	0.62
Super-critical	0.55	0.54	0.52
Ultra super-critical	-	-	0.46

Table 14: Trends in average specific coal consumption

Avg. SCC (kg/ kWh)	2017	2022	2030
Grid	0.62	0.60	0.57
Captive	0.65	0.63	0.58

While SCC reductions in technology are due to efficiency improvements described in section 4.2.3, average SCC for the grid also accounts for technology-wise contribution to generation. The SCC of 0.57 kg/kWh in 2030 for grid represents an eight% improvement over 2017, which is highly significant. Captive generation SCC also improves by 10%, with newer captive sub-critical generation units assumed to be as efficient as grid-based ones[37].

Except technological efficiency, the fact that advanced technologies use higher blending ratios of imported coal also contributes to this improvement. While positive in efficiency terms, this does have associated import (therefore energy security) implications as discussed section 5.4.

5.3.1. Effect of falling GCVs

As discussed in section 4.2.3, the results on total and specific coal consumption of power plants is obtained at constant GCVs of domestic coal, even though the GCVs have historically been falling and expected to continue to reduce in the future. Assuming operating efficiencies remain the same, this implies a greater amount of domestic coal needs to be fed to achieve the same amount of input energy. Accordingly, two sensitivities with domestic coal GCVs falling to 3,650 kcal/kg (slow fall) and 3,450 kcal/kg (fast fall) for power sector coal are examined[38].

[37] Even though captive continues to use sub-critical technology, its efficiency improvement is assumed to be better than the grid owing to lower base efficiency and considerations of competitiveness and environmental compliance.

[38] The calculation assumes varying levels of substitution within domestic coal from the base year (refer to footnote 24), with a greater share of washed (non-coking) coal, reduction in lignite usage, and the share of domestic non-coking coal falling to 70% in 2030 from 80% in 2017.

Table 15: Effect of falling GCVs on Specific Coal Consumption (Grid)

Avg. SCC (kg/kWh)	2017	2022	2030
Constant (3,958 kcal/kg)	0.62	0.60	0.57
Slow fall (3,600 kcal/kg)	0.62	0.61	0.60
Fast fall (3,450 kcal/kg)	0.62	0.64	0.63

From Table 15, it can be inferred that a reduction of 8% and 13% in coal GCVs leads to an SCC increase of 6% and 11% respectively in 2030, compared to constant GCVs. Comparing with 2017, SCC increases in the fast fall case and reduces in the slow fall case. As the weighted average grade of the power sector coal shifts towards G13, the impact on coal demand is shown in Table 16.

Table 16: Additional domestic coal required due to lower GCVs

Change in Coal Demand (Mt (% difference))		Slow Fall			Fast Fall		
		Non-fossil Scenarios					
		Min	Mid	High	Min	Mid	High
Demand Scenarios	High	65	60	50	123	112	95
	Mid	63	57	48	118	107	90
	Min	55	49	40	103	93	75

Additional coal required could range between 40-65 Mt (2.7-4.4% increase) in the case of slow falling GCVs and 75-123 Mt (5.1-8.3% increase) in the fast falling case[39]. On average, about 75 Mt of additional domestic coal may be required on account of falling GCVs.

5.4. Continued dependence on imported coal

The electricity sector contributed 43% to total coal imports (56% non-coking imports) in 2017. This implies a near doubling in the share of imported coal going to power from 2007. Import from grid and captive based plants was 67 and 15 Mt respectively (Table 7). The generation requirement from coal and the capacity, efficiency and PLF mix between sub-super and ultra-supercritical by 2030 dictate the imported demand in 2030, shown in Table 17 across different cases of non-fossil deployment and electricity demand.

Table 17: Imported electric coal demand in 2030

2030 Imported Coal Demand (Mt (% CAGR))		Non-fossil Scenarios		
		Min	Mid	High
Demand Scenarios	High	198 (7.0%)	184 (6.4%)	159 (5.2%)
	Mid	190 (6.7%)	176 (6.0%)	151 (4.8%)
	Min	168 (5.7%)	153 (4.9%)	129 (3.5%)

Comparing with Table 8, we find that imported coal grows at 2 percentage points higher than overall coal demand in 2030, while its share in the mix increases to 15.5%, which is a 3.3 percentage point increase from 2017. By implication, it grows 2.3 percentage points higher than domestic coal under all cases (except when domestic

[39] The increases are reported based on aggregate (domestic and imported) coal demand. In terms of domestic coal, the increments are in the range of 5.7-6.1% and 10.2-10.7% in the slow and fast falling cases respectively.

[40] Subtracting the coal tonnage in Table 17 from Table 8 yields the domestic coal demand.

GCVs are falling)[40]. This indicates a continuation of recent trends—imported coal's share in electricity has grown manifold, realising a 12.7% CAGR in the past five years versus 6.4% for domestic coal[41].

As discussed earlier, dependence on imported coal is primarily because of technological factors and domestic resource quality and availability. One analysis of planned future coal capacity under various stages indicates that this reliance will be difficult to overcome due to technological and logistical reasons, especially in case of falling coal grades domestically. CEA has an express mandate of reducing imported coal dependence, and domestic plants have even managed to cut down imported coal whilst increasing generation in 2017-18 (Central Electricity Authority, 2018c). However, in order to make this phenomenon sustainable, washing of domestic coal to ensure quality commensurate with boiler requirement of advanced technologies will be necessary.

5.4.1. Washed domestic coal as an alternative to imported coal

In 2017, while India's non-coking coal washing capacity was over 105.24 Mtpa, its production was only 45.12 Mt, with a capacity utilisation of just over 50% (Ministry of Coal, 2017). As CIL plans a five-fold increase to its non-coking coal washing capacity—67.5 Mtpa to be added (Coal India Ltd., 2018)— emphasis on improving utilisation will enable import substitution, but it will also increase the need to mine more coal to compensate for middlings and rejects derived from the process.

Washing domestic coal may help in improving domestic utilisation, but it remains to be seen if higher use of washed coal may erode the cost advantage that domestic coal enjoys over imported coal on an energy-delivered basis[42]. However, with India's commitments towards climate mitigation and local pollution concerns, cleaning up domestic coal for power plants may become a necessity in itself. In this light, we calculate the import substitution potential of washed coal with the objective of constraining import shares to less than the levels of 2017.

From section 4.2, washed coal delivers approximately 1000 kcal/kg less than typical imported coal and has a yield rate of 80%. This implies that in order to replace 1 kg of imported coal, approximately 1.22 kg of washed is required, for which 1.53 kg of raw coal needs to be mined. Table 18 shows the amount of imported coal requiring substitution by domestic washed coal under different scenarios and the corresponding requirement of mining raw coal for constant import shares until 2030 (12.2%).

Table 18: Raw domestic coal required for substituting imported with washed coal

Domestic Substitution of Imported Coal (Mt)		Imported Coal Replaced			Raw Coal Mined		
		Min NF	Mid NF	High NF	Min NF	Mid NF	High NF
Demand Scenarios	High	42	39	34	65	60	52
	Mid	41	38	32	62	57	50
	Min	36	33	28	55	50	42

[41] This has led to a 2.8 percentage point increase in imported coal's share to 12.2% in 2017.

[42] An analysis at Brookings shows the difference between delivered cost per unit energy ($/MMbtu) of domestic G11 and Indonesian G4 grade imported coal as 25%, with imported being higher at 3.64 $/MMbtu in July 2017 (the latest month for which complete data is available). Washing costs add at least INR 100/MMbtu (33%) to domestic coal, which can increase based on the coal composition and target ash content.

To replace 28-42 Mt (27%) of imported coal by 2030, approximately 42-65 Mt of domestic coal needs to be mined (median: 55 Mt). The corresponding washed coal consumption is 34-52 Mt. It is important to note that this analysis is at constant GCVs of domestic coal. In case of falling GCVs as shown in section 5.3.1, the yield ratios are likely to be lower by 7-13 percentage points, resulting in even higher amounts of raw coal mining requirements (1.3-1.5 kg per kg of washed coal).

Together, the effect of falling GCVs and washing coal can reduce imports by 38 Mt and increase the domestic raw coal requirement by 130 Mt in the mid-scenario. Table 19 encapsulates the different possibilities leading to a reduction in import shares over the mid-scenario in 2030. These include mid value of falling GCVs (section 5.3), substitution of imported with washed coal (Table 18), and a combination of these cases. Noteworthy is the commensurate increase in washed coal shares in domestic coal consumed (lignite, raw and washed) with falling import shares[43].

Table 19: Cases of import share reduction over mid-scenario (2030)

Consumption (Mt (CAGR))	2017	Mid-Scenario	Falling Domestic GCV	Import Substitution	Falling GCV ^ Import Substitution
Domestic Consumed	590	957 (3.8%)	1,032 (4.4%)	1,003 (4.2%)	1,075 (4.7%)
(of which) Washed	20	170 (17.8%)	186 (18.6%)	216 (20.0%)	237 (20.2%)
Imported Consumed	82	176 (6.0%)	176 (6.0%)	138 (4.1%)	138 (4.1%)
Total Coal	672	1,133 (4.1%)	1,208 (4.6%)	1,141 (4.2%)	1,213 (4.7%)
Imported Share	12.2%	15.5%	14.6%	12.1%	11.4%

Compared to the mid-scenario, domestic coal consumption grows at 4.4-4.7% CAGR. The least growth in aggregate coal consumption occurs in cases of constant domestic coal GCV. Import substitution leads to CAGR of imported coal falling from 6 to 4.1%, and reduction in share of total coal consumption from 2017 levels. In case of falling domestic GCVs with import substitution, imported share is the least at 11.4%, but aggregate coal also grows at the highest rate, reaching 1,213 Mt by 2030. It is worth emphasising that this is only the demand from power sector; if washed coal is used in industry too, then the demand for mining will be even higher.

The washed coal requirement in these sensitivities exceeds the total current private and (estimated) future CIL washing capacity of 160 Mt. At 75% capacity utilisation, total washing capacity may potentially need to grow up to 400 Mt from the existing 105 Mt, as 20-25% of domestic coal may require washing. Compared to this, washed coal capacity will need to grow to 284 Mt in Mid-scenario to maintain constant GCVs without substituting any imports. The analysis points to the need to overcome the financial, logistical, policy and regulatory barriers to coal washing and utilisation as an import substitution strategy. However, washing leads to significant increases in water use for coal preparation, despite reducing water for ash disposal by 30% (Bam, Powell, & Sati, 2017).

5.5. Implication of 500 GW grid-based RE for coal power

There are recent policy indications to target 500 GW RE by 2028, comprising 350 GW solar and 140 GW wind (Kumar, 2019). This would require a stupendous 42.5 GW of capacity addition yearly, whereas the highest yearly RE capacity till date has been less than 12 GW (in 2017-18). If achieved, accommodating such capacity will require an extensive deployment of grid-level storage to assure maximum utilisation of RE generation— something that

[43] Total raw coal requirement = Domestic consumption − Washed consumption + (Washed consumption/ Yield%)

will considerably increase solar electricity prices[44]. Assuming RE receives preferential treatment in merit order despatch and increased levelised cost due to batteries not hindering uptake, Table 20 shows the implications in terms of generation required from coal at grid bus bars, PLF of grid-based coal capacity (at 230 GW), share in net generation from coal and RE (including RTPV but excluding captive generation), and aggregate coal consumption for power sector (including captive generation) at different levels of domestic GCVs (as outlined in section 5.3.1)[45].

Table 20: Implication of 500 GW RE

Effect of 500 GW RE		Coal Net Generation (TWh)	Coal PLF (@260 GW)	Generation share (%)		Aggregate Coal Consumption (Mt (CAGR))		
				Coal	RE	Constant GCV	Slow Falling GCV	Fast Falling GCV
Demand Scenarios	High	1,146 (2.4%)	54.95%	48.3%	38.3%	882 (2.1%)	924 (2.5%)	961 (2.8%)
	Mid	1,074 (1.8%)	51.50%	46.7%	39.6%	832 (1.7%)	872 (2.0%)	906 (2.3%)
	Min	862 (0.4%)	41.32%	41.3%	43.6%	685 (0.2%)	717 (0.5%)	745 (0.8%)

Based on the PLFs derived coal capacity of 230 GW at 500 GW of RE, RE will likely result in a sizeable surplus. In fact, a capacity of 210 GW by 2022, as indicated in section 5.2[46], will suffice by 2030. While the share of RE generation reaches almost 40%, it is in the low demand scenario that RE becomes the dominant source of electricity supply. At base-year domestic GCVs, the growth in coal demand for electricity is modest (0.2-2.1%), but falling GCVs may necessitate up to 80 Mt additional domestic coal consumption[47]. Compared to coal demand in high non-fossil scenario (Table 8), aggregate coal demand reduces by 142 Mt (14-17%) in the 500 GW RE case. This leads into the final discussion on how much overall RE capacity is required in the system to stabilise its absolute coal demand in the future.

5.6. 'Peak Coal' in electricity due to RE— plausible but achievable?

The analyses in the previous sections demonstrate that it is extremely unlikely that India will see "peak coal"[48] in the electricity sector by 2030. This exercise, encapsulated in the 'RE at peak coal' module in Figure 5, approaches the question of RE requirement on the basis of peak coal generation at two future snapshots—2035 and 2040[49]. Given India's ambitious policy for RE deployment for 2022 (and more recently the intentions for 500 GW by 2028), the 2030-2040 time frame for peak coal accounts for these scenarios to play out in the future.

Here, RE generation requirement is calculated as a residual between electricity demand and net generation from all other sources[50] (except coal), and RE capacity is back-calculated, using the 2030 (weighted average) PLFs from

44 At 40% battery storage, a 1 kW solar plant generating 5/kWh per day will be nearly 50% more expensive than today with an LCOE of over INR 4/kWh, even if the battery capital costs reach $100/kWh (Tongia & Gross, Working to turn amibition into reality: The politics and economics of India's turn to renewable power, 2018).

45 500 GW RE is assumed to be reached in 2030 and ONF capacity is set to 'mid' level.

46 In the event of achieving 175 GW RE target, any coal capacity beyond 210 GW by 2022 will result in sizeable stranded capacity.

47 In case of minimum electricity demand, absolute coal consumption from the grid could potentially fall by up to 20 Mt (3percent) from 2017 levels. However, including captive, we obtain a small increase of 13 Mt.

48 'Peaking coal' can be understood as the situation whereby no additional coal generation is required as all demand is met by other (alternative) generation sources. Assuming technological and distribution efficiency becomes no worse, this implies the coal demand (at constant domestic coal GCVs) will reduce at best, and not increase at worst.

49 Note that we define total RE capacity at peak coal in terms of wind and solar only, and do not account for small hydro or biomass beyond 2030.

50 Growth in demand and generation capacity of other sources until 2030 is kept at the 'mid' level of the bounds described in Table 3. After 2030, the capacity addition in other sources is assumed to reach the 'high' level by 2035 after which it remains constant. Therefore, grid-level storage technologies are understood to be cost-competitive by then.

both generation sources[51]. Based on the detailed electricity demand model described in Section 2, the grid net generation requirement between 2030 and 2040 is assumed to grow at 5.5% CAGR between 2030 and 2040[52]. Furthermore, the high, mid and low values of peak coal capacity and PLF (beyond 2030) respectively, along with the corresponding wind and solar capacities (by 2030) are provided in Table 21[53].

Table 21: Peak coal capacity and PLF scenarios

Coal Capacity and PLF	Peak Capacity (GW)	Peak PLF	Wind and Solar by 2030 (GW)
Low	230	60%	490
Medium	260	65%	320
High	280	70%	215

Table 21 shows nine possible combinations of capacity and PLFs considered at which coal generation stabilises by (or after) 2030, beyond which additional demand is met by RE (wind and solar). The implicit assumption here is that battery technology is proven and cost-effective, enabling RE to replace coal at any given time of day. The results obtained for RE capacity thus required is presented in Table 22.

Table 22: RE capacity requirement at peak coal

RE at peak coal (GW)	Peak Coal PLF			
Peak Coal Capacity	2035	Low	Mid	High
	Low	765	694	632
	Mid	701	621	551
	High	659	573	497
	2040	Low	Mid	High
	Low	1,182	1,112	1,052
	Mid	1,119	1,041	972
	High	1,078	994	920

While several insights emerge from Table 22 and need to be examined on their own, the implications of high RE (320 GW wind and solar) with 260 GW of coal capacity by 2030 are examined here, as highlighted in the table. The PLFs of coal power plants range between 60 and 70%.

In such a scenario, RE growth required varies between 11.5 to 17.0% by 2035, and 11.8 to 13.3% by 2040. Contrasting with 16.7% CAGR required between 2017 and 2030 to reach 320 GW of solar and wind capacity as in the high RE case (albeit over a much lower base), these capacity additions seem plausible (even at low peak coal capacity) if the high RE is achieved by 2030 (Table 21).

Overall, this implies a median annual capacity addition of 61 GW from 2030 onwards, compared to 21 GW annually required to reach 320 GW by 2030 as in the high RE scenario. The above needs to be contrasted with a maximum of 11.8 GW of yearly RE capacity in addition to what India has managed to achieve so far. China has added such

[51] The weighted average RE PLF in 2035 (and 2040) is calculated as 23.4%, which factors improvements in solar and wind PLFs with better tracking and higher hub operations respectively.

[52] Assuming the Indian economy grows at 6.5% CAGR between 2030 and 2040, and an average end-use demand elasticity of 0.85.

[53] These pertain to the 500 GW (section 5.5) case, and high and mid-scenarios (Table 3) of RE deployment.

scales of RE today, but on a grid five times larger than India's. By 2030, India's grid would be about half the size of China's grid today. Together with technical, infrastructural, land and resource quality constraints that RE faces, this analysis reflects the scale of challenges before the electricity sector if coal-based generation were to peak in the said time-frames.

The above calculations are based on energy balancing – the ability of RE to meet demand becomes even starker when we factor in time of day, unless there is cost-effective storage technology available (Tongia, Renewable Energy "versus" coal in India – A false framing as both have a role to play, 2018). The costs and challenges of phasing out coal grow as RE's share of supply increases (Tongia, Harish, & Walawalkar, Integrating Renewable Energy Into India's Grid- Harder than it looks, 2018). The recent announcement targeting 500 GW RE may be more ambition-oriented than a firm target, sending a clear message about the large role of RE in the future of India's electricity mix.

6. Conclusion and discussion

The evolving context and prospects on both the demand and supply sides[54] imply that the electricity sector focus must shift from simply adding capacity and units into the system to effectively managing these at the policy, regulatory and implementation levels. Shortfalls per se are no longer the issue–having power available at the right time, place and price, not to mention with the right characteristics such as predictability, ramping capability, etc., will be the real need in the coming years. Notwithstanding these, the supply (energy availability at bus-bars) requirement is expected to grow between 4.6 and 5.7% CAGR between 2017 and 2030.

Over the last decade, overall electricity availability has grown at 6.3% CAGR while coal-based generation has grown at 7.4%, in response to India's electricity needs. Under different scenarios of demand and non-fossil capacity addition, the future net generation requirement from coal is not likely to exceed 5.4% CAGR up to 2030. This implies coal's share in overall net generation may be between 50 to 70% by 2030, down from about 75% in 2017. However, even in the worst-case scenario for coal growth, it is still overwhelmingly the single largest source of electricity generation. Captive generation will also likely see some displacement of coal generation, growing at 4.5-5.5% CAGR depending on industrial growth and energy efficiency.

With approximately 67 GW of possible coal capacity added by 2022, our model shows that around 260 GW coal capacity is likely to suffice through 2030, which points towards delaying some projects in early stages to prevent further capacity overhangs and improve utilisation. Supercritical capacity will more than double in share, and it is likely that some ultra-supercritical capacity will also come up by 2030. This implies the efficiency of the fleet will improve. Together with improved domestic coal quality through stricter grade implementation, this will lead to specific coal consumption improving by about 8% in 2030. It should be noted that a coal capacity of 210 GW will be sufficient if 175 GW of RE is deployed by 2022, and 230 GW by 2030 if a special case of 'very high' RE (500 GW) deployment is considered[55].

[54] On the demand side, changes from the past include surging air-conditioning demand, prospect of electric vehicles, energy efficiency, lower forecasts than historically achieved, etc. For supply, RE-focussed policies, Discom reforms, falling energy and peak deficits, stranded assets in coal, etc. form the new reality.

[55] With PLFs from 61-74% across all demand scenarios.

Overall, given the historical achievements and future targets for non-fossil (renewables, hydro and nuclear), overall coal demand (domestic and imported coal from grid and captive generation) may grow by around 4.1% CAGR till 2030, indicating a moderation from the past. Even at lowest demand and highest non-fossil capacity addition, coal demand is expected to grow at 1.6%, which is non-trivial. This has obvious implications for domestic coal production, particularly CIL, but an even starker one for the Indian Railways, which cross-subsidises a bulk of its passenger fares with mark-ups on the coal it transports. While RE's rise is disproportionately located in a handful of states, mostly in southern and western India, coal reserves are mostly in East India.

Between 2012 and 2030, domestic coal's GCVs have fallen by 2% on average. If this were to continue, more coal will be required to produce the same amount of electricity, so specific coal consumption will not improve commensurate with efficiency improvements. This may necessitate the production of over 120 Mt (10-15%) additional domestic coal. Domestic GCVs can be maintained by phasing out lignite plants (also considered in this analysis) and increasing the share of domestic coking and washed coal in the mix.

Not only this, but with greater shares of advanced coal technologies requiring higher grade lower ash coal, and location and logistics related aspects, imported coal growth is likely to continue. Therefore, its physical share in generation may increase to 15.5% in 2030 from 12.2% in 2017. However, by washing 25% of raw domestic coal by 2030, the share of imported coal can be reduced to below 2017 level. This would require around 400 Mt of (non-coking) washing capacity, up from 105 Mt in 2017. However, an additional 42-65 Mt of raw coal will need to be mined, in addition to addressing the resource requirements and other environmental implications of coal washing.

On the question of coal's role in the electricity mix post-2030, it is certainly conceivable that coal generation may 'peak' with growing RE and favourable progress expected in grid-level storage. But this remains a stiff challenge. While the growth rates seem achievable going by existing targets, the median RE capacity additions required beyond 2030 will be over 60 GW—almost six times the best achieved till date. With the technical, infrastructural, land and resource quality constraints before RE, it is quite likely that such a transition may not be easily forthcoming.

In summary, while we must definitely be prepared for lower coal demands from the electricity sector compared to the recent past, coal will continue to play the dominant role as base-load. The immediate question of stranded assets in coal that threatens the sector as a whole needs to be resolved (new plants delayed, inefficient ones scrapped off, coal linkages improved, etc.) in a manner that does not impede the ongoing clean energy transition. Domestic coal quality checks and assurance mechanisms need to be strengthened to enhance generation efficiency and reduce boiler degradation. Washing greater quantities of domestic coal may check growing coal imports, especially in super-critical boilers away from the coasts. Therefore, the focus of coal-based electricity needs to shift from making more capacity available to efficiently utilising capacity, whilst minimising environmental impact. At the same time, the grid needs to undergo structural and financial improvements to enable growth and integration of RE in a cost-optimised way.

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