DECARBONIZING THE COAL-BASED THERMAL POWER SECTOR IN INDIA

A ROADMAP

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Maps used in this document are not to scale.

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Acronyms

CEA	Central Electricity Authority
DAE	Department of Atomic Energy
DISCOMs	Distribution Companies
GHG	Greenhouse gas
IPCC	Intergovernmental Panel on Climate Change
IPPU	Industrial processes and product use
IGCC	Integrated Gasification Combined Cycle
LCOE	Levelized cost of electricity
MoP	Ministry of Power
MoPNG	Ministry of Petroleum and Natural Gas
MNRE	Ministry of New and Renewable Energy
MoC	Ministry of Coal
NDC	Nationally Determined Contribution
NEP	National Electricity Plan
PLF	Plant Load Factor
PAT	Perform, Achieve and Trade
SHR	Station Heat Rate
SRMC	Short-run marginal cost
RES	Renewable energy sources
R&M	Renovation and modernization
RPO	Renewable Purchase Obligation
RGO	Renewable Generation Obligation
UNFCCC	United Nations Framework Convention on Climate Change
VFD	Variable Frequency Drive

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1

BACKGROUND

INDIA'S ENERGY SECTOR CONTRIBUTES 75 PER CENT OF ITS TOTAL GHG EMISSIONS. COAL-BASED THERMAL POWER PLANTS CONSTITUTE THE MAJOR SOURCE OF THESE EMISSIONS.

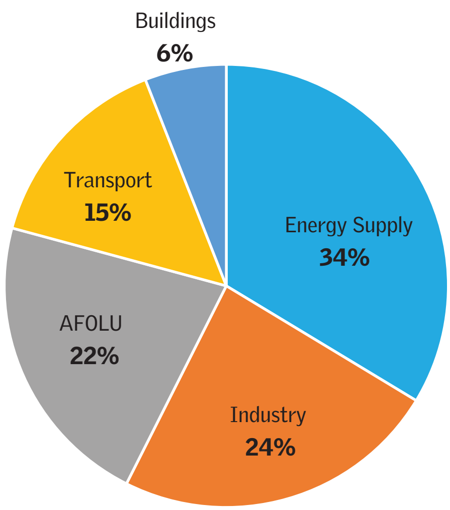
BY MARCH 2025, INDIA'S ELECTRICITY SECTOR'S INSTALLED CAPACITY REACHED A TOTAL OF 475 GW. COAL-BASED THERMAL POWER CONSTITUTES A CONSISTENTLY FALLING YET SIGNIFICANT SHARE OF 45.28 PER CENT.

COAL IS LIKELY TO CONTINUE TO REMAIN A KEY SOURCE OF ENERGY FOR INDIA IN THE COMING DECADES, WITH THE TOTAL INSTALLED CAPACITY OF COAL BASED POWER SLATED TO RISE BEYOND 280 GW.

Due to the exponential increase in anthropogenic greenhouse gas (GHG) emissions, the risks posed by climate change are continually escalating. Anthropogenic emissions of carbon dioxide (CO_2) and other greenhouse gasses (GHGs) are the primary cause of climate change and one of the most pressing challenges of the contemporary world. Significant quantities of CO_2 and other GHGs are emitted every year and they will remain in the atmosphere for hundreds of years.

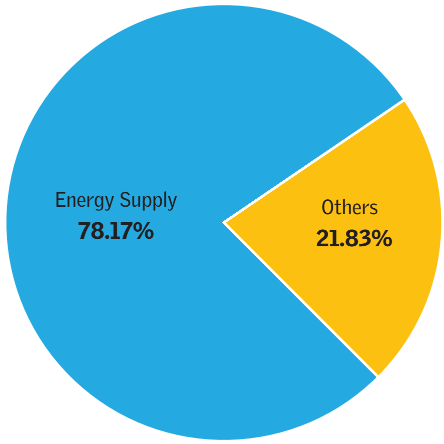
Increasing levels of CO_2 have led to a rise in global temperature and climate change. Current global warming is a result of both recent emissions as well as emissions of the past. According to the Intergovernmental Panel on Climate Change (IPCC), global GHG emissions were estimated at 59 ffl 6.6 $GtCO_2$-eq (one billion tonnes of carbon dioxide) in 2019.[1] Since 1990, there has been a rapid rise in global CO_2 levels. Global GHG emissions in 2019 were about 54 per cent (21 $GtCO_2$-eq) higher than in 1990 (38 ffl 4.8 $GtCO_2$-eq) (the baseline year of the Kyoto Protocol).[2] According to the IPCC, in comparison to other sectors, the contribution of the energy supply sector to these emissions is the highest with a share of 34 per cent. As per the World Resources Institute's online platform Climate Watch, if one looks at the energy sector as a whole (including transport, industry and others), it contributed around 78 per cent of the global GHG emissions in 2019 (see *Graph 1[b]*).[3]

Graph 1(a): Sector-wise global CO_2 emissions, 2019



Source: Emission trends and drivers, IPCC Report, 2022

Graph 1(b): Share of global emissions: Energy versus other sectors, 2019



Source: Global Historical GHG Emissions, Climate Watch

1.1 Indian context

In the third National Communication (NC3) submitted to the United Nations Framework Convention on Climate Change (UNFCCC), the Ministry of Environment, Forest and Climate Change of India presented the updated greenhouse gas (GHG) emissions data for 2019.[4] The report reveals a consistent rise in Indian GHG emissions, surging from 2.8 Gt CO_2-eq in 2016 to 3.1 Gt CO_2-eq in 2019, excluding removals from forests and other land-based sinks.[5, 6] India's emissions accounted for 5.3 per cent per cent of the total global emissions in 2019.[7] More recently, an EU Joint Research Centre (JRC) 2024 report stated that India's emission share of total global emissions has risen to 7.8 per cent as of 2023 (see *Table 1: Sector-wise GHG emissions in 2019 in India*).[8]

In 2019, the energy sector was responsible for the majority of emissions in India, accounting for 75.81 per cent. Industrial processes and product use (IPPU) contributed approximately 8.41 per cent, while agricultural activities made up 13.44 per cent of total emissions (see *Graph 2: Sector-wise GHG emissions in India*).

India's national communication categorizes energy emissions into two sections:

1. Fuel combustion activities and
2. Fugitive emissions from fuels.

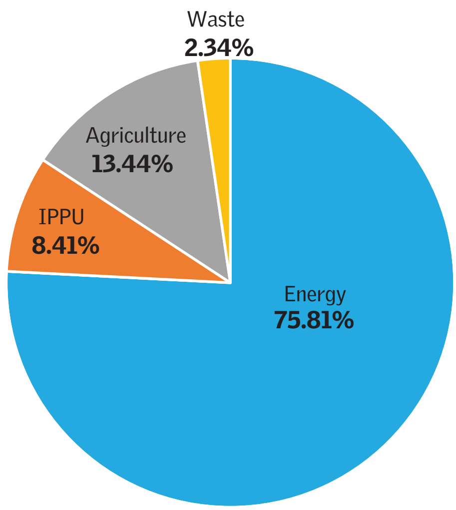
Table 1: India: Sector-wise GHG emissions in India (in gigagram [Gg]), 2019

GHG source and removal	CO_2 emissions	CO_2 removal	CH_4	N_2O	HFC 23	CF_4	C_2F_6	SF_6	CO_2 equivalent
Energy	2,305,998	NO	2,034	83	NO	NO	NO	NO	2,374,330
IPPU	183,044	NO	222	12	2	5	1	0.004	263,540
Agriculture	NO	NO	12542	373	NO	NO	NO	NO	420,968
LULUCF	9,726	496,656	48	1	NO	NO	NO	NO	–485,472
Waste	NO	NO	2684	54	NO	NO	NO	NO	73,189
Memo items	801,279	NO	0.12	0.17	NO	NO	NO	NO	80,1335
Total without LULUCF	2,489,042	-	19,482	522	2	5	1	0.004	3,132,028
Total with LULUCF	2,498,768	496,656	19,531	523	2	5	1	0.004	2,646,556

NO: Not occurring
IPPU: Industrial Processes and Product Use
LULUCF: Land Use, Land Use Change and Forests

Source: India's Third National Communication to UNFCCC, 2023

Graph 2: Sector-wise GHG emissions (CO_2 equivalent) in India, 2019



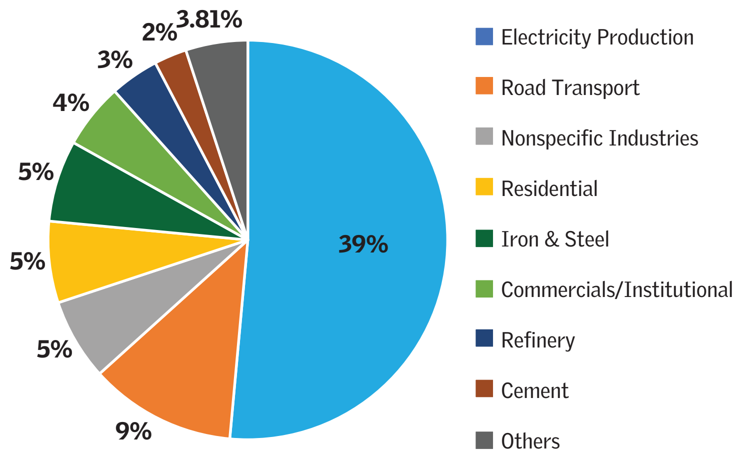
Source: India's Third National Communication to UNFCCC, 2023

The former category includes the following sectors:

1. Energy industries
2. Manufacturing industries and construction
3. Transport
4. Other sectors

Within the energy sector, electricity production was a significant contributor, accounting for 39 per cent of the country's emissions (see *Graph 3: Source-wise*

Graph 3: Souce-wise energy-sector emissions in India, 2019



Source: India's Third National Communication to UNFCCC, 2023

energy sector emissions in India, 2019). Electricity production resulted in a total of 1,221.5 million tonnes of CO_2-eq greenhouse gas emissions in 2019. The remaining 36.81 per cent of energy-related emissions came from sectors such as cement (2 per cent), iron and steel (5 per cent), road transport (9 per cent), and commercial/institutional + nonspecific industries + refineries (13 per cent). Among the country's major greenhouse gases, CO_2 emissions were the most prevalent, comprising 79.47 per cent of total emissions.

Conventional power-generation methods in India primarily rely on fossil fuels, particularly coal, to convert thermal energy into electricity. The combustion of coal results in the emission of various greenhouse gases and pollutants. Given this, it is crucial to closely examine the power sector's emissions, especially coal- and lignite-based thermal power, and develop a strategic roadmap to reduce its emissions.

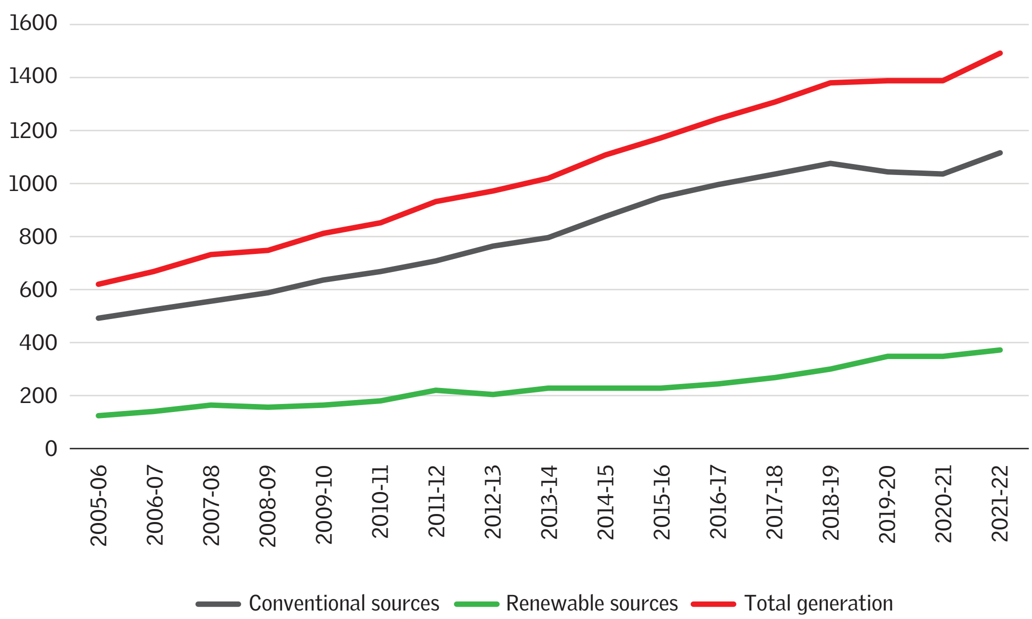
1.2 India's dependence on coal power

The national electricity plan prepared by the Central Electricity Authority (CEA), a body under the Ministry of Power (MoP), Government of India, states that as of March 31, 2022, the installed capacity of power generation in India was 399.5 GW, of which 51 per cent is coal, 2 per cent lignite, 6 per cent gas, 2 per cent nuclear, and 39 per cent renewable energy sources (RES), including large hydro and less than 1 per cent diesel.[9] As per the CEA Monthly Installed Capacity Report,[10] as of March 2025, India's installed capacity has gone up to 475.21 GW, of which the share of coal capacity has gone down to 45.28 per cent, gas reduced to 5.16

per cent, nuclear increased slightly to 1.72 per cent, and RES increased to 46.32 per cent (including large hydro). According to the revised nationally determined contributions (NDC) targets, India stands committed to attain approximately 50 per cent of its cumulative installed electric power capacity from non-fossil fuel-based energy sources by 2030. By March 2025, the RE installed capacity reached 220.09 GW (including large hydro), up from 190.57 GW in March 2024, i.e. an addition of around 29.52 GW. This is a 15.49 per cent growth in a year, which is also the largest addition in a single year for the country until now.[11] Additionally, India's under-construction RE capacity stands at 142.6 GW, including 82 GW of solar, 24.5 GW wind and 35.7 GW of hybrid projects in the pipeline.[12]

In the fiscal year 2005–06, the total electricity generation was 624.2 billion units (BU), in which fossil fuels sources contributed 79.65 per cent, while non-fossil sources accounted for 20.33 per cent.[13] In 2024, average thermal electricity generation comprised 75.4 per cent of the total generation of electricity, with the rest coming from non-fossil sources. Further, notably, the combined average of solar and wind energy generation was 11.84 per cent, indicating a major shift towards renewable energy as this source of electricity was almost non-existent in 2005–06.[14] Despite a significant increase in renewable energy generation over the years, a considerable portion of power generation continues to rely on fossil fuels, mainly coal (see *Graph 4: Electricity generation trends in India: Conventional versus renewable sources [2005–06 to 2021–22]*).

Graph 4: Electricity generation trends in India: Conventional versus renewable sources (2005–06 to 2021–22)



Source: Annual Report, Ministry of Power, 2023–24

The cost and price of renewable energy has consistently dropped in India, driven by technological advancements, a more competitive supply chain and government prioritization. Levelized cost of electricity (LCOE), i.e. the minimum average price at which the electricity generated by the asset/facility is required to be sold in order to offset the total costs of production over its lifetime,[15] is around US $0.048/ kilowatt per hour (Kwh)[16] for utility-scale solar photovoltaics (PV) and US $0.06/ Kwh for coal- fired power plant in India as of 2023, therefore showing renewable energy as cheaper than coal. While solar and wind may appear to be more economical when considering only the LCOE or short-run marginal cost (SRMC), these costs often may not capture system level costs (like grid integration etc.), environmental costs, and support mechanisms (taxes, subsidies etc.) available to any particular generation type.[17] Therefore, comparing solar power and coal is not a straightforward task. As renewable energy capacity grows, it is also a challenge for the country's existing grid infrastructure to adapt to the increasing share of renewable energy and its intermittent nature, especially without affordable energy storage solutions.

2

THERMAL POWER: GENERATION PROCESS, POLICY, DEMAND AND SUPPLY

INDIA'S ANNUAL ELECTRICITY REQUIREMENT HAS GROWN BY AN AVERAGE OF 9.25 PER CENT PER YEAR FROM FY 2021–25 AGAINST THE FORECASTED RISE OF 6.65 PER CENT, RESULTING IN SUSPENSION OF PLANS FOR RETIREMENT OF OLD AND INEFFICIENT UNITS.

70 PER CENT OF INDIA'S COAL-POWER-GENERATION UNITS ARE LESS THAN 15 YEARS OLD. THE SHARE OF SUBCRITICAL UNITS IS FALLING, WITH NEW UNITS EXCLUSIVELY OF SUPERCRITICAL AND ULTRA-SUPERCRITICAL TECHNOLOGY, MARKING AN EXPECTATION FOR RISE IN OPERATIONAL EFFICIENCY LEADING TO LOWER EMISSIONS.

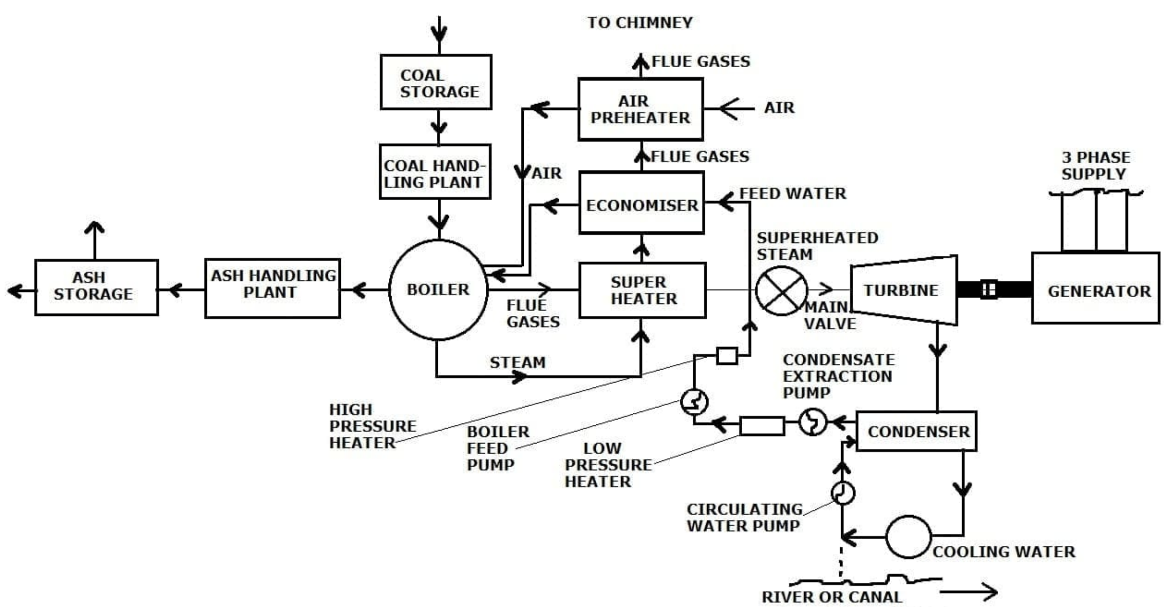
THE NEED FOR DECARBONIZATION OF INDIA'S COAL POWER PLANT FLEET NECESSITATES AN UNDERSTANDING, EVALUATION AND RE-PURPOSING OF GOVERNING POLICIES AROUND DEMAND FORECASTING, POWER PURCHASE AGREEMENTS (PPAs), MERIT ORDER DISPATCH (MOD) AND COAL CESS.

2.1 Generation process

In a coal-based thermal power plant, combustion of fuel (coal/lignite) is the pivotal process where the thermal energy of coal undergoes conversion into electrical energy. Notably, the combustion of coal is the primary source of greenhouse gas emissions from these plants. The sequential phases of electricity generation in a thermal power plant is illustrated in *Figure 1.*

Coal or lignite is transported to thermal power plant facilities through ships, rail and road. At the facility, it initially undergoes pulverization in a pulverizer and is then supplied to the boiler for combustion. During the combustion process in the presence of air or pure oxygen, heat is generated. The generated heat is utilized to raise the temperature of demineralized water, producing high-pressure and high-temperature steam. The generated steam is directed through a series of turbines, rotated by the steam, with turbo generators connected to these turbines converting the mechanical energy into electricity. To ensure higher efficiency, waste heat from the steam leaving the boiler is used to increase the temperature of cold water. Simultaneously, cooling the steam and recycling the condensed water back into the boiler. Throughout the process, ash generated due to the burning of coal, also called fly ash, is collected from flue gas streams through air pollution

Figure 1: Thermal power plant: Process of electricity generation



Source: Thermal power plant: The Mechanical Engineering .com control equipment, and bottom ash is retrieved from the bottom of the boiler as solid waste. Additionally, the water in the cooling cycle is discharged as wastewater once it achieves a specific (six to eight) cycle of concentration (CoC). Cycle of concentration is an important parameter used in cooling towers. It is a measure of the concentration of dissolved solids in the cooling tower's process water. The efficiency of the plant is dependent on the temperature and pressure of the steam being utilized.

2.2 Available technologies and their efficiency

Coal and lignite-based thermal power plants use different technologies for power generation. The major difference amongst these technologies is that of efficiency and emissions. The technologies are:

Subcritical technology: This is the most commonly used technology in coal-based thermal power plants in India. In subcritical technology, the operating conditions are below the critical point of water. (In thermodynamics, a critical point is the end point of a phase equilibrium curve, which is a temperature and pressure combination where a liquid and its vapour can coexist; for water the critical temperature and pressure is 374°C and 22.06 Mpa respectively, and they can reach a maximum efficiency of 38 per cent.)[18]

Supercritical technology: In this technology, steam is generated at a pressure above the critical point of water (373.94°C and 22.064 MPa). Supercritical plants can typically reach an efficiency of 42–43 per cent.[19] All new units in India are required to have at least supercritical technology. The average cost of a new unit is Rs 6,000–7,000 crore, depending upon their capacity variance.[20]

Ultra-supercritical technology: This is similar to supercritical generation, but operates at even higher temperatures and pressures. Thermal efficiencies may reach 45 per cent. Current ultra-supercritical plants operate at temperatures of up to 620°C, with steam pressures in the range of 25–29 MPa.[21]

Advanced ultra-supercritical technology: This uses the same basic principles as ultra-supercritical technology. This technology aims to achieve efficiencies in excess of 50 per cent, which will require materials capable of withstanding steam conditions of 700–760°C and pressures of 30–35 MPa.[22] Developing super-alloys and reducing their cost are the main challenges to the commercialization of this technology.

Integrated gasification combined cycle (IGCC): In this process, electricity is produced via a combined cycle of gas and steam turbines. Coal is partially oxidized in air or oxygen at high pressure to produce fuel gas. This fuel gas is then burned in a combustion chamber, generating hot, pressurized gases that expand through a gas turbine to produce electricity. The hot exhaust gases from the gas turbine are used to raise steam in a heat recovery steam generator, which then expands through a steam turbine to generate additional electricity. Integrated Gasification Combined Cycle (IGCC) systems incorporating gas turbines with a 1,500°C turbine inlet temperature are currently under development and may achieve a thermal efficiency approaching 50 per cent.[23]

Efficiency: A thermal power plant's design efficiency, its coal consumption and CO_2 emissions are mainly determined by the technology it utilizes. The main difference between subcritical, supercritical, ultra-supercritical and advanced ultra-supercritical technologies are the temperature and pressure at which they operate, which affect the heat carrying capacity of the steam and, consequently, its efficiency. Efficiency can be measured in terms of heat rate. Heat rate is the energy required to produce one unit of electricity and is measured in kcal/kWh. The lower the heat rate, the more efficient the plant and the lesser will be the coal consumption and CO_2 emissions from the plant. Estimates of CO_2 emissions for a plant are primarily based on coal consumption. However, if we want to correlate CO_2 emissions directly with a plant's efficiency, approximately 1 per cent rise in efficiency reduces CO_2 emissions by 2–3 per cent. So, if a subcritical plant of 35 per cent efficiency is replaced by an ultra-supercritical plant of 43 per cent efficiency, the CO_2 footprints will be reduced by 16–24 per cent.[24, 25]

2.3 Structure of energy sector in India and energy policy

The energy sector landscape in India is intricately governed by five ministries, each overseeing a specific aspect of power production. The ministries include the Ministry of Power (MoP), the Ministry of Petroleum and Natural Gas (MoPNG), the Ministry of New and Renewable Energy (MNRE), the Ministry of Coal (MoC), and the Department of Atomic Energy (DAE). Among these, the Ministry of Power takes charge of regulating electricity generation. Playing a pivotal role in this dynamic, the Central Electricity Authority (CEA) serves as the principal advisor to the Ministry of Power. Its responsibilities include policy making and national power planning.[26] As part of power planning, CEA releases National Electricity Plans (NEPs), which project demand and consumption, energy production, and set framework and targets for power generation for a planned five-year period. The latest NEP was notified in March 2023, which sets out the plan for two upcoming five-year periods until 2032. The major initiatives in the NEP of 2022–23 are:

- Based on generation planning studies carried out for the period of 2022–27, the likely Installed Capacity for the year 2026–27 is 609,591 MW, comprising 273,038 MW of conventional capacity (coal: 235,133 MW, gas: 24,824 MW, nuclear: 13,080MW) and 336,553 MW of renewable-based capacity (large hydro: 52,446 MW, solar: 185,566 MW, wind: 72,895 MW, small hydro:5,200 MW, biomass:13,000 MW, PSP: 7,446 MW) along with BESS capacity of 8,680 MW/34,720 MWh.

- Based on generation planning studies carried out for the period of 2027–32, the likely Installed Capacity for 2031–32 is 900,422 MW comprising 304,147 MW of conventional capacity (coal: 259,643 MW, gas: 24,824 MW, nuclear:19,680 MW) and 596,275 MW of renewable-based capacity (large hydro: 62,178 MW, solar: 364,566 MW, wind: 121,895 MW, small hydro: 5,450 MW, biomass:15,500 MW, PSP: 26,686 MW; excluding 5,856 MW of likely hydro-based imports) along with BESS capacity of 47,244MW/236,220 MWh. In other words, 66 per cent of the installed capacity by 2031–32 would be renewable and 33 per cent would be from conventional sources.

- For 2026–27, the projected CO_2 emissions would be 1,057 million tonnes and 1,100 million tonnes for 2031–32, increasing from 1081.1 million tonnes of emission in 2022–23.

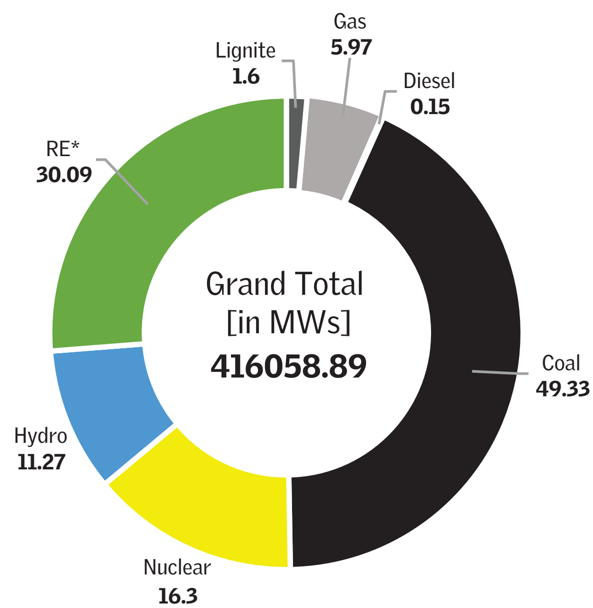
- However, the average grid emission factor is expected to reduce from 0.823 for 2022–23 to 0.548 kg CO_2/kWh in 2026–27 and to 0.430 kg CO_2/kWh by 2031–32.

- The likely retirement of 2121.5 MW was considered for the period 2022–32.[27]

2.3.1 Installed capacity and age of the units

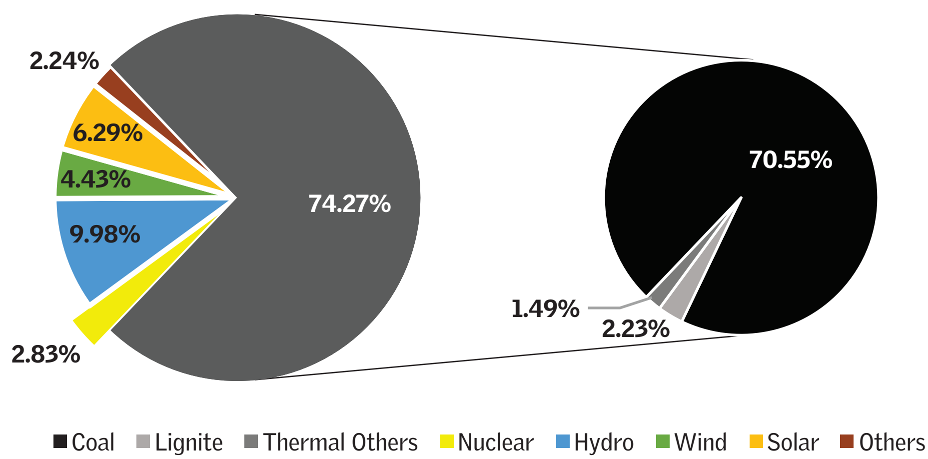
CEA annually refreshes its CO_2 baseline database, containing comprehensive data on all power plants in India. This dataset encompasses details such as plant capacity, power generation, fuel type, fuel consumption, and total CO_2 emissions for each facility.[28] *Graph 5* illustrates the installed capacity, electricity generation and the share of sources for the fiscal year 2022–23. CO_2 emissions are primarily attributed to coal/lignite, naphtha, and gas-operated plants. Given the comparatively lower electricity output from gas and naphtha facilities, this report focuses solely on coal/lignite power plants.

Graph 5(a): Installed capacity mix, March 2023



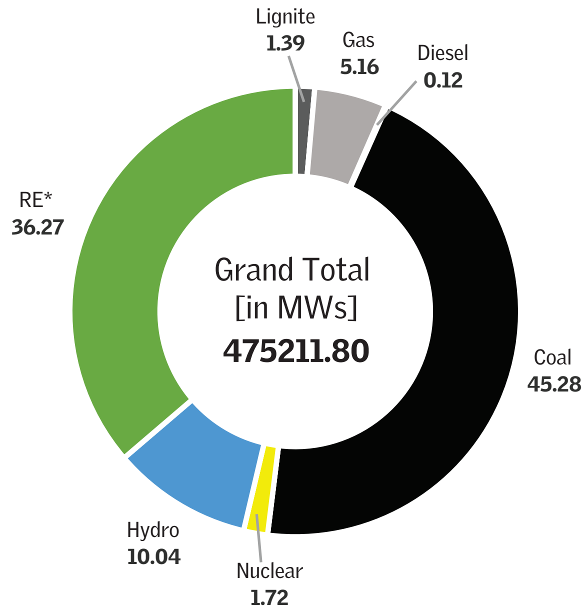
Sources: CEA's All India Monthly Installed Capacity Report; MoP's National Power Portal data

Graph 5(b): Source-wise generation share: FY 2022–23



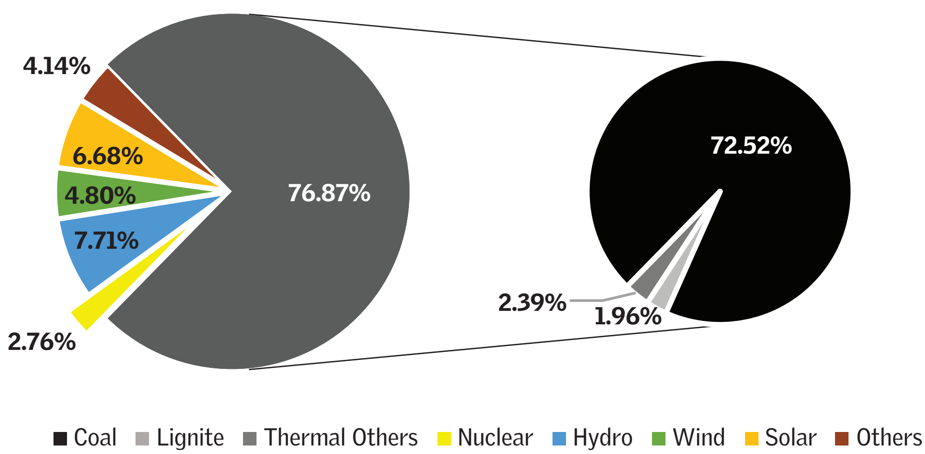
Sources: CEA's All-India Monthly Installed Capacity Report; MoP's National Power Portal data

Graph 6(a): Installed capacity mix, March 2025



MoP's National Power Portal data

Graph 6(b): Source-wise generation share, FY 2023–24



Source: CEA's All India Monthly Installed Capacity report

The total installed capacity of coal-fired thermal power plants in India as of March 31, 2025 is 221.81 GW. The thermal power plants category consists of plants using coal, lignite, gas and diesel as fuel. However, when considering only coal and lignite, the installed capacity is 211.85 GW (almost 90 per cent of the thermal power plant capacity). Further, by March 2025, one can notice that the total installed thermal capacity has fallen in proportion to RE *(RE has increased from 30 per cent to 36 per cent)* but the generation share of thermal power has risen (*74 per cent to 76 per cent)*. For 2022–23, CEA has put out the data for 196 power plants; however, net generation for 16 of them is reported to be zero. Among these, 15 plants, with a combined installed capacity of 4125.70 MW, hail from the private sector, while the remaining plants, with an installed capacity of 250 MW, belong to the state sector. Two plants, BARH STPP I and BARH STPP II, among the 196, exhibit minor discrepancies. Their data is consolidated and reported under BARH STPP I. Therefore, both are clubbed for this analysis (as BARH STPP I and II), resulting in a total of 195 plants being considered for this report. Of the given 195 plants, there are a total of 603 units (see *Table 2: India's coal fleet: Age and capacity distribution, 2022–23)*.

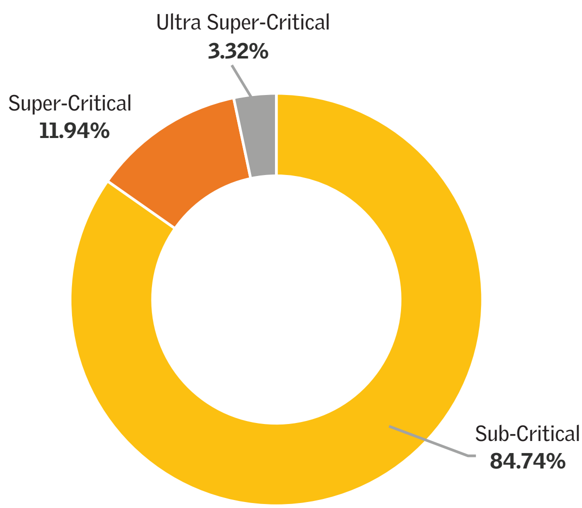
Units below the installed capacity of 660 MW are considered to be subcritical, between 660 and less than 800 MW are considered to be supercritical, and units equal to and above 800 MW are considered to be ultra-supercritical. As can be seen, most of the supercritical and ultra-supercritical units are younger (age < 15 years). At the same time, about 23.5 per cent subcritical units are above the age of 30 years and 19.2 per cent of subcritical units are 15–30 years old. Overall, India has a relatively young coal fleet. Approximately, 39 per cent (83.61 GW) of the installed capacity is less than a decade old and 71 per cent (150.18 GW) of the installed capacity is less than 15 years old. About 19 per cent (40.89 GW) of the installed capacity is older than 25 years. Of the 40.89 GW capacity, a major share (about 70 per cent) belongs to small units of up to 250 MW and less.

Table 2: India's coal fleet: Age and capacity distribution, 2022–23

Unit capacity	Age (in years)				Total
	≥ 30	≥ 15 & < 30	≥ 5 & < 15	< 5	
<250 MW (subcritical)	126	60	61	1	248
≥ 250 and <660 MW (subcritical)	16	56	183	8	263
≥ 660 and <800 MW (supercritical)	0	0	54	18	72
≥ 800 MW (ultra-supercritical)	0	0	15	5	20
Total	142	116	313	32	603

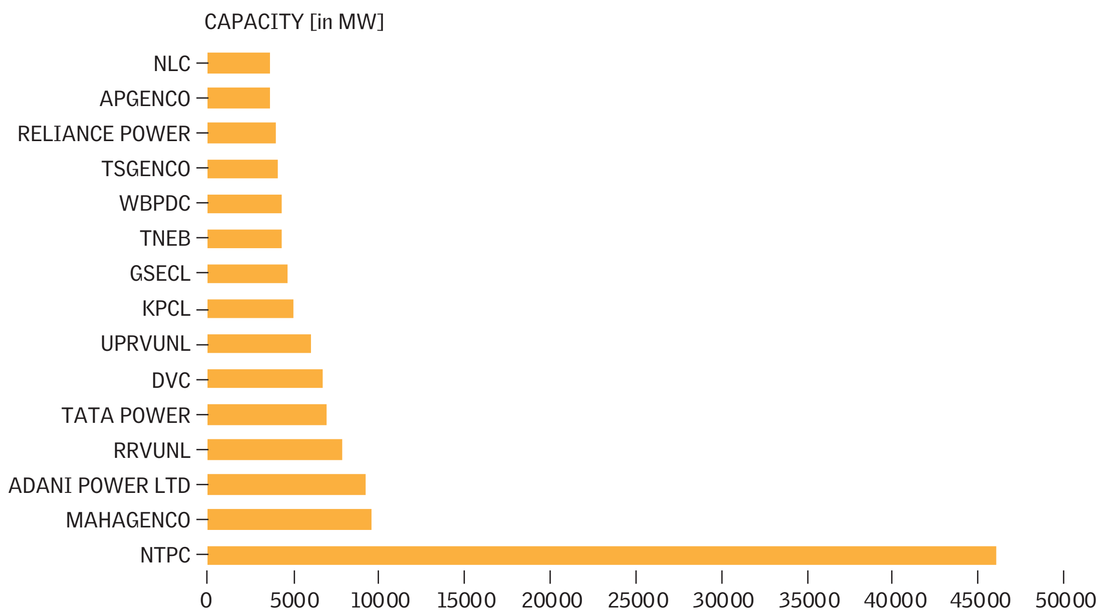
Source: CEA CO_2 database, Version 19

Graph 7: India's coal fleet: Technology-wise split (2022–23)



Source: CEA CO_2 database, Version 19

Graph 8: India's coal capacity: Top 15 companies (2022–23)



*NTPC installed capacity excluding JVs

Source: CEA CO_2 Database, Version 19

Graph 7 shows the installed capacity for 2022–23 of the top 15 companies, which is equal to 59.2 per cent (126029.25 MW) of total installed capacity and 62.1 per cent (680201.58 GWh) of net generation.

2.4 Power Purchase Agreement (PPA)

Visibility and certainty of revenue are essential components for power developers. These components are essential for creditors to provide long-term finance to plant developers. In contrast, a distribution company (mostly DISCOMs in India) needs certainty over their energy demands for a consistent time frame. A Power Purchase Agreement (PPA) is the formalized instrument that creates this bridge. Power providers get certainty of income flows for their production and the distribution companies get assurance on power supply.

2.4.1 Key aspects of Indian PPA model

India has long had an energy supply shortage owing to lack of built-up capacity for energy. Capital shortage was another issue that impeded the creation of the requisite capacity.

The power sector was considered a strategic heavy industry, while power distribution was a state monopoly. Most PPAs were signed with DISCOMs, with majority plants supplying to standalone DISCOMs of respective states. As support for power-generating industries, the length of PPAs were considered key.

The model PPAs in India have three components to determine their financial viability, i.e. concession period, fuel costs and capital costs. The variable costs are dependent on the cost of fuel used and vary depending upon the fuel supply. Each contracted power producer has an established installed capacity. Ninety per cent of the installed capacity is identified as the normative capacity of the plant (standard level of electricity generation capacity that a plant can produce under normal operational conditions) within the accounting period. Each plant must supply as per their normative capacity to avoid attraction of penalties. Further, a power plant must use 85 per cent of the electricity generated within their normative period to be supplied to the contracted DISCOMs. Like any large infrastructural projects, thermal power plants also have provision for insurance and indemnity covering natural calamities and commercial impossibility events within the PPA. Additionally there is one added novelty, i.e. indemnity in case of *'political actions'*. Recognizing political upheavals and their consequences on power supply, political actions are placed under the insurance ambit of *'Force Majeure'*. This insulation extends to policy shifts against fossil fuel plants, providing for indemnity to lenders and pre-determined termination payout in case their shutdown happens owing to any future climate pledges of India. However, India faces a prospect of US $169 billion in stranded assets if it chooses to retire its coal and oil units in line with 2° Celsius pledge of the Paris Agreement.[29]

Further, unlike the 2013 model and its predecessor agreements which allowed for upward revision of tariff owing to inflation effect on variable costs, the 2022 model now binds the price component with Wholesale Price Index (WPI), therefore allowing for both upward and downward revision of costs. In addition to that, NITI Aayog now runs a dashboard for transparency of price via its *India Climate & Energy Dashboard*[30] and provides plant-wise details of variable and fixed costs of fuel that is being distributed.

2.4.2 Length of PPAs and related effects

The concession period is synonymously understood as the tenure of the contract period. Prior to the uptick in renewable energy in a big way since the mid-2010s, fossil fuel power plants with their high capital costs required long-term visibility. The policy sentiment is reflected in the Ministry of Power's 2013 model PPA, which posits 30 years including construction period as the minimum standard. This was extendable for 15 years at the option of either party. On top of it, a further extension of 15 years was possible by an agreement of both parties.

A PPA locks in the DISCOM to pay for the fixed costs of the agreed time period. This policy legacy has two effects with renewable energy uptake. Increased renewable energy capacity during the time period of PPA cannot be integrated into supply by the DISCOMs without a high uptake in demand of energy. Conversely, if renewable energy is integrated into the grid's supply, the individual plant load factor of the fossil fuel plants (mostly thermal in India) goes down. The plant will run on a lower PLF, leading to lower efficiency. Yet, the DISCOMs are required to pay for the fixed costs as agreed in the PPA. In addition, PPAs factor in inflation and account for upward revision of tariffs. Thus, even if technological innovation has brought down energy production costs in the market, an energy producer has no incentive to incorporate them and can continue to charge the DISCOMs for higher prices.

A thermal power plant recovers its costs over a rundown of 25 years,[31] thus financial efficiency suggests a conversion of fixed costs payouts beyond that time-period into investment obligation. Curiously, a review of the Central Electricity Authority's (CEA's) *Thermal Broad Status Reports* of recent months shows unit addition within an already existing thermal power plant does not require a new separate PPA but allows extension of the already signed PPA between the contracted entities.[32] Only 30 per cent of power plant units are less than 5 years old, thus locking majority of coal supply into the old PPA structure.[33]

Policy shifts towards renewable energy uptake and compounded by the huge dues of DISCOMs called for a review of this. The recent 2022 model PPA created the following three divisions of PPAs: *first*, long-term PPAs (seven years and above); *second*, medium-term PPAs (more than one year up to five years); and, *third*, short-term PPAs (one day to 365 days). Shorter-tenure PPAs allow grid owners flexibility to factor in seasonal demands and adverse/unconventional weather events, and create competitive costs of energy with the ability of DISCOMs to buy energy from market exchanges of the same. Additionally, it incentivizes energy producers to create higher efficiency for their energy produced. Further, the Central government introduced the SHAKTI policy to create a competitive bidding element for coal purchase and keep variable prices in check with market forces. The PUShP Portal was launched by CEA to enable PPAs to be more flexible with respect to coal prices (only upwards) within a time-bound manner so that DISCOMs do not pay more for the electricity produced.

2.4.3 Renovation and modernization component in PPAs

Operation and maintenance of an energy plant must be undertaken by the supplier/utility owner, while upkeeping in strict compliance of good industry practices. This is independently moderated by the respective monitoring agencies. Modal PPA, 2022 interprets 'development' to include renovation, refurbishing, augmentation, upgradation and other incidental activities. Article 5.1.1 of the same text obligates the supplier to undertake all 'development' and procure the finances for the same. This obligation runs parallel to the obligation to supply energy as contracted within the PPA on a per hourly basis.

CEA's Thermal Project Renovation and Modernisation Division estimated in their 2020 report that approximately 10,000 MW of the total thermal capacity is due to R&M work.[34] Until the new guidelines came into being that allow for flexibilization, 'generation maximization' was the norm, meaning no matter that your plant is inefficient and has high emission intensity, units were allowed to run until they reach their life cycle of approximately 25–30 years. This policy locked in these units into PPA, allowing them to run. A 2022 study by IIT Bombay estimates that without PPA, the GHG emission quantity of our thermal power plants could be reduced by 40 per cent (considering PPAs prior to the new modal PPA).[35] The new guidelines place the responsibility for R&M work on the utility owner. The utility owner has to factor in the shutdown of the plant during the time period and the cost of retaining staff for eventual restart of the plant beyond the R&M process. If, however, a plant recovers its capital cost within 25 years of operation and the R&M burden is placed solely on the utility owner, it is a double whammy on the utility owner. Conclusively, it is expecting a utility owner to operate with no commercial incentive for the entire life cycle of the business.

2.4.4 PPAs lack incentives for thermal power stations to modernize

Harmonization of PPAs with reduction of their overall life cycle has been identified in the *Standing Committee Report on Energy*.[36] The limitation of downward cost revision due to PPAs needs to be addressed to prevent uncompetitive energy payments. Old long-term PPAs are forcing a slowdown of integration of RE into our energy grid. Despite lower plant load factor, DISCOMs are due to pay for the contracted fixed costs, causing consumers to pay for energy not used. The structure of PPAs do not account for R&M costs and place the burden of the same on plant owners. The R&M process, which is necessitated by our continuous need of thermal energy despite uptake of RE, needs a relook on the burden aspect of the process as the current mechanism is not commercially feasible for the utility owner. The plant owner receives no financial payment for the duration of their R&M process, preferring to run their inefficient and high emitting plant for as long as they can.

Further, there is no clause for pause within a PPA over the duration of R&M to prevent penalties being levied on the Utility owner who is undertaking R&M process to become more efficient. Therefore, the state can do a comprehensive cost benefit analysis of upgradation of plants for their R&M vis-*à*-vis the cost of termination of old PPAs and by factoring in the emission factor of the plant and review the utility of running such plants. A separate budget allocation for this review via a designated scheme can assist in heightened decarbonization pathway within the thermal energy industry.

2.5 Merit Order Dispatch (MOD)

Merit Order Dispatch (MOD) is the process of selecting power plants to generate electricity based on the lowest marginal cost among the power plants. In India, MOD is managed by NLDC (National Load Dispatch Centre) under the Ministry of Power and Regional and State Load Dispatch Centres (RLDCs/SLDCs) under state governments. Power plants are given merit order ranks based on the variable cost of generation. This cost is the sum of the fuel cost and O&M costs. These days, renewable energy is given the first priority with a must-run status. Renewable energy is preferred for dispatch over other sources of electricity production.

2.5.1 Criteria for MOD

National merit order dispatch is implemented for power-generating stations. CEA monitors and resolves issues arising around implementation of the scheme. The status of implementation is sent to the Ministry of Power (MoP) on a quarterly basis. It is reviewed by the MoP or CEA after one year.[37]

In order to utilize the cheapest power, power plants with cheaper power are utilized with maximum capability and are considered or preferred over other plants. Plants with cheaper power are usually the pithead plants or plants situated not far from the mines.

India's installed generation capacity has been increasing over the last few decades. There is, however, a mismatch in peak electricity demand and generational capacity, leading to a decline in Plant Load Factor (PLF) for coal-based thermal power plants. For instance, the generational capacity in 2018 was 344 GW (including 70 GW RE), but peak electricity demand remained at 173 GW. This mismatch resulted in un-requisitioned power from coal plants, with cheaper power sometimes remaining unused while costlier power was dispatched, increasing the overall cost of electricity. As a development, the following developments were made:

- The Ministry of Power finalized a revised structure of Day-Ahead National level Merit Order Despatch Mechanism, as per Press Information Bureau April 26, 2023 report.[38] According to this, merit orders are now finalized a day prior against the prior mechanism of finalizing 1.5 hours before. In the earlier system, only NTPC thermal plants were included. While in the new system, all regional thermal power plants and intra-state thermal plants are considered. This will be implemented and operated by the Central Electricity Regulatory Commission (CERC) and GRID-INDIA respectively.

- This has been implemented to lower the overall cost of electricity generation, which will translate into lower electricity prices for consumers. Moreover, it will also help states maintain resource adequacy in a cost-effective manner while maintaining the PLF and efficiency.

- The Central Electricity Authority (CEA) in its notification on September 26, 2018 has made recommendations for the installation of pollution control equipment by TPPs. Due to the installation of flue gas desulphurization (FGD), a rise in the variable cost in a range of 2.71 to 6.68 paisa per unit was expected.[39] This increase in variable cost would further have had an impact on merit order dispatch. However, according to the direction from the Ministry of Power (MoP) to Central Electricity Regulatory Commission on May 30, 2018, it was clarified that impact of this cost incurred due to the environmental norms will not be considered for MOD till March 31, 2022.[40] This deadline was further extended to December 31, 2022 on July 30, 2019. MoEFCC on March 31, 2021 issued an amendment to EPA named Environmental (Protection) Amendment rules, 2021 notifying a timeline for following the emission norms and deadlines to be followed by TPPs. The 2019 notification also specifies that TPPs not complying with new emission norms may be considered for lower merit order ranks as compared to the plants that follow the norms.

2.5.2 Environmental merit order dispatch

MODs that consider cost as the only criteria end up providing no incentive for power-generating units to improve their efficiency and emission intensity. To make emissions an important factor for the sector, South Korea has implemented a system of environmental merit order dispatch. Environmental merit order dispatch refers to the scenario where power plants with lesser emissions or in other terms 'environmentally good' are dispatched earlier. This is done by incorporating a higher cost on carbon and thereby dispatching units with lesser emissions based on the merit order ranks.

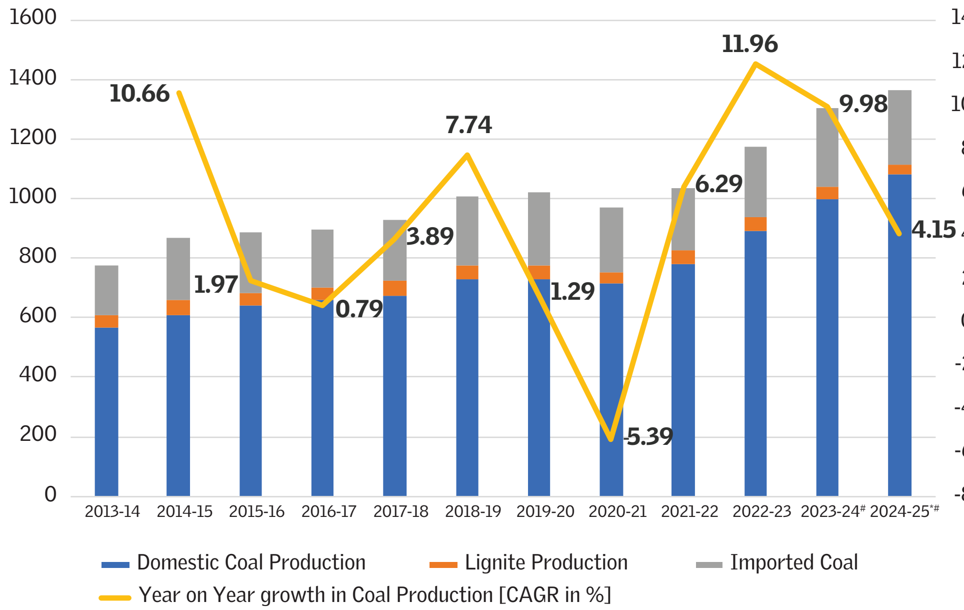
Korea has published a Carbon Neutral Strategy in 2021. In the Carbon Neutral Strategy, Korea lays principles to achieve decarbonization in the electricity sector by facilitating carbon pricing through the emissions trading system by increasing the portion of paid carbon allowances and reflecting carbon costs in electricity rate. In the 8th Basic Plan for Long-term Electricity Supply and Demand (BPLE), 2017-2031, the Korean government introduced environmental dispatch to incorporate the cost of allowance into the electricity sector to facilitate fuel switching to have less polluting industries. This cost of allowance is then introduced into the variable cost which will reflect on the merit order.[41]

There are countries/regions (such as the European Union) that incorporate carbon pricing or priority dispatches to favour clean energy resources in electricity dispatch. But South Korea is the only country that explicitly mentions environmental merit order dispatch as such.

2.6 Coal cess

India's continuous reliance on coal to meet its unprecedented rising energy demand has led to a considerable increase in its annual coal production capacity. The consumption includes the usage of domestic & imported coal alongside lignite

Graph 9: India's coal usage and annual growth (2013–14 to 2024–25*)



GST collected data is estimated values and not actual as per Union Budget documents.
* Coal produced figures are on the basis of projected figure for the last four months of the FY.

Source: Annual Reports, Ministry of Coal

production. Since 2013-14, the annual coal production has increased by 75 per cent, rising from 776.89 MT to an estimated figure of 1361.76 MT for 2024-25 (see *Graph 9: India: coal usage and annual growth (2013–14 to 2024–25*). Awareness of coal's impact on greenhouse gas emissions and the need to finance a clean energy shift brought in a policy of taxing coal usage. The policy was based on the polluter pays principle, recognizing the impacts of coal usage on environment and the issue of climate change. The fund was initially called the Clean Environment Cess and was levied from 2010 to 2017. In 2017, the fund was harmonized within the GST Compensation Cess to cushion the state revenues. With the continued rise in coal usage, the government's revenue is increasing from its levy per tonne of production. Now that the deadline for the fund is approaching, our analysis in this segment traces the fund's usage and its revenue potential in the decarbonization journey of the coal sector.

2.6.1 Beginnings (2010–17)

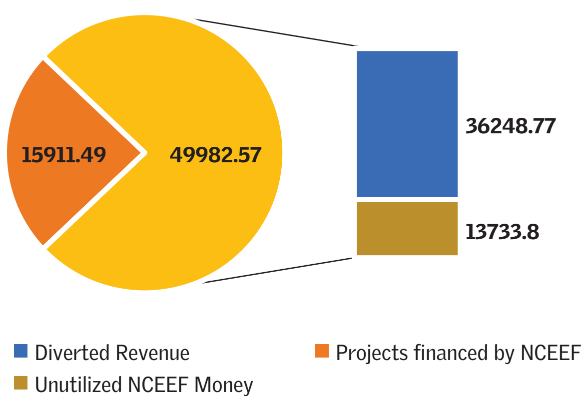
The Clean Environment Cess (CEC) was introduced by the Government of India in 2010 on all coal sales, including imports and exports. Initially set at Rs 100/tonne, it was reduced to Rs 50/tonne the same year. In 2014, its scope was expanded to include clean environment initiatives, and the rate was restored to Rs 100/tonne.

It was later increased to Rs 200/tonne in 2015–16 and Rs 400/tonne in 2016–17. The Finance Act of 2016 also formally renamed the tax as the 'Clean Energy Cess' to reflect its widened mandate. The collected revenue from the fund in the time period of 2010–17 was Rs. **65,894.06 crore**.

To manage the collection and utilization of the proceeds, the **National Clean Energy and Environment Fund** (**NCEEF**) was established via the Finance Act of 2010–11. Its primary purpose was to finance and promote clean energy initiatives and support research in clean energy and related activities. Over time, the scope of the fund was expanded to include broader clean environment initiatives as well. The amount collected in the fund was used to finance green projects approved by the Inter-Ministerial Group (IMG) chaired by Finance Secretary. The fund's proceeds were used to finance governmental green schemes and green technology support.

As per the Union Budget receipts from 2010–17, the total collection from the cess stands at Rs 65,894.06 crore. The majority of the funding went to the Ministry of New and Renewable Energy (MNRE). At the same time, the rest was distributed to the Ministry of Environment, Forest and Climate Change (MoEFCC) and Ministry of Water Resources, River Development and Ganga Rejuvenation. Yet, only **45 per cent** (**Rs 29,645.29 crore**) of the collected fund was transferred to the NCEEF. Out of the proceeds collected, only 53.7 per cent (Rs 15,911.49 crore) was spent, with the remaining money left unutilized. Overall, the Central government utilized only **24.1 per cent** of the total collected revenue. Alternatively, one can conclude that a significant portion of the revenue collected under the Clean Environment/

Graph 10: Cess fund utilization (2010–17) (in Rs crore)



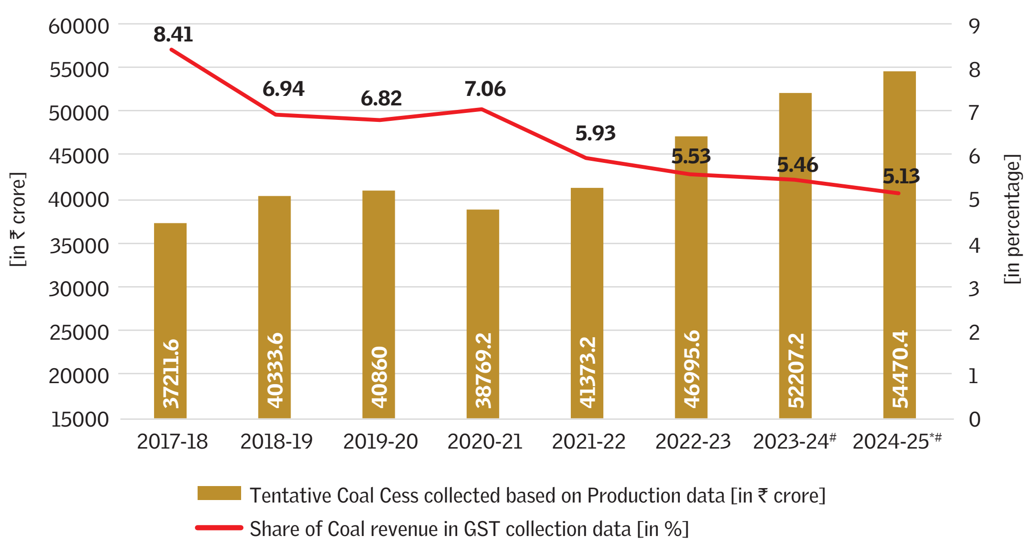
Source: Department of Expenditure, Ministry of Finance

Clean Energy cess via coal production and imports was never used for its intended purpose, with as much as ***75.9 per cent remaining unutilized*** (see *Graph 10: Cess fund utilization [2010–17]*).

2.6.2 2017 onwards: The Goods and Services Tax advent

With the advent of GST in 2017, the Clean Energy/Clean Environment/coal cess was harmonized with the GST Compensation Cess. The GST Compensation Cess is to provide compensation to the states for the loss of revenue arising on account of the implementation of the goods and services tax in pursuance of the provisions of the Constitution (101st Amendment) Act, 2016.[42] The levied cess was repurposed but continued to be collected under the GST head. The GST levy remained the same as it was under the coal cess and is applied to coal (domestic and imported) and lignite at the rate of Rs 400 per tonne of production. Introduced in 2017, the harmonization of coal cess into GST fold, the generated revenue has been **Rs 3,52,220.8 crore**. *(Revenue from coal is not individually published, CSE has calculated the revenue using the coal produced figures from the Ministry of Coal.)* Using the Union Budget tax receipt data from 2017–25, *Graph 11* shows the revenue from coal cess and its share in the total GST collection revenue. From our analysis, we note that despite a significant increase in coal production, the share of

Graph 11: CSE analysis: Coal cess revenue and GST share (2017–25)

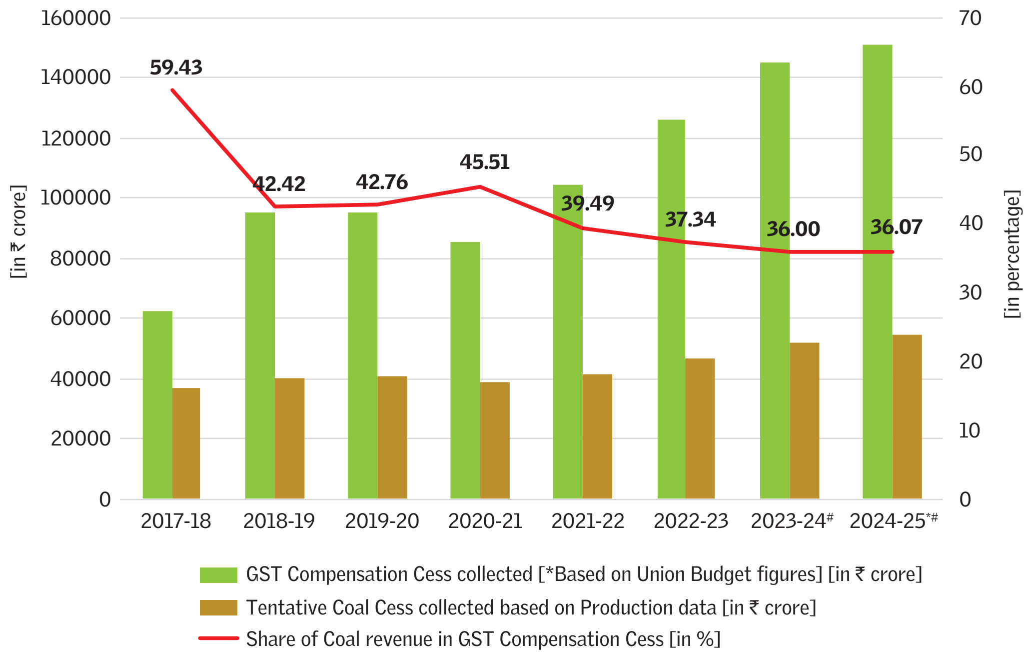


#uses Budget Union Budget Estimated Receipts from Cess (2023–25)

*FY 2024–25 Coal produced value includes projected figure (Dec.–Mar.) of Ministry of Coal

Source: Union Budget Union Budget Tax Receipts Actual (2017–25)

Graph 12: CSE analysis: Coal cess's fiscal role in GST compensation cess (2017–25)



uses Union Budget estimated receipts from cess (2023–25)

*FY 2024–25 Coal produced value includes projected figure (Dec.–Mar.) of Ministry of Coal

Source: Union Budget Tax Receipts Actual (2017–25)

coal cess has declined in relation to the GST revenues as other sources of revenue have risen in a growing economy. Notably, none of this money is now being used for clean energy or coal decarbonization or for environmental policy benefit.

Initially, with GST in its premature state, the compensation cess was an essential source of revenue for states. Almost a decade later, economic growth has risen, and the tax pool has widened. Subsequently, we analysed the share of coal cess revenue in the total compensation cess collected by the Union. This highlights the declining coal revenue share within the overall compensation cess fund. With growing economic activity across states, one can note that the replaceability/expendability of coal components vis-à-vis the compensation cess is notable. The revenue ought to be used for cleaner energy through initiatives like decarbonization of India's coal fleet, expansion of renewable energy etc., which was its original intended purpose.

The above table illustrates that the revenue share of coal in compensation cess for various states has fallen considerably while their revenue streams from elsewhere have risen. Consequently, highlighting the reduced relevance of this revenue within the GST pool.

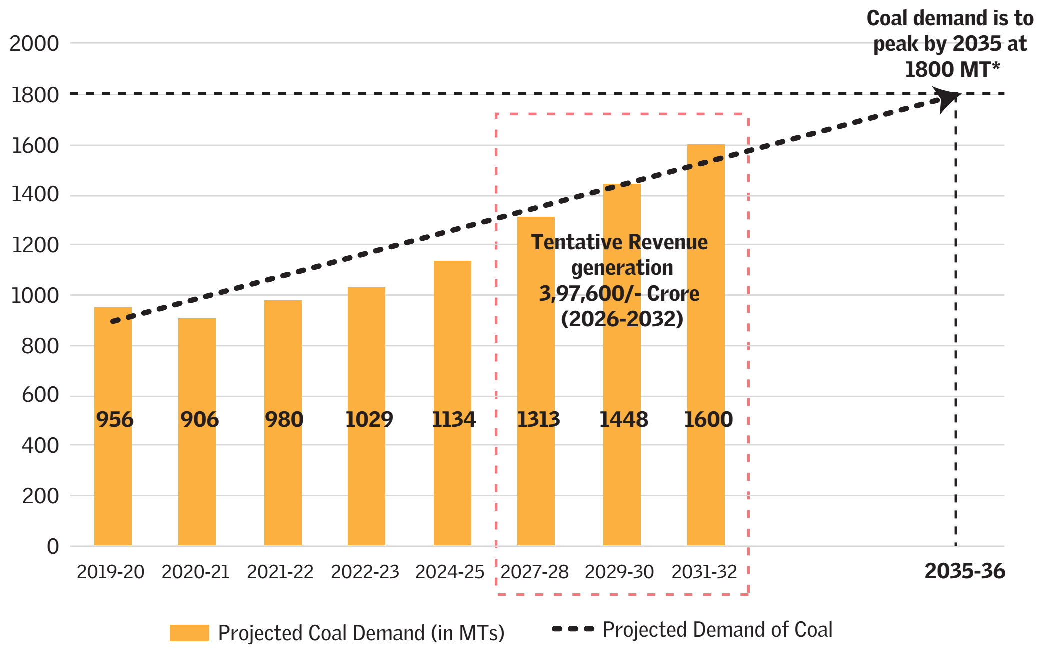
2.6.3 Future use of cess

India's coal production has increased year on year. The Ministry of Coal anticipates a peak of coal production for India in the forthcoming decade of 2030–35. India's annual coal production growth rate (CAGR) over the past decade (2014–24) stands at **4.85 per cent.** In the past four years, after the COVID-19 pandemic slump, the CAGR has almost doubled and stands at **8.1 per cent.** Like our energy demand forecast, the overall demand for coal for 2023–24 was estimated at 1,233.86 million tonnes (MT).[43] Yet, our production exceeded the estimates to match our rising energy needs. As stated earlier, our estimated coal usage, including domestic production and imported, is 1,361.76 MT for 2024–25. Similarly, India's lignite production has remained steady in the range of 40–48 MT over the period of 2014–24.

In 2022's winter session of the Indian parliament, the Minister of Coal, Mr Pralhad Joshi, in a written reply in Lok Sabha, stated that coal would stay a major energy source in the foreseeable future. The country will require the base load capacity of coal-based generation for stability and energy security. Furthermore, he mentioned that India's coal demand will likely peak during 2030–35. As coal production continues to rise into the future, this translates into a steady flow of income over the coming decade. In 2022, the Ministry of Coal released a coal demand projection for the current decade. The data shows that the projected demand for the next five years has already been exceeded two years ahead of schedule.

With new coal-based power plants under construction, demand for coal will continue to rise before it settles into a consistent baseline. This projection translates into a continued revenue windfall from coal production. Our conservative coal demand projection analysis estimates a revenue of **Rs 3,97,600 crore by 2032**. This estimate is based on the projected demand figures and calculating the cess at the current rate of Rs 400 per tonne of coal produced (see *Graph 13: Untapped potential: Revenue forecast from future coal demand: CSE analysis*). The revenue estimate is approximately 59 per cent of the total planned capital expenditure on new coal-based thermal power plants.

Graph 13: CSE analysis: Untapped potential—Revenue forecast from future coal demand



Source: Projection based on Ministry of Coal & National Electricity Plan 2022–32, CEA; CSE analysis

2.6.4 Policy suggestion

The GST Compensation Cess is scheduled to end by March 2026, and its future is currently under deliberation by a Group of Ministers within the GST Council. From an environmental and climate change perspective, revenues generated through coal production should be redirected towards reducing emissions from coal-based power. Such a shift would ultimately benefit end users, as the reduction in GHG emissions and improvements in air quality directly impact them. After a decade of diverting these funds to offset GST-related revenue shortfalls, it is imperative to realign them with their original purpose. As an indirect tax, the cess is effectively borne by power consumers. Therefore, it is both equitable and necessary that this revenue be invested in making power generation cleaner and less carbon intensive. Decarbonizing the coal power sector comes with the co benefits of improved efficiency and reduced air pollution.

2.7 Demand forecasting

Demand projection of power supply is key to plan for consistent growth of an economy. India's power sector in the recent years has consistently fallen short of meeting its growing power demand owing to poor demand projection planning.[44] Relevant authorities anticipate a continuous rise in the power demands and their desire to meet it.[45] To effect change, Central Electricity Authority's (CEA) 'Guidelines for Medium and Long Term Power Demand Forecast, 2023' confirmed the methodology for the demand projection by agreeing on the 'PEUM' (Partial End Use Methodology) model.[46] Demand projection within the 20th EPSC (Electrical Power Survey Committee) carried the projection based on the same, eliminating the confusion on projection methodology modelling of the 19th EPSC (see *Table 3: CEA forecast for peak electricity demand* and *Table 4: CEA forecast for electricity demand*).

The 20th EPSC report sheds the earlier format of projection within three different scenarios and provides us with one conclusive number for each prospective year.

Table 3: CEA forecast for peak electricity demand (in MW), 2019 projection

Year	7.3% GDP (BAU scenario)	8% GDP (optimistic scenario)	6.5% GDP (pessimistic scenario)	Projection by PEUM
2016–17	158,994	158,994	158,994	161,834
2021–22	201,481	202,330	195,133	225,751
2026–27	255,911	259,628	239,299	298,774
2031–32	319,794	333,152	293,462	370,462
2036–37	398,172	427,497	359,882	447,702

*All forecasts are reported for average weather conditions. See details of each scenario

Source: CEA's Long Term Electricity Demand Forecasting, August 2019

Table 4: CEA forecast for electricity demand (2021–22 to 2031–32)

Region	Energy requirement (in MU)			Peak demand (in MW)		
	2021–22	2026–27	2031–32	2021–22	2026–27	2031–32
Northern region	418,188	592,312	773,545	73,367	97,898	127,553
Western region	428,994	596,793	763,198	65,437	89,457	114,766's
Southern region	35,1611	460,853	596,557	61,165	80,864	107,259
Eastern region	164,542	232,971	308,103	26,043	37,265	50,420
Northeastern region	18,312	24,904	32,373	3,437	4,855	6,519
All India	**1,381,646**	**1,907,835**	**2,473,776**	**203,115**	**277,201**	**366,393**

Source: CEA's National Electricity Plan 2022–32, March 2023

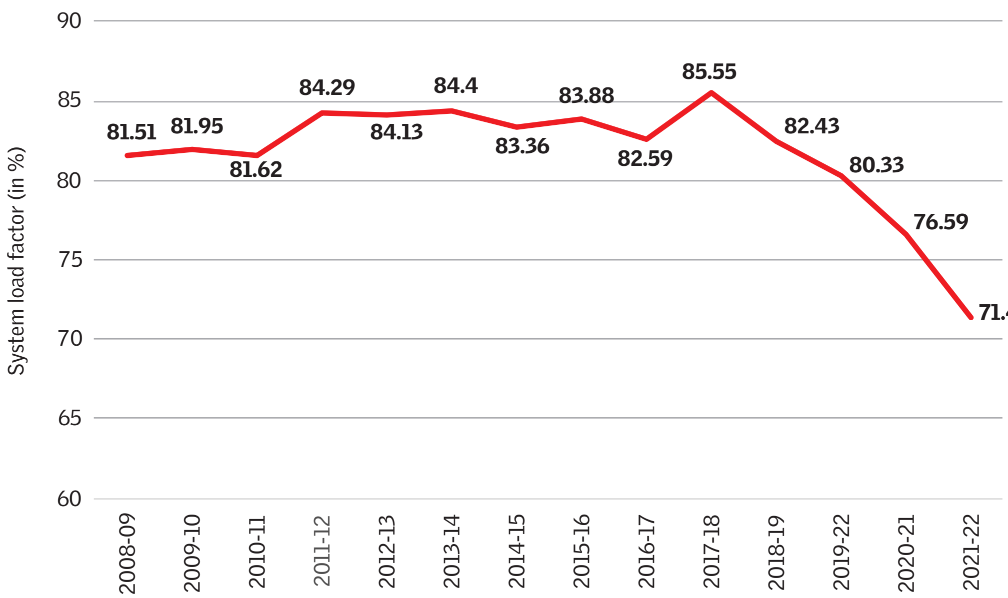
Peak demand figures are also calculated on a per day basis, per week basis and on a monthly basis. For the EPSC Report, the peak demand is the annual average of peak demand calculated via summing up at state's respective DISCOM's data which considers the average end use energy consumption (historical data) + prospective factors (growth rate + policy impacts) + annual load factor & regional T&D efficiency.

2.7.1 Annual load factor

Annual System Load Factor is the ratio of the energy availability in the system to the energy that would have been required during the year if the annual peak load met was incident on the system throughout the year. As per the 20th EPSC, the annual load factor has seen a reduction.

However, this indicates the power system is utilizing its generating capacity less efficiently, meaning there are larger gaps between peak demand periods and average demand, resulting in more idle capacity for long non-peak periods and potentially higher costs for electricity generation due to underutilization of the system.[47] Underutilization indicates generation gap between peak and average requirement and an inadequacy to manage power generation vis-à-vis supply of electricity into the grid. Options like flexibilization within thermal plants can

Graph 14: India System Load Factor (in percentage terms) (2008–09 to 2021–22)



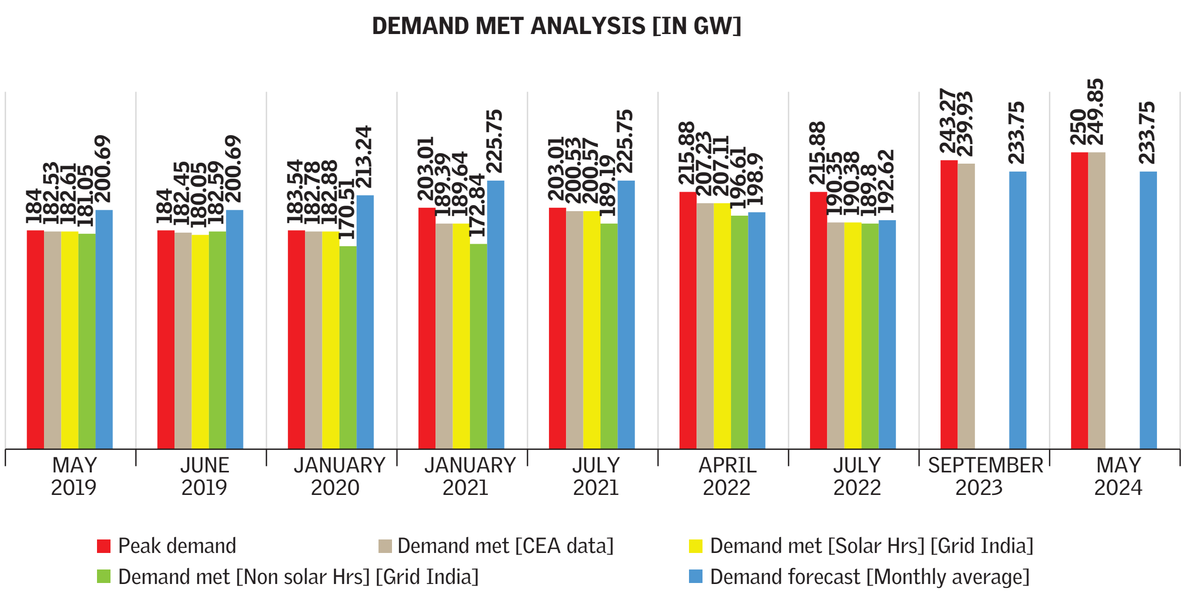
Source: CEA's National Electricity Plan 2022–32, March 2023 redress this by immediate correction of production. This will increase the per-unit cost of the power thus produced, making it unattractive for purchase by DISCOMs. A higher systemic load factor, on the other hand, will generate a greater total output which will reduce the cost per unit of energy generated.[48] Achieving higher system load factor highlights efficient energy use and reduction of energy wasted. Overall decarbonization improves when the system load factor goes up even if individual plant load factor goes down.

2.7.2 Demand–supply analysis

Despite the changes in the system of forecasting energy demand, the country is still facing shortfall of energy. For more accurate planning, one has to analyse the demand shortfall in actual terms.

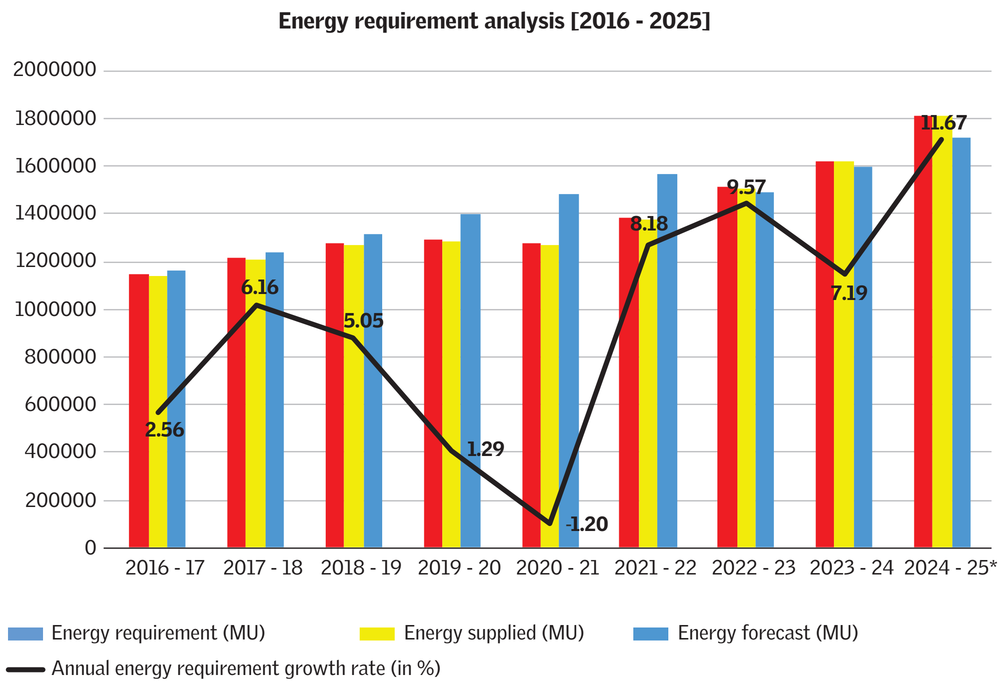
The above data considers the peak demand in each year and our capacity to supply the same. One can notice that we have consistently fallen short of meeting the peak demand. The capacity to meet peak demand falls further during non-solar hours. This shows a lack of energy storage capacity and its ability to handle demand when solar energy is off grid. Under Indian Electricity Grid Code, 2023 an additional obligation to provide weekly forecasts for demand was added into Operating Code, Article 31. This data provides us with weekly forecasting figures

Graph 15: Load analysis: Yearly peak demand met of solar, non-solar hours versus forecasted demand, 2019–24 (in GW)



Source: CEA Dashboard and GRID India Report on Demand Pattern Analysis, 2023

Graph 16: Energy requirement and supply analysis with forecasted demand growth (2016–17 to 2024–25)



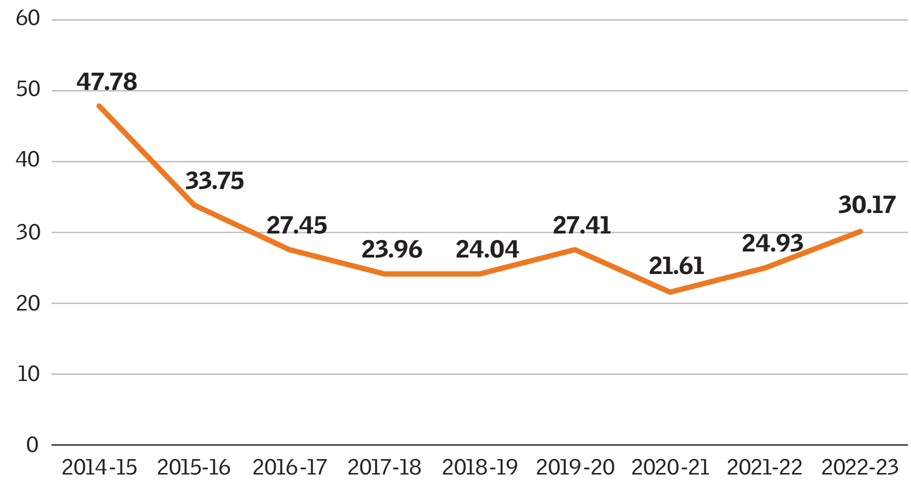
Source: 20th Electric Power Survey of India, CEA Dashboard & GRID India's Monthly Demand Forecasting Reports

for demand since 2022. As forecasting disclosure became transparent, the peak demand has exceeded the forecasted figure (see *Graph 16: Energy requirement and supply analysis with forecasted demand growth*).

Graph 16 illustrates our shortfall in meeting our energy requirements. Additionally, although until 2021 forecasted demand was higher than the actual demand, we were unable to create additional capacity in tune with our own stated goal. Beyond 2021, when the impact of the COVID-19 pandemic abated, we can see a clear rise in the overall energy requirement. Further, our energy requirement has exceeded our forecasted levels. As stated earlier, this has been paramount since the new weekly demand forecast was brought in. Interestingly, despite overshoot in energy requirement beyond the forecasted figure, we are able to meet energy requirement beyond the forecasts. Yet, one needs to understand that the supply met needs to be of requisite quality, which we analyse going ahead.

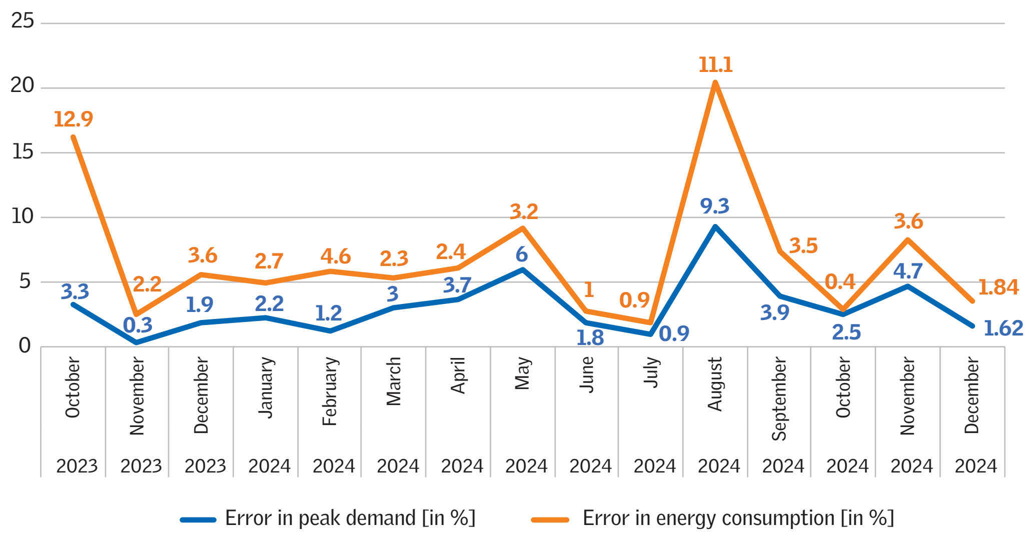
Moreover, the Indian Electricity Grid Code (IEGC) specified by the Central Electricity Regulatory Commission (CERC) mandates the operating band for frequency of grid as 49.90–50.05 hertz (Hz). *Graph 17* illustrates that the energy

Graph 17: Grid frequency deviations beyond IEGC band (49.9–50.05 Hz), 2014–23



Source: CEA Annual Report, 2022–23

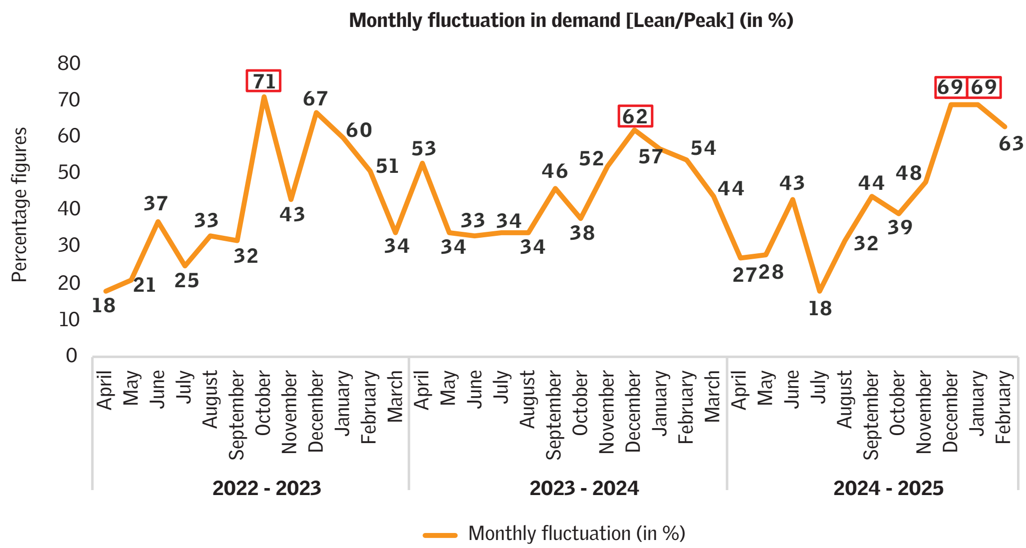
Graph 18: GRID India monthly forecasting error report data: Peak demand and energy requirement, 2023–24



Source: GRID India Monthly Error Report

supplied via the GRID regularly fails to meet the designated quality. Quality of energy supply is pertinent for the health of appliances one uses. Post 2021, we see a 10 per cent degradation in the quality of energy supplied. In 2022–23, 30 per cent of our electricity supply was not of requisite quality.

Graph 19: CSE analysis: Monthly fluctuations in lean and peak demand, 2022–25



Source: CSE analysis of GRID India Monthly Forecast Figures

The 2023 Central Electricity Regulatory Commission rules under Article 31.2(h) & 31.2(i) mandate a monthly error report to improve efficiency of demand forecasting via GRID India.

Above data further illustrates a high margin in forecasting our demand for energy. Complementing this with our overall supply deficiency, we can see that our planned forecasting for energy requirement vis-à-vis our rising growth rate for energy needs upgradation.

Within the monthly demand for energy, the fluctuation level is also getting more volatile, making energy planning more cumbersome. Interestingly, we see the highest level of fluctuation during the winter months. This corresponds with the grid's expectation for higher demand during summers but not so much during winters. One can note that the energy needed during these months is varying highly largely owing to the heating planet.

2.7.3 Revising demand planning

The above analysis illustrates the deficiency within our demand forecasting capacity. The steep rise in energy demand beyond the monsoon months (June–August) illustrates the effect of climate change in India's energy needs. The demand pattern analysis needs to take into account the adverse weather conditions prevalent across regions.

The National Grid comprises five sub-grids. As supply met consistently falls short of the demand, analysis of the absolute supply shortage has a differentiated impact. Understanding this reveals that the variance in supply availability is starker than the all-India analysis shows. A mere upward revision of the energy forecast is not enough to provide consistent electricity to all Indians. The consumption of air conditioners and electric vehicles is slated to rise in the near future, placing higher load on the grid during non-solar hours of the day. Because of the high adverse impact of climate change, energy supply planning needs to undertake a more comprehensive analysis of the methodology, with decadal forecasts for regions not just the optimum method. Regular revision of forecasts with more variable factors read into the same could be needed going ahead.

3

GHG EMISSIONS FROM THE THERMAL POWER SECTOR

CEA DATA FROM 2022–23 INCLUDES 603 COAL AND LIGNITE POWER UNITS, OF WHICH 41 UNITS DID NOT GENERATE ANY ELECTRICITY DURING THE YEAR.

CSE ANALYSED THEIR PERFORMANCE BASED ON TECHNOLOGY, CARBON INTENSITY, EFFICIENCY, STATION HEAT RATE AND OWNERSHIP TO IDENTIFY TOP AND LEAST PERFORMING UNITS ACROSS THE FLEET.

SUPERCRITICAL AND ULTRA-SUPERCRITICAL UNITS, THOUGH CAPABLE OF HIGHER EFFICIENCY THAN SUBCRITICAL UNITS, ARE UNDERUTILIZED, WITH 23 PER CENT OF THE 92 UNITS OPERATING AT PLF BELOW 50 PER CENT.

According to the third National Communication (NC3) by India to the UNFCCC, electricity generation contributed 1,233.55 million tonnes or 39 per cent of total emissions of the country in 2019.[49] Although the percentage share of GHG emissions from electricity production has remained largely constant, net emitted GHGs from the sector increased from 819.69 million tonnes in 2010 to 1,233.55 million tonnes in 2019 (an approximately 50 per cent increase). Installed capacity rose proportionally from 159.40 GW to 356.10 GW between those years (2010–19) of which coal power capacity increased from 84.20 GW to 200.70 GW (an increase of 138.31 per cent).[50, 51]

3.1 Sector-wise emission analysis

Sector-wise (Centre, private, state) data of installed capacity (in MW), gross generation (GWh), net generation (GWh), auxiliary consumption (per cent), emission factor (tonne/MWh), total emissions CO_2 (million tonnes), plant load factor (PLF [per cent]) and efficiency (per cent) for FY 2022–23 are reported in *Table 6*.[52] In 2022–23, Central sector plants accounted for 31.8 per cent of installed capacity and produced 37.4 per cent of net generation. The private sector held 35.4 per cent of installed capacity and contributed 31.5 per cent to net generation. Meanwhile, state-sector plants comprised 32.8 per cent of installed capacity and generated 31.1 per cent of net generation. Despite having the highest installed capacity, the private sector emits the least CO_2, primarily due to its lower generation share compared to both the Central and state sectors. Additionally, the average emission factor of private sector plants is the lowest, with the Central sector falling in the middle and the state sector having the highest average emission factor (see *Table 6: Sector-wise share of coal-power gneeration and emisssions in India).*

Table 5: Share of electricity sector in GHG emissions in India (UNFCCC submission)

Year and report	Total GHG emissions (Mt CO_2 eq)	GHG emissions from electricity production (Mt CO_2 eq)	Percentage share of electricity generation in total GHG emissions
2010 (BUR1)	2,136.84	819.69	38.36
2014 (BUR2)	2,607.49	1,078.15	41.35
2016 (BUR3)	2,838.89	1,122.23	39.53
2019 (NC3)	3,132.03	1,233.55	39.39
2020 (BUR4)	2,959	1,171.62	39.5

Source: India Biennial Update Report and National Communications to UNFCCC

Table 6: Sector-wise share of coal-power generation and emissions in India

Sector	Installed capacity (MW)**	Gross generation (GWh)	Average auxiliary consumption (per cent)	Net generation (GWh)	Average emission factor (tonne/ MWh)	Total emissions CO_2 (million tonnes)	Average PLF (per cent)#	Average efficiency (per cent)
Centre	67,640.0 (31.8 per cent)	438,808.91 (37.1 per cent)	7.48	409,204.69 (37.4 per cent)	1.00	396.83	65.80	32.94
Private	75,239.7 (35.4 per cent)	371,337.32 (31.4 per cent)	6.75	345,258.79 (31.5 per cent)	0.84	327.82	44.58	32.66
State	69,669.5 (32.8 per cent)	372,190.58 (31.5 per cent)	9.20	340,841.36 (31.1 per cent)	1.06	355.64	54.81	30.4

** Installed capacity as on March 31, 2023

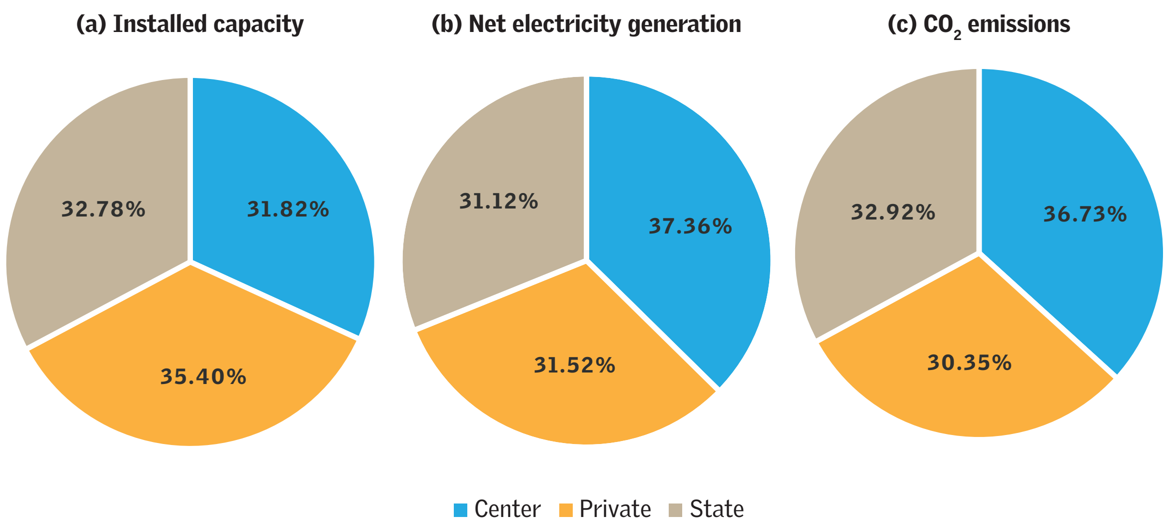
PLF values are calculated using net generation (GWh)'

PLF (per cent) = (Net generation (GWh)/(Installed capacity [MW] * 8.760))*100

Source: CSE analysis of CEA CO_2 baseline database, Version 19

Average auxiliary consumption (electricity used for plant operation) is the highest among state-operated plants and the lowest among private ones, indicating the low efficiency of state-owned plants. Given the lower generation share of private plants, their average plant load factor is consequently lower as well. In contrast, plants operated by the Central sector exhibit the highest net generation and PLF. However, it is worth noting that the average PLF of Central plants stands at 65.8 per cent, which can be improved. A higher PLF will result in lower cost of the generated electricity by spreading the fixed costs. A plant producing higher electricity will be paid their fixed costs over their total production and that will spread the payment, reducing the cost of per unit of electricity, and thereby reducing the cost of purchase for generated electricity for respective DISCOMs (distribution companies). In other words, if the plant load factor is increased, the cost of electricity for the end consumer would be lower (see *Graph 20: Sector-wise percentage share of (a) installed capacity and (b) net electricity generation (c) total CO_2 emissions in India*).

Graph 20: Sector-wise percentage share of (a) installed capacity (b) net electricity generation (c) CO_2 emissions in India



Source: CEA CO_2 baseline database, Version 19

3.2 Details of plants and units in the analysed database

In the CEA baseline database for the year 2022–23, a total of 195 coal and lignite based thermal power plants are listed, each with a varying number of units commissioned on different dates.[53] As the date of commission is provided unit-wise and for the purpose of accuracy and effectiveness, the overall analysis in this report largely focuses on individual units. Across these plants, data for 603 units has been provided, 41 of which have a net electricity generation of zero leaving 562 units for analysis. Among these, eight units have generated electricity, however, their fuel consumption data is unavailable. Further, the net generation from these units cumulatively adds up to 0.04 per cent of the total generation. Therefore, excluding these eight units belonging to three plants, our subsequent analysis focuses on the remaining 554 units. The eight units that generated electricity and did not report fuel consumption are listed in Table 7. Out of the 554 units analysed, 418 units exhibit a plant load factor (PLF) greater than or equal to 50 per cent, while the PLF of the remaining 136 units falls below 50 per cent.

Units of Vijeswaran GT in the analysed data appear to have been incorrectly categorized as coal-fired. Its missing fuel consumption data further supports this discrepancy. Analysis of older data indicates that this plant is gas-fired.

Table 7: Plants/units lacking fuel consumption data

S. no.	Unit name	Plant name	Date commissioned	Sector	State	Net generation (GWh)
1.	Simhapuri TPP	SIMHAPURI TPP	February 21, 2014	Private	Andhra Pradesh	112.42
2.	Simhapuri TPP		December 31, 2014	Private	Andhra Pradesh	10.91
3.	Vijeswaran GT	VIJESWARAN GT	August 31, 1990	State	Andhra Pradesh	53.24
4.	Vijeswaran GT		March 2, 1991	State	Andhra Pradesh	54.62
5.	Vijeswaran GT		April 1, 1998	State	Andhra Pradesh	57.50
6.	Vijeswaran GT		March 30, 1992	State	Andhra Pradesh	98.89
7.	Vijeswaran GT		December 23, 1997	State	Andhra Pradesh	57.24
8.	Dishergarh TPP	Dishergarh TPP	March 27, 2019	Private	West Bengal	38.28

Source: CEA CO2 baseline database, Version 19

3.3 Technology-wise analysis of emissions

As mentioned previously, units below the installed capacity of 660 MW are considered as subcritical, those in the range of 660–800 MW are considered to be supercritical and equal or above 800 MW are considered as ultra-supercritical. In this section, technology-wise different parameters of the total 554 units are analysed with respect to their emissions (see *Table 8: Technology-wise emission analysis of coal-/lignite-based 554 thermal units*).

Until 2009, all coal-based thermal power plants in India operated on subcritical technology. In 2010, the first supercritical power plant was commissioned. By 2012, as part of the 12th Five-Year Plan, it was determined that 50 per cent of subsequent coal capacity installations would be supercritical and from the 13th Five-Year Plan onwards, 100 per cent capacity will be supercritical.[54] As of FY 2022–23, approximately 69 per cent of the installed capacity remains subcritical, accounting for 70 per cent of generation and 72 per cent of emissions. As we know that ultra-supercritical and supercritical plants are much more efficient than subcritical units, given the higher number of subcritical units, it is expected that emissions from these units would also be higher. Further, on a technology-wise comparison, average values of parameters such as emission factor, SHR and auxiliary consumption are also elevated for subcritical units.

Despite having nearly comparable plant load factors, subcritical units exhibit an average auxiliary consumption of 9.14 per cent—approximately 47 per cent higher

Table 8: Technology-wise emission analysis—554 coal-/lignite-based thermal units

Technology	No. of units	Average values					Aggregate values		
		Age	Emission factor (tonne/ MWh)	PLF (per cent)	SHR (kcal/ kWh)*	Auxiliary cons. (per cent)	Installed capacity (MW)	Net gen. (GWh)	Total CO_2 (million tonnes)
Subcritical	463	20.75	1.07	60.21	2,789.87	9.14	141,644.5 (68.98 per cent)	766,573.96 (70.02 per cent)	781.65 (72.32 per cent)
Supercritical	72	8.03	0.92	61.91	2,441.44	6.19	47,690 (23.23 per cent)	258,683.52 (23.63 per cent)	237.82 (22 per cent)
Ultra-supercritical	19	7.15	0.89	51.28	2,365.95	6.79	16,000 (7.79 per cent)	69,561.88 (6.35 per cent)	61.31 (5.67 per cent)
*Station heat rate (SHR): Heat input/Net generation Heat input = Fuel consumed * GCV of the fuel									

Source: CEA CO_2 baseline database, Version 19

than supercritical units and 34 per cent higher than ultra-supercritical units. Similarly, the average emission factor for subcritical units stands at 1.07 tonne/ MWh—about 16 per cent higher than supercritical units and 20 per cent higher than ultra-supercritical units. As previously mentioned, the heat rate, which measures the amount of heat required to produce one unit of electricity and is expressed in kcal/kWh, is also notably higher for subcritical units, with an average value of 2789.87 kcal/kWh—approximately 14 per cent higher than supercritical units and 17 per cent higher than ultra-supercritical units.

Although the above analysis offers a comprehensive overview of emissions across different technologies, it is crucial to pinpoint the top performers and underachievers within each technology individually. This approach allows for a more nuanced understanding of the factors contributing to the poor performance of certain units. In the subsequent tables, we present the top 10 best- and least-performing units for each technology in terms of emission factors. Given the large number of plants utilizing subcritical technology, we have subdivided them into two categories based on installed capacity: units with less than 250 MW and units with 250 MW or greater. The plant load factor significantly influences both total CO_2 emissions and heat rate of the unit. Consequently, we have identified the best and least performing units with PLF 50 per cent or above. In other words, on a yearly average the unit operated at least half of its capacity. When a unit's load factor is less, it indicates that the unit has been operating a much lower capacity and might have to be shut down and restarted frequently, which increases the emissions as well as heat rate. Out of the total 554 units analysed, 418 units boast of plant load factors of 50 per cent or higher, while 136 units fall below the 50 per cent threshold.

3.3.1 Comparison of best- and least-performing units technology-wise (in terms of SHR and CO_2 emissions)

This section compares and puts out the list of the best- and least-performing thermal power units based on **technology** and capacity considering only the CO_2 emissions and the station heat rate. Although it is clear that there are various factors (such as fuel type) affecting the heat rate and emissions, it would be interesting to begin with to see which of the power-generating thermal units operating above 50 per cent PLF are the most and least efficient and emitting.

Subcritical units with installed capacity < 250 MW

Units with similar load factors and installed capacity offer a basis for comparing their emission factors and efficiencies (see *Table 9: Best-performing subcritical units with capacity <250 MW, Table 10a: Least performing subcritical units with capacity <250 MW* and *Table 10b: Least performing subcritical units with capacity <250 MW)*. Interestingly, six out of the ten best-performing units in this category are nearly or over 40 years old, with two units nearing 25 years of age. The SHR of these top performers is in the range of 2060.57–2591.38 kcal/kWh, while their emission factors are in the range of 0.74–0.98 tonne/MWh. Conversely, the SHR of the least-performing units falls in the range of 2,976–3,443.06 kcal/kWh, with emission factors are in the range of 1.3–1.45 tonne/MWh. Notably, there exists a positive correlation between SHR and emission factors, as the least-performing units exhibit higher SHR values, while the opposite holds true for the best-performing units. Similarly, auxiliary consumption is higher for the least-performing units and lower for the best-performing ones. Of the ten least-performing units, eight, belonging to the Neyveli Lignite Corporation Limited (NLC), attributed to their reliance on lignite as a fuel source.

Comparing similar capacity and load factor units would be insightful. For example, Ramagundem STPS (R_GUNDEM STPS) Unit 1, and Neyveli ST II Unit 1 have similar installed capacities, net generation and load factors. However, their emission factors differ significantly at 0.97 and 1.45, respectively. Both units are dependent on Indian coal/lignite; Ramagundem STPS (R_GUNDEM STPS) consumed 662,200 tonnes of coal with a calorific value of 3,489 kcal/kg. Neyveli ST II, however, consumed 1,288,120 tonnes (almost double) of lignite with a calorific value of 2,556 kcal/kg. This variance results in Neyveli ST II emitting close to 1.3 million tonnes of CO_2, compared to Ramagundem STPS emitting only

0.8 million tonnes of CO_2. This highlights the need for the usage of efficient and high-quality fuel as a source.

Subcritical units with installed capacity >= 250 MW

Similar trends are evident among subcritical units with installed capacities >= 250 MW (see *Tables 10a: Best-performing subcritical units with capacity >= 250 MW* and Table 10(b): *Least-performing subcritical units with capacity >= 250 MW*). Emission factors range from 0.87 tonne/MWh for the best-performing unit to 1.57 tonne/MWh for the least-performing unit. SHR values range from 2,425.07 to 4,162.86 kcal/kWh for the best- and least-performing units, respectively. Predominantly, there exists a positive correlation between SHR and emission factors, meaning units with higher emission factors tend to have higher SHR values and vice versa. For instance, KORBA STPS Unit 7, operated by NTPC, and BHUSAWAL Unit 4 of MAHAGENCO both possess similar installed capacities. However, BHUSAWAL Unit 4 exhibits a 10 per cent lower plant load factor and significantly higher SHR value at close to 3,042.75 kcal/kWh compared to KORBA's 2,427.69 kcal/kWh. Despite both units utilizing coal with similar calorific values—3374 kcal/kg for KORBA and 3,358 kcal/kg for BHUSAWAL—the efficiency of BHUSAWAL Unit 4 falls short when compared to the performance benchmark set by KORBA Unit 7. This analysis underscores the imperative of enhancing the efficiency of underperforming units/plants. It emphasizes the need for efficiency upgrades rather than advocating for the outright shutdown of low-performing units. Further, as the age of all the units except for two units is less than 15 years in the top 10 least-performing units, there is very much more reason to increase the efficiency of these plants.

Supercritical units

SHR and emission factors have similar relations for supercritical units as well (see *Table 11(a): Best-performing supercritical units, Table 11(b): Least-performing supercritical units and Table 11(c): Performance of supercritical units operating below 50 per cent PLF*). SHR values range from 2,228.83 kcal/kWh to 3154.21 kcal/kWh for the best and least performing units, respectively. Emission factors span from 0.84 to 1.19 tonne/MWh for the best and least-performing units, respectively. Despite the general perception that supercritical technology is more efficient than subcritical technology, three of the least performing supercritical units exhibit higher heat rate values in comparison to the least performing subcritical units with capacity >= 250 MW.

Comparing similar supercritical technology units, for instance, SEMBCORP GAYATRI (SGPL) Unit 2 and KORADI EXTENSION Unit 10 both have similar installed capacities and plant load factors. SGPL utilizes a mix of imported and national coal with an average calorific value of 3727 kcal/kg, while KORADI relies solely on national coal with a calorific value of 3,767 kcal/kg. Despite comparable net generation figures, SGPL emits 3.16 million tonnes of CO_2 compared to KORADI's 4.23 million tonnes, highlighting the potential for efficiency improvements. The intention of this analysis is not to single out one particular underperforming unit but rather employ it as an illustration to underscore the importance and broader opportunity for enhancing the efficiency of similar capacity and load factor units such that the overall emissions are minimal.

Subcritical units with installed capacity <250 MW

Table 9(a): Best-performing subcritical units with capacity <250 MW (in terms of emission factor and SHR)

Name	Unit no.	Company	Sector	Age	Fuel and avg. GCV	Capacity	Emission factor (tonne/MWh)	PLF (per cent)	SHR (kcal/kWh)	Efficiency (per cent)	Auxiliary consumption (per cent)	Net generation (GWh)	CO_2 emissions (MT)
Torangallu IMP*	1	JSW Energy	Private	25.2	Coal (5,000; 6,000)	130	0.74	84.4	2,060.6	41.7	7.3	961.2	0.71
Torangallu IMP*	2	JSW Energy	Private	25.2	Coal (5,000; 6000)	130	0.82	64.2	2,281.1	37.7	8.4	730.8	0.60
Korba STPS	2	NTPC	Centre	40.8	Coal (3,000; 3,500)	200	0.97	89.5	2,549.9	33.7	8.3	1,567.5	1.52
Ramagundam STPS	1	NTPC	Centre	40.7	Coal (3,000; 3,500)	200	0.97	51.8	2,548.0	33.7	10.5	906.8	0.88
Korba STPS	3	NTPC	Centre	40.4	Coal (3,000; 3,500)	200	0.97	89.4	2,566.3	33.5	8.3	1,567.0	1.53
Ramagundem STPS	3	NTPC	Centre	39.6	Coal (3,500; 4,000)	200	0.97	72.2	2,564.9	33.5	10.8	1,265.4	1.23
Singrauli STPS	1	NTPC	Centre	42.5	Coal (3,500; 4,000)	200	0.98	74.9	2,578.7	33.3	8.8	1,311.4	1.28
Korba STPS	1	NTPC	Centre	41.4	Coal (3,000; 3,500)	200	0.98	80.8	2,581.6	33.3	8.6	1,416.4	1.39
Bakreswar	5	WBPDC	State	15.2	Coal (4,000; 4,500)	210	0.98	76.5	2,585.6	33.3	8.5	1,408.0	1.38
Kota	7	RRVUNL	State	15.2	Coal (3,000; 3,500)	195	0.98	75.1	2,591.4	33.2	11.2	1,282.9	1.26

Name	Unit no.	Company	Sector	Age	Fuel and avg. GCV	Capacity	Emission factor (tonne/ MWh)	PLF (per cent)	SHR (kcal/ kWh)	Efficiency (per cent)	Auxiliary consumption (per cent)	Net generation (GWh)	CO_2 emissions (MT)
Kota	6	RRVUNL	State	21.0	Coal (3,000; 3,500)	195	0.98	81.9	2,592.4	33.2	10.8	1,398.3	1.38
Bakreswar	4	WBPDC	State	16.6	Coal (4,000; 4,500)	210	0.99	88.3	2,612.0	32.9	8.5	1,625.0	1.61
Torrent Power (Sabarmati)	5	Torrent Power	Private	35.9	Coal (4,500; 5,000)	121	0.99	81.7	2,626.8	32.7	8.4	866.0	0.86
Vindhyachal STPS	4	NTPC	Centre	34.6	Coal (3,500; 4,000)	210	0.99	77.6	2,618.6	32.8	8.5	1,428.1	1.42
Vindhyachal STPS	6	NTPC	Centre	33.5	Coal (3,500; 4,000)	210	1.00	89.4	2,626.0	32.7	8.5	1,645.0	1.64
Singrauli STPS	2	NTPC	Centre	41.7	Coal (3,500; 4,000)	200	1.00	75.8	2,623.3	32.8	8.9	1,327.2	1.32
Vindhyachal STPS	5	NTPC	Centre	34.4	Coal (3,500; 4,000)	210	1.00	81.7	2,628.4	32.7	8.5	1,502.1	1.50
Torrent Power (Sabarmati)	4	Torrent Power	Private	39.6	Coal (4,500; 5,000)	121	1.00	82.9	2,650.9	32.4	8.0	879.0	0.88
Vindhyachal STPS	2	NTPC	Centre	36.0	Coal (3,500; 4,000)	210	1.00	84.4	2,629.3	32.7	8.5	1,553.1	1.55
Singrauli STPS	4	NTPC	Centre	40.8	Coal (3,500; 4,000)	200	1.00	77.0	2,630.5	32.7	9.1	1,348.5	1.35

: Plants use oil and imported coal as their fuel.

Source: CEA CO_2 baseline data, 2022–23

Table 9(b): Least-performing subcritical units with capacity <250 MW (only coal) (in terms of emission factor and SHR)

Name	Unit no.	Company	Sector	Age	Fuel and avg. GCV	Capacity	Emission factor (tonne/MWh)	PLF (per cent)	SHR (kcal/kWh)	Efficiency (per cent)	Auxiliary consumption (per cent)	Net generation (GWh)	CO_2 emissions (MT)
Chakabura TPP	2	ACB India Ltd	Private	10.4	Coal (2,000; 3,000)	30	1.36	64.3	3,580.5	24.0	13.5	168.8	0.23
Kheda II	4	MAHAGENCO	State	23.6	Coal (3,000; 3,500)	210	1.30	50.8	3,410.8	25.2	11.3	934.0	1.22
Niwari TPP	2	BLA Power Ltd	Private	5.2	Coal (3,000; 3,500)	45	1.30	55.4	3,433.0	25.0	12.3	218.2	0.28
Kheda II	3	MAHAGENCO	State	24.2	Coal (3,000; 3,500)	210	1.29	63.2	3,407.6	25.2	10.6	1,162.0	1.50
Korba-West	2	CSEB	State	40.4	Coal (3,500; 4,000)	210	1.24	65.7	3,263.7	26.3	10.5	1,209.0	1.50
Ratija TPP	2	SCPL LTD	Private	7.7	Coal (2,000; 3,000)	50	1.23	56.0	3,251.1	26.4	11.9	245.4	0.30
Koradi	6	MAHAGENCO	State	42.4	Coal (3,000; 3,500)	210	1.22	63.4	3,160.6	27.2	11.5	1,167.0	1.42
North Chennai	1	TNEB	State	29.8	Coal (3,000; 3,500)	210	1.20	50.0	3,100.1	27.7	10.4	920.5	1.11
Sanjay Gandhi	1	MPGPCL	State	31.4	Coal (3,500; 4,000)	210	1.18	59.4	3,098.9	27.7	9.9	1,093.0	1.29
GHTP (Leh. Moh.)	1	PSEB	State	26.6	Coal (4,000; 4,500)	210	1.18	53.6	3,104.1	27.7	9.0	986.0	1.16
North Chennai	2	TNEB	State	29.4	Coal (3,000; 3,500)	210	1.17	54.3	3,068.9	28.0	9.2	998.2	1.17
Sanjay Gandhi	2	MPGPCL	State	30.4	Coal (3,500; 4,000)	210	1.17	57.1	3,083.5	27.9	9.5	1,049.6	1.23
Southern Repl.	1	CESC	Private	34.0	Coal (4,500; 5,000)	67.5	1.17	51.0	3,075.5	28.0	8.5	301.6	0.35
Kolaghat	3	WBPDC	State	40.0	Coal (3,000; 3,500)	210	1.16	61.0	3,055.7	28.1	11.0	1,122.0	1.30
Obra-A	9	UPRVUNL	State	44.5	Coal (3,000; 3,500)	200	1.16	58.8	3,037.4	28.3	10.9	1,031.0	1.19
Kolaghat	5	WBPDC	State	33.4	Coal (3,000; 3,500)	210	1.15	56.8	3,035.5	28.3	11.1	1,045.0	1.21
Korba-West	4	CSEB	State	38.4	Coal (3,500; 4,000)	210	1.15	68.9	3,034.3	28.3	9.6	1,268.0	1.46
Chandrapur Coal	3	MAHAGENCO	State	39.3	Coal (3,000; 3,500)	210	1.15	50.5	3,009.9	28.6	11.9	929.4	1.07
Bandel	5	WBPDC	State	41.8	Coal (3,500; 4,000)	210	1.14	76.5	3,009.2	28.6	9.5	1,407.0	1.61
Kolaghat	4	WBPDC	State	30.6	Coal (3,000; 3,500)	210	1.14	60.3	3,009.8	28.6	11.1	1,109.0	1.27

Table 9(c): Least-performing subcritical units with capacity < 250 MW (coal + lignite) (in terms of emission factor and SHR)

Name	Unit no.	Company	Sector	Age	Fuel and average GCV	Capa-city	Emi-ssion factor (tonne/ MWh)	PLF (per cent)	SHR (kcal/ kWh)	Effi-ciency (per cent)	Auxiliary consumption (per cent)	Net genera-tion (GWh)	CO_2 emissions (MT)
Neyveli ST II	6	NLC	Centre	31.8	Lignite (2,000; 3,000)	210	1.45	55.6	3,443.1	25.0	12.3	1,023.4	1.49
Neyveli ST II	1	NLC	Centre	36.6	Lignite (2,000; 3,000)	210	1.45	52.1	3,435.4	25.0	11.7	958.4	1.39
Neyveli ST II	7	NLC	Centre	31.1	Lignite (2,000; 3,000)	210	1.45	61.6	3,436.5	25.0	10.7	1,133.5	1.64
Neyveli ST II	3	NLC	Centre	38.4	Lignite (2,000; 3,000)	210	1.44	57.7	3,418.6	25.2	11.8	1,060.7	1.53
Neyveli ST II	5	NLC	Centre	32.6	Lignite (2,000; 3,000)	210	1.42	56.2	3,373.1	25.5	10.7	1,033.0	1.47
Neyveli ST II	4	NLC	Centre	33.4	Lignite (2,000; 3,000)	210	1.37	59.6	3,248.8	26.5	7.1	1,096.1	1.50
Chakabura TPP	2	ACB India Ltd	Private	10.4	Coal (2,000; 3,000)	30	1.36	64.3	3,580.5	24.0	13.5	168.8	0.23
K_Kheda II	4	MAHAGENCO	State	23.6	Coal (3,000; 3,500)	210	1.30	50.8	3,410.8	25.2	11.3	934.0	1.22
Niwari TPP	2	BLA Power Ltd	Private	5.2	Coal (3,000; 3,500)	45	1.30	55.4	3,433.0	25.0	12.3	218.2	0.28
K_Kheda II	3	MAHAGENCO	State	24.2	Coal, (3,000; 3,500]	210	1.29	63.2	3,407.6	25.2	10.6	1,162.0	1.50
Neyveli FST Ext	1	NLC	Centre	21.8	Lignite (2,000; 3,000)	210	1.25	82.7	2,975.9	28.9	9.0	1,521.3	1.91
Neyveli FST Ext**	2	NLC	Centre	21.0	Lignite (2,000; 3,000)	210	1.25	71.3	2,975.9	28.9	9.0	1,310.9	1.64
Korba-West	2	CSEB	State	40.4	Coal (3,500; 4,000)	210	1.24	65.7	3,263.7	26.3	10.5	1,209.0	1.50
Ratija TPP	2	SCPL LTD	Private	7.7	Coal (2,000; 3,000)	50	1.23	56.0	3,251.1	26.4	11.9	245.4	0.30

Name	Unit no.	Company	Sector	Age	Fuel and average GCV	Capa-city	Emi-ssion factor (tonne/ MWh)	PLF (per cent)	SHR (kcal/ kWh)	Effi-ciency (per cent)	Auxiliary consumption (per cent)	Net genera-tion (GWh)	CO_2 emissions (MT)
Barsingar Lignite	2	NLC	Centre	13.5	Lignite (2,000; 3,000)	125	1.22	73.8	2,908.4	29.6	12.6	808.0	0.99
Barsingar Lignite	1	NLC	Centre	14.1	Lignite (2,000; 3,000)	125	1.22	63.2	2,895.2	29.7	12.6	692.0	0.84
Koradi	6	MAHAGENCO	State	42.4	Lignite (3,000; 3,500)	210	1.22	63.4	3,160.6	27.2	11.5	1,167.0	1.42
North Chennai	1	TNEB	State	29.8	Coal (3,000; 3,500)	210	1.20	50.0	3,100.1	27.7	10.4	920.5	1.11
Jallippa Kapurdi TPP	7	Raj West Power Ltd (JSW)	Private	11.4	Lignite (3,000; 3,500)	135	1.20	70.5	2,853.0	30.1	10.2	834.1	1.00
Jallippa Kapurdi TPP	1	Raj West Power Ltd (JSW)	Private	14.8	Lignite (3,000; 3,500)	135	1.20	67.7	2852.6	30.1	10.2	800.5	0.96

: **Plants not on the R&M list

: Plants use lignite as their fuel

Source: CEA CO_2 Baseline data: 2022–23

Subcritical units with installed capacity >= 250 MW

Table 10(a): Best-performing subcritical units with capacity >= 250 MW (in terms of emission factor and SHR

Name	Unit no.	Company	Sector	Age	Fuel and average GCV	Capacity	Emission factor (tonne/MWh)	PLF (per cent)	SHR (kcal/kWh)	Efficiency (per cent)	Auxiliary consumption (per cent)	Net generation (GWh)	CO_2 emissions (MT)
Torangallu Ext*	1	JSW Energy Ltd	Private	15.3	Coal (5,000; 6,000)	300	0.87	54.0	2,425.1	35.5	7.6	1,418.9	1.23
Trombay Coal*	1	Tata Power	Private	40.5	Coal (4,000; 4,500)	500	0.89	57.2	2,495.6	34.5	6.1	2,507.0	2.24
Trombay Coal*	2	Tata Power	Private	14.9	Coal (4,000; 4,500)	250	0.90	62.6	2,524.5	34.1	7.1	1,372.0	1.24
K_Gudem New	4	TSGENCO	State	13.1	Coal (3500; 4000)	500	0.91	78.8	2,404.0	35.8	5.2	3,452.2	3.15
Haldia	2	Haldia Energy Ltd	Private	9.5	Coal (3,000; 3,500)	300	0.92	74.0	2,416.2	35.6	5.1	1,945.0	1.78
Tamnar TPP	1	OP Jindal	Private	10.4	Coal (2,000; 3,000)	600	0.92	59.1	2,433.0	35.3	5.3	3,108.9	2.86
Korba STPS	7	NTPC	Centre	13.6	Coal (3,000, 3,500)	500	0.92	78.9	2,427.7	35.4	5.2	3,455.1	3.18
Budge Budge	1	CESC	Private	26.9	Coal (3,500; 4,000)	250	0.93	69.6	2,437.7	35.3	7.9	1,523.9	1.41
Budge Budge	2	CESC	Private	25.4	Coal (3,500; 4,000)	250	0.93	73.2	2,437.9	35.3	7.9	1,602.5	1.48
Tamnar TPP	4	OP JINDAL	Private	9.4	Coal (2,000; 3,000)	600	0.93	62.9	2,443.9	35.2	5.3	3,305.2	3.06
Anpara	6	UPRVUNL	State	9.2	Coal (3,500; 4,000)	500	0.93	89.3	2,445.2	35.2	5.6	3,909.6	3.63
R_Gundem STPS	7	NTPC	Centre	19.9	Coal (3,000; 3,500)	500	0.93	64.4	2,451.0	35.1	6.7	2,822.3	2.62
Anpara	7	UPRVUNL	State	8.4	Coal (3,500; 4,000)	500	0.93	87.7	2,446.3	35.1	5.5	3,841.1	3.57

Name	Unit no.	Company	Sector	Age	Fuel and average GCV	Capacity	Emission factor (tonne/MWh)	PLF (per cent)	SHR (kcal/kWh)	Efficiency (per cent)	Auxiliary consumption (per cent)	Net generation (GWh)	CO_2 emissions (MT)
Singareni TPP		Singareni Collieries	State	8.4	Coal (4,000; 4,500)	600	0.93	86.6	2,446.5	35.1	6.2	4,554.0	4.23
Chandrapur_ Coal	8	MAHAGENCO	State	9.4	Coal (3,000; 3,500)	500	0.93	70.1	2,474.7	34.7	5.3	3,072.6	2.85
Anapara "C"	2	LANCO Anapara Power	Private	12.7	Coal (3,500; 4,000)	600	0.93	68.9	2,454.8	35.0	5.2	3,622.2	3.37
Anapara "C"	1	LANCO Anapara Power	Private	12.7	Coal (3,500; 4,000)	600	0.93	77.6	2,454.8	35.0	5.2	4,080.8	3.80
Chandrapur Coal	9	MAHAGENCO	State	8.4	Coal (3,000; 3,500)	500	0.93	73.7	2,488.9	34.5	5.7	3,228.3	3.01
Singareni TPP	2	Singareni Collieries	State	7.7	Coal (3,500; 4,000)	600	0.93	79.7	2,458.2	35.0	5.9	4,187.0	3.91
Kakatiya TPP (Stage II)	2	TSGENCO	State	8.6	Coal (3,500; 4,000)	600	0.94	79.3	2,462.7	34.9	5.4	4,166.0	3.90

: *Plants use oil and imported coal as their fuel.

Source: CEA CO_2 baseline data: 2022–23

Table 10(b): Least-performing subcritical units with capacity >= 250 MW (coal + lignite) (in terms of emission factor and SHR)

Name	Unit no.	Company	Sector	Age	Fuel and average GCV	Capa-city	Emi-ssion factor (tonne/ MWh)	PLF (per cent)	SHR (kcal/ kWh)	Efficiency (per cent)	Auxiliary consumption (per cent)	Net generation (GWh)	CO_2 emissions (MT)
Balco TPP**	1	Balco India Pvt Ltd.	Private	9.2	Coal, (3500, 4000)	300	1.57	60.5	4,162.9	20.7	8.4	1,590.4	2.50
Neyveli TPS (Z)	1	TAQA	Private	21.8	Lignite (2,000; 3,000)	250	1.25	51.1	2,966.1	29.0	8.0	1,119.5	1.40
Neyveli New TPP**	2	NLC	Centre	3.5	Lignite (2,000; 3,000)	500	1.18	76.0	2,800.5	30.7	6.1	3,330.5	3.93
Neyveli New TPP**	1	NLC	Centre	4.6	Lignite (2,000; 3,000)	500	1.18	77.4	2,798.3	30.7	6.1	3,388.9	4.00
Bhusawal**	4	MAHAGENCO	State	12.4	Coal (3,500; 4,000)	500	1.15	69.7	3,042.7	28.3	6.3	3,053.0	3.51
Bhusawal**	5	MAHAGENCO	State	10.6	Coal (3,500; 4,000)	500	1.14	61.1	3,027.3	28.4	6.4	2,677.0	3.06
GHTP (Leh. Moh.) **	4	PSEB	State	16.0	Coal (4,000; 4,500)	250	1.13	64.2	2,978.4	28.9	7.7	1,406.0	1.59
Chandrapur Coal	6	MAHAGENCO	State	32.4	Coal (3,000; 3,500)	500	1.11	51.7	2,914.9	29.5	9.5	2,263.5	2.51
K_Kheda II**	5	MAHAGENCO	State	13.0	Coal (3,000; 3,500)	500	1.10	73.9	2,928.6	29.4	5.9	3,237.0	3.57
Marwa TPP**	1	CSPGCL	State	10.4	Coal (3,000; 3,500)	500	1.10	51.7	2,887.7	29.8	6.0	2,264.0	2.48
Chhabra TPS	2	RRVUNL	State	14.3	Coal (3,500; 4,000)	250	1.09	60.7	2,862.2	30.0	10.5	1,329.2	1.45
Panipat	8	HPGCL	State	19.5	Coal (3,500; 4,000)	250	1.09	69.4	2,873.3	29.9	9.4	1,520.5	1.65
Pathadi TPS PH -I	1	LANCO Amarkantak	Private	15.2	Coal (3,000; 3,500)	300	1.08	54.9	2,856.7	30.1	8.7	1,443.1	1.56
Parli	7	MAHAGENCO	State	14.5	Coal (3,000; 3,500)	250	1.08	53.5	2,810.3	30.6	11.4	1,171.0	1.27

Name	Unit no.	Company	Sector	Age	Fuel and average GCV	Capa-city	Emi-ssion factor (tonne/ MWh)	PLF (per cent)	SHR (kcal/ kWh)	Efficiency (per cent)	Auxiliary consumption (per cent)	Net generation (GWh)	CO_2 emissions (MT)
Panipat	7	HPGCL	State	19.9	Coal (3,500; 4,000)	250	1.08	76.6	2,856.0	30.1	9.2	1,678.5	1.81
Chhabra TPS	1	RRVUNL	State	14.8	Coal (3,500; 4,000)	250	1.08	69.9	2,839.1	30.3	10.4	1,531.2	1.65
D.P.L.	8	DPL	State	10.4	Coal (3,500; 4,000)	250	1.08	75.3	2,834.5	30.3	10.8	1,648.0	1.77
Chhabra TPS	3	RRVUNL	State	10.9	Coal (3,500; 4,000)	250	1.07	73.1	2,818.6	30.5	9.9	1,601.5	1.71
Kalisindh	2	RRVUNL	State	9.2	Coal (3,500; 4,000)	600	1.07	50.5	2,817.5	30.5	6.6	2,654.9	2.84
Parli	6	MAHAGENCO	State	17.5	Coal (3,000; 3,500)	250	1.07	59.5	2,797.2	30.7	11.5	1,303.0	1.39

: **Plants not on the R&M list

Source: CEA CO_2 Baseline data: 2022–23

Supercritical units

Table 11(a): Best-performing supercritical units (in terms of emission factor and SHR)

Name	Unit no.	Company	Sector	Age	Fuel and average GCV	Capacity	Emission factor (tonne/ MWh)	PLF (per cent)	SHR (kcal/ kWh)	Efficiency (per cent)	Auxiliary consumption (per cent)	Net genera-tion (GWh)	CO_2 emi-ssions (MT)
Rajpura TPP	2	Nabha Power Ltd	Private	10.1	Coal (3,500; 4,000)	700	0.84	82.6	2,228.8	38.6	4.6	5,066.3	4.28
Rajpura TPP	1	Nabha Power Ltd	Private	10.5	Coal (3,500; 4,000)	700	0.85	78.8	2,256.2	38.1	4.6	4,832.9	4.13
I.B.VALLEY	4	OPGC	State	5.0	Coal (3,000; 3,500)	660	0.86	71.4	2,265.3	38.0	5.2	4,130.5	3.55
Nabi Nagar STPP (NEW)	3	NTPC JV/ NPGCL	Centre	3.4	Coal (3,500; 4,000)	660	0.88	65.2	2,313.6	37.2	5.2	3,769.1	3.30
H_GANJ B EXP-II	1	UPRVUNL	State	2.5	Coal (3,500; 4,000)	660	0.88	50.1	2,273.4	37.8	7.4	2,894.0	2.53
Sembcorp Gayatri (SGPL TPP)	1	SGPL	Private	7.7	Coal (3,500; 4,000)	660	0.88	70.7	2,417.8	35.6	5.3	4,090.3	3.58
Painampuram (SGPL P1)	1	Sembcorp Energy India Ltd-P1	Private	9.5	Coal (3,500; 4,000)	660	0.88	76.2	2,358.6	36.5	5.3	4,404.8	3.87
Painampuram (SGPL P1)	2	Sembcorp Energy India Ltd-P1	Private	8.9	Coal (3,500; 4,000)	660	0.88	69.5	2,357.3	36.5	5.3	4,019.6	3.54
I.B. Valley	3	OPGC	State	5.1	Coal (3,000; 3,500)	660	0.88	74.3	2,323.6	37.0	6.0	4,297.8	3.79
Sembcorp Gayatri (SGPL TPP)	2	SGPL	Private	7.5	Coal (3,500; 4,000)	660	0.88	61.9	2,431.2	35.4	5.3	3,581.0	3.16
Mahatma Gandhi TPP	1	Jhajjar Power Ltd	Private	12.6	Coal (3,500; 4,000)	660	0.89	63.9	2,343.7	36.7	6.0	3,692.8	3.27
Kawai TPP	1	Adani Power Ltd	Private	11.2	Coal (3,500; 4,000)	660	0.89	75.5	2,368.5	36.3	5.4	4,362.4	3.88
Nabi Nagar STPP (NEW)	1	NTPC JV/ NPGCL	Centre	5.1	Coal (3,500; 4,000)	660	0.89	65.2	2,356.4	36.5	5.1	3,769.7	3.36
Prayagraj (Bara) TPP	2	Tata Power	Private	7.9	Coal (3,500; 4,000)	660	0.89	68.0	2,350.3	36.6	5.6	3,930.6	3.51

Name	Unit no.	Company	Sector	Age	Fuel and average GCV	Capacity	Emission factor (tonne/ MWh)	PLF (per cent)	SHR (kcal/ kWh)	Efficiency (per cent)	Auxiliary consumption (per cent)	Net genera-tion (GWh)	CO_2 emi-ssions (MT)
Mouda STPS	4	NTPC	Centre	7.4	Coal (3,000; 3,500)	660	0.89	69.3	2,372.9	36.2	5.0	4,008.4	3.58
Prayagraj (Bara) TPP	1	Tata Power	Private	8.6	Coal (3,500: 4,000)	660	0.89	70.0	2,353.7	36.5	5.7	4,048.7	3.62
Kawai TPP	2	Adani Power Ltd	Private	10.6	Coal (3,500; 4,000)	660	0.89	70.4	2,385.5	36.0	5.5	4,071.2	3.64
Mahatma Gandhi TPP	2	Jhajjar Power Ltd	Private	12.3	Coal (3,500; 4,000)	660	0.90	68.2	2,375.8	36.2	6.5	3,941.4	3.53
Lalitpur TPP	3	Lalitpur Power Gen Co Ltd	Private	8.4	Coal (3,500; 4,000)	660	0.90	64.0	2,359.8	36.4	5.2	3,703.0	3.32
Lalitpur TPP	1	Lalitpur Power Gen Co Ltd	Private	9.2	Coal (3,500; 4,000)	660	0.90	64.5	2,359.9	36.4	5.2	3,732.0	3.34

: *Plants use oil and imported coal as their fuel.

Source: CEA CO_2 baseline data: 2022–23

Table 11(b): Least-performing supercritical units (in terms of emission factor and SHR)

Name	Unit no.	Company	Sector	Age	Fuel and average GCV	Capa-city	Emission factor (tonne/ MWh)	PLF (per cent)	SHR (kcal/ kWh)	Efficiency (per cent)	Auxiliary consumption (per cent)	Net generation (GWh)	CO_2 emi-ssions (million tonnes)
Koradi Extn	10	MAHAGENCO	State	7.6	Coal (3,500; 4,000)	660	1.19	61.4	3,154.2	27.3	7.55	3,552	4.24
Koradi Extn	9	MAHAGENCO	State	8.4	Coal (3,500; 4,000)	660	1.16	54.1	3,070.6	28.0	7.94	3,130	3.64
Koradi Extn	8	MAHAGENCO	State	9.4	Coal (3,500; 4,000)	660	1.14	62.0	3,014.2	28.5	6.57	3,586	4.09
Chhabra TPS	6	RRVUNL	State	5.4	Coal (3,500; 4,000)	660	1.04	58.8	2,745.3	31.3	5.93	3,400.58	3.53
Chhabra TPS	5	RRVUNL	State	7.3	Coal (3,500; 4,000)	660	1.02	59.2	2,708.4	31.7	6.28	3,425.23	3.51
Suratgarh	8	RRVUNL	State	2.8	Coal (3,500; 4,000)	660	0.97	50.1	2,546.3	33.8	6.88	2,897.676	2.80
Barh STPP I	1	NPGCL	Centre	2.8	Coal (3,500; 4,000)	660	0.96	65.6	2,531.9	34.0	6.80	3,793.67	3.66
Talwandi Sabo	3	Talwandi Sabo Power	Private	8.4	Coal (3,000; 3,500)	660	0.96	60.9	2,524.0	34.1	6.92	3,522	3.37
Meja STPP	1	JV NTPC and UPRVUNL	Centre	6.4	Coal (3,500; 4,000)	660	0.95	69.6	2,508.2	34.3	5.86	4,025.047	3.84
Meja STPP	2	JV NTPC and UPRVUNL	Centre	3.6	Coal (3,500; 4,000)	660	0.95	50.3	2,508.2	34.3	5.86	2,910.137	2.77
Shri Singaji Malwa TPP	4	MPPGCL	State	5.4	Coal (3,000; 3,500)	660	0.95	56.6	2,484.7	34.6	5.87	3,270	3.09
Talwandi Sabo	1	Talwandi Sabo Power	Private	10.1	Coal (3,000; 3,500)	660	0.93	64.7	2,464.0	34.9	6.97	3,739	3.49
Barh STPP II	1	NTPC	Centre	10.7	Coal (3,500; 4,000)	660	0.93	78.2	2,456.6	35.0	5.52	4,520.95	4.20
Raikheda	2	Raipur Energen Limited	Private	8.4	Coal (3,000; 3,500)	685	0.93	57.6	2,459.6	35.0	9.95	3,456.7	3.21
Talwandi Sabo	2	Talwandi Sabo Power	Private	8.8	Coal (3,000; 3,5000	660	0.93	60.3	2,445.7	35.2	6.59	3,487	3.23
Sipat STPS	5	NTPC	Centre	12.2	Coal (3,000; 3,500)	660	0.92	87.0	2,442.7	35.2	5.40	5,030.9	4.65
Tirora TPP-II	4	Adani Power Ltd	Private	10.4	Coal (3,500; 4,000)	660	0.91	73.4	2,408.7	35.7	5.42	4,245.807	3.88
Tirora TPP-II	5	Adani Power Ltd	Private	9.9	Coal (3,500; 4,000)	660	0.91	71.6	2,408.5	35.7	5.42	4,140.034	3.78
Sasan UMPP	4	Reliance Power	Private	10.2	Coal (4,000; 4,500)	660	0.91	89.9	2,402.9	35.8	6.03	5,197.631	4.74
Barh STPP II	2	NTPC	Centre	9.4	Coal (3,500; 4,000)	660	0.91	70.2	2,399.1	35.8	5.41	4,057.04	3.69

Source: CEA CO_2 Baseline Data: 2022-23

Table 11(c): Performance of supercritical units operating below 50 per cent PLF (in terms of emission factor and SHR)

S. no.	Name	Unit no.	Company	Sector	Age	Fuel and average, GCV	Capa-city	Emi-ssion factor (tonne/ MWh)	PLF (per cent)	SHR (kcal/ kWh)	Effi-ciency (per cent)	Auxiliary consumption (per cent)	Net generation (GWh)	CO_2 emissions (MT)
1	North Karanpura*	1	NTPC	Centre	1.5	Coal (3,000; 3,500)	660	0.59	10.4	1,538.7	55.9	4.2	600	0.35
2	Solapur STPP	2	NTPC	Centre	5.4	Coal (3,500; 4,000)	660	0.88	46.0	2,331.7	36.9	6.5	2,661.21	2.34
3	Khargone STPP St-I	2	NTPC	Centre	4.4	Coal (3,000; 3,500)	660	0.88	38.2	2,338.4	36.8	7.1	2,208.36	1.94
4	Raikheda	1	Raipur Energen Limited	Private	9.4	Coal (3,000; 3,500)	685	0.90	48.8	2,383.7	36.1	9.7	2,929.6	2.63
5	Mundra TPP	5	Adani Power Ltd	Private	13.6	Coal (4,000; 4,500)	660	0.91	29.6	2,552.1	33.7	8.5	1,713.076	1.56
6	Mundra TPP	9	Adani Power Ltd	Private	12.4	Coal (4,000; 4,500)	660	0.91	30.5	2,553.3	33.7	8.5	1,762.073	1.61
7	Sasan UMPP	1	Reliance Power	Private	10.6	Coal (3,500; 4,000)	660	0.91	27.7	2,406.3	35.7	6.0	1,599.175	1.46
8	Mundra TPP	6	Adani Power Ltd	Private	13.0	Coal (4,000; 4,500)	660	0.91	31.8	2,558.7	33.6	8.5	1,840.66	1.68
9	Shri Singaji Malwa TPP	3	MPPGCL	State	5.7	Coal (3,000; 3,500)	660	0.92	47.6	2,404.9	35.8	6.3	2,751	2.52
10	Solapur STPP	1	NTPC	Centre	7.3	Coal (3,500; 4,000)	660	0.93	49.1	2,466.6	34.9	6.4	2,837.71	2.64
11	Mundra TPP	7	Adani Power Ltd	Private	12.7	Coal (4,000; 4,500)	660	0.93	15.8	2,616.9	32.9	8.5	911.55	0.85
12	Mundra TPP	8	Adani Power Ltd	Private	12.4	Coal (4,000; 4,500)	660	0.95	13.7	2,649.9	32.4	8.5	789.42	0.75
13	Suratgarh	7	RRVUNL	State	4.4	Coal (3,500; 4,000)	660	0.96	25.3	2,526.5	34.0	7.0	1,461.694	1.40
14	Bellary TPS	3	KPCL	State	8.4	Coal (3,500; 4,000)	700	1.15	44.5	3,017.3	28.5	7.2	2,731	3.14

: Recently operational unit

Ultra-supercritical units

Table 12: Performance of ultra-supercritical units (in terms of emission factor and SHR)

Name	Unit no.	System (company)	Sector	Age	Fuel and average GCV	Capa-city	Emi-ssion factor (tonne/ MWh)	PLF (per cent)	SHR (kcal/ kWh)	Effi-ciency (per cent)	Auxiliary consumption (per cent)	Net generation (GWh)	CO_2 emissions (MT)
Mundra UMPP	2	TATA Power	Private	12.0	Coal (5,000; 6,000)	800	0.83	27.3	2,323.7	37.0	8.4	1,911.57	1.59
Kudgi	1	NTPC	Centre	7.6	Coal (3,000; 3,500)	800	0.83	56.9	2,206.2	39.0	5.8	3,990.42	3.31
Kudgi	2	NTPC	Centre	7.4	Coal, (3,000; 3,500)	800	0.83	50.3	2,209.1	38.9	6.1	3,527.02	2.93
Mundra UMPP	5	TATA Power	Private	11.4	Coal (5,000; 6,000)	800	0.83	43.8	2,332.8	36.9	8.4	3,072.07	2.56
Mundra UMPP	1	TATA Power	Private	12.4	Coal (5,000; 6,000)	800	0.83	50.9	2,334.8	36.8	8.4	3,566.68	2.97
Mundra UMPP	3	TATA Power	Private	11.8	Coal (5,000; 6000)	800	0.84	31.3	2,348.8	36.6	8.4	2,194.60	1.84
Kudgi	3	NTPC	Centre	6.4	Coal (3,000; 3,500)	800	0.85	44.7	2,271.9	37.8	6.2	3,129.43	2.67
K_GUDEM NEW	1	TSGENCO	State	5.6	Coal (4,000; 4,500)	800	0.86	57.3	2,257.1	38.1	4.7	4,013.00	3.45
Darlipalli STPP St-I	1	NTPC	Centre	4.6	Coal (2,000; 3,000)	800	0.86	69.0	2,271.4	37.9	6.1	4,833.56	4.18
Lara	2	NTPC	Centre	4.1	Coal (2,000; 3,000)	800	0.87	79.0	2,286.9	37.6	5.7	5,534.71	4.80
Darlipalli STPP St-I	2	NTPC	Centre	3.0	Coal (2,000; 3,000)	800	0.87	82.5	2,283.8	37.7	6.3	5,782.32	5.02
Lara	1	NTPC	Centre	6.4	Coal (2,000; 3,000)	800	0.88	77.8	2,333.0	36.9	6.2	5,454.77	4.82
Gadarwara	1	NTPC	Centre	6.4	Coal (3,500; 4,000)	800	0.89	63.7	2,354.8	36.5	5.9	4,464.84	3.96
Gadarwara	2	NTPC	Centre	3.5	Coal (3,500; 4,000)	800	0.89	61.9	2,360.9	36.4	6.7	4,336.21	3.86

Name	Unit no.	System (company)	Sector	Age	Fuel and average GCV	Capacity	Emission factor (tonne/MWh)	PLF (per cent)	SHR (kcal/kWh)	Efficiency (per cent)	Auxiliary consumption (per cent)	Net generation (GWh)	CO_2 emissions (MT)
Yermarus TPP	2	KPCL	State	7.4	Coal (3,000; 3,500)	800	0.92	38.5	2,407.8	35.7	7.8	2,699.71	2.48
Wanakbori	8	GSECL	State	4.8	Coal (3,500; 4,000)	800	0.92	56.2	2,422.9	35.5	5.2	3,935.00	3.64
Yermarus TPP	1	KPCL	State	8.4	Coal (3,000; 3,500)	800	0.94	23.8	2,471.1	34.8	7.8	1,667.99	1.58
Damodaram Sanjeevaiah	2.00-3.00	APPDCL	State	9.4	Coal (3,500; 4,000)	1600	1.03	18.2	2,724.3	31.6	7.7	2,557.55	2.64
Damodaram Sanjeevaiah	1	APPDCL	State	9.9	Coal (3,500; 4,000)	800	1.04	41.2	2,751.8	31.2	7.1	2,890.45	3.02

: Units operating with PLF below 50 per cent

: Units operating with PLF at 50 per cent

Source: CEA CO_2 baseline data: 2022–23

3.4 Company-wise analysis

Table 13 presents data on the top 20 net electricity generating companies, detailing their total CO_2 emissions and average emission factors. Among these producers, three companies operate within the Central sector, four are in the private sector, and the remaining 13 are affiliated with the state sector.

NTPC, a significant entity in the Central sector, contributes approximately 26.6 per cent to net generation. Despite this, its average emission factor of 0.97 tonne/MWh aligns with the national average for coal-based thermal power plants. However, other Central sector companies such as Damodar Valley Corporation (DVC), with an emission factor of 1.03 tonne/MWh, and Neyveli Lignite Corporation (NLC), with an emission factor of 1.33 tonne/MWh, exceed this benchmark, emphasizing the pressing need for efficiency enhancements within the sector. Further, the average age of plants within NTPC and NLC stands at 22.34 and 22.47 years (nearing retirement age as per the advisory by the Ministry of Power [MoP]), respectively, indicating the need to carefully monitor the efficiency and emission intensity of such plants for any corrective measures wherever required. Among the top-generating private-sector companies, namely Reliance Power, Tata Power,

Table 13: India's top 20 power-generation companies—net generation, total emissions and emission factors

		Aggregate values		Average values	
Company	Sector	Net generation (GWh)	Total CO_2 emissions (million tonnes)	Emission factor (tonne/MWh)	Age (years)
NTPC	Center	291,342.18	275.49	0.97	22.34
MAHAGENCO	State	47,033.33	53.18	1.17	23.96
DVC	Centre	40,077.45	39.97	1.04	17.01
Adani Power Ltd	Private	38,477.37	34.82	0.91	12.03
RRVUNL	State	34,724.69	36.13	1.05	18.87
UPRVUNL	State	31,895.17	31.85	1.04	26.88
WBPDC	State	29,162.81	29.88	1.05	24.31
Tata Power	Private	28,049.36	24.71	0.9	15.45
Reliance Power	Private	27,969.28	25.41	0.91	9.96
TSGENCO	State	23,659.77	22.54	1	14.51
TNEB	State	20,715.22	22.18	1.09	30.52
GSECL	State	20,098	21.82	1.19	29.34
NLC	Centre	19,857.2	25.68	1.33	22.47
APGENCO	State	18,623.96	19.6	1.07	26.29
KPCL	State	16,771.74	18.09	1.08	21.25
HPGCL	State	14,516.17	14.61	1.02	17.44
MPGPCL	State	13,004.58	13.69	1.08	20.41
MPPGCL	State	12,366	12.09	0.98	7.52
CSEB	State	12,291.71	13.17	1.09	28.90
OP Jindal	Private	12,283.07	11.4	0.93	9.79

Source: CEA CO_2 baseline database, version 19

Adani Power, and OP Jindal, all boast of average emission factors below 0.93 tonne/MWh, indicative of commendable performance metrics. Conversely, the 13 state-sector companies out of the top 20 net electricity-generating companies have emission factors surpassing 1 tonne/MWh. Moreover, several state-owned companies, including UPRVUNL, TNEB, GSECL, APGENCO, and CSEB, have plants with an average age nearing or surpassing retirement age as specified in CEA's advisory. For instance, the average age of plants within these companies stands at 26.88, 30.52, 29.34, 26.29 and 28.90 years, respectively, underscoring the urgent need to repurpose less efficient, aging plants or units within these entities that have exceeded their operational lifespan.

4

FUTURE CAPACITY ADDITIONS, EMISSIONS AND TARGETS

INDIA'S COAL-BASED POWER CAPACITY IS EXPECTED TO GROW BEYOND THE NATIONAL ELECTRICITY PLAN 2022–23 ESTIMATE OF 262 GW TO OVER 280 GW BY 2031–32.

CURRENTLY, 29.9 GW OF COAL POWER CAPACITY IS UNDER CONSTRUCTION, 23.3 GW IS ON HOLD, AND 11.7 GW IS PLANNED FOR FUTURE EXPANSION.

AS PER THE GOVERNMENT OF INDIA'S REPLY IN PARLIAMENT, THE THERMAL CAPACITY ADDITION IS EXPECTED TO ENTAIL AN EXPENDITURE OF MINIMUM RS 6,67,200 CRORE BY 2031–32.

4.1 Future emissions

According to the latest NEP[55] for the fiscal year 2021–22, the peak demand and energy requirement are recorded at 203,014 MW and 1,379.81 billion units (BU), respectively. The installed capacity as of March 31, 2022, was 399,496.61 MW, which saw an increase to 410,339.23 MW by December 31, 2022. Projections for the year 2026–27 anticipate a peak demand of 277,201 MW and an energy requirement of 1,907.8 BU. Looking further ahead to 2031–32, these figures are expected to rise to 366,303 MW for peak demand and 2,473.8 BU for energy requirement. Yet, India's electricity demand has breached projection figures of the NEP following an unprecedented growth post COVID-19 pandemic.

The NEP provides a resource-wise breakdown of the installed capacity as of December 31, 2022, as well as projections for 2026–27 and 2031–32 (see *Table 14: India's current and projected installed capacity by energy source).*

The forthcoming decade (2025–35) is anticipated to witness a significant surge in renewable installed capacity, particularly in solar and wind energy. Concurrently, projections indicate an increase in coal- and lignite-based installed capacity, albeit with a reduction in its overall percentage contribution to 28.8 per cent by 2031–32, down from 52.8 per cent. This shift is attributed to the escalation in renewable energy installations. For FY 2022–23, the net generation of electricity from coal and lignite-based thermal power plants accounted for approximately 73 per cent, whereas RE contributed approximately 13 per cent (**see** *Graph 5[b]: Source-wise*

Table 14: India's current and projected installed capacity by energy source (in MW)

Resource	As of March 31, 2022	Percentage of total IC	2026–27	Percentage of total IC	2031–32	Percentage of total IC
Hydro	41,977	10.5 per cent	52,446	8.6 per cent	62,178	6.90 per cent
PSP	4,746	1.2 per cent	7,446	1.2 per cent	26,686	3.00 per cent
Small hydro	4,848	1.2 per cent	5,200	0.9 per cent	5,450	0.60 per cent
Solar PV	53,996	13.5 per cent	1,85,566	30.4 per cent	3,64,566	40.50 per cent
Wind	40,358	10.1 per cent	72,896	12.0 per cent	1,21,895	13.50 per cent
Biomass	10,682	2.7 per cent	13,000	2.1 per cent	15,500	1.70 per cent
Nuclear	6,780	1.7 per cent	13,080	2.1 per cent	19,680	2.20 per cent
Coal + lignite	210,700	52.8 per cent	2,35,133	38.6 per cent	2,59,643	28.80 per cent
Gas	24,899	6.2 per cent	24,824	4.1 per cent	24,824	2.80 per cent

Source: CEA National Electricity Plan 2023

Table 15: NEP projections of gross generation by resource type (2026–27 and 2031–32)

Source	2026–27		2031–32	
	Gross generation (BU)	Percentage	Gross generation (BU)	Percentage
Coal + lignite	1203.4	59.4	1334.8	50.1
Gas	34.1	1.7	33.4	1.3
Nuclear	77.9	3.8	117.6	4.4
Hydro	207.7	10.3	246.2	9.2
PV	339.3	16.8	665.6	25.0
Wind power	153.5	7.6	258.1	9.7
Other RE	9.1	0.4	10.0	0.4
Total	2025.0	100.0	2665.7	100.0

Source: CEA National Electricity Plan 2023

generation share). Similar projections for gross generation for 2026–27 and 2031–32 are outlined in the NEP, delineating the resource-wise distribution as shown in Table 15. According to the projections outlined in *Table 15*, the installed capacity of renewable energy (RE), encompassing PSP, small hydro, solar PV, wind and biomass, is poised for substantial growth.

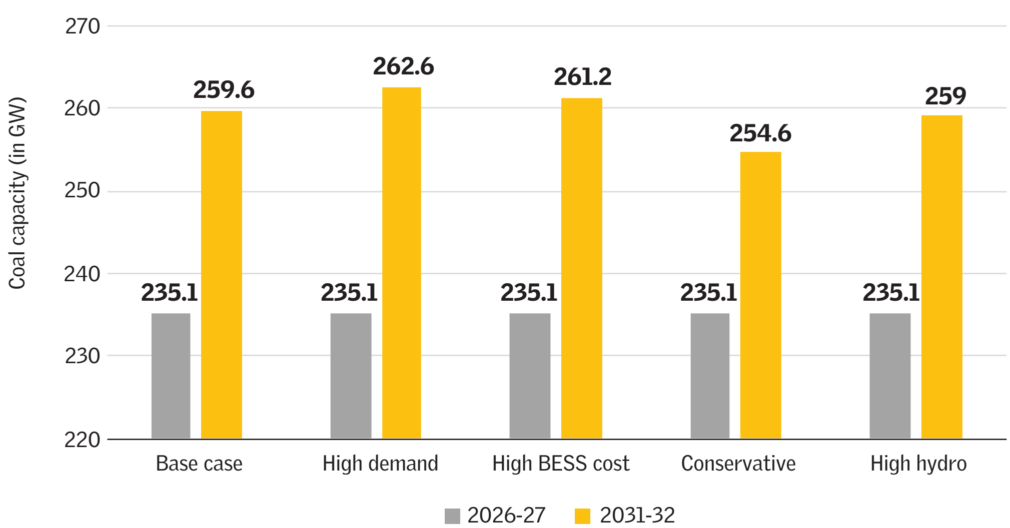
As per the NEP projections, it is expected to rise from 28.7 per cent in 2021–22 to 46.6 per cent in 2026–27 and further to 59.3 per cent by 2031–32. Despite this significant surge in RE capacity, coal-based power generation is forecasted to remain substantial, accounting for 50.1 per cent in 2031–32. The share of RE generation is anticipated to increase from 13 per cent in 2022-23 to 24.8 per cent in 2026–27 and to 35.1 per cent in 2031–32. This increase in RE generation capacity is expected to drive a reduction in the grid's emission factor, decreasing from 0.71 $kgCO_2/kWh_{net}$ to 0.43 $kgCO_2/kWh_{net}$. As per the NEP, **despite this reduction, overall greenhouse gas (GHG) emissions from coal power generation are projected to increase from 1,002.02 million tonnes in the fiscal year 2021–22 to 1,100 million tonnes by 2031–32**. The average emission factor across all coal-based power generation plants has seen a slight decrease, declining from 0.99 $kgCO_2/kWh_{net}$ in 2015–16 to 0.97 $kgCO_2/kWh_{net}$ in 2022–23. This reduction has been credited to the adoption of new supercritical and ultra-supercritical units characterized by higher efficiency, coupled with the implementation of initiatives such as the Perform Achieve and Trade (PAT) scheme.

4.2 Future capacity additions

As stated above, India's electricity demand has breached the forecasted figures. Therefore, as per the NEP, in the high-demand scenario, India's coal capacity was to reach 262.6 GW (see *Graph 21: Likely coal capacity in different scenarios in 2026–27 and 2031–32*). To illustrate its vision of capacity addition, the NEP produced a list of coal capacity under-construction within Annexure 5.3 of the report. The NEP also provided a list of likely candidates for additional thermal power plants during 2022–32 (see *Table 17: List of* candidate thermal plants for likely benefits in 2022–32). The combined capacity addition via the two lists was 47.88 GW only.

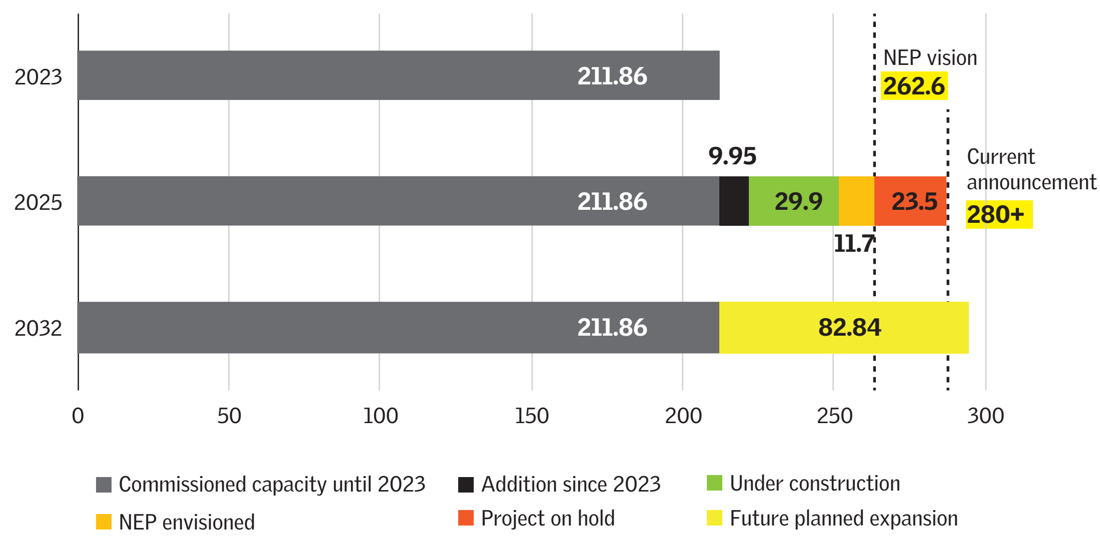
Owing to the rising demand for electricity and non-integration of renewable energy at the same pace, India's coal capacity plans have undergone a massive reset. In the Monsoon Session 2024, MP Shripad Naik, *MoS (Ministry of Power)* in a written reply in the Rajya Sabha, stated the minimum new addition to India's coal capacity will be 80 GW by 2031–32, highlighting a 32-GW new addition. The total capacity for coal and lignite will then be 283 GWs, as stated by the minister in the Parliament. The estimated capital cost for setting up of new coal-based thermal capacity as considered in National Electricity Plan is Rs 8.34 crore/MW (at 2021–22 prices). Hence, the thermal capacity addition is expected to entail an minimum

Graph 21: Likely coal capacity in different scenarios in 2026–27 and 2031–32



Source: Central Electricity Authority, Exhibit 5.5a of National Electricity Plan, 2022–23, p. 144

Graph 22: Coal capacity addition—Current and future plans, 2023–32 (in GW)



Source: CSE analysis on basis of multiple policy documents

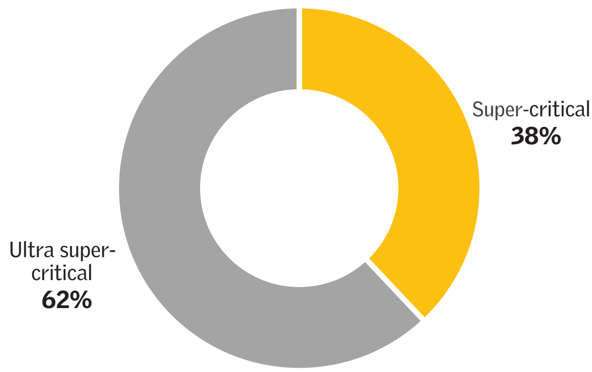
expenditure of **Rs 6,67,200 crore by 2031–32**. India's likely addition of coal capacity is illustrated in *Graph 22*, with the baseline of NEP and government's new announcement represented via dotted lines on the axis.

Between the publication of NEP and March 2025, India has added 9.95 GW of new coal power plants (see *Table 18: New additions, March 2023–25*). The newly added capacity comprises 10 units of sub-critical technology, adding 7 GW to installed capacity. 2.9 GW of ultra-supercritical technology have been added via four units. There is a total of 29.9 GW of capacity under-construction (see *Graph 23: Technology split of under-construction coal power plants*).

CEA publishes a monthly, *Broad Status Report of Under-Construction Thermal Power Plants*. The report comprises three major components, including, *first*, the under-construction coal power plants and detailed report on each unit and their stage of construction; *second*, a list of coal power plants where work is on hold or are unlikely to be commissioned—this segment sheds light on the reason for the hold up and the future scope of these power units; and *third*, an executive summary of coal addition.

Currently, 40 units of coal power plants are under construction. Within the under-construction coal power plants, CSE analysed the March 2025 report and produced the units under construction and their tentative addition (see *Table 16:*

Graph 23: Technology split of under-construction coal power plants (as of March 2025)



Source: CEA: Broad status report on under-contruction thermal projects, March 2025

Under-construction coal power plants). Colour coding has been used to illustrate the technology split of the units under construction. Within the 29.9 GW under construction, 12 GW worth of capacity is slated to be added by 2025 itself. Further, none of the three projects within the private sector were mentioned within the future planned addition of the NEP's *Annexure 5.4*. Also, the March 2025 broad status report provides details of 23.5 GW of coal capacity on hold. These projects are likely to be revised with plans abound to that already in the pipeline. In conclusion, India's coal capacity is to rise continuously with no sign of peak coal capacity in sight.

Table 16: Under-construction coal power plants (sector-wise) (as of March 2025)

Name of the project	State	Agency in-charge	Category	LOA date	Unit	Capacity (in MW)	Total capacity (in MW)
CENTRE SECTOR							
Barh STPP St-I	Bihar	NTPC	Supercritical	Mar-05	U-3*	660	1,980
Buxar TPP	Bihar	SJVN	Supercritical	Jun-19	U-1*	660	
					U-2*	660	
Ghatampur TPP	Uttar Pradesh	NUPPL	Supercritical	Aug-16	U-2*	660	1,320
					U-3*	660	
North Karanpura STPP	Jharkhand	NTPC	Supercritical	Feb-14	U-3*	660	660
Supercritical Total							**3,960**
Patratu STPP	Jharkhand	PVUNL	Ultra-supercritical	Mar-18	U-1*	800	2,400
					U-2	800	
					U-3	800	
Singrauli STPP, St-III	Madhya Pradesh	NTPC	Ultra-supercritical	Mar-24	U-1	800	1,600
					U-2	800	
Talcher TPP St-III	Odisha	NTPC	Ultra-supercritical	Sep-22	U-1	660	1,320
					U-2	660	
NLC Talabira TPP	Odisha	NLC	Ultra-supercritical	Jan-24	U-1	800	2,400
					U-2	800	
					U-3	800	
Khurja SCTPP	Uttar Pradesh	THDC	Ultra-supercritical	Aug-19	U-2*	660	660
Koderma TPS, Ph-II	Jharkhand	DVC	Ultra-supercritical	Nov-24	U-1	800	1,600
					U-2	800	
Lara STPP St-II	Chhattisgarh	NTPC	Ultra-supercritical	Aug-23	U-1	800	1,600
					U-2	800	
Sipat STPP St-III	Chhattisgarh	NTPC	Ultra-supercritical	Sep-24	U-1	800	800
Ultra-supercritical Total							**12,380**
Central sector Total							**16,340**

Name of the project	State	Agency in-charge	Category	LOA date	Unit	Capacity (in MW)	Total capacity (in MW)
STATE SECTOR							
Ennore SCTPP	Tamil Nadu	TANGEDCO	Supercritical	Sep-14	U-1	660	1,320
					U-2	660	
North Chennai TPP St-III	Tamil Nadu	TANGEDCO	Supercritical	Jan-16	U-1*	800	800
Udangudi STPP St-I	Tamil Nadu	TANGEDCO	Supercritical	Dec-17	U-1*	660	1,320
					U-2*	660	
Sagardighi TPP St-III	West Bengal	WBPDCL	Supercritical	Dec-18	U-5*	660	660
Yadadri TPS	Telangana	TSGENCO	Supercritical	Oct-17	U-1*	800	3,200
					U-3*	800	
					U-4*	800	
					U-5*	800	
Super-Critical Total							**7,300**
DCRTPP Extn.	Haryana	HPGCL	Ultra Supercritical	Feb-24	U-3	800	800
Obra-C STPP	Uttar Pradesh	UPRVUNL	Ultra Supercritical	Dec-16	U-2*	660	660
Ultra-supercritical total							**1,460**
State sector total							**8,760**
PRIVATE SECTOR							
Mahan STPP*	Madhya Pradesh	Mahan Energen Ltd	Ultra-supercritical	Aug-23	U-1	800	1,600
					U-2	800	
Raipur Ext TPP Ph-II*	Chhattisgarh	Adani Power	Ultra-supercritical	Jun-24	U-1	800	1,600
					U-2	800	
Raigarh USCTPP, St-II*	Chhattisgarh	Adani Power	Ultra-supercritical	Oct-24	U-1	800	1,600
					U-2	800	
Private sector total							**4,800**
Grand total							**29,900**

: *Units slated to be commissioned in 2025

: *Plants not mentioned in the National Electricity Plan, 2022–23

Source: CEA's Broad Status Report of Under-Construction Thermal Power Plants, March 2025

Table 17: List of candidate thermal plants for likely benefits in 2022–32

S. no.	Name of project	State	Sector	Total capacity (MW)
1	NLC Talabira STPS*	Odisha	Central	3 x 800 = 2,400
2	Lara STPP-II*	Chhattisgarh	Central	2 x 800 = 1,600
3	Sipat-III*	Chhattisgarh	Central	800
4	Darlipali-II	Odisha	Central	800
5	TPS-II second expansion	Tamil Nadu	Central	2 x 660 = 1,320
6	Singrauli STPP-III*	Uttar Pradesh	Central	2 x 800 = 1,600
7	Raghunathpur TPS, PH-II	West Bengal	Central	2 x 660 = 1,320
8	Durgapur TPS	West Bengal	Central	800
9	Koderma TPS*	Jharkhand	Central	2 x 800 = 1,600
10	Meja-II	Uttar Pradesh	Central	2 x 660 = 1,320
11	Buxar	Bihar	Central	1 x 660 = 660
12	Supercritical PP, Korba West	Chhattisgarh	State	2 x 660 = 1,320
13	Chandrapura	Maharashtra	State	1 x 660 = 660
14	Amarkantak TPS	Mp	State	1 x 660 = 660
15	Koradi (replacement)	Maharashtra	State	2 x 660 = 1320
16	Ukai TPC, TAPI U#7	Gujarat	State	1 x 800 = 800
17	Singrani U#3	Telangana	State	1 x 800=800
18	Yamuna Nagar TPP U#3*	Haryana	State	1 x 800 = 800
TOTAL				**20,580 MW**

: *LOA Issue and plants now under-construction

Source: Annexure 5.4, National Electricity Plan, 2022–23

Table 18: New additions, March 2023–25 (coal power plants commissioned post NEP, 2023)

Name of project	Sector	Location	Category	No. of units	Capacity (in Mw)	Total capacity (in Mw)
Ghatampur TPP/ NLC JV U-1, 2, 3	Central	Uttar Pradesh	Supercritical	1	660	660
North Karanpura TPP/ NTPC U 1,* 2, 3	Central	Jharkhand	Supercritical	2	660	1,320
Sri Damodaram TPS ST-II	State	Andhra Pradesh	Supercritical	1	800	800
Dr. Narla Tata Rao TPS ST-V	State	Andhra Pradesh	Supercritical	1	800	800
Jawaharpur STPP/ UPRVUNL Unit 1, 2	State	Uttar Pradesh	Supercritical	2	660	1,320
Yadadri TPS Unit 1–5	State	Telangana	Supercritical	1	800	800
Panki TPS Extn.	State	Uttar Pradesh	Supercritical	1	660	660
Bhusawal STPP Unit 1	State	Maharashtra	Supercritical	1	660	660
Total				**10**		**7,020**
Khurja SCTPP Unit 1, 2	Central	Uttar Pradesh	Ultra-supercritical	1	660	660
TelanganA PH-I/NTPC U-1,2	Central	Telangana	Ultra-supercritical	2	800	1,600
Obra-C STPP/UPRVUNL Unit 1, 2	State	Uttar Pradesh	Ultra-supercritical	1	660	660
Total				**4**		**2,920**
Grand total				**14**		**9,940**

Source: CSE analysis of CEA Thermal Broad Status Report from 2023 to 2025

4.3 Future targets on emission intensity and renewable additions of top 15 companies

As thermal power companies in India are making efforts to decarbonize the power sector, one major part of the effort is to reduce the emission intensity/overall emissions of their existing thermal power fleet. The second major part would be to reduce their dependence on coal-based power by increasing their clean/renewable energy portfolio. Keeping these two goals in mind, different power companies have declared targets related to emission reduction, power plant decarbonization and addition of future renewable capacity, which has been collated by CSE from their latest annual reports and websites (see *Table 19: India's top 15 companies—*

Table 19: India's top 15 companies—Projected RE additions and emission intensity goals

Company	Emission-related targets or achievements	Renewable additions for future
NTPC Details from annual report 2022–23[56]	The shift to supercritical and ultra-supercritical technology led to an 8 per cent reduction in emission intensity, an 8 per cent increase in efficiency, and a fuel-saving of approximately 2 per cent per unit of power	Target: 60 GW of renewable capacity by 2032 4.2 GW of nuclear addition under process Decommissioned 1,385 MW of thermal power units as per their annual report 2022–23
MAHAGENCO Details from annual report 2020–21[57]		Solar projects of 2,795 MW are in various stages of implementation as per their annual report 2020–2159
Adani Power Ltd Details from annual report 2022–23[58]	Target of 20 per cent liquid ammonia co-firing. Future targets include higher co-firing percentages reaching up to 100 per cent mono-firing at the Adani Power Mundra Coal Fired Power Plant as per their annual report of 2022–23.	Adani Green, a subsidiary of Adani group of industries, has set the target to achieve 45 GW of renewable energy capacity by 2030, as reported in AGEL's annual report 2022–23.
RVUNL Details from annual report 2020-21[59]		RVUNL has planned to develop a 2,000-MW solar park under the Ministry of New and Renewable Energy (MNRE) scheme Ultra Mega Renewable Energy Power Parks (UMREPP) mode-8 to avail CFA (Central financial assistance) and instal an 810-MW Solar Power Project as reported in their annual report 2020–21.
Tata Power Details taken from annual report 2022–23[60]	Phase out all coal-based capacity before 2045, with the closure of contractual obligations and useful life	Total RE capacity of 6,571 MW, including 2,654 MW projects under various stages of implementation as reported in their annual report 2022–23.
DVC Details taken from annual report 2022–23[61]	Ongoing R&D: Development of biomass pellets Integration of micro-steam turbine system in the existing vapour absorption refrigeration system (VAM) for harnessing waste energy into electrical energy at KTPS, DVC	DVC is working to tap Solar PV and Pumped Storage Hydro potential in its command area with a target to add more than 5.5GW Renewable Energy capacity by FY32.
UPRVUNL	-	-
KPCL	-	-

Company	Emission-related targets or achievements	Renewable additions for future
GSECL[62]		2,500 MW of solar projects on government wasteland near GETCO S/S are under construction/ implementation. Implementing 3,325-MW ultra mega RE park at Khavda
TNEB	-	-
WBPDC[63]		57.5 MW of solar capacity is under construction/implementation
TSGENCO	-	-
Reliance Power	-	-
APGENCO	-	-
NLC[64]		RE capacity to reach 6031 MW by 2030

Source: CSE analysis of latest annual reports and company websites

Projected RE additions and emission). Table 19 also documents specific achievements made by these companies with respect to these topics.

Among the list of top 15 thermal power-generating companies, CSE was unable to find any individual targets of emission reduction for thermal power plants as well as no RE-related targets for six companies. Only eight companies out of 15 had RE-related targets or initiatives/achievements and none of the 15 companies have set any emission reduction or emission intensity target. Only Tata Power has declared a deadline to phase out its coal-based capacity by 2045. This doesn't portray a very strong intent from the side of individual power companies towards decarbonization or moving away from coal power. It certainly highlights the uncertainty amongst power companies as to how the power sector would pan out in the coming times especially keeping in mind the growing energy demand in the country and questions on reliability on RE.

5

PATHWAYS FOR REDUCTION OF CARBON EMISSION

CSE OUTLINED POLICY MEASURES SUCH AS EFFICIENCY IMPROVEMENTS, R&M, RENEWABLE ENERGY INTEGRATION, BIOMASS COFIRING AND CCUS AS DECARBONIZATION PATHWAYS TO REDUCE CARBON EMISSIONS FROM TPPs.

CSE ANALYSIS SHOWS THAT CONSIDERING AGE AS THE SOLE CRITERION FOR RETIREMENT AND R&M OF THERMAL UNITS NEEDS RECONSIDERATION, AS SOME OLDER UNITS ARE AMONG THE TOP PERFORMERS, WHILE MANY YOUNGER UNITS PERFORM POORLY.

CSE ANALYSIS SHOWED THAT EFFICIENCY IS NOT ALWAYS INVERSELY IMPACTED BY USAGE OF DOMESTIC COAL. IN 2022–23, 12 SUBCRITICAL UNITS USING LOW-GCV COAL STILL MET THE INDUSTRY'S 35 PER CENT EFFICIENCY BENCHMARK.

STATE-OWNED COAL POWER UNITS HAVE THE HIGHEST AVERAGE EMISSION FACTOR, AT 1.06 TONNES/MWH, COMPARED TO 1.0 TONNE/MWH FOR CENTRE-OWNED PLANTS AND 0.84 TONNE/MWH FOR PRIVATELY OWNED PLANTS.

In this chapter, we will delve into various strategies aimed at reducing carbon emissions within the thermal power sector. Among these strategies are:

- Efficiency improvement (Renovation & Modernization [R&M])
- Renewable energy obligations (including biomass co-firing) and integration (through flexibilization)
- Carbon capture utilization and storage (CCUS)

As the demand for energy in India rises and as financing for building new coal-based power plants becomes challenging, improving our existing plant fleet by making plants efficient and low on emissions becomes extremely important. Therefore, first and foremost it is crucial to evaluate the impact of efficiency enhancement on emission reduction in coal- and lignite-based thermal power plants. While it is obvious that boosting efficiency leads to emission reduction, the extent of this reduction and the achievable targets through efficiency improvements require a detailed analysis, which is discussed further. Other pathways for decarbonization are analysed in detail in the chapter.

5.1 Efficiency improvement

5.1.1 Analysis of role of efficiency on emissions

Efficiency is the measure of how much of the thermal energy has been converted into electrical energy. The higher the efficiency of a power plant, the lower is its coal usage, emissions per unit and coal consumption. Therefore, efficiency analysis is imperative. As mentioned previously, the CEA database for the year 2022–23 includes data for a total of 603 units of which 41 units had no net generation and eight units had not reported their fuel consumption data, leaving 554 units for analysis. Of these 554 units, 418 had their plant load factor (PLF) values greater than 50 per cent. Efficiency analysis of these 418 units has been done. Efficiency is calculated using the following formula:

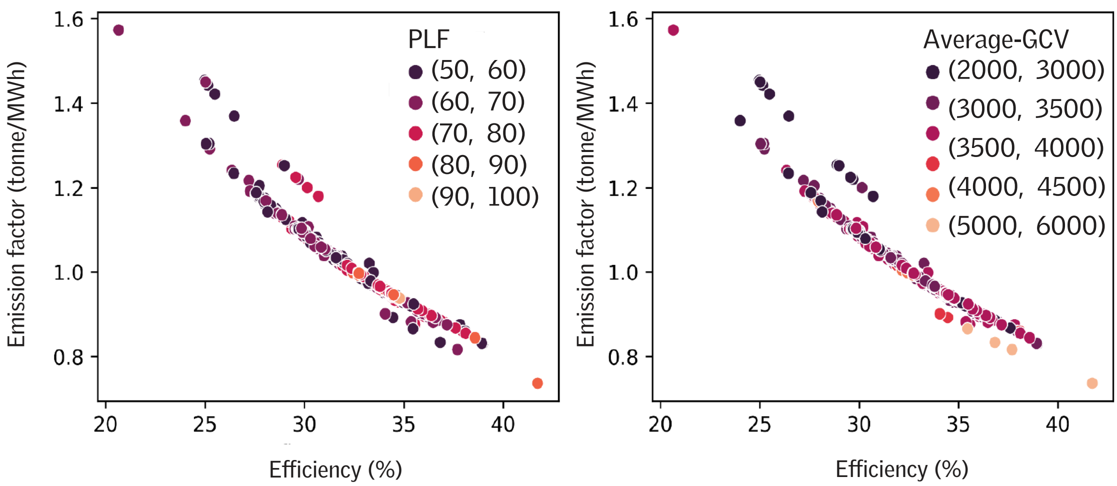
$$Efficiency = \frac{Net\ electricity\ generated\ (GWh) * 859.845}{GCV\ (kcal/kg) * Amount\ of\ fuel\ used\ (kg)} * 100$$

In the above formula, the constant 859.845 is a conversion factor for converting kWh to kcal. Efficiency is calculated using the net generation data of power generating units. Firstly, the role of PLF and GCV on efficiency and emission factors is analysed.

5.1.2 Correlation between plant load factor (PLF), efficiency and emission factor

As per the analysis of CEA data on thermal power plants, efficiency and emission factor are linearly correlated to each other as expected. Interestingly, PLF, above a certain level, shows varied influence on emission factor and efficiency. There are eight units with PLF greater than 70 per cent with lower efficiency (less than 30 per cent) and higher emission factor (greater than 1.2 tonne/MWh). The average GCV of these units is less than 4,000 kcal/kg (see *Figure 2: Correlation of efficiency and emission factor considering PLF [r50 per cent] and average GCV ranges*). Similarly, there are 11 units with PLF in the range of 50–60 per cent with efficiencies greater than 35 per cent and emission factor less than 0.93 tonne/MWh, the average GCV of these units is greater than 4,000 kcal/kg. This clearly shows that a higher PLF is not always a determinant of higher efficiency and lower emissions. In fact the trends in the data analysis are such that it makes it difficult to establish a very direct and strong correlation between the two. This clearly indicates that there are several other operational aspects that influence the efficiency of a thermal power plant.

Figure 2: Correlation of efficiency and emission factor considering PLF (≥50%) and average GCV ranges



Source: CSE analysis on CEA CO_2 baseline database, Version 19

5.1.3 Correlation between GCV, efficiency and emission factor

All the units reported utilize either national coal, imported coal or a combination of both.

Figure 3: Formula for average GCV

$$Average\ GCV = \frac{GCV_{national} * Consumption_{national} + GCV_{imported} * Consumption_{imported}}{Consumption_{national} + Consumption_{imported}}$$

Therefore, average GCV (kcal/kg) per unit has been calculated as the weighted average as follows:

Similar to PLF, the role of GCV of the fuel used by the units also seem to have a varied influence on the efficiency and the emission factors of the units. There is, however, a slight trend of units using higher GCV coals with better efficiencies or lower emission factors and vice-versa (see *Figure 2*). Therefore, for further analysis, minimum and maximum values of efficiencies and emission factors technology-wise in all the average GCV ranges are presented (see *Table 20: Emission factor and efficiency by technology across GCV bands*). *Table 20* also separates units using coal and lignite as fuels for better comparison.

Table 20: Emission factor and efficiency by technology across GCV bands

Fuel	Technology	Average GCV	Emission factor (tonne/MWh)				Efficiency (per cent)		
			count	minimum	maximum	different	minimum	maximum	different
Coal	Subcritical	(2,000, 3,000)	24	0.92	1.36	0.44	24.01	35.34	11.33
		(3,000, 3,5000	138	0.92	1.3	0.38	25.05	35.59	10.54
		(3,500, 4,000)	136	0.91	1.57	0.66	20.66	35.77	15.11
		(4,000, 4,500)	20	0.89	1.18	0.29	27.7	35.15	7.45
		(4,500, 5,000)	4	0.99	1.17	0.18	27.96	32.73	4.77
		(5,000, 6,000)	3	0.74	0.87	0.13	35.46	41.73	6.27
		Subtotal	325						
	Supercritical	(3,000, 3,500)	12	0.86	0.96	0.1	34.07	37.96	3.89
		(3,500, 4,000)	41	0.84	1.19	0.35	27.26	38.58	11.32
		(4,000, 4,500)	5	0.91	0.91	0	35.78	35.99	0.21
		Subtotal	58						
	Ultra-supercritical	(2,000, 3,000)	4	0.86	0.88	0.02	36.86	37.85	0.99
		(3,000, 3,500)	2	0.83	0.83	0	38.92	38.97	0.05
		(3,500, 4,000)	3	0.89	0.92	0.03	35.49	36.52	1.03
		(4,000, 4,500)	1	0.86	0.86	0	38.1	38.1	0
		(5,000, 6,000)	1	0.83	0.83	0	36.83	36.83	0
		Subtotal	11						
Lignite	Subcritical	(2,000, 3,000)	16	1.14	1.45	0.31	24.97	30.73	5.76
		(3,000, 3,500)	8	1.2	1.2	0	30.14	30.16	0.02
		Subtotal	24						

Source: CSE analysis on CEA CO_2 baseline database, Version 19

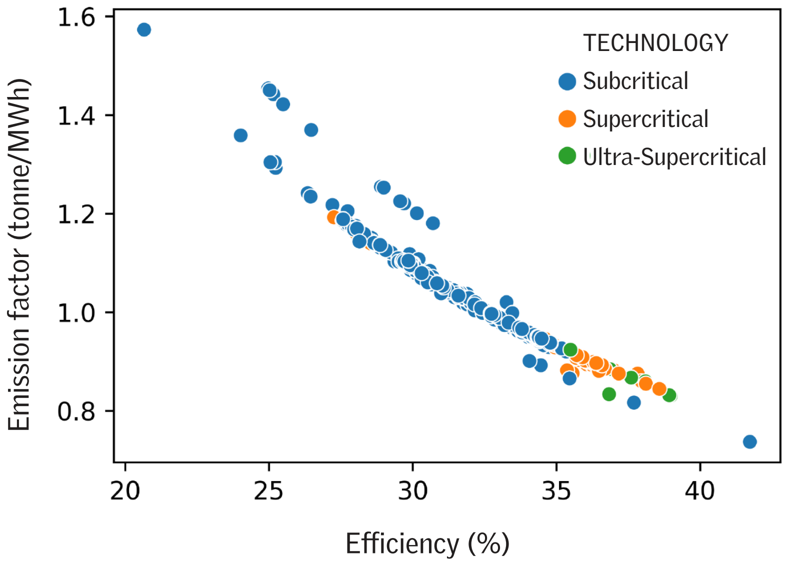
Apart from the established fact that using higher GCV coal results in higher efficiency and lower emission factors, *Table 20* also highlights that there are units in all the GCV ranges that have higher efficiencies and lower emission factors. Further, there are units that use coal with GCV in the range of 4,500–5,000 kcal/kg and even then have an emission factor of 1.17 tonne/MWh with a lower efficiency of 27.96 per cent. Similarly, as can be seen from *Figure 2* and *Table 20*, there are a large number of units that use coal with GCV in the range of 3,000–4,000 kcal/kg that have higher efficiencies and lower emission factors compared to units using coal with GCV of 5,000 kcal/kg. Therefore, the argument suggesting that Indian coal with lower GCV values always results in higher emissions is unsubstantiated. It is evident that the emission factor correlates linearly with efficiency, but units with a higher PLF and higher fuel GCV may not necessarily be having high efficiency and low emissions, leaving a substantial scope of improvement through efficiency measures in the plant.

Additionally, *Table 20* also provides a value **different** for both emission factor and efficiency, which is the difference between **maximum** and **minimum** values in each section, respectively. For units using higher GCV coals, the difference between maximum and minimum emission factors and efficiencies is low. However, for units using lower GCV coals, the difference is higher. The comparison here is happening between units with characteristics that are operating on similar fuel type, technology, and operating conditions (PLF >=50 per cent), the only variable influencing emissions is efficiency. Therefore, it is clear that improving efficiency would reduce the gap between maximum and minimum emission factors. If all units were to operate at the lowest emission factor within their category (discussed in detail in the next chapter), the resulting reduction in emissions would be significant. Hence, enhancing efficiency in the units is a crucial priority.

5.1.4 Role of technology on efficiency

Is the enhancement of efficiency directly correlated with technological advancement? Analysing the data reveals intriguing insights. The average efficiency of units with a PLF greater than 50 per cent stands at 32.5 per cent. Subcritical units exhibit an average efficiency of 31.87 per cent. Supercritical and ultra-supercritical units boast an average efficiency of 35.7 per cent. Looking at Figure 16, it is clear at the first glance that subcritical units drag down the overall efficiency. Supercritical and ultra-supercritical units consistently outperform in comparison to subcritical units, indicating a substantial influence of technological advancements on efficiency metrics. The Ministry of Heavy Industries sets efficiency benchmarks at 35 per cent for subcritical, 40 per cent for supercritical, and 42 per cent for ultra-supercritical units. However, the most efficient unit, achieving a remarkable

Figure 4: Correlation between efficiency and emission factor by unit technology



Source: CSE analysis based on CEA CO_2 baseline database, Version 19

41.73 per cent efficiency, belongs to the subcritical category and there are a few others like that, but many of these units are using coal of high GCV (see *Figure 4: Correlation between efficiency and emission factor by unit technology*).

Among the 418 units analysed, 16 out of 349 subcritical units exhibit efficiency greater than 35 per cent (which is considered a good rate) (see *Table 21: Efficiency leaders among subcritical units*).

Similarly, among 418 units analysed, 13 out of the 58 supercritical units have efficiency less than 35 per cent (see *Table 22: Low efficiency supercritical units*). Interestingly, 10 out of 16 high-efficiency units of the subcritical category belong to the private sector and 10 out of 13 low-efficiency units of the supercritical category belong to the state or Central sectors. The emission factor of all the high-performing subcritical units presented in *Table 21* is less than or equal to 0.93 tonne/MWh and the average age of these units is 15.08 years. Further, apart from the three JSW energy units, all other subcritical units utilize coal with an average GCV in the range of 3,000–4,000 kcal/kg. This analysis underscores a crucial point: existing subcritical units with high emission factors, running on coal within the average GCV range, can substantially reduce emissions simply by enhancing their efficiency. Given that the majority of India's thermal power plants fall under

Table 21: Efficiency leaders among subcritical thermal power units

S. no	Name	Unit no.	Capacity	Sector	System	Emission factor (tonne/ MWh)	Age (years)	PLF (per cent)	Efficiency (per cent)	Average GCV (kcal/kg)
High efficient subcritical units										
1.	Anapara 'C'	1	600	Private	Lanco Anapara Power	0.93	12.48	77.64	35.03	3661
2	Anapara 'C'	2	600	Private	Lanco Anapara Power	0.93	12.49	68.91	35.03	3,661
3	Anpara	6	500	State	UPRVUNL	0.93	8.93	89.26	35.17	3,590
4	Anpara	7	500	State	UPRVUNL	0.93	8.18	87.7	35.15	3,590
5	Budge Budge	1	250	Private	CESC	0.93	26.65	69.59	35.27	3,761
6	Budge Budge	2	250	Private	CESC	0.93	25.18	73.17	35.27	3,761
7	Haldia	2	300	Private	Haldia Energy Ltd	0.92	9.23	74.01	35.59	3,185
8	K_Gudem New	4	500	State	TSGENCO	0.91	12.87	78.82	35.77	3,774
9	Korba Stps	7	500	Centre	NTPC	0.92	13.37	78.88	35.42	3,374
10	R_Gundem Stps	7	500	Centre	NTPC	0.93	19.62	64.44	35.08	3,494.44
11	Singareni Tpp	1	600	State	Singareni Collieries	0.93	8.16	86.64	35.15	4,002
12	Tamnar Tpp	1	600	Private	OP Jindal	0.92	10.17	59.15	35.34	2,993.27
13	Tamnar Tpp	4	600	Private	OP Jindal	0.93	9.12	62.88	35.18	2,935.54
14	Torangallu Ext	1	300	Private	JSW Energy Ltd	0.87	15.03	53.99	35.46	5,344.09
15	Torangallu IMP	1	130	Private	JSW Energy	0.74	24.98	84.4	41.73	5,251.31
16	Torangallu IMP	2	130	Private	JSW Energy	0.82	24.98	64.18	37.69	5,516.69

Source: CEA baseline database, Version 19

the subcritical category, it is imperative to prioritize efficiency improvements. While future installation plans lean towards supercritical or ultra-supercritical plants, and that is a strict necessity, enhancing the efficiency of existing subcritical units remains essential. Similarly, while retiring aged and inefficient units is necessary, improving efficiency stands as a paramount objective.

5.1.5 Technologies for efficiency improvement

The efficiency of a thermal power plant can be improved by improving certain factors and introducing certain updated technologies in the operation of a power plant. A large number of power plants in India have still not adopted these improvisations and technologies which can bring a substantial improvement in their efficiency.[65]

Table 22: Lowest efficiency among supercritical thermal units

S. no.	Name	Unit no.	Capacity	Sector	System	Emission factor (tonne/ MWh)	Age (years)	PLF (per cent)	Efficiency (per cent)	Average GCV
Low efficient supercritical units										
1	Barh STPP I	1	660	Centre	NPGCL	0.96	2.52	65.62	33.96	3,534.1
2	Chhabra TPS	5	660	State	RRVUNL	1.02	7.1	59.24	31.75	3,983.19
3	Chhabra TPS	6	660	State	RRVUNL	1.04	5.11	58.82	31.32	3,975.87
4	Koradi EXTN.	8	660	State	MAHAGENCO	1.14	9.11	62.02	28.53	3,824.85
5	Koradi EXTN.	9	660	State	MAHAGENCO	1.16	8.15	54.14	28	3,823.01
6	Koradi EXTN.	10	660	State	MAHAGENCO	1.19	7.36	61.44	27.26	3,836.9
7	Meja STPP	1	660	Centre	JV NTPC and UPRVUNL	0.95	6.11	69.62	34.28	3,661.21
8	Meja STPP	2	660	Centre	JV NTPC and UPRVUNL	0.95	3.32	50.33	34.28	3,661.21
9	Raikheda	2	685	Private	Raipur Energen Limited	0.93	8.12	57.61	34.96	3,011.68
10	Shri Singaji Malwa TPP	4	660	State	MPPGCL	0.95	5.12	56.56	34.61	3,391
11	Suratgarh	8	660	State	RRVUNL	0.97	2.59	50.12	33.77	3,703.87
12	Talwandi Sabo	1	660	Private	Talwandi Sabo Power	0.93	9.89	64.67	34.9	3,260.01
13	Talwandi Sabo	3	660	Private	Talwandi Sabo Power	0.96	8.11	60.92	34.07	3,270.65

Source: CEA baseline database, Version 19

- **Fuel quality (coal washing)**

Coal inherently contains non-combustible ash. When burned, this ash remains as residue and contributes to particulate matter pollution, alongside other GHG emissions. To reduce ash content and improve coal quality, coal washing is recommended. Coal washing has several advantages, including increased power plant efficiency, reduced particulate emissions and lower coal consumption per MWh of electricity produced.[66] There are, however, disadvantages also; washing decreases the coal's volatile matter, increases its moisture content, and the water used in the washing process contains effluents that require treatment before disposal, leading to additional environmental and economic concerns. In the current scenario, therefore, not many plants are seen adopting the practice of coal washing.

- **Optimization of combustion**

Combustion optimization, which includes focusing on mill performance, reducing excess oxygen in the furnace, and adjusting the air/fuel ratio and air flows—can improve plant efficiency by 1–2 percentage points. This optimization is typically achieved through advanced system controls and extensive use of sensors for enhanced data collection.[67]

- **Turbine retrofitting**

The turbine is a crucial component of the steam cycle, responsible for initiating the conversion of mechanical energy to electrical energy. Due to its continuous operation at elevated temperatures and pressures, it is prone to deterioration. Replacing damaged seals, rotors, blades, inlet valves, and the inner high-pressure intermediate-pressure turbine casing can significantly enhance the unit's efficiency. Such retrofits can increase efficiency by up to 4–5 per cent.[68]

- **Variable frequency drive (VFD)**

As previously mentioned, a portion of the energy generated by a unit is consumed by the unit itself for its operations, known as auxiliary power. Variable frequency drive technology helps manage this by controlling the operation of feed-water pumps and induced draught fans, adjusting their voltage and frequency as needed, thereby, reducing the auxiliary power consumption and increasing the efficiency of the unit/plant.

- **Digitalization (integration of AI)**

A range of digital technologies, such as big data, analytics, artificial intelligence, digital twins and advanced monitoring and control systems, have been developed and applied to power plants. These tools facilitate the automated collection, analysis, and optimization of power plant operations. They allow operators to visualize and simulate the functioning of individual equipment, processes, and the entire plant, making it easier to monitor performance and address operation and maintenance (O&M) needs. AI and machine learning-based advanced analytics can predict or identify potential issues and suggest appropriate actions, providing real-time responses to prevent or resolve problems. Overall, digitalizing power plants can enhance efficiency by up to 2–3 percentage points and reduce emissions of air pollutants and CO_2.[69]

5.2 Renovation and modernization (R&M) and retirement

In the previous section, the efficiency analysis was based solely on PLF, average GCV and the technology used, without considering the age of the units. Among the 418 units with a PLF of 50 per cent or higher, 125 units are 25 years or older, while 293 units are less than 25 years old. In the National Electricity Plan (NEP), CEA has notified that to reduce carbon emissions from the thermal power sector, efficiency improvement measures through Renovation and Modernization (R&M) of old and inefficient units is undertaken and units in which R&M is not possible are being considered for retirement. In July 2023, CEA released a list of 233 units to be considered for R&M.[70]

The selection criteria set by CEA for selection a power-generating unit are as follows:

- Unit installed capacity equal to or more than 150 MW with reheat cycle to be considered for R&M. Further, environmental-friendly technologies for smaller size capacity can also be explored.
- For R&M, units after eight to10 years of operation and with gross heat rate deviations more than 15–20 per cent from the design gross heat rate, even after regular annual overhauling, should be considered for R&M of turbine, boiler and all critical associated equipment.
- For life extension, units that have completed 20 years shall be selected for assessment.
- Ash dyke sustenance and feasibility of modification/improvement of in-plant facilities for better ash utilization to be ascertained. As a prerequisite, an ash management plan should be ensured before taking up R&M/LE works.
- Feasibility of compliance of prevailing environmental norms (considering space constraint) may be ascertained.
- The cost of R&M/LE&U works shall not exceed 50 per cent of the EPC cost of a new generating unit of indigenous origin (BHEL). If the R&M/LE&U works are limited to BTG, the cost ceiling shall be restricted to 50 per cent of the new BTG unit only. A detailed study, however, should be carried out to ensure its techno-economic viability. The payback period may be limited to seven to eight years.

In addition to this, CEA's Thermal Projects R&M Division produces quarterly review reports on the work status of R&M projects across central and state thermal units.[71] As per the latest quarterly report of CEA on the matter of R&M, the plan covers 7,360 MW of cumulative capacity, i.e. 10 per cent of the 2022 announced plan or 0.3 per cent of the total thermal capacity of India. The quarterly review plan for R&M does not include major thermal units, i.e. units with capacity above 500 MW. Costs of R&M work on thermal plants are capped to 50 per cent of the price of a new unit, this cost of R&M has to be born by the utility owner and not by the DISCOMs.

R&M AND ENERGY COSTS

Overview

Energy costs from individual power plants are locked in via their respective PPAs with the co-party DISCOMs, with visibility via the NITI Aayog's India Energy and Climate dashboard. However, as discussed earlier, the PUShP portal allows for upward revision of these prices by necessary amendments within the PPAs. Any capital investment undertaken by the utility owner will form part of the fixed charges that are charged.

As R&M work are part of the 'development' obligation and are to be borne by the plant owner, cost recovery will be shifted down towards the supply chain, i.e. end users. The current state of Indian electricity policy is dominated by state-owned DISCOMs. The majority of Indian electricity consumption is by agriculture and household users. DISCOMs in India suffer from huge losses, especially owing to their T&D losses and their inability to recover cost of energy from the consumers. The Indian model subsidizes prices for its consumers, i.e. household and agriculture entities, and charge higher from industrial clusters. DISCOMs may pay for higher unit price of electricity as utility owners will attempt to recover their capital costs, but the same may not be passed onto end users. This may not, however, be an issue where thermal units undergoing R&M are state-owned and the supplier DISCOM is also state-owned as the R&M cost will come from the taxpayers' pool already. The challenge will come in where a private party is involved.

Regionally dependent power users may suffer during the downtime of thermal units undergoing R&M unless the supply shortage is mitigated via alternative sources. Indian users currently face shortage of electricity supply and sub-par quality of supply. Yet, electricity prices in India as amongst the highest in comparison to its Asian counterparts.[72] Noteworthily, in relation to the world average, India's energy prices is amongst the highest when weighed on basis of Purchasing Power Parity (PPP).[73] Since COVID19 Pandemic, the average electricity prices have doubled.[74] This is partly due to the spread of cost for electricity produced.

R&M work will assist in better energy efficiency for the citizens, thus investment in the same is beneficial for all and a legal mandate of the State. The issue of pricing becomes relevant where either the power plant or the DISCOM is a private entity. Costs of R&M works on thermal plants are capped to 50 per cent of the price of a new unit, thus making it a cost-feasible and sustainable solution to India's energy demands.[75] Until now, such works have not taken place on larger thermal units, i.e. units >250 MW.[76] During this time period, the production of RE has risen while reducing the per unit cost of RE vis-à-a – vis its fossil energy counterpart.

Analysis

The R&M for thermal plants has positive externalities and therefore the onus is on the state to rationally divide its positives. Under these externalities, efficiency of energy supplied and the progressive optimization of the plant's running cost to balance out the costs of R&M. Furthermore, the opportunity cost provided via saving on expenditure of new units should be accounted for. Additionally, the structural issues of energy costs in India are unlikely to be compounded further by R&M efforts of thermal plants. DISCOMs and plant owners are needed to first quantify their costs before passing on any new burden of the same on the end consumers. As things stand, R&M will scantly affect end consumers in terms of pricing.

Table 23: List of coal-based units for likely retirement during 2022–32
(Colour coded: yellow: No electricity generated in 2022–23; green: PLF above 50 per cent in 2022–23)

S. no.	Name of the project	No. of units	State	Sector	Organization	Total capacity (MW)
1	Tanda TPS U 1–4	4	Uttar Pradesh	Centre	NTPC	4*110 = 440
2	Bandel U 2	1	West Bengal	State	WBPDC	1*60 = 60
3	Kota TPS Units 1, 2	2	Rajasthan	State	RRVUNL	2*110 = 220
4	Harduaganj TPS Unit 7	1	Uttar Pradesh	State	UPRVUNL	110
5	GEPL TPP PH-I Units 1, 2	2	Maharashtra	Private	GEPL	2*60 = 120
6	Salora TPP U1	1	Chattisgarh	Private	VVL	135
7	Titagarh TPS Units 1–4	4	West Bengal	Private	CESC	4*60 = 240
	Total no. of units	15	Total capacity			1,325

Source: CEA National Electricity Plan, 2022–23

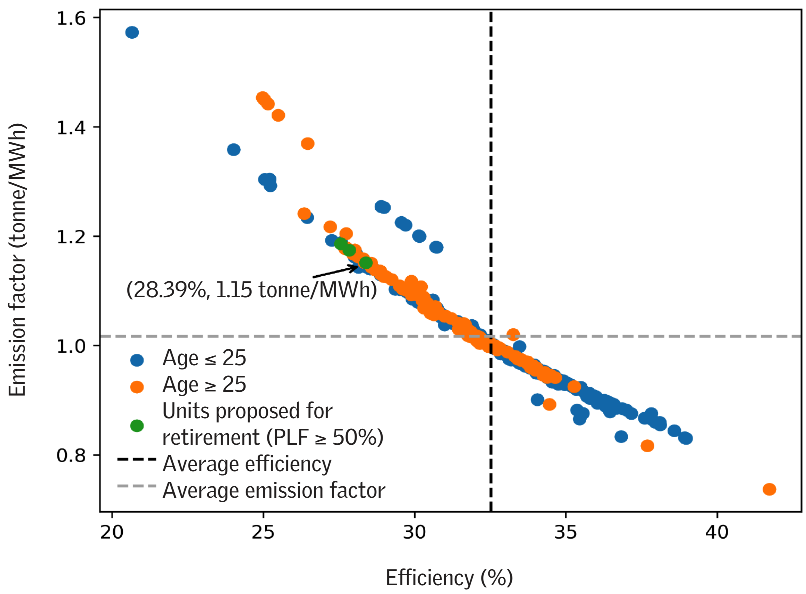
As of January 31, 2024, CEA reported on its website that a total capacity of 17.2 GW of coal/lignite power plant units have been retired. In the NEP, CEA has identified 22 units with a capacity of 2121.5 MW for retirement, of which seven units, totalling 796.5 MW, have already been retired. Fifteen units remain (see *Table 23: List of coal based units for likely retirement during 2022–32*).

In the list of units for retirement, seven did not generate any electricity in 2022–23. Of the remaining eight units that generated electricity, five had a PLF of less than 50 per cent, and three had a PLF above 50 per cent. In total, these 15 units contributed only 0.37 per cent of the total emissions from the coal and lignite-based thermal power sector. Therefore, even if these are retired, it may not bring any substantial reduction in the emissions of the sector.

In *Figure 5*, the efficiency and emission factors of all units with a PLF >= 50 per cent are plotted, with units over 25 years old highlighted in orange, and the three aforementioned units highlighted in green. Among these three units, Bandel plant, Unit 2 of West Bengal, operated by WBPDC, had the highest efficiency (28.39 per cent) and lowest emission factor (1.15 tonne/MWh) (annotated in *Figure 5*).

Using this unit as the benchmark, we have filtered the rest of the units based on the criteria: PLF r 50 per cent, age > 25 years, efficiency R 28.39 per cent, and emission factor r 1.15 tonne/MWh from the 418 units (units with PLF >= 50 per cent). A total of 18 units meet these criteria. Details of these units are presented in Table 25, categorized and sorted by PLF per cent. As mentioned previously, CEA has recommended old and inefficient units for Renovation & Modernization (R&M) operations. As shown in Table 24, of the 18 units, 15 are listed for R&M,

Figure 5: Correlation of efficiency and emissions by age and retirement proposal (PLF ≥50%)



Note: All units in the plot have PLF >= 50 per cent)

and the remaining three are neither being retired nor considered for R&M. Of the three units not selected for either retirement or R&M, one has a capacity below 150 MW, and the remaining two probably lack a reheat cycle or adequate space. However, if these units do not meet the criteria for R&M, they could have also been considered for retirement.

Similar to the previous list, we have filtered units based on the criteria: PLF ≥ 50 per cent, age ≤ 25 years, efficiency ≤ 28.39 per cent, and emission factor ≥ 1.15 tonne/MWh, identifying units younger than 25 years that perform poorly compared to Bandel, Unit 2 (best-performing retiring unit). There are 11 such units as listed in *Table 25*. Only two of the 11 units are included in the R&M list. Two of these units operate primarily on lignite, explaining their higher emission factors. However, the remaining units operate on coal and are relatively young, necessitating improvements in efficiency and emission reductions. Previous sections have established that units operating with an average GCV of 3,000–4,000 kcal/kg achieve efficiencies above 32 per cent and emission factors close to 0.9 tonne/MWh, so GCV is not likely to play a crucial role on efficiency. Additionally, the list includes two supercritical units. The Indian coal fleet is transitioning to supercritical and ultra-supercritical units to reduce emissions. Therefore, it is crucial for these units to maintain higher efficiencies, and any reasons for decreased efficiencies should be addressed immediately.

Table 24: Units aged 25+ years with efficiency and emissions below the best performer in the retirement list

(Colour coded: green: Included in R&M list; red: Not included in R&M list)

Name	Unit no.	Sector	Capacity (MW)	Auxiliary cons. (per cent)	Net generation (GWh)	Emission factor (tonne/ MWh)	PLF (per cent)	Average GCV (kcal/kg)	Efficiency (per cent)	Age (years)
PLF >= 50 per cent										
Korba-West	4	State	210	9.62	1,268	1.15	68.93	3,640	28.34	38.19
Korba-West	2	State	210	10.51	1,209	1.24	65.72	3,640	26.35	40.14
Koradi	6	State	210	11.55	1,167	1.22	63.44	3,227	27.2	42.14
Neyveli ST III	7	Centre	210	10.69	1,133.48	1.45	61.62	2,556	25.02	30.92
Kolaghat	3	State	210	11.02	1,122	1.16	60.99	3,303	28.14	39.83
Neyveli ST II	4	Centre	210	7.13	1,096.08	1.37	59.58	2,556	26.47	33.15
Sanjay Gandhi	1	State	210	9.93	1,092.99	1.18	59.41	3,723	27.75	31.15
Obra-A	9	State	200	10.89	1,031	1.16	58.85	3,430	28.31	44.32
Neyveli ST II	3	Centre	210	11.78	1,060.74	1.44	57.66	2,556	25.15	38.15
Sanjay Gandhi	2	State	210	9.5	1,049.6	1.17	57.06	3,723	27.89	30.15
Kolaghat	5	State	210	11.06	1,045	1.15	56.81	3,277	28.33	33.18
Neyveli ST II	5	Centre	210	10.66	1,033.03	1.42	56.16	2,556	25.49	32.39
Neyveli ST II	6	Centre	210	12.28	1,023.45	1.45	55.63	2,556	24.97	31.56
North Chennai	2	State	210	9.17	998.17	1.17	54.26	3,111	28.02	29.15
GHTP (Leh. Moh.)	1	State	210	9.04	986	1.18	53.6	4,262.72	27.7	26.39
Neyveli ST II	1	Centre	210	11.66	958.37	1.45	52.1	2,556	25.03	36.34
Southern Repl.	1	Private	67.5	8.54	301.62	1.17	51.01	4,677	27.96	33.77
North Chennai	1	State	210	10.36	920.45	1.2	50.04	3,120.76	27.74	29.57

Source: CSE's analysis based on CEA CO_2 database, Version 19

5.2.1 Shortcomings in R&M policy

The policy report comprehensively addresses major aspects related to renovation and modernization, including guidelines for selecting candidate units, objectives of the operation, viable business models, guidelines for preparing bidding documents, and concludes with a list of 233 candidate units to be considered in the coming years for renovation, modernization and life extension. However, the policy has the following shortcomings, which need to be addressed for it to be effective:

Table 25: Underperforming young units (<25 years) based on efficiency and emission metrics

(Cells in green are units included in R&M list)

Name	Unit no.	Sector	Capacity (MW)	Auxiliary cons. (per cent)	Net Generation (GWh)	Emission factor (tonne/ MWh)	PLF (per cent)	Average GCV (kcal/kg)	Efficiency (per cent)	Age (years)
PLF >= 50 per cent										
Bhusawal	4	State	500	6.32	3,053	1.15	69.7	3,538.86	28.26	12.21
Chakabura TPP	2	Private	30	13.48	168.85	1.36	64.25	2,095.00	24.01	10.15
K_Kheda II	3	State	210	10.62	1,162	1.29	63.17	3,434.18	25.23	23.98
Surat LIG	3	Private	125	13.27	680	1.17	62.1	2,585.10	28.06	14.12
Koradi Extn.	10	State	660	7.55	3,552	1.19	61.44	3,836.90	27.26	7.4
Balco TPP	1	Private	300	8.41	1,590.41	1.57	60.52	3,532.96	20.66	8.97
Surat LIG	2	Private	125	13.86	640	1.19	58.45	2,588.23	27.58	24.55
Ratija TPP	2	Private	50	11.86	245.37	1.23	56.02	2,156.00	26.45	7.53
Niwari TPP	2	Private	45	12.32	218.19	1.3	55.35	3,120.00	25.05	4.97
Koradi Extn	9	State	660	7.94	3,130	1.16	54.14	3,823.01	28	8.19
K_Kheda II	4	State	210	11.3	934	1.3	50.77	3,429.19	25.21	23.38

Source: CSE's analysis based on CEA CO_2 database, Version 19

- **Lack of clear deadlines**: Although the report has segregated units with respect to when they will cross the age of 20 years during 2022–30, no clear deadline has been set for the stakeholders to complete the R&M operations. Setting clear deadlines for each phase of the R&M operations would help ensure timely implementation and accountability.

- **Unaddressed units with age above 25 years**: The policy does not clarify the status of units that are low in efficiency and high on emissions (see *Table 24*: *Units over 25 years old with lower efficiency and emission factors compared to the best-performing unit in the retirement list*) and are neither in the list of retired units in the National Electricity Plan (NEP) nor in the R&M list. It is unclear whether these units will be retired, continue to operate as they are, or remain idle. Providing clear guidelines on the status and future of units not covered in the R&M or retirement lists would eliminate ambiguity and aid in planning.

- **Unaddressed units less than 25 years old:** As mentioned in the previous section, 11 units (below the age of 25 years) perform poorly compared to the best-performing retiring unit (Bandel U2, WBPDC). The policy does not address poorly performing units regardless of their age. Targeting these underperforming units is also essential to ensure overall efficiency and performance improvements.

- **Specific targets for efficiency improvements**: In the minimum objectives, points like increasing boiler efficiency and reducing turbine heat rate were mentioned. However, specific targets for these operational improvements were missing. For example, a percentage reduction target in turbine heat rate could have been provided to ensure units strive to reach an ambitious target in these R&M operations.

5.3 Renewable energy

According to the revised NDC, India is committed to achieving 50 per cent of its cumulative installed electric power capacity from non-fossil fuel-based energy sources by 2030. However, the NEP projects that by 2032, thermal power (coal, lignite, and gas) will account for 51.4 per cent of gross generation; non-fossil fuel sources (hydro, including imports, solar PV, wind and other renewables) will contribute 44.3 per cent; and nuclear power will make up 4.4 per cent of gross generation. Additionally, as previously mentioned, greenhouse gas emissions from the thermal sector are expected to increase to 1,100 million tonnes by 2032. In the NDCs, India declared to reduce its emissions intensity of its GDP by 45 per cent by 2030 from the 2005 level. Therefore, it is imperative to transition to low-carbon non-fossil fuel-based electricity generation. Two of the major policies planned to target the thermal power sector and shifting the drive towards non-fossil fuel-based electricity are 1. Renewable Purchase Obligation (RPO) and 2. Renewable Generation Obligation (RGO).

5.3.1 Renewable Purchase Obligation

In 2021, the Ministry of Power (MoP) issued a notification mandating obligated entities, mainly DISCOMs, in each state to meet the minimum share of electricity purchase from renewable energy sources. On July 22, 2022, the MoP issued the Renewable Purchase Obligation (RPO) and Energy Storage Obligation trajectory till 2029–30. According to this policy, for 2022–23 the RPO percentage was set to be 24.61 per cent and as per the trajectory it is to grow till 43.33 per cent by 2029–30.

In instances where targets are not met, states can utilize the tradable renewable energy certificate (REC) mechanism, which holds comparable equivalence to RE-based power. The RPO trajectory witnessed a periodic increase to nearly 23 per cent in 2023 from 2.75 per cent in 2016. In 2023, the Union Ministry of Power revised the RPO targets to reflect the increasing share of renewable energy in generation, aiming for 39 per cent by 2028. These revisions came into effect from April 1, 2024.[77]

This rising RPO trajectory is increasing the pressure directly on DISCOMS and indirectly on thermal power companies, leaving them with the choice to either invest in cleaner power sources or face shortage in demand over the time, thus endangering the technical and financial viability of their thermal power plants.

5.3.2 Renewable Generation Obligation

On February 27, 2023, the Ministry of Power released a notification titled 'Renewable Generation Obligation as per Revised Tariff Policy, 2016'.[78] The notification emphasizes, 'any power generating company establishing a coal-/lignite-based thermal generating station and having the Commercial Operation Date (COD) of the project on or after 1st April 2023 shall be required to establish renewable energy generating capacity (in MW), i.e. Renewable Generation Obligation (RGO) of a minimum of forty percent (40 per cent) of the capacity (in MW) of a coal-/lignite-based thermal generating station or procure and supply renewable energy equivalent to such capacity.' As per the timeline, the notification states that any coal/lignite thermal-generating station with COD between April 1, 2023 and March 31, 2025 is required to meet the RGO criteria by April 1, 2025 and any coal/lignite station with COD after April 1, 2025 is to meet RGO criteria by COD.

On October 6, 2023, the Ministry of Power published a Draft Notification on Renewable Generation Obligation revising the criteria established in the previous notification.[79] Firstly, in the draft notification the renewable energy source for RGO is distinctively established as hydro, wind, solar including its integration with combined cycle, biomass, biofuel cogeneration, urban or municipal waste and such other sources as recognized or approved by the Central government. The draft notification further establishes the criteria for RGO (see *Table 26: RGO compliance deadline on basis of Commercial Operation Date [COD]).*

Table 26: RGO compliance deadline on basis of Commercial Operation Date (COD)

Commercial Operation Date (COD) of coal-/lignite-based generating station	Minimum RGO (per cent)	Due date for RGO compliance
On or before March 31, 2023	6 per cent	April 1, 2026
	10 per cent	April 1, 2028
April 1, 2023–March 31, 2025	10 per cent	April 1, 2025
April 1, 2025 onwards	10 per cent	From COD of coal-/lignite-based generating station

Source: Ministry of Power notification, 2022

In the draft notification, the methodology for estimating the shortcoming in renewable generation was provided in tonnes of oil equivalent. Accordingly, penalty is levied on stations that do not comply with the above policy, as determined according to the established methodology for estimation. The proposed notification is a draft notification and the date of implementation has not been announced as of now. Since this is a very important step to curb emissions, it would be helpful if the policy is implemented as soon as possible.

As mentioned previously, biomass is included in RGO, i.e. electricity generated using biomass is considered as renewable energy. This is in accordance with international definitions. Therefore, biomass co-firing done in coal-based thermal power plants will be considered as renewable energy. Renewable additions by major companies are as given in Table 27.

Table 27: Renewable energy expansion targets of major companies by 2032

Company	Renewable additions for future
NTPC	Target: 60 GW of renewable capacity by 2032
MAHAGENCO	Solar projects of 2,795 MW are in various stages of implementation
RVUNL	RVUN have planned to develop a 2,000-MW solar park under the UMREPP Mode-8 scheme of MNRE to avail CFA (Central financial assistance) and installation of 810 MW solar power project
Tata Power	Total RE capacity of 6,571 MW, including 2,654 MW projects under various stages of implementation
DVC	DVC is working to tap solar PV and pumped storage hydro potential in its command area with a target to add more than 5.5 GW renewable energy capacity by FY 2032
GSECL	2500 MW of Solar projects on government waste land near GETCO S/S are under construction/implementation. Implementing 3325 MW Ultra mega RE park at Khavda.
WBPDC	57.5 MW of solar capacity is under construction/implementation
NLC	RE capacity to reach 6,031 MW by 2030

Source: CSE analysis based on the annual reports of companies

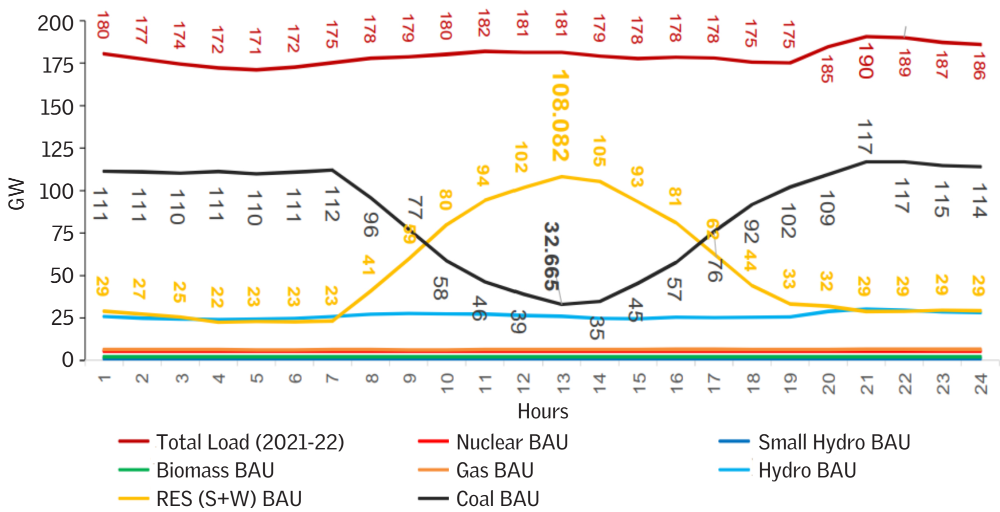
FLEXIBILITY OF THERMAL POWER PLANTS

Background and necessity:
In the nationally determined contributions, India aims to reduce the emission intensity of its GDP by 45 per cent by 2030 from the 2005 level and also it aims to achieve about 50 per cent cumulative electric power installed capacity from non-fossil fuel based energy resources by 2030. However, growth of renewable energy faces three major issues:

- Variability: It varies from moment to moment
- Uncertainty: It cannot be predicted with any certainty in advance
- Concentration: It is concentrated during a limited number of hours of the year

Flexible operation of existing coal-fired power plants is required to ensure security, reliability of power supply and stability of electricity grids while maximizing generation from renewable energy sources (RES) and integration of the same into the grid. Flexible operation of thermal power plants is essential for handling the instability of renewable generation between solar and non-solar hours as previously highlighted via demand analysis during non-solar hours (see *Graph 15: Load analysis: Peak demand met*).

Figure 6: CEA's illustration of demand and generation on a critical day



Source: CEA Report: Flexible Operation of Thermal Power Plants for Integration of Renewable Generation

Current status

CEA Report on flexibalization (2023) recognizes greener options for flexible power supply during demand ramp-up as thermal power remains the key ingredient for India's power supply mix. With higher renewable energy penetration by 2030 (500 GW), and to avoid renewable energy curtailment, thermal units may have to operate below 40 per cent of their minimum technical load. The global industrial best practice is to operate below 25 per cent of their minimum technical load. The day-wise flexibility requirement of the Indian power system demand is increasing at 8–9 GW/annum, and it reached a maximum of 72 GW during winter of 2021–22. Cost of retrofitting units to optimize them for flexibilization is approx. Rs 30–40 crore per thermal unit.[80] On an all India basis, thermal flexibility is on an increasing trend, approaching 30–35 per cent of the total thermal plants during 2021–22. About 40 per cent of India's thermal units are reaching minimum generation levels/ PLF in the range of 60–70 per cent (see *Table 28: Technical challenges in relation to flexibilization*).[81]

Table 28: Technical barriers to to flexibilization of TPPs

Key parameters	Advantage	Disadvantage	Limitations
Start-up time	The shorter the start-up time, the quicker a power plant can reach the minimum load.	Faster start-up times put greater thermal stress on the component.	The thermal gradient for components.
Minimal load	The lower the minimal load, the larger the range of generation output.	At minimum load, the power plant operating at low efficiency.	At low load, it is difficult to ensure a stable combustion.
Ramp rate	A higher ramp rate allows a power plant operator to adjust net output more rapidly	Rapid change in firing temperature results in thermal stress (level at which the material's chemical nature is altered).	Allowable thermal stress and unsymmetrical deformations, storage behaviour of the steam generator, quality of fuel used, the time lag between coal milling and turbine response.

Source: *Flexibilty in Thermal Power Plants*, Agora Energiewelde, 2017

Crucially, coal quality plays a pivotal role in operation of plants at their minimum load capacity. Policy intervention is needed as Indian coal as used right now is not suitable for the same for the majority of plants. Key technical requirement for flexibilization is that the generating unit's Minimum Power Level should be 40 per cent. These generating units should have the ramp rate capability of minimum 3 per cent per minute for their operation between 70–100 per cent of maximum continuous power rating/PLF and should have ramp rate capability of minimum 2 per cent per minute for their operation at 55–70 per cent of maximum continuous power rating/ PLF.[82] Additionally, the **Control and Instrumentation (C&I) system** (integrated technological system that uses IoT to automate production) plays a crucial role for flexible operation. Plant status transparency, the availability of operating data, sophisticated data assessments and advanced controls are a prerequisite for operating a power plant with enhanced flexibility.[83]

5.4 Biomass cofiring

5.4.1 Policy

The decline in air quality in northern India has been linked to stubble burning, a practice where straw stubble remaining after the harvest of paddy and other crops is set on fire. An estimated 30–40 million tonnes of stubble are burned annually in northwest India. This stubble has the potential to generate 45,000 million units of electricity per year if co-fired with coal in existing coal-fired power plants.[84]

On November 17, 2017, the Ministry of Power (MoP) issued its first notification on biomass co-firing titled: 'Biomass utilization for power generation through co-firing in coal-based power plants'. In this notification, published on the CEA's website, the Ministry stated: 'All fluidized bed and pulverized coal units (coal-based thermal power plants) except those having ball and tube mill, of power generation utilities, public or private, located in India, shall endeavor to use 5-10 per cent blend of biomass pellets made, primarily, of agro residue along with coal after assessing the technical feasibility, viz. safety aspects etc.'

On October 8, 2021, the Ministry of Power (MoP) updated the biomass policy, making it mandatory for all coal-based thermal power plants to replace 5 per cent of their coal consumption with biomass. This policy requires coal power plants to blend their coal with 5 per cent biomass pellets, becoming effective one year from the policy's issuance. Furthermore, the biomass co-firing percentage must increase to 7 per cent two years after the policy's implementation. In the revised policy, ball and tube mill power plants are advised to use torrefied biomass pellets with volatile content below 22 per cent.

Revised biomass policy for thermal power plants

The Ministry of Power has revised its biomass co-firing policy, initially issued on October 8, 2021, through a modification dated June 16, 2023. Under the revised mandate, thermal power plants (TPPs) are required to co-fire 5 per cent biomass with coal starting from FY 2024–25, with the obligation increasing to 7 per cent from FY 2025–26.[85]

To support biomass availability and procurement, the government has introduced multiple initiatives, including financial assistance schemes by MNRE and CPCB, priority sector lending status for biomass pellet manufacturing by RBI, and the creation of biomass procurement provisions on the GeM portal. Additionally, a vendor database has been finalized under the SAMARTH initiative, along with the issuance of a revised long-term biomass supply contract.

The revised policy also broadens the scope of biomass feedstocks, incorporating various agro-residues such as stubble, husks, and stalks from crops like paddy, maize, mustard, jute, and cotton, as well as horticultural waste and other biomass sources like bamboo by-products, pine needles and elephant grass.

5.4.2 Current status

The National Mission on the Use of Biomass in Thermal Power Plants reports that (as of February 25, 2025) 68 thermal power plants have initiated biomass co-firing, with a cumulative total of 17.42 lakh metric tonnes (LMT) of biomass co-fired resulting in 20.91 LMT of CO_2 saved.[86]

5.4.3 Challenges

- As per the biomass co-firing policy, approximately 0.25–0.3 million tonnes of biomass pellets are required annually for every 1,000 MW of power generation capacity when co-fired at 7 per cent. However, there is a significant gap between demand and supply, primarily due to the limited number of pellet manufacturers, especially large-scale, in the country. Currently, the national pellet manufacturing capacity stands at 7,000 tonnes per day, while the requirement is around 95,000 to 96,000 tonnes per day, according to the National Mission on the Use of Biomass in Thermal Power Plants.

- In addition to the above point, there is an issue of intermittency, since biomass supply is not consistent, TPPs end up co-firing biomass based on availability and not as an annual practice.

- Rising cost of biomass pellets: The cost of pellets available for power plants has soared from Rs 8–9 per kg in January, 2021 to Rs 12–14 per kg in June 2022.[87]

- Rising demand from other sectors: biogas plants, biofuels among other sectors also demand biogas in one form or another. There is a need to allocate the resource so as to not create a shortage of agro-residue. Steps need to be taken to ensure adequate supply to coal-fired power plants.

- Only 233 units are included in the R&M list. However, out of the 603 total units, 511 are subcritical units with an average age of 20 years. Therefore, many units beyond the 233 listed will require boiler revamping to accommodate biomass co-firing. To effectively implement biomass co-firing, provisions must be made to facilitate the necessary boiler upgrades for these additional units.

5.4.4 Industry best practices

Earlier, NTPC successfully established co-firing of 7 per cent to 10 per cent non-torrefied biomass with coal at NTPC Dadri. Recently, NTPC Limited achieved a new milestone by successfully demonstrating 20 per cent torrefied biomass co-firing at its Unit 4 in Tanda, Uttar Pradesh.[88]

Internationally, Mitsubishi Hitachi Power Systems, Ltd (MHPS) has successfully achieved a wood pellet biomass fuel mixing ratio of 34 per cent, in heat value, at a pulverized coal-fired power generation facility, marking as the highest co-firing possible.[89]

5.5 Carbon Capture Utilization and Storage (CCUS)

The International Energy Agency (IEA) defines Carbon Capture, Utilization, and Storage (CCUS) as the process of capturing CO_2 emissions from large point sources, such as power plants and industrial facilities that burn fossil fuels or biomass as fuels. There are several technologies for capturing CO_2 which are majorly dependent on the following three processes:[90]

- Solvent-based absorption
- Adsorption
- Cryogenic separation

5.5.1 Current status

Globally, there are approximately 21 CCUS facilities with the capacity to capture around 40 million tonnes per annum (MTPA) of CO_2, which is only about 0.1 per cent of the nearly 40 giga-tonnes per annum (GTPA) of global emissions. IEA has a CCUS database updating projects across the globe that are either implemented or under construction.[91] According to this database, there are CCUS projects at various stages of implementation with a combined capacity to capture 134.22 million tonnes of CO_2 per year from the power and heat sector.

In India, CCUS is currently limited to pilot scale in sectors like refinery, steel and power sector, with some pilot projects by IOCL, NTPC, JSW and Tata Steel. However, there are no commercial-scale dedicated CCUS projects in the country.[92]

5.5.2 Scope of CCUS in India

NITI Aayog has reported that India possesses a theoretical storage capacity of approximately 393–614 gigatonnes of CO_2 through various methods, including Enhanced Oil Recovery (EOR), Enhanced Coal Bed Methane Recovery (ECBMR), and storage in deep saline aquifers and basaltic rocks. However, these are estimates and the actual storage potential of Indian sedimentary basins is yet to be accurately determined.

5.5.3 Challenges

- Major CO_2-emitting point sources, such as power plants, steel industries, refineries and cement factories, are spread across the nation and are not connected to these potential storage sites. Therefore, there is a need for a comprehensive transport infrastructure to connect these sources to the sinks, such as a pipeline network.

- In terms of utilization of captured CO_2 to make products, there are alternative routes available to manufacture and sell those products at cheaper costs, thus not making a good economic case for CCU in India currently.

- Since no large-scale commercially viable CCUS project has yet been operational in India even after many years of initiatives and announcements by companies in India, the feasibility and viability of CCUS in India remains uncertain.

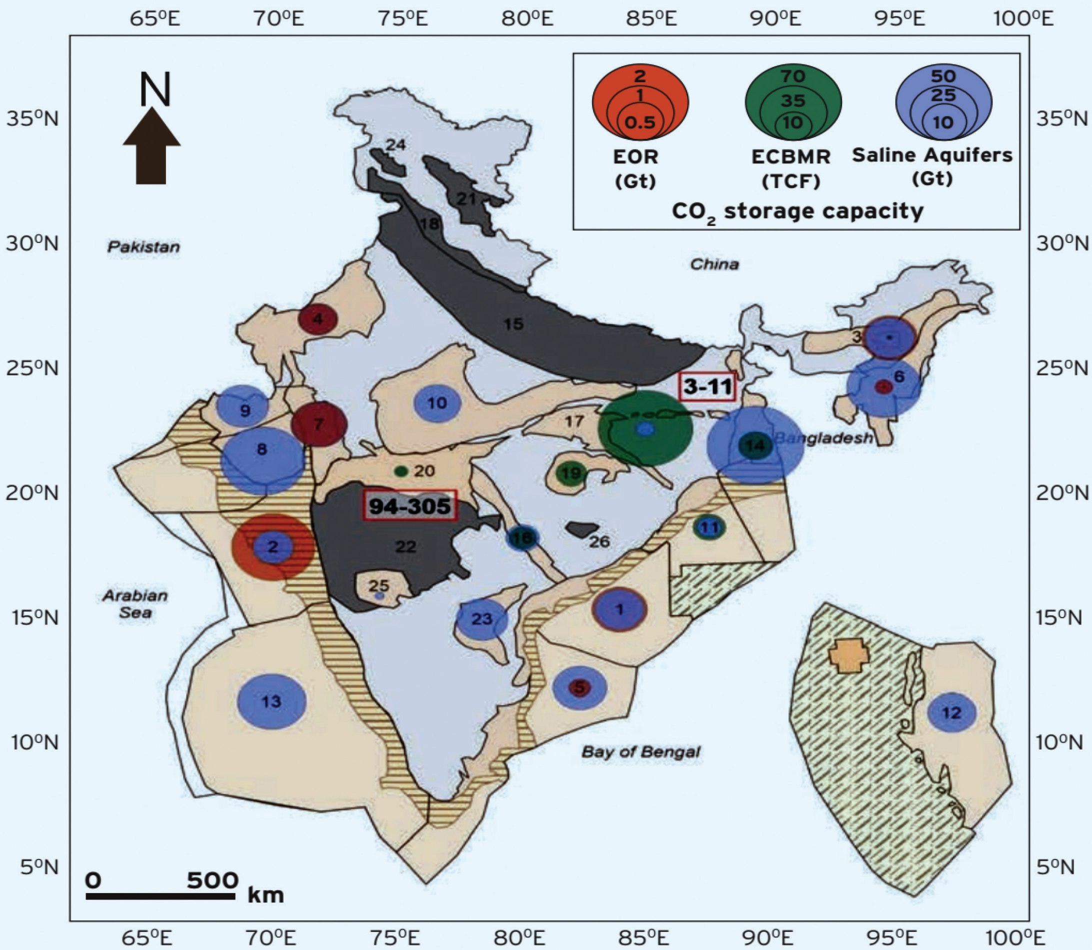
- Significant investment, policy and financial support will be required to develop the necessary infrastructure and prove the commercial viability of CCUS in the Indian context.

AMMONIA COFIRING

Along with biomass co-firing, various organizations are currently considering the use of ammonia for cofiring.[93] The chemical formula of ammonia is NH_3—it contains nitrogen and hydrogen. Ammonia is flammable, making it suitable for co-firing. However, it burns at a much slower rate (about one-fifth that of methane).[94] Due to its nitrogen content and slow burning rate, ammonia combustion leads to the production of NOx. Consequently, burner adjustments are required to ensure NOx emissions are comparable to those from coal burning. While NOx can be treated, the primary advantage of co-firing with ammonia is its carbon-free nature.

Ammonia is produced using hydrogen, and currently most hydrogen is generated from natural gas via steam methane reforming. Therefore, the ammonia produced today is not green. However, since hydrogen can be produced from renewable sources, ammonia production can also be made green. This raises the question: does it make sense to produce hydrogen using electricity (even if renewable), use it to produce ammonia, and then combust ammonia to produce electricity? The cost economics and technical feasibility of this process needs to be analysed to answer that question.

Map 1: Sedimentary basins of India along with their CO_2 storage potential



- Sedimentary basins
- Precambrian basement
- Basins with insufficient data
- CO_2 storage capacity in basalt (Gt)
- Shallow water areas
- Unassessed deepwater areas

Category-I basins	Category-II basins	Category-III basins
1. Krishna-Godavari	8. Saurashtra	13. Kerala-Konkan
2. Mumbai Offshore	9. Kutch	14. Bengal-Purnea
3. Assam-Shelf	10. Vindhyan	15. Ganga-Punjab
4. Rajasthan	11. Mahanadi	16. Pranhita-Godavari
5. Cauvery	12. Andaman	17. Satpura-South Rewa-Damodar
6. Assam-Arakan Fold belt		18. Himalayan Foreland
7. Cambay		19. Chhattishgarh
		20. Narmada
		21. Spiti-Zanskar
		22. Deccan Syncline
		23. Cuddapah
		24. Karewa
		25. Bhima-Kaladgi
		26. Baster

Source: CCUS Policy Framework and its Deployment Mechanism in India, NITI Aayog, 2022

6

EMISSION SCENARIOS, FINDINGS AND RECOMMENDATIONS

CSE'S DECARBONIZATION SCENARIOS ARE BASED ON THREE LEVERS—ACHIEVING BENCHMARK EFFICIENCY, TECHNOLOGY-WISE PLF ADJUSTMENT AND BIOMASS COFIRING.

CSE'S ANALYSIS SHOWS THAT ACHIEVING BENCHMARK EFFICIENCY COMBINED WITH 20 PER CENT BIOMASS COFIRING CAN REDUCE CO_2 EMISSIONS BY 31.8 PER CENT, CUTTING 423 MILLION TONNES FROM THE BUSINESS-AS-USUAL LEVEL OF 1,332.7 MILLION TONNES.

CSE'S SECOND COMBINED SCENARIO ESTIMATES THAT SHIFTING A LARGER SHARE OF POWER GENERATION TO NEWER SUPERCRITICAL AND ULTRA-SUPERCRITICAL UNITS CAN REDUCE CO_2 EMISSIONS BY 32.5 PER CENT COMPARED TO THE BUSINESS-AS-USUAL SCENARIO.

Building on the pathways discussion from the previous chapter, this chapter examines the business as usual emissions, followed by the potential for emission reductions through efficiency improvements and increased biomass cofiring across both existing and future power plant units until 2031–32. To assess the impact of these strategies, CSE has developed various scenarios, projecting the expected emission reductions that could be achieved through their implementation.

6.1 Business-as-usual emission scenario

The business as usual (BAU) scenario is the first future emission scenario projected for 2031–32 which basically puts out the projected CO_2 emissions the coal-based thermal power sector in India would emit if they continue generating power at their current operational metrics and emission factor until 2031–32.

6.1.1 BAU scenario: Assuming NEP projections hold true

Considering India is now in a high-demand scenario of the NEP and retirement plants have been cancelled, the capacity considered is one mentioned in the NEP, i.e. 262.64 GW. Future capacity additions are in super and ultra-supercritical, with no new subcritical unit in plans. Therefore, we are aware of the subcritical capacity, but the capacity split between super-critical and ultra-supercritical units is unknown. Hence, the generation figures are combined for these two categories. Further, CEA has projected an average PLF of 0.58 for 2031–32. Using the formula, we estimated the technology-wise net generation.

Installed capacity (MW) = (Net generation (GWh)/(PLF 8.760))*100*

Total CO_2 emissions have been calculated based on the technology-wise net generation, taking the current average emission factor from each technology. The formula used for calculation of emissions and emission factor:

*Total emissions (in million tonnes) = Generation (gwh) * emission factor (tonne/mwh) * 1000/10^6*

$$Emission\ factor = \frac{Total\ CO_2\ emission\ from\ the\ plant}{Net\ Generation}$$

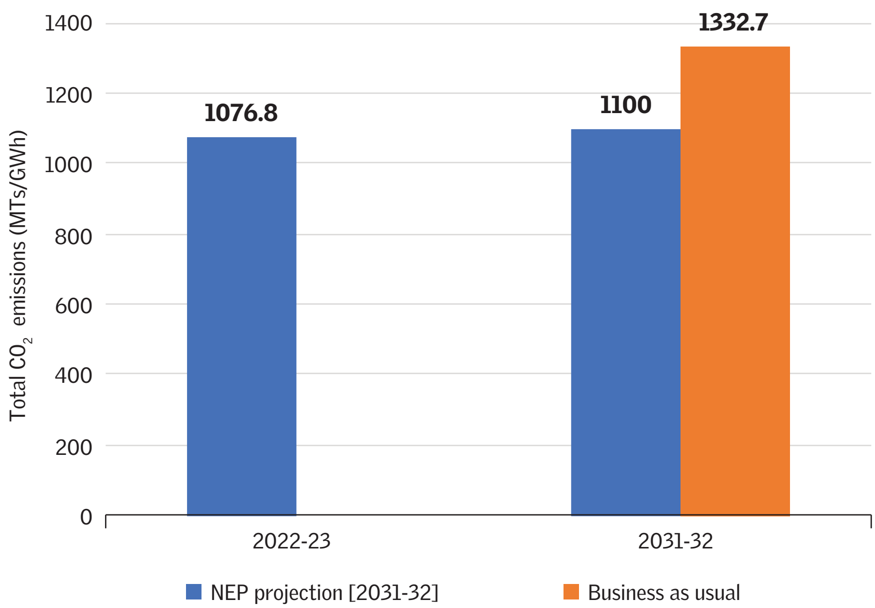
Table 29: Technology-wise future generation and emissions (BAU scenario)

Technology	Capacity GW (percentage share)	Net generation GWh (percentage share)	BAU emission factors (tonne CO_2/MWH)	Total CO_2 emissions (tonnes of CO_2)
2031–32				
Subcritical	148.84 (56.67 per cent)	756,356.65 (56.67 per cent)	1.07	809.3 (60.72 per cent)
Supercritical and Ultra-supercritical	113.8 (43.33 per cent)	578,294.72 (43.32 per cent)	0.905	523.35 (39.28 per cent)
			Total CO_2 emissions	1,332.7

Source: CEA CO2 database, Version 19

The BAU scenario clearly shows that if power generation continues at the current emission rate to meet the projected electricity demand for 2031–32 as envisaged by NEP, CO_2 emissions will increase around 23.7 per cent annually by 2031–32 when compared to total CO_2 emissions (1,076.8 MT CO_2) in 2022–23 as given in the CEA baseline database. There will be a 33 per cent increase in emissions by 2031–32 when compared to the CO_2 emissions in 2021–22 (1,002 MTs CO_2) as declared in NEP. The subcritical fleet's high emission factor also results in a higher proportion of emissions coming from the subcritical units, illustrating that an equal PLF split among subcritical, supercritical and ultra-supercritical units is not a wise policy move (see *Graph 24: BAU scenario—Emission projections 2031–32*).

Graph 24: BAU scenario—Emission projections 2031–32



Source: CSE analysis of CEA CO_2 database, Version 19

6.1.2 BAU 2 scenario: Assuming coal retains dominance in generation mix

This BAU scenario is based on the NEP's assumption that RE generation will gain momentum and therefore coal will be needed for 50.1 per cent of the total generation mix. Yet, as illustrated in section 2.3.1, coal powers 74.4 per cent of the total generation mix (as of March 2025). The share will fall but in case demand keeps breaching the supply limit and RE capacity addition does not outpace demand, coal's production will have to be ramped up to supply electricity. If this holds true, the PLF of the future capacity will rise beyond the NEP's projection.

The average share of coal in the generation mix over the FY 2022-24 has been 75 per cent. To provide electricity equivalent to the NEP's projected future energy requirement based on future coal capacity, which is 185 BU out of 247.37 BU. To supply this electricity, the deemed PLF of the future capacity will have to be 80.02 per cent across all units independent of the technology. This BAU 2 scenario is to reflect the steep emission rise if RE capacity addition is not accelerated (see *Table 30:* Technology-wise future generation and emissions *[BAU 2 scenario]*).

Table 30: Technology-wise future generation and emissions (BAU 2 scenario)

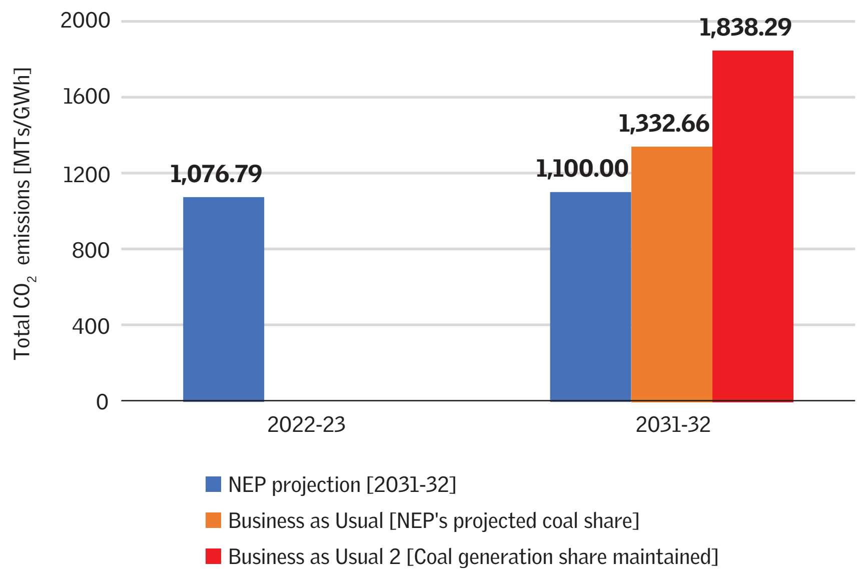
(Coal retains its current generation share mix in the future)

Technology	Capacity GW (percentage share)	Net generation GWh (percentage share)	BAU emission factors (tonne CO_2/MWH)	Total CO_2 emissions (tonnes of CO_2)
2031–32				
Subcritical	148.84 (56.67 per cent)	1,043,331.48 (56.67 per cent)	1.07	1,116.36 (60.72 per cent)
Supercritical and ultra-supercritical	113.8 (43.33 per cent)	797,709.77 (43.32 per cent)	0.905	721.91 (39.28 per cent)
			Total CO_2 emissions	1,838.3

Source: CSE analysis of CEA CO_2 database, Version 19

The analysis considers the NEP's high demand installed capacity projections (see *Graph 21: NEP Exhibit 5.5a—Likely coal capacity in different scenarios in 2026–27 and 2031–32*). Yet, based on the announcement of the government in Parliament, the new capacity will be above 280 GW, signifying that actual emissions from coal may be between the two BAU scenarios suggested by CSE. In conclusion, the above measure elucidates the scale of challenge and the paramountcy for strategies to achieve decarbonization of the coal power sector.

Graph 25: BAU 2 scenario—Emission projections, 2031–32



Source: CSE analysis of CEA CO_2 database, Version 19, 2022–23

6.2 Decarbonization levers

Having analysed the emission factor of the current fleet, CSE's subsequent analysis is to suggest tools for emission reduction across the coal fleet and quantify CO_2 savings from deployment of the same. Our analysis primarily deploys two levers, namely, **efficiency improvement** and **biomass cofiring**. Within each lever, we have provided sub-scenarios to optimally implement the tools for maximum emission reductions.

6.2.1 Efficiency and R&M

6.2.1.1 Assessment of units with subpar performance than NEP retirement plants

The NEP has identified several units scheduled for retirement by 2032. However, there are units currently in operation that perform subpar compared to the most efficient unit on the retirement list, yet they are not slated for retirement or renovation and modernization (R&M). These units cumulatively represent 1,312.5 MW of capacity (see *Table 31: Power units outside reirement and R&M consideration).*

The analysis of unit ages reveals that all units are over 25 years old, with **five of them nearing or exceeding 40 years** and **three units surpassing the 40-year mark** (42.14, 44.32, 53.98 years). The plants are likely to face operational and environmental challenges associated with aging infrastructure.

Given their suboptimal performance, high emissions and low efficiency, it is recommended to conduct a thorough audit of these units. Since CEA had issued an advisory on January 20, 2023 to not retire any thermal units till the year 2023, based on the audit findings, *first* a decision should be made to assess the possibility to improve their performance, else, in the case no possibility or economic case, repurposing or retirement can be considered as per CEA guidelines of April 2024.[95]

Table 31: Power units outside retirement and R&M consideration

Name	Unit no.	Sector	Capacity (MW)	Auxiliary cons. (per cent)	Net generation (GWh)	Emission factor (tonne/ MWh)	PLF (per cent)	SHR (kcal/ kWh)	Efficiency (per cent)	Age (years)
PLF >= 50 per cent										
Koradi	6	State	210	11.55	1,167	1.22	63.4	3160.63	27.2	42.14
Obra-A	9	State	200	10.89	1,031	1.16	58.8	3037.43	28.31	44.32
Southern Repl.	1	Private	67.5	8.54	301.62	1.17	51.0	3075.45	27.96	33.77
PLF < 50 per cent										
Southern Repl.	2	Private	67.5	8.54	279.78	1.17	47.3	3,078.58	27.93	33.11
Kutch Lig.	3	State	75	14.17	309	1.75	47.0	4,035.87	21.31	27.14
R_Gundem – B	1	State	62.5	14.42	232.16	1.21	42.4	3,168.41	27.14	53.98
Nashik	5	State	210	12.98	744	1.21	40.4	3,165.05	27.17	43.31
Bhusawal	3	State	210	15.36	606	1.66	32.9	4,351.08	19.76	42.05
Durgapur	2	Centre	210	19.01	109.43	1.58	5.9	4,145.26	20.74	42.46
Total			1,312.5 MW							

Source: CSE analysis of CEA CO_2 database, Version 19, 2022–23

6.3 Decarbanization Lever 1: Improving efficiency

Table 29 presents the current capacities by technology (along with their percentages) and the future capacities, taking into account the proposed retirement and new additions as outlined by the CEA in the NEP. According to the NEP, the CEA projects a gross generation of 1,334.7 TWh for 2032. To match the generation projection, we adjusted the expected PLF of 58 per cent for the coal fleet to its decimal factor of 0.5801 for 2031–32, and calculated the generation from technologies for 2031-32.

Similarly, we identified the best-performing units for each technology as the baseline. As previously mentioned, our analysis includes 554 units, of which 418 have a PLF of 50 per cent or higher. Majority of these units use coal with an Average GCV ranging from 3,000–3,500 kcal/kg to 3,500–4,000 kcal/kg. Therefore, we focused on the emission factor for units using coal with an average GCV below 4,000 kcal/kg and PLF above 50 per cent. Further, due to the vast size of the subcritical fleet of units, we have estimated 50 per cent of subcritical capacity at benchmark emission factor and rest of the 50 per cent subcritical fleet at a lower benchmark emission factor of a unit that has an age profile beyond 25 years. We have picked 25 years as the parameter as the CEA normally considers the life cycle of a thermal unit to be 25 years.

For supercritical and ultra-supercritical units, as we are unaware of the future capacity split, we have calculated the emission factor by taking the benchmark unit emission factor within the current units running of these two technologies. The scenario has been developed based on efficiency improvement with benchmarked emission intensity targets. Within the efficiency improvement, we have overlaid it with two PLF presumptions and created scenarios on its basis. Within Scenario 1, the PLF of the coal fleet is determined as per the NEP's projection which is 58 per cent. Our analysis discloses the emission factor difference between subcritical and super/ultra-supercritical units. For Scenario 2 and 3, we adjusted the PLF of each technology to provide maximum emission reductions.

6.3.1 Scenario 1: Benchmark performance achievement

The emission factor of best-performing units for each technology, considering all units, is illustrated in *Table 32*. The scenario showcases the potential reduction if the fleet can achieve the benchmark emission factor.

Table 32: Technology-wise benchmark emission factor

Technology	Benchmark emission factor (tonne/MWH)
50 per cent of subcritical capacity	0.91
50 per cent of subcritical capacity	0.93
Supercritical and ultra-supercritical	0.83

Source: CEA CO_2 database, Version 19, 2022–23

To arrive at the benchmark emission factors, we have analysed the units technology-wise and arrived at the emission factor accordingly.

- **Subcritical**

Considering the size of the subcritical fleet, the benchmark has been split equally. For 50 per cent of the fleet, the benchmark considered is from the best-performing unit. For the rest of the fleet, the benchmark considered is from the emission factor achieved by two CESC that which are above the age of 25 years.

Best performer: TSGENCO's state-owned K_gundem New, unit no. 4, with a capacity of 500 MW, age of 13.1 years and a PLF of 78.8 per cent, achieved an emission factor 0.91 tonne CO_2/MWh.

Best performer (age > 25 years): CESC-owned Budge Budge, unit no. 1, with a capacity of 250 MW, age of 26.9 years and PLF of 69.6 per cent, achieved an emission factor 0.93 tonne CO_2/ MWh.

We believe that the reduction can be higher as achieved by smaller and older units being operated by JSW Energy and Tata Power. Operational standards play a huge role in emission reduction beyond the fuel usage. Our report confirms that units operating on domestic coal can achieve lower emission factor. Nevertheless, in India, units beyond 25 years of age are running on high PLF. Herein, we want to highlight the low emission factor achieved by the said units. The Trombay Unit is above 40 years of age and yet running at high efficiency levels.

JSW Energy

Torangallu IMP unit no. 1 and 2, with a capacity of 130 MW each and PLF of 84.4 per cent and 64.2 per cent respectively, achieved emission factor 0.74 tone CO_2/ MWh and 0.82 tone CO_2/MWh respectively.

Torangallu EXT unit no. 1, with a capacity of 300 MW and a PLF of 54 per cent, achieved an emission factor of 0.87 tonne CO_2/MWh.

Tata Power

Trombay unit no. 1 and 2, with a capacity of 500 MW and 250 MW and a PLF of 57.2 per cent and 62.6 per cent respectively, achieved emission factors of 0.89 tonne CO_2/MWh and 0.90 tonne CO_2/MWh respectively.

Their achievements debunk the myth of subcritical technology being a polluting one, as by operational methods, the units of various capacity and age can achieve lower emission intensity. However, considering that the majority of the fleet operates on domestic coal, the emission reduction can take place in a like-for-like scenario. Therefore, the units mentioned above of JSW Energy and Tata Power are excluded as they use gas and imported coal as their primary fuel and are not included in the benchmark analysis.

- **Supercritical/ultra-supercritical**

The NEP considers the supercritical and ultra-supercritical technology in the same breath. Additionally, we are not aware of the technology split of future unannounced capacity addition. As none of the units meet the Government of India's standard for efficiency (see *Section 5.1.2*), we have considered the two together and taken the lower emission factor among them. The best-performing unit used as the benchmark in super/ultra-supercritical category is NTPC's Kudgi unit which achieved an emission factor of 0.83 tonne CO_2/MWh.

Supercritical

The supercritical technology is only a decade old and all units within this technology are young. The benchmark was calculated considering the best performing unit between both super and ultra-supercritical category. The emission factor of the best performing Super-Critical unit is not too far behind the one achieved by ultra-supercritical unit.

Best performer: Nabha Power's privately owned Rajpura TPP (Punjab) unit no. 2, with a PLF of 82.6 per cent, running on domestic coal supplied by Coal India achieved emission factor 0.84 ton CO_2/MWh.

Ultra-supercritical

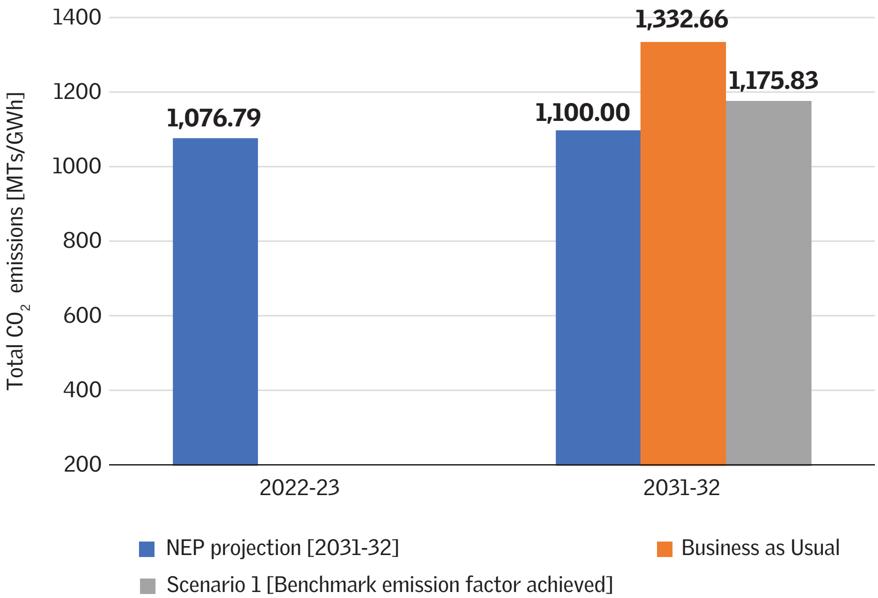
The ultra-supercritical technology is less than a decade old but will contribute significantly in the coming decade as seen above in the future addition section of the report. The benchmark was calculated as the top-performing unit in the category.

Best performer: NTPC's centrally owned Kudgi (Karnataka) unit no. 1 and 2, with a PLF of 56.9 per cent and 50.3 per cent, running on domestic coal supplied by Coal India, achieved an emission factor 0.83 tonne of CO_2/MWh.

Assuming that all units in each technology category achieve these benchmarked emission factors due to R&M operations, the total emissions from coal-based thermal power plants for the above mentioned generation values would be

- **1,175.83 million tonnes CO_2:** If benchmarked emission factors are achieved (scenario 1). This is a reduction of 156.82 million tonnes which is almost 11.7 per cent less than BAU emissions.

Graph 26: Decarbonization lever 1—Scenario 1 illustrated (benchmark emission factor)



Source: CSE analysis

PLF alteration for higher efficiency gains

Beyond benchmark emission factor achievement, further emission reductions can be unlocked by altering PLF of units depending upon their technology of operation. India moved away from subcritical technology for higher efficiency gains. To maximize the gains, a uniform PLF for all units independent of their technology of operation is not advisable. As mentioned in our decarbonization lever segment, to achieve higher gains from efficiency alteration of PLF for different technologies is advisable. Table 29 and 30 illustrate that a shift away from subcritical units can help achieve a higher level of emissions reductions owing to the superior emission factor achieved by super and ultra-supercritical units. The tables indicate that if PLF is considered equally across all units, the subcritical units have a higher proportion of emissions. Therefore, a further reduction in emissions can be achieved if higher generation is allocated to super and ultra-supercritical units. Out of the 554 units within the CEA 2022–23 database, 92 units with 63.03 GW of capacity operate on super or ultra-supercritical technology. Currently, 22 units of these technology are operating below 50 per cent PLF. This reflects an underutilization of an environmentally efficient coal fleet. From an economic perspective, this is an inefficient operational scenario as higher utilization will result in higher coal savings too.

As per NEP's projection of energy generation requirement from coal for 2031–32 stands at 1,334.7 TWh. This figure is of gross requirement and therefore we created the scenario of presumed PLF for subcritical capacity and supercritical/ultra-supercritical capacity and proposed scenario for emission reduction. The scenario considers the benchmark emission factors deployed in creation of Scenario 1 and overlays on that the presumed PLF to illustrate additional emission reductions via higher allocation towards the supercritical and ultra-supercritical units. Understanding the technical limitations of the current fleet, Scenario 3 has been created to display emission-reduction possibilities but have not been used for our combined emission-reduction pathways.

6.3.2 Scenario 2: Conservative PLF alteration

NEP's projection of energy-generation requirement from coal for 2031–32 stands at 1,334.7 TWh. The total-generation figure must correspond with this figure. The installed capacity and emission factors from Scenario 1 are used and only the PLF for the category has been altered. The PLF for all subcritical units, given their current capacity, is considered 50 per cent. As the total generation figure is fixed, the remaining capacity, i.e. of supercritical and ultra-supercritical units, will have to operate at a PLF of 68.46 per cent. The values assumed for creation of scenario 3 are given the table below:

Table 33: Scenario 2 (conservative PLF alteration)—relevant estimates

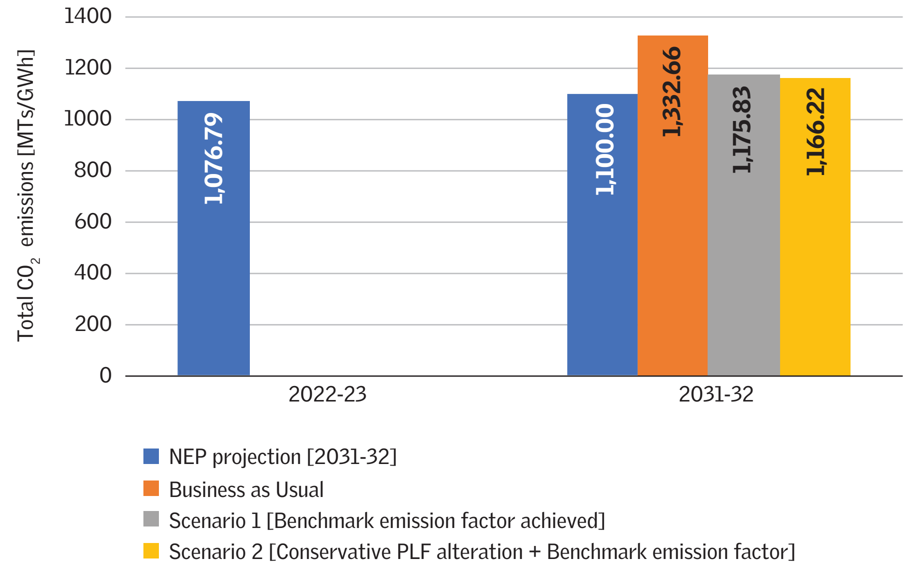
Technology	Benchmark emission factor (tonne/MWH)	Installed capacity (in GWs)	Presumed PLF
50 per cent of subcritical capacity	.91	74.42	50 per cent
50 per cent of subcritical capacity	0.93	74.42	50 per cent
Supercritical and ultra-supercritical	0.83	113.8	68.46 per cent

Source: CEA CO_2 database, version 19, 2022–23

Assuming that all units in each technology category achieve these benchmarked emission factors due to R&M operations, and we operate the units at the suggested PLF, the total emissions from coal-based thermal power plants for the generation values mentioned in *Table 33* would be:

- **1,166.22 million tonnes CO_2:** This is a reduction of 166.43 million tonnes CO_2 which is almost 12.5 per cent less than BAU emissions. This is a 0.8 per cent (9.6 million tonnes CO_2) higher reduction than in Scenario 1.

Graph 27: Decarbonization lever 1—Scenario 1 and 2 illustrated (conservative PLF alteration)



Source: CSE analysis

6.3.3 Scenario 3: Accelerated PLF alteration

Given that supercritical and ultra-supercritical units can operate at a higher PLF than the 68.46 per cent, the CEA database reveals that units of these technologies can operate at higher PLF, with Reliance Power's Sasan Ultra Mega Power Project's thermal units operating at PLF above 85 per cent. Therefore, in Scenario 3, to create greater reductions, we assume a higher PLF for supercritical and/or ultra-supercritical units, i.e. at 80 per cent. The installed capacity and emission factors from Scenario 1 are used and only the PLF across the categories has been altered. For scenario 3, knowledge of future capacity is presumed as per the NEP. As the total generation figure is fixed, the remaining capacity, i.e. of subcritical units, will have to operate at a PLF of 41 per cent. The values assumed for creation of scenario 3 are given *Table 34*.

Table 34: Scenario 3 (accelerated PLF alteration)—Relevant estimates description

Technology	Benchmark emission factor (tonne/MWH)	Installed capacity (in GW)	Presumed PLF
50 per cent of subcritical capacity	0.91	74.42	41 per cent
50 per cent of subcritical capacity	0.93	74.42	41 per cent
Supercritical and ultra-supercritical	0.83	113.8	80 per cent

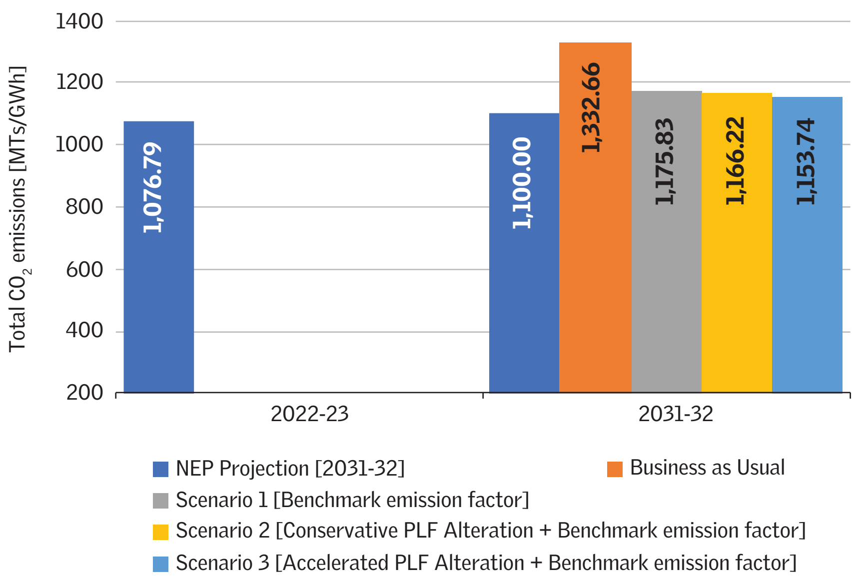
Source: CEA CO_2 database, Version 19, 2022–23

Assuming that all units in each technology category achieve these benchmarked emission factors due to R&M operations, and we operate the units at the suggested PLF, the total emissions from coal-based thermal power plants for the generation values in Table 34 would be:

- **1,153.74 million tonnes CO_2:** This is a reduction of 178.91 million tonnes CO_2 which is almost 13.4 per cent less than BAU emissions. This is a 1.8 per cent (22.1 million tonnes CO_2) higher reduction than in Scenario 1.

Scenario 3 is not referred to in our combined scenario for emission reductions. For realization of this scenario, the coal power plants will require a higher level of flexibilization within subcritical units to bring their minimum technical load to 40 per cent. Alternatively, this may result in shutdown of certain subcriticals unit owing to redundancy of operations. We are aware of the requisite Just Transition necessity to take such a policy decision and do not advocate for the same. Therefore, for all practical purposes, Scenarios 1 and 2 have been considered. In *Graph 29*, we provide the emission-reduction potential of all efficiency improvement scenarios.

Graph 28: Decarbonization Lever 1: Efficiency improvement scenarios illustrated (in MT CO_2)



Source: CSE analysis

6.3.4 BAU 2 scenario: Achieving benchmark efficiency

As illustrated in Section 6.1.2, India may not shake off its reliance on coal in the coming decade. Considering the demand projections and capacity addition forecast of NEP have not held true, the likeliness of missing the target for generation mix is real too.

To meet rising demand, running subcritical units at low PLF will not be an option and we will need the entire fleet to operate at a minimum of 79.8 per cent PLF to meet the generation requirement. In such a scenario, the emission reduction of the current fleet becomes paramount. The scenario of decarbonization here follows the methodology of Scenario 2, wherein benchmark efficiency is applied for the entire fleet and the PLF is adjusted to meet the target generation requirement. Table 35 elaborates the data presumed to create the scenario.

Table 35: BAU 2 scenario (benchmark efficiency)—Relevant estimates description

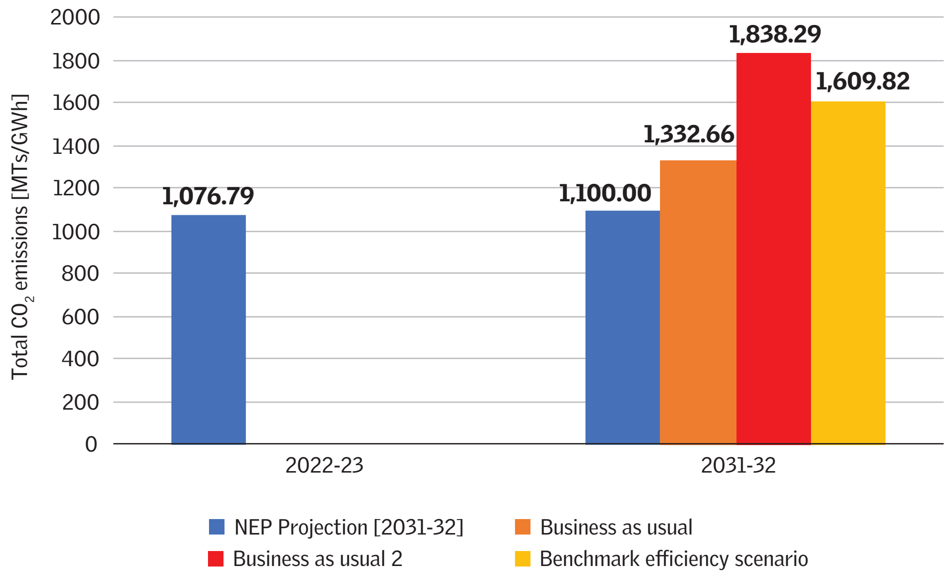
Technology	Benchmark emission factor (tonne/MWH)	Installed capacity (in GW)	Presumed PLF
50 per cent of subcritical capacity	0.91	74.42	79.89 per cent
50 per cent of subcritical capacity	0.93	74.42	79.89 per cent
Supercritical and ultra-supercritical	0.83	113.8	80 per cent

Source: CEA CO_2 database, Version 19, 2022–23

The subcritical fleet has to operate at a minimum of 79.8 per cent PLF to keep up with the generation figure. Hence the emission reductions achieved are given in *Graph 29*.

Total emissions in the case of coal retaining its primacy in our energy mix rise from 1,332.7 MT to **1838.3 MT**. This is a **37.9 per cent** increase in total emissions from the BAU scenario. Nevertheless, achieving benchmark efficiency for the entire fleet of coal units will result in similar reduction as achieved by Scenario 1 (Section 6.2.2.1), i.e. **12.42 per cent,** and bring the emissions down to 1609.8 MT.

Graph 29: BAU 2 scenario (benchmark efficiency)—Emission-reduction potential



Source: CSE analysis

6.4 Decarbonization Lever 2: Biomass cofiring

As mentioned in the previous chapter, CEA has mandated biomass co-firing in all thermal generation units. Depending on the type of mill used, different types of biomass (pellets, torrefied, and torrefied with organic content below 22 per cent) are proposed. Under the revised mandate on biomass co-firing (June 2023), thermal power plants (TPPs) are required to co-fire 5 per cent biomass with coal starting from FY 2024–25, with the obligation increasing to 7 per cent from FY 2025–26. The biomass co-firing percentage is based on weight. Therefore, to assess future emission reductions, we need to estimate the amount of coal required in 2032.

6.4.1 Future coal consumption

For 2024, approximately 760 million tonnes of national coal and 51 million tonnes of imported coal were consumed. To estimate future coal consumption, the weighted average heat rate (WAHR) (kcal/kWh) of each unit was calculated using the following formula:

Figure 7: Calculation of Weighted Average Heat Rate (WAHR)

$$WAHR = \frac{National\ coal\ consumed * GCV_{national} + Imported\ coal\ consumed\ (kg) * GCV_{imported}}{Net\ Generation\ or\ Gross\ Generation}$$

Given that the CEA projects a gross generation of 1334.7 BU for 2032, we used gross generation in the denominator. The mean of this gross WAHR parameter was considered to be the WAHR in the business-as-usual scenario for 2032. Similarly, the weighted average GCV of each unit was calculated using the following formula:

Figure 8: Calculation of average Gross Calorific Value (GCV)

$$Average\ GCV = \frac{GCV_{national} * Consumption_{national} + GCV_{imported} * Consumption_{imported}}{Consumption_{national} + Consumption_{imported}}$$

Using the mean of this weighted average GCV as the GCV of the coal in 2032, we calculated the amount of coal required for 2032 as follows:

Figure 9: Calculation of coal required

$$Coal\ required = \frac{Gross\ WAHR * Gross\ Generation}{Mean\ weighted\ average\ GCV}$$

The current average WAHR of gross generation for all units which use coal of average GCV below 4,000 kcal/kg and have a PLF above 50 per cent is 2453.92 kcal/kWh. With a gross generation projected at 1334.7 BU (or TWh) for 2032 and a mean weighted average GCV of 3529.38 kcal/kg (current value), approximately 928 million tonnes of coal will be required to generate the projected electricity in 2032.

In contrast, for units using coal with an average GCV below 4,000 kcal/kg and having a PLF above 50 per cent, the current minimum WAHR technology-wise are as follows: **Subcritical: 2,236.48 kcal/kWh, Supercritical: 2,105.55 kcal/kWh, Ultra-supercritical: 2,074.05 kcal/kWh**. Assuming that R&M operations lead to efficiency improvements reaching these values for all units of each technology, and using the projected generation percentages from each technology, we estimate that approximately 818.36 million tonnes of coal with an average GCV of 3529.38 kcal/kg will be required to generate the projected electricity.

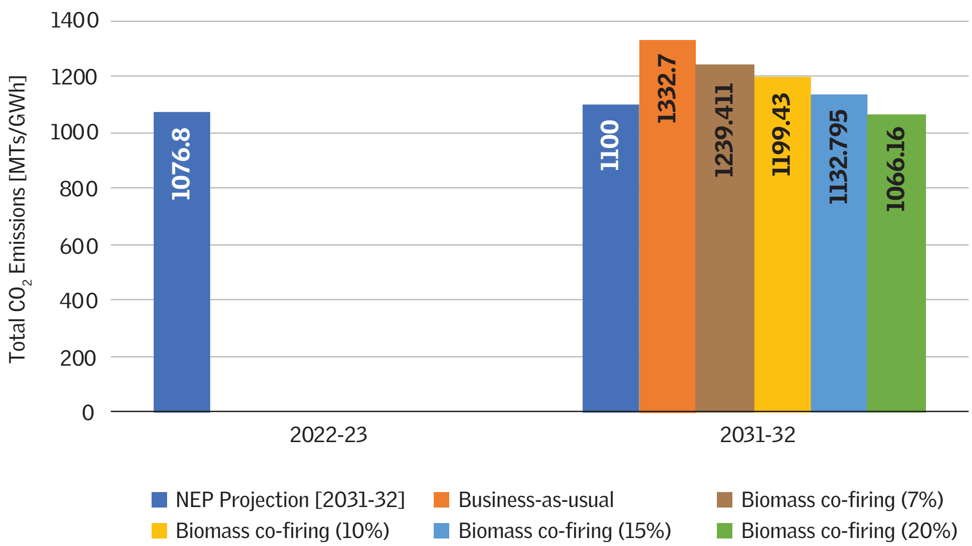
6.4.2 Biomass required

In the revised policy proposed by MoP, as mentioned previously, an initial 5 per cent of biomass co-firing has been proposed. Considering 5 per cent of weight from the previous estimate of 928 million tonnes of coal, we arrive at 46.4 million tonnes of biomass. However, since the estimated biomass available currently is 230 million tonnes, co-firing 5 per cent is easily possible.[96] Similarly, for 7 per cent cofiring, we arrive at 65 million tonnes, for 15 per cent we arrive at 140 million tonnes, and for 20 per cent we arrive at 185.6 million tonnes. The current available biomass is 230 million tonnes, and MNRE's report projects that biomass power potential will increase by 2032. Therefore, the available biomass is expected to rise, indicating that we can envisage co-firing at least 20 per cent by 2032.[97] Since NTPC's Unit #4 in Tanda, UP has demonstrated 20 per cent torrefied biomass co-firing, it is feasible to achieve this in other units as well.[98] In addition, the MNRE report[99] provides the weighted average GCVs of various crop residues, averaging 4,185 kcal/kg, which is close to that of coal used. Consequently, replacing a weight percentage of biomass would result in a similar percentage reduction in emissions. For example, replacing 5 per cent of coal with biomass would lead to a 5 per cent reduction in emissions.

6.4.3 Scenario: Biomass cofiring

Based on the above analysis for biomass availability and emission reduction potential, CSE calculated the reduction in emissions from the Business-as-usual scenario if biomass is cofired at 7 per cent, 10 per cent, 15 per cent and 20 per cent

Graph 30: Decarbonization Lever 2 (biomass cofiring) scenarios—Emission-reduction potential



Source: CSE analysis

by 2031–32. We can see a progressive decline in total emissions. *Graph 30* provides the emission- reduction potential of the sector at different percentage of co-firing.

With the gradual increase in biomass co-firing in power plants, total emissions show a consistent decline from the business-as-usual scenario (**1,332.7 MT CO_2**) to a 20 per cent biomass cofiring scenario (**1,066.16 MT CO_2**), representing a **20 per cent reduction** in emissions. The total reduction potential stands at **266.54 MT CO_2** . The findings demonstrate that partial biomass substitution can significantly cut emissions, making it a viable strategy for decarbonizing coal-fired power generation.

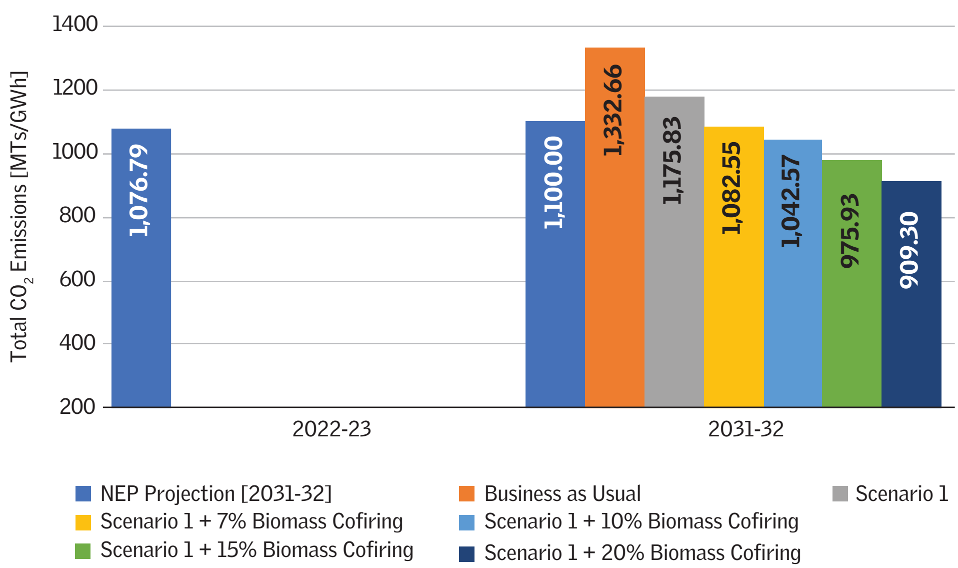
6.5 Decarbonization levers combined: Potential for 2032

In this concluding segment for decarbonization pathways, we have combined the two decarbonization levers. Benchmark efficiency achievement is displayed with various shares of biomass cofiring to display the emission-reduction potential. The segment concludes with a combined scenario of maximum emission-reduction potential for the sector. Scenario 3 has not been considered in this segment owing to technical limitation of the current coal fleet to adopt it.

6.5.1 Scenario 1 + Biomass cofiring

If the efficiency improvements are implemented alongside increased biomass cofiring (considering various percentage scenarios), emissions will decrease (see *Graph 31: Scenario 1 + Biomass co-firing*).

Graph 31: Scenario 1 + Biomass cofiring > Emission reductions potential



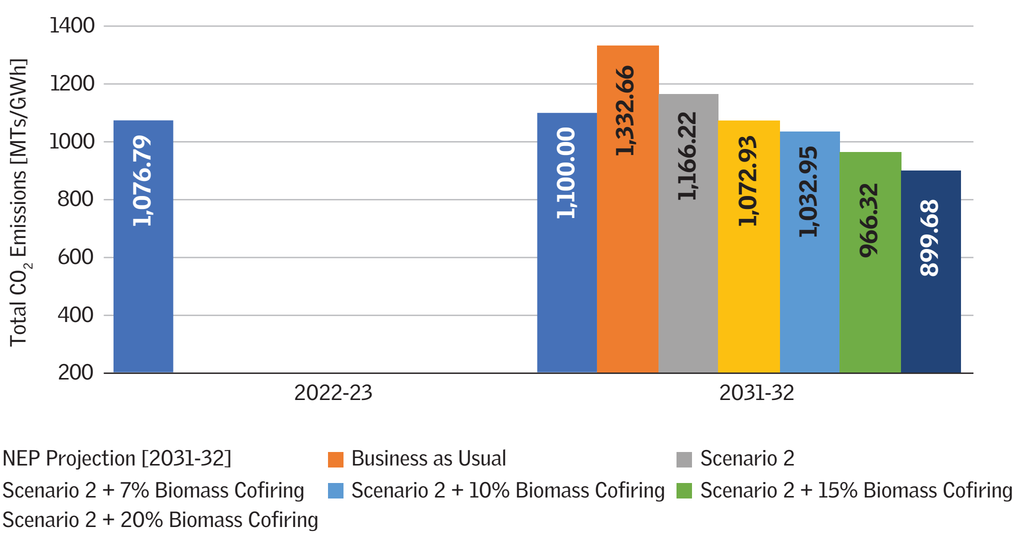
Source: CSE analysis

Graph 31 suggests that implementing biomass cofiring, along with all power plants achieving benchmark efficiency, can reduce CO_2 emissions by 190.7 **million tonnes** (MT) of CO_2 compared to CEA's NEP projections. Furthermore, the reduction can be by over **423 MT** CO_2 from the business-as-usual (BAU) scenario. This translates to a potential **31.8 per cent reduction** (**from BAU**) in emissions when biomass cofiring is increased to **20 per cent**.

6.5.2 Scenario 2 + Biomass cofiring

In this combined scenario we extrapolate Scenario 2's potential of benchmark efficiency with a conservative PLF alteration with various biomass cofiring percentage inclusion. Recalling Scenario 2, wherein we have combined benchmark efficiency factors and presumed the PLF of subcritical power plants at 50 per cent to suggest additional emission reduction than Scenario 1. Similar to previous segment, we have applied various biomass cofiring percentages, awnd by increasing biomass co-firing to **20 per cent**, our estimates suggest a reduction in

Graph 32: Scenario 2 + Biomass cofiring: Emission reductions potential



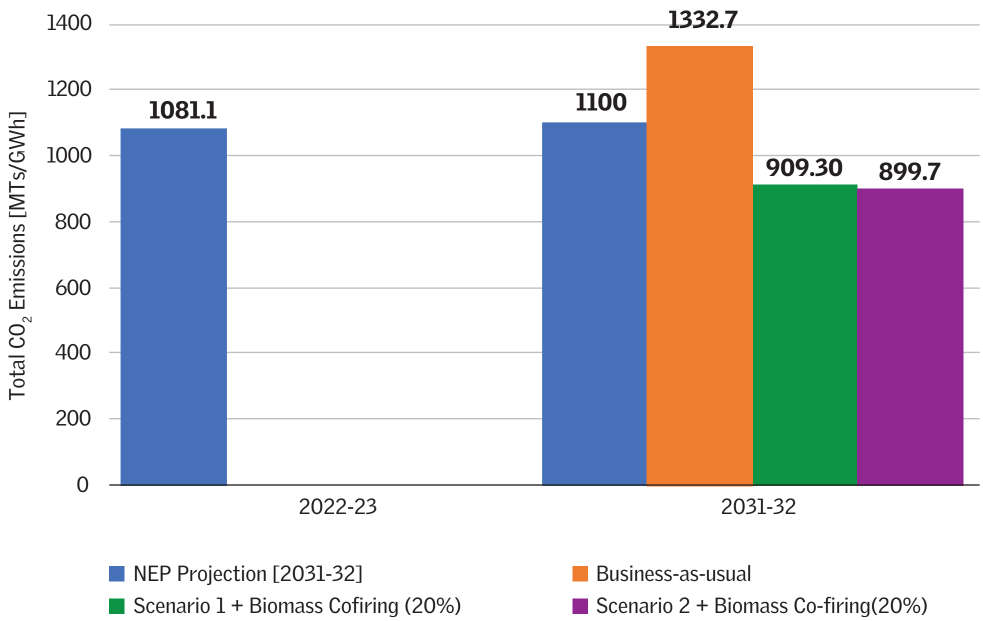
Source: CSE analysis

CO_2 emissions by 200.3 **million tonnes** CO_2 compared to CEA's NEP projections. Furthermore, emissions can be reduced by **433 million tonnes** CO_2, representing a **32.5 per cent reduction** from the business-as-usual scenario. This underscores the substantial impact of biomass integration and along with running higher efficiency units at higher PLF to create improvements in decarbonizing coal-based power generation.

6.5.3 Combined scenarios

To sum up our decarbonization pathways, we have displayed the highest emission reduction scenarios together. The graph displays the NEP's projection, BAU scenario and our two suggested pathways, i.e. Scenario 1 + 20 per cent biomass cofiring and scenario 2 + 20 per cent biomass cofiring.

Graph 33: Decarbonization potential: Combined scenarios



Source: CSE analysis

As shown in *Graph 33*, CEA projected that in 2031–32 emissions would reach about 1,100 MT of CO_2. However, under the business-as-usual scenario, emissions are estimated to rise to 1,332.7 MT of CO_2. However, with new capacity additions and upgradation of existing capacity towards the benchmark emission factors for all units is achieved then emissions will reach **1,175.83** MT of CO_2. Further, shifting a larger generation burden towards supercritical and ultra-supercritical units will result in higher emission reductions. Operating all subcritical units at 50 per cent PLF will result in **1,166.22 million tonnes CO_2** of emissions. **This signifies 11.7 per cent and 12.5 per cent emission reductions** from BAU scenario respectively.

With Scenario 1 and increasing biomass co-firing to 20 per cent, our emissions can be as low as **909.3 MT of CO_2.** This can result in a reduction of **423 MT** CO_2 from the business-as-usual (BAU) scenario. This translates to a potential **31.8 per cent reduction (from BAU)** in emissions when biomass cofiring is increased to **20 per cent**.

By achieving Scenario 2 and increasing biomass co-firing to 20 per cent, then, based on our calculations, our emissions can be as low as **899.7 MT of CO_2**. This is a **32.5 per cent** decline in emissions from the BAU estimated emissions. Conclusively, this will result in **18.2 per cent** emission reduction from the NEP projected emission figures.

Serious consideration and implementation of biomass co-firing is highly recommended. Currently, thermal power plants (TPPs) are required to cofire 5 per cent biomass with coal, starting from FY 2024–25, with the obligation increasing to 7 per cent from FY 2025–26. As mentioned earlier, following the example of NTPC unit #4 at TANDA, which demonstrated 20 per cent biomass co-firing, it is recommended that all units aspire to achieve this percentage by 2032. As of March 2025, 68 TPPs have started biomass cofiring and the MoP has set a target of 10,000 tonnes of biomass to be cofired every day for the FY 2025–26.

The current emissions estimates account for the rising share of renewable energy in the generation mix. Without this shift, emissions from coal-based generation would be significantly higher (BAU Scenario 2). Considering the rising demand for electricity in India, the coal fleet will be required to operate at a higher PLF than estimated in Scenario 1 and 2. Therefore, public policy must focus on upgrading existing infrastructure. Reforms to the current coal fleet are essential to reduce the emission intensity of its operations. To undertake this, we suggest the following measures to achieve decarbonization goals of our TPPs.

6.6 Findings and recommendations

This report has attempted to deep dive into different aspects of coal-based thermal power plants to understand the feasible roadmap for the decarbonization of the sector. In this study, CSE conducted an analysis of coal-based thermal power plants data largely from 2022–23 and also looked at their past data wherever available. The analysis under this study has led to certain findings and recommendations that could be crucial for decision making in future and laying down the decarbonization roadmap for the sector. Some of these would directly play a role while some would play an indirect/external role in decarbonizing the Indian coal based thermal power plants.

- **Need for improving efficiency/operational optimization of the current fleet**: Currently there is a large scope of improving the efficiency of the existing thermal power plants operating in the country. According to the CSE developed scenario for 2031–32, with benchmarked emission performance (see Scenario 1), a reduction of **11.7 per cent** (or 156.8 million tonnes of CO_2) emissions can be achieved from the BAU scenario. With biomass co-firing at 20 per cent, this reduction can be further extended to **31.8 per cent** (***see combined scenario***). A life cycle assessment of all thermal units should be undertaken to gauge various improvements that can be undertaken to highlight individual improvements for each thermal unit.

While there is a renovation and modernization list that aims to improve the efficiency of more than 233 plants, the issue is that there seems to be no concrete plan with a timeline as as to how this can be done at an accelerated pace across the country. Apart from the requirement of finance, the plants/units might also have to shut or close down for renovation and modernization. Therefore, some findings and recommendations of CSE with respect to renovation and modernization are following:

- ***Submit R&M plans for individual units in the R&M list***: Detailed audits of units listed in the R&M list by CEA should be conducted on priority by the units themselves and based on the findings, a time bound R&M plan should be submitted by these units to the CEA/ Ministry of Power in a specified time frame.

- ***Set a deadline for R&M plans and execution***: A clear deadline needs to be set for all units and plants in the R&M list to submit a renovation and modernization plan for all their units with a well-defined timeline to a dedicated monitoring agency. An alternative source of electricity during the R&M period should be prescribed in advance to cover for the loss of supply for the said duration.

- ***Consideration of inclusion of CSE's least performing units in the R&M list*****:** Out of 22 least performing units (operating at PLF 50 per cent and above) listed by CSE for the year 2022–23, nine plants are not included in the R&M list, because the R&M list has a criteria of age above 20 years. These plants should be audited and based on the findings should be considered for addition to the R&M list.

- ***Many younger units operating at high PLF are also inefficient***: There are 10 units with PLF higher than 65 per cent and aged less than 20 years with an emission factor more than 1.05 tonne/MWh. Even with a coal GCV in a similar range as of lower emission intensity units, we need to assess if these units need any R&M interventions as even with a higher PLF and younger age the emission intensity remains high.

- o ***Dedicated budget/scheme for R&M/LE efforts*****:** Thermal power units are a high emitting industry but are key to India's energy security and therefore to fast track their efficiency efforts, a dedicated scheme to support this effort is essential. A standalone scheme will ensure that financial and logistical challenges of the same are overcome in a time bound manner. Legislative scrutiny via standalone scheme will enhance transparency efforts. This can enable further scrutiny from parliamentary standing committee and can be individually assessed by Comptroller and Auditor General (CAG).

- **Revise age criteria for retirement or R&M of TPPs**: CEA's 2020 note and its recent R&M policy, all consider age as the basic criteria for shortlisting/considering plants for retirement and for renovation and modernization. CSE's analysis finds that age alone cannot be the criteria to decide on their retirement or the need for renovation and modernization for efficiency improvement in thermal power plants.

  Our analysis found eight units with age 25 years and above among the top 100 subcritical units in terms of emission intensity and efficiency with PLF above 50 per cent using coal with CV between 3,000–4,500 Kcal. This even included one 40-year-old unit, Trombay Coal Tata Power. Similarly, CSE's data analysis also found that among the list of 100 thermal power units with the highest emission factors (with more than 50 per cent PLF, using coal CV in the range of 3,000–4,500 Kcal), 49 units are below the age of 20 years and around 10 units are below the age of 10 years.

  In the 418 plants that operated at more than 50 per cent PLF, around 95 units less than 25 years of age are below the average fleet efficiency of 32.5 per cent. Moreover, 27 of these units are below 30 per cent efficiency. This also includes five supercritical thermal units. Therefore efficiency/SHR and emission intensity should be considered as a criteria for inclusion of plants/units in the R&M list. A continuing poor performance could form the basis of putting such a plant or unit in the R&M list.

  Clearly showing age alone cannot be a yardstick to make crucial decisions about their need of efficiency improvement and retirement. Consideration of factors like CO_2 emission intensity, efficiency, station heat rate, air pollution control measures, PLF are other important parameters to be considered before planning to renovate and modernize or retire any unit or plant.

- **Enhance biomass cofiring through incentivization/penalties and market stabilization:** As per the CSE scenario, with the gradual increase in biomass cofiring in power plants, total emissions show a consistent decline from the business-as-usual scenario (1,332.7 MTs) to a 20 per cent biomass co-firing scenario (1,066.16 MTs), representing a 20 per cent reduction in emissions. However, its broader adoption is hindered by challenges such as rising biomass prices, supply chain issues, and the lack of an effective framework for enforcement which includes penalties and incentives. To address these obstacles, it is recommended that a permanent regulatory body be established to manage biomass allocation across competing uses—including its growing demand from industries and biogas plants—and to implement a robust pricing mechanism to stabilize costs. In tandem, a comprehensive enforcement strategy combining both penalties and targeted incentives should be introduced, drawing on the progress achieved in the Delhi-NCR region, to ensure compliance and promote cleaner, more efficient thermal power generation nationwide.

- **State power plants are underperformers, require focused interventions:** CSE's analysis of 2022–23 data shows the average emission intensity of state owned thermal power plants is 1.06 tonne/MWh compared to 1 tonne/MWh of Centre-owned plants and 0.84 tonne/MWh of privately owned plants. In terms of efficiency, the average efficiency of state owned plants is around 30 per cent compared to the Centre and private-owned fleet which are above 32 per cent average efficiency. The state-owned plants also had the highest average auxiliary consumption of 9.20 per cent compared to 7.48 per cent and 6.75 per cent of Centre and privately owned plants respectively. In CSE's list of 32 least-performing subcritical and supercritical units, 14 units (almost half) are owned by states. Although state-owned plant/units play a crucial role in meeting the electricity demand of a particular state, state governments would need to create the necessary regulatory framework and support system to improve the performance of their plants. Currently, a large number of state-owned plants are in a must-run status to fulfill the electricity demand while ignoring the need for improving their operational, environmental and emission related issues.

- **TPPs need to take up emission intensity targets:** Coal-based thermal power companies, plants and units must establish emission intensity targets to drive decarbonization efforts. CSE's analysis reveals that hardly any company has set such targets at the company, plant, or unit level. While the uncertainty of power supply due to merit order dispatch and fluctuating demand poses challenges in setting fixed targets, plants operating above a certain PLF threshold should still adopt emission intensity benchmarks. Furthermore, since these entities are not included in the upcoming Indian Carbon Credit and Trading Scheme, they will not be subject to market-driven emission intensity targets. Establishing clear reduction goals at the operational level is essential to ensure accountability and progress toward a lower-carbon power sector.

- **Redefine Merit Order Dispatch**: The current merit order dispatch in the country is solely based on the cost of electricity. Plants with higher costs are placed lower in the MOD. The policy invariably affects the newly constructed super and/or ultra-supercritical power plants.

  - ***Underutilization of efficient fleet***: The national average PLF of the units under all three technologies, one finds the highest average PLF is of the least efficient technology, i.e. subcritical (with 68 per cent PLF) followed by supercritical (61.9 per cent) and ultra-supercritical (54 per cent), which is just the reverse of their efficiency order. As per the 2022–23 database, 22 units of supercritical and ultra-supercritical technology operate below 50 per cent PLF.

  - ***Cost criteria affects emissions***: The MOD is based on the cost component of per unit generation. This gives preference to units with a lower variable cost irrespective of its efficiency and emissions. Consequently, even units with older technology and higher emission factor often are given preference above units with new technology and lower emission factor. The distance between coal generation units from coal mines invariably affects variable cost component therefore, coal units located further away from coal mines are more affected by this. Thermal units closer to coal mines benefit from this structure as they get preference independent of their higher emission factors. Additionally, the new power plants with efficient technologies often get coal procurement contracts/agreements at a higher price compared to the older plants which again increases their variable costs affecting their ranking in the dispatch.

  - ***High environmental cost***: The current criteria does help in making electricity cheaper and accessible at affordable prices but creates a negative externality by causing higher GHG emissions and air pollution. The short-term gain of cheap power results in long-term impact of higher emissions and its impacts.

- o ***Lack of incentives***: The cost-based parameter in the merit order leads to no incentive for improving plant efficiency and reducing emission intensity. The upcoming Indian carbon market also does not include the power sector thus there is hardly any incentive to emit less.

- o ***Implement an environmental MOD***: A consideration of emission parameters in MOD, to incentivize decarbonization. Our report highlights the South Korean model of environmental merit order dispatch wherein power plants with lesser emissions or in other terms 'environmentally good' are dispatched earlier. The model imposes a higher cost on carbon and thereby dispatching units with lesser emissions based on the merit order ranks. MOD improvement will incentivize best performing plants leading to lower emissions from power supply.

- **Revisit PPAs for decarbonization acceleration**: PPAs are not only instrument of power purchase but have wide impact on the overall decarbonization processes within the industry. Length of PPAs plays an immense role in power structure and it is now known that shorter PPAs are better for incorporation of RE within the power grid. Approximately more than 70 per cent of the thermal power is covered within old PPAs, which means they are locked in with long duration. New units within existing power plants are also covered within the old PPAs of the power plants instead of creation of a standalone new PPA.

  We recommend certain changes within the larger policy canvassing aspects of PPAs as following:

  - o ***Reduce term time of PPAs:*** A PPA term length review of the current fleet is suggested as it can assist in identifying the actual scope of decarbonization through PPA amendments. A comprehensive cost benefit analysis of the cost of termination of old PPAs vis-à-vis amendment of length of PPAs should also be undertaken. Lengthy PPAs are an impediment in two ways. Older PPAs provide no scope for downward revision of cost of electricity supplied. Additionally, the entire burden of R&M is on the plant owner and thus there is no incentive to bring in new technology as the plant owner is assured of his income. Secondly, PPAs lock in the GRID's energy supply to thermal power even if RE is being added. Despite new RE installation, the GRID is obligated to buy in thermal power due to the agreements.

  - o ***R&M cost sharing provision in PPAs:*** PPAs should be revised to incorporate provisions for cost compensation during Renovation and Modernization (R&M) of thermal power plants. The current structure does not account for R&M expenses, placing the full financial burden on plant owners while providing no revenue support during the upgrade period. As a result, plant operators often choose to continue running inefficient, high-emission units rather than invest in modernization. Additionally, the absence of a clause allowing a temporary pause in PPA obligations during R&M leads to financial penalties for non-generation, further discouraging efficiency improvements. To address this, PPAs should be modified to include mechanisms for cost-sharing between DISCOMs and plant owners, financial support during the R&M period, and structured provisions to temporarily adjust contractual obligations without penalties. A dedicated financial scheme or budget should be allocated for this to support both the parties.

- o ***Incentivize revision of PPAs****:* Decarbonization efforts have to be commercially appealing for the end user for their necessary uptake. Insulating consumer by burdening DISCOMs for energy prices is not economically viable. Similarly burdening the plant owner for the entire cost of optimization without creating an ecosystem that necessitates the same is also futile. The old PPA structure does not incentivize improving efficiency and reducing emissions, therefore there is a need to have enough incentives for decarbonizing and optimizing power plants which then leads to further incentivizing acceptability to revise the older PPAs into the new and flexible ones that accommodate the window for allowing and facilitating decarbonization efforts. Additionally plants opting for new, flexible and shorter PPAs should receive added benefits over the ones with old PPAs. The revision of PPAs could bring relief to the DISCOMS and make power generation cleaner through more decarbonization of the existing fleet and integration of renewable energy.

  The PPAs should be a tool for thermal power upgradation and decarbonization and not mere instruments of contract for power supply at a specified cost. The policy challenges are multi-pronged and therefore require a holistic level of changes to improve the overall systemic issues.

- **Repurpose coal levy towards decarbonization:** The GST compensation cess is scheduled to end by March 2026, and its future is currently under deliberation by a Group of Ministers within the GST Council. From an environmental perspective, revenues generated through coal production should be redirected toward decarbonizing coal-based power. Such a shift would ultimately benefit end-users, as the resulting reductions in GHG emissions and improvements in air quality directly impact them. Following the underutilization of the cess in the early 2010s and the diversion of its proceeds to GST compensation since 2017, future revenues generated through the levy on coal should be repurposed to deliver environmental benefits. With an estimated Rs 3,97,600 crore expected to be collected over the next six years, these funds should be directed toward supporting the coal fleet in improving thermal efficiency and optimizing operational processes to lower emission factors and reduce overall emission intensity. As an indirect tax, the cess is effectively borne by power consumers. Therefore, it is both equitable and necessary that this revenue be invested in making power generation cleaner and healthier. Decarbonizing the coal power sector comes with the co benefits of improved efficiency and reduced air pollution.

- **Uncertain demand forecasting requires revaluation:** CEA and Grid India have been forecasting the demand for electricity (peak and overall demand) for the country over the years. Post the 20th electric power survey (EPS) in 2022–23, Grid India also integrated a weekly forecast of electricity demand. Pre-2022, our overall demand forecast was well above the actual demand (although our supply never met the actual energy demand) but post-2022, after the weekly assessment was started by GRID India, our overall demand regularly offshoots the forecast figures (see graph 1). Forecasted electricity requirement has an average shortfall of 2.6 per cent from 2022 to 2025, with 2024-25's forecasted shortfall to be 5.1 per cent. Post 2022, after the pandemic's impact subsided, the peak demand forecast for consecutive years fell short of the actual demand (see *Graph 16: Energy requirement and supply analysis with forecasted demand growth* [2016–17 to 2024–25]). Since 2023's latest amendments mandating monthly shortfall/error reporting, peak demand fell short by 2 per cent and 3.8 per cent for 2023 and 2024 respectively. Although in 2024, CEA made a media statement of a much higher peak demand (260 GW), their actual estimate fell short of the actual peak demand. This clearly shows that there is a need to revisit our forecasting methodologies to make it more robust as the kind of transformational growth and transition India is going through, probably certain factors are not making into the estimates of these forecasts. Therefore a committee or group of experts should be constituted to re-look at the forecasting methodologies we are employing and will employ in the coming years as India goes through a massive transition both in terms of greening and growth of its economy.

- **Accurate demand estimates key to planning coal power phase down**: Due to the surge in actual demand beyond the estimates, the Ministry of Power had to change its plans on coal power within a short duration of the National Electricity Plan for this decade being put out. The shift from listing plants for retirement in the National Electricity Plan (NEP) to an advisory against retiring any unit before 2030, along with a planned coal-based capacity addition of around 46 GW in the NEP now being cited as potentially rising to around 80 GW in media statements, reflects a significant change in coal power policy direction. The uncertainty around demand led to hasty decisions and media statements along with derailing the initiatives and commitment of the Indian government towards phasing down coal. An accurate demand estimate, would allow India to clearly allocate its future possible sources of power to meet the demand reliably, a clearer number beyond which India can abstain on adding any further coal capacity and a detailed phase down plan for the coming years.

- **Flexibilization of thermal power plants needs to be incorporated with a check on emission factor:** To achieve flexible power generation power plants need to operate at a lower technical load. Since Indian high-ash coal is not suitable for 26 per cent minimum load operation(an international benchmark), steps need to be taken to allow plants to improve the average minimum load operation of coal-fired power plants to 40 per cent. Moreover, this figure may need to be decreased further below 40 per cent considering the 500 GW renewable integration by 2030. With this, the overall emission intensity of the grid would go down but thermal power emissions might rise as plants will be operating at lower efficiency. Therefore, we need to take steps to allow plants to work at lower technical load and still keep the emissions in check. One of the step could be to uniformalize the coal quality to a certain GCV range. Further, the C&I system is the link joining all aspects important for efficient plant operation. It should be in the focus of any flexibility project as the benefits and the cost effectiveness are unbeatable. Cost of retrofitting units to optimize them for flexibilization is approx. Rs 30–40 crore per thermal unit and this needs to be accounted for in the policy going ahead. Furthermore, a monitoring dashboard is necessary for transparency on implementation of the CEA's suggested roadmap for retrofitting thermal units for flexibilization.

- **Renewable generation obligations**: If a renewable generation policy comes in for thermal power plants, it should have a fixed target for biomass cofiring. This will ensure that existing power plants are reducing emissions under the policy. Moreover, this policy can also lead to tapping the largely underutilized land under many thermal power plants for renewable energy uptake.

7

REPORT SUMMARY

THIS CHAPTER PRESENTS A SYNTHESIS OF THE REPORT'S KEY FINDINGS, OUTLINING CRITICAL POLICY MEASURES ASSESSED THROUGHOUT THE STUDY.

IT HIGHLIGHTS CSE'S MAJOR INSIGHTS AND CLEARLY DISTINGUISHES BETWEEN TECHNICAL AND SYSTEMIC RECOMMENDATIONS FOR DECARBONIZING THE COAL-BASED THERMAL POWER SECTOR.

Decarbonizing thermal power plants is key to reducing India's future greenhouse gas (GHG) emissions. Electricity generation accounts for 39 per cent of the total GHG emissions of India, with thermal power as the anchor of India's electricity sector predominantly contributing to the economy's consistent growth. Thermal power plants contribute above 75 per cent of the total generation of India's electrical consumption across sectors, resulting in 1,221.5 MT/CO_2-eq emissions in 2019, as per India`s third national communication report to UNFCCC.

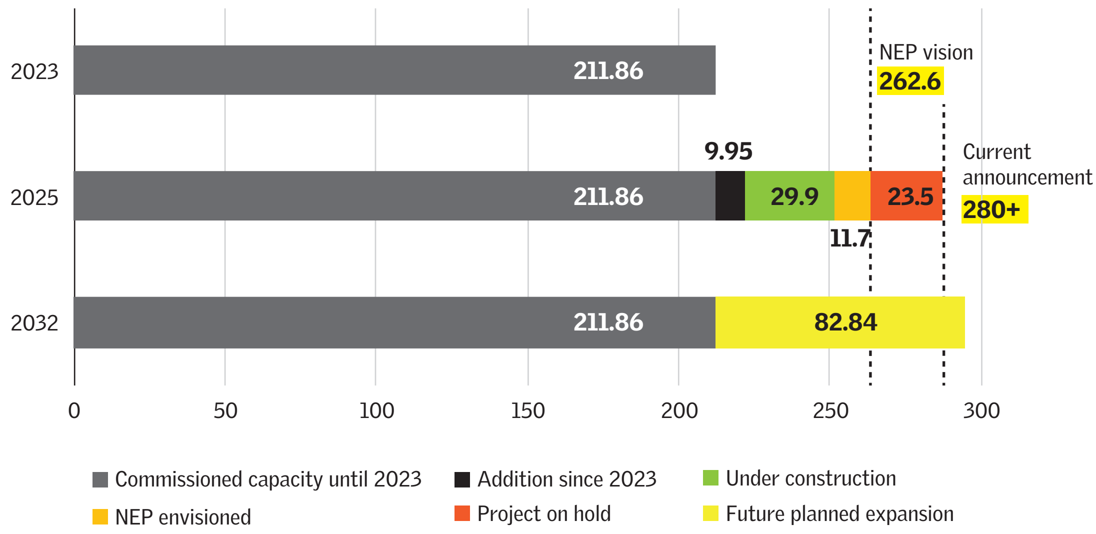
India's NDC targets to achieve 50 per cent cumulative electric power installed capacity from non-fossil fuel sources by 2030. India has increased its non-fossil electricity capacity from a negligible base to nearly 46.3 per cent of its total installed capacity by March 2025, a remarkable growth within just a decade with maximum addition in solar and wind. Despite the progress in RE's capacity addition, RE generation remains below 12 per cent (excluding hydro) of the electricity mix for FY 2024–25. As the supply of electricity from renewables remains intermittent, coal-dominant thermal energy is likely to continue to dominate India's energy-generation mix in the coming years. Coal seems to remain the mainstay of India's energy security future. Therefore, going ahead, strong and strategic measures for emission reduction from coal power plants will be paramount to reduce the overall emissions from the sector.

7.1 Current fleet and future additions

Coal-fired thermal energy is one of the oldest industrial processes in the modern history of mankind. Electricity is generated via use of combustion of coal resulting in heat that turns the turbines to generate electrical power via it. The key components that determine the capacity to undertake this are the boiler, the series of turbines, generator, condensers and the cooling towers. Technology to undertake the burning process determines the efficiency of the plant, with higher efficiency resulting in lower coal consumption and lower CO_2 emissions. There are namely three types of technology in operation in India, i.e. subcritical, supercritical and ultra-supercritical. There is also a more advanced technology, i.e. advanced ultra-supercritical technology, of which India plans to set up a plant in the state of Chhattisgarh.

Coal provides above 75 per cent of the electricity generation of India. According to the CEA baseline data of 2022–23, around 84.7 per cent of India's coal power plants operate using subcritical technology, with a national average efficiency of 32.5 per cent. Nearly 12 per cent of the fleet is running on supercritical technology, which has a national average efficiency of 35.4 per cent. India has recently adopted ultra-supercritical technology, which boasts a national average efficiency of

Graph 34: Coal capacity addition—Current and future plans [in GW] (2023–32)



Source: CSE analysis on basis of multiple policy documents

36.4 per cent, although only 3.3 per cent of its fleet utilizes it. However, India's thermal power plants are running below the expected efficiency levels. The Ministry of Heavy Industries sets efficiency benchmarks at 35 per cent for subcritical, 40 per cent for supercritical, and 42 per cent for ultra-supercritical units. The coal power plant sector has a proportionate split of one-third of total installed capacity among Centre (*31.8 per cent*), state (*32.8 per cent*) and private (*35.4 per cent*) power plants (see *Table 6: CSE analysis: India sector-wise power generation and emission share).*

At the point of the National Electricity Plan (NEP) 2022–23 in March 2023, India's installed capacity for coal and lignite stood at 211.86 GW. Since then, until March 2025, 9.95GW of new capacity has been added. Therefore, as of March 2025, India's coal fired thermal capacity stands at 221.85 GW, which is approximately 45 per cent of the total installed capacity. The NEP provided a list of likely additions by 2032. Furthermore, 23.5 GW of coal capacity is on hold due to regulatory or financial issues.

Owing to rising demand, India's coal capacity is slated to rise beyond the NEP's projected estimates.As per the NEP, India's projected expansion by 2031–32 was 262.6 GW (in a high-demand scenario). However, in August 2024, the Government of India informed the nation via Parliamentary discussion that India will expand its capacity up to 283 GW by 2032, i.e. a likely addition of 70+ GW in the next six to seven years. Currently, 29.9 GW of new coal expansion is under various stages of construction. Among the plants under construction, 62.3 per cent of the capacity will operate on ultra-supercritical and the rest, i.e. 37.6 per cent, will operate on supercritical technology. As per the government's reply in the parliament, the thermal capacity addition is expected to entail an expenditure of minimum **Rs 6,67,200 crore** by 2031–32.

A thermal power plant's payback lifecycle is considered to be between 25–30 years. By this time the plant pays off its own fixed cost. Mostly PPAs are also signed with this lifecycle estimate in mind. According to 2022–23 baseline data analysed by CSE, India's coal fleet is young, with 57 per cent of the fleet being up to 15 years old consisting of a mix of sub, super and ultra-supercritical technology. The older coal fleet (above 25 years), however, runs entirely on subcritical technology, with 19.2 per cent of the entire subcritical fleet being 15–30 years old and 23.5 per cent of the subcritical fleet being above 30 years of age.

7.2 Policy scenario and challenges

Thermal power generation's decarbonization is overseen by three key bodies. The Central Electricity Authority (CEA) handles future planning and progress monitoring, publishing documents like the National Electricity Plan and annual generation targets. The Ministry of Power sets tariff rules and oversees power generation issues such as Power Purchase Agreements and plant generation figures. GRID India manages electricity demand and supply through the National Grid. This report highlights key policy issues that must be addressed to reduce emissions from coal-fired power plants.

7.2.1 Power Purchase Agreements

India's Power Purchase Agreements (PPAs) have historically ensured revenue security for thermal power producers and financing confidence for investors. However, long-term contracts—often lasting 25+ years—have created rigidities in the power sector. These legacy PPAs (assumingly covering more than 70 per cent of the fleet) tie DISCOMs into paying fixed costs regardless of plant efficiency or demand, discouraging integration of renewable energy (RE) and modernization of old coal plants. The 2022 model introduces shorter tenures (short, medium and long term), yet fails to address core issues, with old PPA structure still being adopted by multiple upcoming units. Renovation and Modernization (R&M) costs are borne solely by utility owners, with no compensation for the shutdown period required for any form of major upgradation and neither any provision to pause contracts. As a result, many inefficient plants continue to operate rather than upgrade. While newer tools like SHAKTI and the PUShP portal bring transparency to coal and power procurement, they don't change the outdated incentive structure. The current PPA framework is misaligned with decarbonization goals, locking in high emissions and high costs. The report recommends reforming PPAs to link payments to performance, emissions and flexibility, making them more adaptive to evolving energy priorities and climate goals.

7.2.2 Merit Order Dispatch

The merit order dispatch (MOD) is based on the cost component of per unit generation. India's MOD system prioritizes power generation from the lowest-cost sources. Historically, this benefits pithead coal plants but overlooks environmental performance. The national average PLF of the units under all three technologies, one finds the highest average PLF is of the least efficient technology, i.e. subcritical (with 68 per cent PLF) followed by supercritical (61.9 per cent) and ultra-supercritical (54 per cent), which is just the reverse of their efficiency order. As per the 2022–23 database, 22 units of supercritical and ultra-supercritical technology operate below 50 per cent PLF. The current MOD is solely based on the cost of electricity, placing plants with higher generation costs at a lower order. The policy invariably affects newly constructed supercritical and ultra-supercritical power plants. The distance between coal generation units from coal mines invariably affects variable cost component. Coal units located further away from coal mines are more affected by this, as the MOD will give preference to units with lower variable costs irrespective of their operational efficiency. Thermal units closer to coal mines benefit from this structure as they get preference independent of their higher emission factors. The current criteria does help in making electricity cheaper and accessible at affordable prices but creates a negative externality by causing higher GHG emissions.

Recent reforms now plan dispatch a day ahead and include more thermal plants, aiming to improve cost-efficiency and reliability. However, MOD still excludes environmental costs such as emission and pollution controls, missing an opportunity to incentivize cleaner energy. This report highlights South Korea's Environmental MOD (eMOD) as a model to be looked at, where carbon pricing influences dispatch priorities. India's system could evolve similarly by embedding carbon and efficiency metrics into MOD. This would align dispatch with climate goals, reward low-emission plants, and drive cleaner, more efficient energy use across the grid.

7.2.3 Demand forecasting–supply-side issues

Indian power demand forecasting is estimated via the Electrical Power Survey Committee under CEA in their 20th survey report prepared every five years and managed by GRID India on a weekly basis. The EPS data is used for power generation planning, including the number of new power plants needed and the plant load factor of existing power plants. Post-2021, after the abatement of the COVID-19 pandemic, India's annual electricity requirement has grown by an average of 9.25 per cent per year from FY 2021–25, while the 20th EPS had forecasted an annual growth rate for electricity requirement at approximately 6.65 per cent only. This highlights that India's power demand for electricity has consistently breached the forecasted figures assumed in the 20th EPS, 2022 report. Consequently, unreliable forecasting affects power supply. GRID India's Forecasting Error Report for 2024 (see *Graph 18: GRID India monthly forecasting error report data: Peak demand and energy requirement (2023–24)*) reveals an average shortage of 3 per cent for electricity requirement and peak electricity supply. CSE's energy requirement analysis for FY 2024–25 vis-a-vis 20th EPS forecasted energy requirement analysis for the year suggests the shortfall to rise to 5 per cent.

The shortfall becomes more pronounced during the non-solar hours when RE is not available (see *Graph 15: Load analysis: Peak demand met—solar, non-solar hours versus forecasted, yearly peak [2019–24])*. To meet rising demand, thermal units operate beyond their estimated generation target. Yet, the supplied electricity is not of the requisite quality wherein, 30 per cent of the total electricity supply breached the quality standard of the CERC regulations, placing individual appliances and the transmission network at risk. Compounding the challenge is the high fluctuation between peak and lean demand, especial during the winter months, typically a period of lower power demand, with the last three years (2022–25) seeing an average monthly fluctuation of 57.6 per cent. The fluctuation results in inconsistent thermal operations affecting their overall efficiency.

As a result of rising demand, power supply is kept higher than actual consumption levels to prevent power shortage in case of sudden demand surge. The high supply with lower actual consumption is leading to a consistent decline in the national grid's system load factor from the peak of 85.55 per cent in 2017–18 to 71.4 per cent in 2021–22. This reflects idle capacity in the grid for long periods reducing efficiency of the national grid. This inefficiency of planning and forecasting increases generation costs and pushes consumers to pay for electricity they may not actually use. Moreover, the government's decision to cancel planned retirements of old, inefficient units further entrenches dependence on high-emission sources. Ultimately, consumers are bearing the financial and environmental burden of outdated infrastructure and policy inertia, receiving costlier, lower-quality, and carbon-intensive electricity in return.

7.3 GHG emissions: Current scenario

Analysing data submitted by India's third communication (NC3) to UNFCCC, India's GHG emissions from electricity generation have recorded a 50 per cent, rising from 819 in 2010 to 1,233.5 MT/CO_2 in 2019. Over the past decade, BUR submitted to the UNFCCC show that the share of emissions (38.36 per cent in 2010 and rising marginally to 39.5 per cent by 2019) from the electricity sector dominated by coal has remained constant over the decade. Yet, the actual emissions have increased by 50 per cent, portraying the need for taking measures to reduce the carbon emissions in the future.

7.3.1 Sector-wise emissions

The coal power plant sector has a proportionate split of one-third of total installed capacity among Centre (*31.8 per cent*), state (*32.8 per cent*) and private (*35.4 per cent*) power plants. However, the generation percentage differs, with Centre-controlled power plants providing a larger share of 37.1 per cent into the generation mix than the other two owing to their higher PLF (plant load factor). The average PLF of the sector stood at 65.8 per cent, 54.81 per cent and 44.58 per cent among Centre, state and private TPPs respectively. Yet, CSE's analysis of the sector-wise emission data analysis revealed that the distribution of total emissions among the three sectors is largely split in equal proportion (*Centre: 396 MT [36.7 per cent]; state: 355 MT [32.9 per cent]; private: 327 MT [30.3 per cent] in Table 6*). This is because of the variance in emission factors of the sectors (*Centre: 1; state: 1.06; private: 0.84*) and their overall efficiency in production of electricity (see *Table 6: CSE analysis: India's sector-wise power generation and emission share*). In conclusion, the state government-owned power plants have a higher emission factor. Hence, we recommend taking measures to improve efficiency of state-owned thermal power plants.

7.3.2 Technology-wise emissions

Subcritical thermal units dominate India's coal fleet, as supercritical were introduced only in the 2010s and ultra-supercritical from 2019 onwards. This is reflected in the unit share of the three technologies, with subcritical dominating with 463 units as of 2022–23 while 72 and 20 units of supercritical and ultra-supercritical respectively. The average emission factor of subcritical units is the highest, i.e. 1.07 tonne/MWh (compared to 0.92 tonne/MWh of supercritical and 0.89 tonne/MWh of ultra-supercritical), and their average age is 20.75 years. Among them, R GUNDEM-B in Telangana is the oldest operational unit having been commissioned in May 1970, 55 years ago. Additionally, subcritical units have an average auxiliary consumption rate of 9.14 per cent, which is approximately 47 per cent higher than supercritical and 34 per cent higher than ultra-supercritical units. Similarly, their average station heat rate is 14 per cent higher than supercritical and 17 per cent higher than ultra-supercritical units. The overall GHG emissions of subcritical units comprise 72.32 per cent of the total emissions. Yet, the decarbonization measures need not be limited to older power generation units; they have to encompass all units collectively as illustrated by our analysis.

7.4 Benchmarking thermal units: CSE analysis

All thermal units operating at a Plant Load Factor (PLF) above 50 per cent have been analysed to identify the 20 top-performing units in terms of CO_2 emission intensity and efficiency across the country, benchmarked by technology type—subcritical, supercritical and ultra-supercritical. A unit operating below 50 per cent PLF needs frequent closure and restarting resulting in a higher heat rate and therefore 136 units are excluded from the analysis. Similarly, India's subcritical thermal power plant fleet is vast and to analyse it better we have divided them into two categories for benchmarking purposes. The categories include, *first*, units with less than 250 MW capacity and, *second*, units with equal to or greater than 250 MW. To highlight a targeted improvement plan, we've enlisted the 20 least performing units in all three categories.

I. Subcritical category (less than 250 MW)

The best-performing units subcritical units, (see *Table 9a: Best performing subcritical units with capacity < 250 MW*) are largely operated by the Centre. Crucially, the age profile of these units is between 38–42 years. This highlights the emission factor of a unit is not proportional to the age of the unit. Coal quality is also not the primary factor as the units use coal of similar GCV, i.e. G12–14 (3,000–3,800).

JSW Energy's Torangallu IMP units are the best performing despite being above the age of 25 years. One needs to note that Unit #1 has the highest efficiency among all units in the database. However, these units use a blend of coal with oil and therefore aren't the best example for our analysis.

Among the best-performing coal units, NTPC's KORBA STPS in Chhattisgarh stands out as the units are almost 40 years old and primarily rely on domestic coal of lower GVC value, engage minimal use of oil for blending and yet have low emission factor. Despite being the oldest among the three units, Unit no. 2 has 0.96 tonne/MWh emission factor and a high efficiency of 33.7 per cent. Younger units need assessment for their low efficiency as none of them reach the benchmarked 35 per cent efficiency either.

To understand the issues of low efficiency, we've created two lists of least-performing units, i.e. *first*, exclusively for coal units and, *second*, a combined list of coal + lignite. *Table 9c* highlights the efficiency concerns of the sector as numerous units are below the age of 25 years and exhibit low efficiency. One can note that units of smaller capacity, i.e. below 100 MW are quite low on efficiency despite being some of the youngest.

II. Subcritical category (250 MW or above)

The benchmarked units as presented in *Table 10a* safely establish that efficiency of thermal units is not solely reliant on the type of coal used. Further, age is not the primary criteria for emission factor. Furthermore, every sector can achieve high efficiency in their coal unit operation by undertaking the right measures. Tata Power's Trombay units operate beyond 40 years and posit an emission factor of 0.89 with sector-leading efficiency figures across the country. K_Gudem New by TSGENCO illustrates this by achieving the category`s leading efficiency with a low auxiliary consumption percentage. Budge Budge units operated by CESC are above 25 years and achieve a low emission factor.

Among the least-performing units, BALCO TPP stands out for being a young unit *(age 9.2 years)*, yet is the least efficient one with the highest emission factor. Table 10b highlights lack of regulatory oversight that results in inefficient operations of coal units. The average age of least-performing coal units is merely 17.4 years and yet these units are high emitting. A policy initiative to address this is one of the key recommendations of CSE's report.

III. Supercritical category

The decade of 2010 saw the shift towards supercritical coal power units as the new mainstay. The technology was brought in for its higher efficiency leading to lower emissions and coal consumption. Although the Ministry of Heavy Industry benchmarks efficiency of this technology at 40 per cent, we note in *Table 11a* that no Indian coal unit manages to achieve that. Furthermore, **20 per cent** of the units within this category operate at PLF below 50 per cent, resulting in untapped environmental gains. The best-performing coal power unit is operated by Nabha Power Ltd at their Rajpura TPP that boasts an emission factor of 0.84 tonne/MWh. Commendably, all the units among the top 20 supercritical units, barring one, use domestic coal for their operations and yet post emission factors below 0.9 tonne/MWh.

Among the least performing units, however, the KORADI EXTN Unit # 10 and 9 operated by MAHAGENCO (a supercritical technology plant) posts an emission factor that is below some subcritical units and their efficiency is equally poor. As highlighted in our subsequent emission-reduction scenarios, the country can achieve significant reduction by improving operation efficiency of these units up to the level of their top performing peers. Non-technical recommendations within our analysis can significantly assist in structurally improving emission reductions.

IV. Ultra-supercritical category

The majority of the under-construction fleet of coal power plants belong to the ultra-supercritical technology. The Ministry of Heavy Industry benchmarks efficiency of this technology at 42 per cent. *Table 12* highlights that Indian units operating below the stated claims and analysis of the limitations into the same will significantly improve emission reductions. NTPC's KUDGI Unit# 1 and 2 are the top-performing units, using domestic coal as their primary fuel highlighting emission reduction is not primarily reliant on the source of coal. We however notice an underutilization of the plants as **40 per cent** of these units operate at a PLF below 50 per cent. These units should be utilized at a higher level for higher environmental gains as analysed in Scenario 3.

7.4.2 Company-wise analysis

CSE analysed the top 20 net power-generation companies within three sectors representing the average emission factor and the age of their fleet (see *Table 13)*. NTPC leads the sector with 26.6 per cent of total generation and an emission factor of 0.97 tonne/MWh that aligns with the national average emission factor. Units of the company have a sector-leading emission factor of 0.86–0.87 tonne/MWh and achieved efficiency as high as 36–37 per cent, highlighting the scope of appreciation within its own large fleet of thermal units although other Central companies like DVC and NLC in the list had an average emission intensity of 1.03 tonne/MWh and 1.33 tonne/MWh respectively. The average age of NTPC and NLC plants was around 22 years.

The private power generation sector, led by Reliance Power, Tata Power, Adani Power and OP Jindal, all boast average emission factors below 0.93 tonne/MWh, indicative of commendable performance metrics. RAJPURA TPP run by Nabha Power Ltd leads the industry with the lowest auxiliary consumption percentage across the entire sector, i.e. 4.62 per cent, and boasts an emission factor of 0.84–0.85 tonne/MWh.

The list of top 20 net power generators included 13 state sector companies. All of these state power companies have emission factors surpassing 1 tonne/MWh. The average age of the plants of several of these companies is 26–30 years.

Additionally, only a few companies have individual decarbonization pathways with specific emission-reduction targets in the public domain. Adani Power has plans to cofire up to 20 per cent ammonia cofiring at their Mudra TPP. CSE has analysed the scope of ammonia cofiring in the report (*see Box: Ammonia cofiring*). NTPC's planned shift towards supercritical and ultra-supercritical power generation is aligned with the national policy of a shift away from subcritical units to increase generation efficiency.

7.5 Pathways for emission reduction

CSE analysed the various pathways that could lead to reduced carbon emissions from coal-/lignite-based thermal power plants. This section looks at the current status, feasibility and various aspects influencing the acceptance and implementation of these pathways that are currently being discussed and explored by the sector.

7.5.1 Efficiency factors

Improving the efficiency of the current fleet can be a major step in reducing carbon emissions from coal power plants in India. There are several factors that are said to play a role in the efficiency of a power plant. CSE analysed the CEA baseline data to understand the trend in the efficiency of the current fleet (above 50 per cent PLF) in correlation to the factors that are said to or could possibly impact efficiency. CSE's analysis clearly shows a linear correlation between efficiency and emission factor as expected.

Some of the findings from CSE's analysis with respect to other factors were:

• *Plant load factor (PLF)*

Efficiency of a thermal power unit is reflected via reduction in coal consumption leading to lower emissions. CSE's analysis reveals a limited impact of PLF on efficiency of a thermal unit. The analysis showed some units with even higher PLF (>70) show a lower efficiency (less than 30 per cent) and do not show a decline in emission factor, and some units with PLF in the range of 50– 60 per cent have efficiency higher than 35 per cent and a much lower emission factor. This clearly shows that a higher PLF is not always a determinant of higher efficiency and lower emissions, thereby emphasizing the importance of other elements such as operational optimization, fuel and technology in determining higher efficiency and reduction in carbon emissions.

• *Gross calorific value (GCV)*

Generally a coal plant that uses coal of higher GCV results in a lower emission factor, and based on CSE's analysis the trend is also largely true for Indian power plants. However, CSE's analysis portrays a significant number of thermal units that use coal of higher GCV and despite that have a high emission factor (see *Table 20)*.

CSE's latest analysis shatters the long-standing myth that lower GCV in Indian coal leads to higher emission factors. In reality, 12 subcritical power generation units using low-GCV coal are meeting the industry's 35 per cent efficiency benchmark. This shows that cleaner, more efficient power is possible even with lower-grade coal. Additionally, 166 subcritical power units across the country are operating at efficiencies above 32.1 per cent, surpassing the national average for subcritical plants and proving that better performance is achievable.

Similarly, among supercritical and ultra-supercritical power plants, the top performers are those using Indian coal, reinforcing the fact that significant emission reductions are possible without relying on imported fuel.

• *Technology*

CSE's analysis confirms the role of technology in the capacity for power generation units for emissions reduction. Figure 4 of the report highlights the clear trend of higher efficiency and lower emission factor owing to technology. Yet, the analysis also throws light on the below-industry-benchmark efficiency performance of supercritical (38–42 per cent) and ultra-supercritical (42–45 per cent) power-generation units, illustrating the scope for emission reduction owing to operational improvements beyond technology.

7.5.2 Renovation and modernization (R&M)

Rising power demand has put the brakes on thermal plant retirements, making renovation and modernization (R&M) of existing units more critical than ever. CSE's analysis highlights the need to look beyond the age of the unit for R&M works (see *Table 24 and 25)*. Nine power-generation units <25 years are not included in the R&M list but have high emission factor and low efficiency, signifying the need to look beyond age for R&M works. Similarly, three units >25 years with lower efficiency and high emission factor have been omitted from the list for R&M.

Further, for units within <25 years of age and >50 per cent PLF, CEA's R&M plans do not include 84 subcritical units operating below the national average (32.1 per cent) and 173 subcritical units operating below 34 per cent efficiency, which is a major number of installed thermal capacity that have scope for improvement in efficiency.

At the policy level, CSE's analysis reveals that current power purchase agreements (PPAs) offer little incentive for operators to improve efficiency and act as a major barrier to progress. Hence, a critical gap of the current R&M policy is the failure to set clear efficiency targets. Without these targets, meaningful emission reductions from the existing fleet is unlikely unless corrective measures are adopted as recommended. The obligation to urgently make changes lies with the plant operators and the state must amend the policy to streamline the same (see *Box: R&M and energy costs)*.

7.5.3 Retirement

In 2022, NEP proposed 15 units for retirement and CEA's proposed list for R&M included 233 units. CSE has analysed nine power-generation units performing worse than the most efficient unit on the retirement list under the NEP (see *Table 24*: *Units aged 25+ years with efficiency and emissions below the best performer in retirement list*). The analysed units neither feature in NEP's retirement policy nor in CEA's R&M plans. These units are >25 years and the oldest among them is 53 years old. These subcritical units have a cumulative capacity of 1,312.5 MW and their average efficiency stands at 25.28 per cent. CSE proposes a priority performance assessment of these units and based on the assessment findings a decision should be made to assess the possibility to improve their performance. Otherwise, in the case of no possibility or economic case, repurposing or retirement can be considered as per CEA guidelines of April 2024.

7.5.4 Renewable energy

India's renewable energy (RE) targets will result in reduced generation from the existing thermal capacity resulting in reduced emissions. Flexibilization of existing power generation units is key to incorporating RE into the power-generation mix of the national grid. Upgrading atomization in thermal plants to improve ramp rate requires retrofitting the existing thermal fleet with *Control and Instrumentation (C&I) systems,* as they are key to complementing power supply during non-solar hours of operation without impacting the system load factor (see *Box: Flexibility of thermal power plants)*.

Further, Renewable Purchase Obligation (RPO) and Renewable Generation Obligation (RGO) are key policy interventions to shift focus towards RE, including biomass cofiring obligation. CSE's report also lists the RE additions announced by major thermal power generation companies (see *Table 26: RGO compliance deadline on basis of commercial operation date*).

7.5.5 Biomass cofiring

Biomass or agriculture residue is recognized as renewable energy and its usage is a key policy consideration for emission reduction of thermal power plants. Until 2025, all thermal power plants are obligated to cofire 5 per cent biomass with coal for their generation. From 2025–26, this obligation will increase to 7 per cent. A major chunk of the thermal fleet is non-compliant with this obligation. As per latest reports, only 68 thermal power plants are undertaking biomass cofiring at different levels of cofiring percentage.

NTPC's Unit#4 at Tanda, Uttar Pradesh, successfully cofired 20 per cent torrefied biomass, establishing a national benchmark. Further, Mitsubishi Power in Japan achieved 34 per cent biomass cofiring to establish an industry standard for decarbonization of the power sector. CSE's emission-reduction estimates show that maximum scope of emission reduction is possible by taking up increased biomass cofiring. Substantial progress is being made by the thermal power plants in Delhi-NCR, while plants across other states need to catch up (see *Section 6.4*).

7.5.6 Carbon capture utilization and storage (CCUS)

Globally, IEA database shows 21 facilities reducing 0.1 per cent of global emissions via CCUS. As per NITI Aayog's estimates, India possesses a theoretical storage capacity of approximately 393–614 gigatonnes of CO_2 through various methods, including Enhanced Oil Recovery (EOR), Enhanced Coal Bed Methane Recovery (ECBMR), and storage in deep saline aquifers and basaltic rocks. However, there is no functional prototype for the power industry as of now. In India, NTPC's Vindhyachal plant's Unit #13 has plans to capture 20 tonnes of CO_2 from the flue gas of the plant. CSE suggests technical studies need to be undertaken to build related infrastructure and assess the feasibility of the process for utilization at thermal plants.

7.6 CSE's proposal for coal decarbonization: Scenarios

Decarbonization of the thermal power sector will require a multipronged approach. Taking the National Electricity Plan as the base, our report projects emission reduction scenarios by implementing the most impactful pathways of decarbonization that are possible to scale in this decade and which are also the part of various government policies but require more ambition. We have adopted two primary levers for decarbonization, i.e. efficiency improvement and biomass cofiring. CSE analysed the levers to propose emission reduction scenarios for the thermal power sector, briefly discussed in the following:

1. **Business-as-usual scenario**: NEP's projection for 2031–32 for energy requirement for India is 2,473.7 BU. The National Electricity Plan (NEP) projects an average 58 per cent plant load factor (PLF) for the thermal fleet by 2031–32. At current emission rates and the proposed and planned increased capacity, this would lead to total emissions of 1,332.7 million tonnes (MT), a 23 per cent annual increase from the 2022–23 emission figures baseline.

   If NEP projections do not hold true, i.e. the demand for energy remains high while RE integration remains at the same level, coal's share in our generation mix will remain the same. To analyse this, we have created a BAU 2 scenario with total generation share of coal being kept at the same base as it is in March 2025, i.e. 74.4 per cent. In such a scenario, the total emissions from coal will rise from 1,332.7 MT to 1,838.2 MT. This will be a **37.9 per cent** increase from the BAU projections.

2. **The first approach is to improve the emission factors based on the best-performing units in each category:** Our report analyses CEA's baseline data to identify top-performing units by technology based on their emission factors. For each technology segment, we established a benchmark by taking the emission factor data from the best performing unit of the category. If all units within each technology match these benchmarks, total emissions would fall by 11.7 per cent compared to the BAU scenario, bringing total emissions down to 1,175.83 MT, which is 156.82 MT lower than BAU.

   Due to the high number of plants in the subcritical segment with varying age profile, efficiency improvements have been benchmarked at two factors. A detailed illustration of the performance of benchmarked units is provided in Section 6.2.2.

3. **The second approach is to conservatively alter PLF of different technology categories**: Our report's analysis reveals a considerable difference in emission factor of subcritical units and super/ultra-supercritical units. While India is moving towards newer technologies, the decarbonization journey necessitates allocation of power efficiently to achieve lower emissions. Based on NEP's share of energy requirement from coal, our scenario allocates 50 per cent PLF for subcritical units and a higher PLF of 68.46 per cent to super and ultra-supercritical category units. The shift towards super/ultra-supercritical creates an additional emission reduction of 0.8 per cent in comparison to Scenario 1. This will reduce our total emissions by 166.43 MT from the BAU emissions.

4. **The third approach is towards an accelerated PLF alteration**: Advancing our analysis of optimum allocation power efficiently to newer technologies, in Scenario 3 we have assumed a minimum PLF of 80 per cent for super and/ or ultra-supercritical units across the country. Based on the NEP's share of energy requirement from coal, our analysis reveals that subcritical units will need to run at only 41 per cent PLF. The higher share towards super and/or ultra-supercritical units results in 1.8 per cent higher reduction in comparison to Scenario 1. This also sheds light on an overcapacity in the subcritical category if RE integration keeps up pace as per NEP projections. We have not recommended this approach owing to the technical limitations of the subcritical fleet.

5. **Biomass cofiring**: CSE's analysis is based on NEP's thermal-power generation projections for 2031–32, with fuel requirements estimated accordingly. It explores four scenarios with varying levels of biomass co-firing: 7 per cent, 10 per cent, 15 per cent and 20 per cent. With the gradual increase in biomass cofiring in power plants, total emissions show a consistent decline from 1,332.7 MT as per business-as-usual to 1,066.16 with 20 per cent biomass co-firing scenario, representing a **20 per cent reduction** in emissions. Biomass availability is supported by both our research and estimates from the Ministry of New and Renewable Energy (MNRE). Domestically, NTPC's Tanda Unit#4 has demonstrated 20 per cent biomass cofiring, illustrating the technical feasibility of the same. Additionally, research shows the weighted average calorific value of available biomass from various crop residues is 85 kcal/kg, which is close to that of coal used, resulting in proportionate reduction of emissions. For example, 5 per cent biomass cofiring will result in 5 per cent emission reduction on average across all units.

6. **Combined scenario:** We have created two combined scenarios, namely Scenario 1 + Biomass cofiring and Scenario 2 + Biomass cofiring. The emission reductions suggested in our scenarios provide a key insight into the pathways for reduction and the high potential to achieve the same.

    - The combination of Scenario 1 + Biomass cofiring wherein the units achieve benchmark emission factor and operate as per NEP's projected PLF of 58 per cent across all technologies. With Scenario 1 and increasing biomass cofiring to 20 per cent, CSE's analysis reflects that our emissions can be reduced to **909.3 million tonnes of CO_2.** This can result in a reduction of **423 million tonnes** of CO_2 from the business-as-usual (BAU) scenario.

This translates to a potential **31.8 per cent reduction** (**from BAU**) in emissions when biomass cofiring is increased to **20 per cent**.

- With the combination of Scenario 2 + Biomass cofiring to 20 per cent, CSE's analysis reflects that our emissions can be as low as **899.7 million tonnes of CO_2**. This is a **32.5 per cent** decline in emissions from the BAU estimated emissions. Conclusively, this will result in **18.2 per cent** emission reduction from the NEP projected emission figures.

7.7 Findings of the report

This report presents several key findings that highlight systemic challenges and performance gaps within India's coal-based thermal power sector. These findings stem from a detailed analysis of unit-level data, emission intensities, operational efficiencies and demand–supply dynamics observed in recent years. They reveal broad structural and operational challenges within the coal-based thermal power sector, to underscore the need for a more comprehensive and data-driven approach to planning and managing the sector's road towards decarbonization.

I. **Need to accelerate biomass cofiring**: The statutory obligation of 5 per cent biomass cofiring remains largely unmet. Only 68 coal-power plants are engaging in cofiring to varying degrees, with limited transparency regarding their actual cofiring levels. Notably, NTPC's Unit #4 in Tanda, Uttar Pradesh, successfully cofired 20 per cent torrefied biomass, setting a new national benchmark. According to CSE's estimates, 20 per cent biomass cofiring along with benchmark efficiency could lead to a **31–32.5 per cent** reduction in emissions compared to the BAU scenario, equivalent to a reduction of approximately 156–433 MT/CO.

II. **Rethinking age-based R&M**: Using the age of thermal units as the sole criterion for R&M needs reconsideration. CSE's analysis shows that eight subcritical units over 25 years old rank among the top 100 in the country in terms of efficiency and low emission intensity. By contrast, 49 units below the age of 20 years and 10 units below 10 years are among the least-performing units in the same category. This highlights the need for R&M decisions to be based on performance metrics such as efficiency and emission intensity, rather than age alone.

III. **Efficiency gaps across all technologies**: A majority of India's thermal power units operate below the benchmarked efficiency levels across all three technology categories. A total of 95 subcritical units below 25 years of age operate below the national efficiency average. Additionally, five supercritical thermal units also operate below the subcritical national efficiency average (32.1 per cent). These findings underscore the urgent need for setting clear efficiency-related targets to drive performance improvements.

IV. **Merit Order Dispatch incentivizes higher emissions**: Currently MOD prioritizes cost alone, overlooking emission intensity and plant efficiency. The current system leads to the underutilization of newer, more efficient super and ultra-supercritical power plants, many operating at PLFs below 50 per cent. The approach results in a mismatch between plant efficiency and dispatch priority, with cost outweighing environmental impact. The absence of incentives for low-emission generation further discourages efficiency improvements, especially as the power sector remains outside the ambit of the Indian carbon market. Additionally, location-based cost advantages give preference to plants near coal mines, regardless of their emission levels. In contrast, older and less efficient sub-critical units continue to be prioritized due to lower generation costs, despite higher emissions. The system discourages efficiency improvement and emission reduction, reinforcing a loop of inefficient power supply into the grid.

V. **Units with efficient technologies are underutilized:** If one looks at the national average PLF of the units under all three technologies, one finds the highest average PLF is of the least efficient technology, i.e. subcritical (with 68 per cent PLF) followed by supercritical (61.9 per cent) and ultra-supercritical (54 per cent), which is just the reverse of their efficiency order. To add to this, as of 2022–23, 14 out of 72 supercritical units (20 per cent), eight out of 20 ultra-supercritical units (40 per cent) had an annual average PLF of less than 50 per cent. This clearly shows that as we invest huge sums of money in building plants with more efficient technologies, our current system is unable to reap its benefits to the levels it should.

VI. **Efficiency and emission intensity of plants is not determined only by the quality of coal**: CSE's analysis shows that units dependent on domestic coal can achieve low emission factor and high efficiency. According to 2022–23 data, 12 subcritical power generation units using domestic coal are meeting the industry's 35 per cent efficiency benchmark. Additionally, 166 subcritical power units using domestic coal across the country are operating at efficiencies above 32.1 per cent, surpassing the national average for subcritical plants and proving that better performance is achievable. This shows that cleaner, more efficient power is possible, subject to plants undertaking optimum maintenance and operations management.

VII. **High emissions, low efficiency of state-owned TPPs**: State-owned coal power units have the highest average emission factor at 1.06 tons/MWh, compared to 1.0 tonne/MWh for Centre-owned plants and 0.84 tonne/MWh for privately owned plants. These units also operate at the lowest efficiency levels, averaging around 30 per cent. According to CSE's analysis, half of the least-performing subcritical units in terms of efficiency and emission intensity are state-owned.

VIII. **Diversion of coal cess away from climate action**: Introduced in 2010, the Clean Environment Cess (later renamed the Clean Energy Cess) was levied indirectly on each tonne of coal produced or imported in India, generating Rs 65,894.06 crore in 2010–17. However, only Rs 15,911.49 crore was utilized for its intended purpose, with 75.9 per cent of the collected funds either diverted or left unutilized. Since 2017, the levy on coal has been subsumed under the GST regime as part of the GST Compensation Fund. At a rate of Rs 400 per tonne, this levy has generated an estimated Rs 3,52,220.8 crore between 2017 and 2025. With India's coal consumption projected to increase, revenues from this levy are expected to grow accordingly. CSE`s analysis finds that if the levy continues in its current form, it could account for approximately 59 per cent of the total planned capital expenditure on new coal-based thermal power plants. The cess can cover a substantial portion of the funds required to upgrade the operations and efficiency of our existing fleet if directed towards it.

IX. **Accurate demand projection is necessary**: There is growing uncertainty around electricity demand forecasts in India. Demand projected for 2026–27 has already been surpassed, indicating that actual consumption has significantly outpaced the National Electricity Plan (NEP) estimates. For 2024, GRID India's weekly assessments indicate a 3 per cent average error in forecasts.

X. **Demand forecast is critical for planning of energy mix**: Errors in demand assessment have disrupted retirement plans for non-performing ageing thermal units and skewed capacity addition projections. In response, the Central Electricity Authority in 2023 has advised against any retirement of power plants until 2030, effectively locking inefficient and high emitting coal plants into the system. NEP 2021–22 had estimated that coal capacity in a high demand scenario would need to be 262.6 GW (2473.7 BU) by 2031–32. However, the government, based on current supply and demand estimations has informed Parliament that the country would need to install 283 GW of coal power by 2032.

XI. **Flux of peak/lean demand**: The fluctuation between peak and lean demand projections of GRID India, with the last three years (2022–25) seeing an average monthly fluctuation of 57.6 per cent highlight the growing challenge of predicting demand. These fluctuations also impinge on the emission efficiency of individual plants as frequent shut-downs and changes in loads impact the overall performance of the plant. Sophisticated demand forecasting with the ability to predict fluctuations shall assist in management of base load demand.

XII. **Legacy PPAs a barrier to reform**: Over 70 per cent of thermal power is currently tied to long-term legacy PPAs, limiting flexibility for integrating renewable energy and disincentivizing efficiency improvements. These agreements often include outdated cost structures and place the full burden of renovation and modernization (R&M) on plant owners, discouraging upgrades due to lack of financial support and penalties for non-generation. New units are frequently absorbed under old PPAs, bypassing opportunities for more modern, performance-linked agreements.

XIII. **Lack of incentives for modernization**: The lack of clauses allowing temporary suspension of obligations during R&M leads to financial penalties for non-generation, making it more viable for operators to continue running inefficient, high-emission units. Similarly, there are no structured incentives or policy mechanisms for revising outdated PPAs to reflect modern energy goals. Without significant structural reform, PPAs will continue to lock the grid into high-emission and low-efficiency thermal supply, acting as a major barrier to both modernization and meaningful decarbonization of the sector.

XIV. **Flexibilization is key to RE integration:** Flexibilization of coal power units is essential for integrating 500 GW of renewable energy by 2030. Adjustments to ramp rate, startup time and minimal load are key to ensuring a consistent power supply during the morning and evening hours when RE goes off the grid. Technical upgrades require enabling lower technical load operations, ideally around or below 40 per cent. Modernizing the Instrumentation and Control (I&C) systems is critical to improving operational efficiency and managing flexibility cost-effectively. The minimum technical load for Indian units is higher than for its global counterparts, which needs to go down for higher RE integration. On an all-India basis, thermal flexibility is on an increasing trend, approaching 40 per cent of the total thermal plants during 2021-22. The retrofitting cost for flexibilization, estimated at Rs 30–40 crore per unit, needs to be factored into policy planning.

7.8 Recommendations

As India strives to meet its climate goals and ensure a reliable energy supply, decarbonizing this sector has become a national imperative. This report by the Centre for Science and Environment (CSE) presents a comprehensive analysis of coal-based thermal power plants, primarily using data from 2022–23, with the aim of identifying a feasible roadmap for the sector's decarbonization. The report proposes technical solutions with increased ambition to realize emission reductions on a technology spectrum. Additionally, we propose to bring in certain systemic changes in some of the existing frameworks currently followed within the sector which would be crucial in facilitating decarbonization of the thermal power sector in India.

8.2.1 Technical recommendations

I. **Biomass cofiring**: Strict implementation of biomass co-firing across the country with the support of state governments will result in greater emission reduction along with efficient utilization of an agricultural byproduct. We've presented scenarios of 7 per cent, 10 per cent, 15 per cent and 20 per cent cofiring and recommend a push towards 20 per cent cofiring to achieve major emission reduction.

II. **Renovation and modernization**: Upgrading existing thermal units to meet benchmark performance levels highlighted within CSE's analysis will improve overall fleet efficiency, delivering better cost-effectiveness and environmental returns for each unit of power generated. We recommend:
   - A time-bound R&M policy with a deadline for units below national average efficiency benchmark beyond the age criteria currently in place. This will also include younger units that are highly inefficient.
   - A unit-wise audit for R&M assessment of all inefficient units and a standalone budget for implementation of the said policy.

III. **Emission intensity targets**: As thermal power plants are exempt from the upcoming Indian Carbon Credit and Trading Scheme, they will not be subject to market-driven emission intensity targets. Therefore setting some form of emission intensity reduction targets for individual power-generating units is essential to ensure accountability and progress towards decarbonization of the power sector.

IV. **Flexibilization of TPPs:** As RE generation increases beyond the current levels, integration of RE into our grid's power supply would be technically difficult without flexibilization of TPPs. While not all units may require flexibilization simultaneously, those operating in regions with growing renewable energy (RE) penetration will likely need to adopt it earlier.

With RE increasing, overall emissions from the sector would come down, but operating coal-fired plants at low loads can lead to marginally higher emissions per unit of electricity produced due to decreased efficiency, a guideline with effective measures to address this should also be put into place.

- To reduce emissions, it is essential to implement measures such as standardizing coal quality within a specified gross calorific value (GCV) range.
- To track progress on flexibilization, identify and list units region-wise that will support grid measures for RE integration.
- A quarterly report on the implementation of flexibilization should be prepared, aligned with R&M and RE quarterly reports, for synchronized planning, tracking progress and quantifying associated costs across various units.

8.2.2 Recommendations for systemic changes

I. **Upgrade Merit Order Dispatch:** The MOD should be restructured to account for environmental performance alongside cost. Incorporating emission intensity into dispatch decisions will align power generation with decarbonization goals. An Environmental MOD will incentivize cleaner technologies, promote efficiency and reduce long-term environmental costs. India can draw from global models, such as South Korea's, to design a system that prioritizes low-emission generation while ensuring reliable and affordable power.

II. **Repurpose coal cess**: Following the underutilization of the cess during 2010–17 and the diversion of its proceeds to GST compensation since 2017, CSE recommends that future revenues generated through the levy on coal should be repurposed to deliver environmental benefits. With an estimated Rs 3,97,600 crore expected to be collected over the next six years, these funds should be directed toward supporting the coal fleet in improving thermal efficiency and optimizing operational processes to lower emission factors and reduce overall emission intensity.

III. **Revisit PPAs**: The penalty structure of the present PPAs disincentivize downtime in generation to achieve efficiency improvement. The PPAs prevent cost reductions and RE integration into the power supply. Decarbonization efforts have to be commercially appealing for all stakeholders, i.e. plant owners, DISCOMs and end users. Overall, the PPAs can serve as instruments for ensuring commercial viability by incorporating contractual clauses that also support thermal power upgradation and decarbonization beyond merely functioning as contracts for power supply at a specified cost. We recommend:

- A shorter tenure of PPAs for the upcoming coal power generation units. Additionally, we strongly advice against inclusion of new units within older PPAs of the power plant to prevent locking in of inefficient power generation into the grid.
- Modification of PPAs to include cost-sharing and support measures for Plant owners/ or some form of compensation, for financial support during the R&M period. Furthermore, we suggest inclusion of provisions to temporarily adjust contractual obligations without penalties during the R&M period.
- A scheme for adjustment of cost differentiation for inclusion of new clauses in power purchase on the basis of efficiency / emission factor and downward revision of fixed costs on grounds of running units beyond their life cycle. This will incentivize revision of PPAs to reflect larger policy goals.

IV. **Demand forecasting:** India must urgently revamp its electricity demand forecasting methodologies to reflect the country's evolving growth, energy transition trajectory and demand fluctuations. A dedicated committee or expert group should be constituted to evaluate and strengthen forecasting models. Accurate and robust demand estimates are critical for informed coal planning, preventing abrupt policy shifts, avoiding unnecessary coal capacity additions, and ensuring a reliable and sustainable energy transition.

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CSE's analysis of all thermal units listed in the CEA CO_2 Database (Version 19, 2022–23) can be accessed through the following link.

https://www.cseindia.org/full-list-of-thermal-units-analyzed-by-cse-cea-co2-database-version-19-2022-23-12769

The analysis can also be viewed by scanning the QR code provided below.

As India's demand for electricity soars, the coal-based power sector is poised to meet a major chunk of this growth. With India's coal capacity slated to go beyond 280 GW in the near future, it is imperative to decarbonize the sector.

This report highlights the technical and systematic challenges that influence the emissions of the sector. It analyses the emission intensity of the current fleet to contextualize its performance and provide future pathways for emission reduction.

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