

Decarbonizing the Indian Power Sector by 2037: Evaluating Different
Pathways that Meet Long-Term Emissions Targets
by

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ABSTRACT

The Indian government is aiming to reduce carbon emissions intensity in the power sector through incentivizing the addition of renewables sources into the grid. India has set the goal that at least 40% of total power capacity must be non-fossil fuel-based by 2030 with more ambitious goals expected to be set for 2040 and 2050. To meet the decarbonization goals by the next decades, the central government is promoting a large-scale development of wind turbines and solar photovoltaic power plants.

Achieving long-term decarbonization in the Indian power sector presents several challenges to the current electric grid. For example, the current generation mix relies heavily on coal power plants such that integrating solar and wind plants (i.e., variable renewable energy (VRE) sources) adds several layers of economic and technical complexity. Other challenges include improving the national quality of service and reducing local emissions. The overall effect is amplified by India's rapidly increasing electricity consumption, which has necessitated the build-out of additional capacity to meet the future load.

The following thesis analyzes potential pathways to the decarbonization of India's grid by 2037. The study explores 24 different scenarios, each considering different technology costs (solar, wind, and storage), setting different gas prices, and defining different emissions limits. The analysis uses the capacity expansion model "GenX" developed internally at MIT. GenX is a deterministic capacity expansion planning model. The model optimizes generation, storage, and transmission capacity expansion decisions and dispatch of generation and storage resources on an hourly basis to meet the electricity demand in a year, at the lowest cost possible.

The study successfully identifies the trade-offs between system costs, global emissions, and local emissions levels for different scenarios, enabling the assessment of the long-term impact of large infrastructure decisions in the electric power sector. Of the findings: (1) Scenarios without emission limits, continue to be dominated by coal and emissions rose relative to 2017 levels. (2) Scenarios with emissions limits had an increased share of VRE sources, greater than 50% in some scenarios. (3) Some scenarios with high VRE penetration required significant dispatchable capacity that could ramp up suddenly to meet net load, reaching 270 GW in peak load days. (4) Gas-based plants competed directly with storage technologies; both technologies are flexible and can adapt to abrupt changes in VRE generation. However, as storage costs rise, gas plants begin to dominate the generation mix. There are some challenges in developing new gas plants, as plants cycling increase and the gas fleet is underutilized in some scenarios.

The thesis also addresses the policy implications for each scenario. To reduce greenhouse gasses emissions, setting emissions limits can be hard to enforce. Imposing a carbon tax is ideal, although

it is hard to set the right price. Setting a non-fossil fuel portfolio standard can not necessarily help reduce emissions to a specific target. Many regulatory changes are required to encourage higher levels of VRE penetration such as promoting better coordination between state and regional system operators, reducing uncertainty in the use of the gas infrastructure, and promoting the development of storage technologies.

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1 Introduction

1.1 Motivations

Climate change, one of society's biggest challenges, is gaining relevance in most countries' political agendas. The fear of experiencing adverse effects that are and will be caused by the rise in temperature, not only environmentally but also socio-politically, is slowly driving countries to action. Member countries of the United Nations Framework Convention on Climate Change (UNFCCC) have held several meetings and discussions on how to reduce greenhouse gas emissions (GHG), the leading cause behind the rise in temperatures. A total of 195 members of the UNFCCC signed the Paris Accords by April 2016¹, by which they commit to implementing the necessary measures that would keep the rise in average temperature below 2°C. Countries that ratified the Paris Accords are currently implementing policies that help them achieve committed goals. However, the challenges faced by different countries differ significantly. On the one hand, wealthy countries can allocate significant resources, financial and technical, to develop and deploy clean technologies replacing fossil-fuel-based sources. On the other hand, developing countries lack resources, while they face multiple challenges besides climate change, such as promoting economic growth, and decreasing inequality, among others.

India has a pivotal role in achieving global goals. With over 1.3 billion people, India accounts for over 17% of the global population (United States Census Bureau 2019), but emitted in 2016 roughly over 6.5% (2,075 million tons) of total GHG emissions (International Energy Agency 2018). However, the country still has a long road to achieving economic development: Indian GDP per capita is still far below the average observed of member countries of the Organization for Economic Co-operation and Development (OECD)². If India follows an economic growth pathway similar to that of developed countries, GHG emissions will increase significantly, surpassing the global targets. Hence, India has a difficult task, reducing its emissions intensity without compromising economic growth.

Most of the GHG emissions have historically come from the power sector, the industry that is now leading the transformation to non-carbon emitting sources. If India follows the global trend, then it will have to decarbonize its power mix, an ambitious challenge, considering that over 75% of electricity generated comes from coal-based plants and the emissions per MWh generated are far higher than in Europe and the United States³. The purpose of this thesis is to explore future decarbonization scenarios in the power sector; under different technical and cost assumptions, what are the future power mixes that would achieve different GHG emissions targets?

¹ Although, up to date, 186 countries have ratified the agreement.

² In 2016, average GDP per capita (purchasing power parity) for OECD countries was \$38,170 while in India, \$5,933. (Organisation for Economic Co-Operation and Development 2019)

³ In 2016, India emitted 0.72 tons of CO₂ per MWh generated, while USA and the European Union, 0.44 and 0.33, respectively (International Energy Agency 2018).

1.2 Background

India is among the countries that signed the Paris Accords and submitted its Intended National Determined Contribution (INDC). India committed to reducing the emission intensity of its GDP⁴ between 33% and 35% by 2030, based on 2005 levels (Government of India 2015). The power sector is one of the main GHG emitters; in 2016, 52% of the total greenhouse gas emissions came from the power sector (International Energy Agency 2018). As a part of the efforts to reduce the emissions intensity, the country established a renewable portfolio target, stating that at least 40% of total power capacity must be non-fossil fuel-based⁵. Most of the targeted capacity will be achieved through the development of solar photovoltaic (solar PV) and wind power plants. As a first step and in the current 13th National Electricity Plan⁶, elaborated by the Central Electricity Authority (CEA)⁷, the central government is aiming to achieve 175 GW in renewable sources installed capacity by March 2022, mainly composed by solar PV and wind sources⁸. Furthermore, a tentative 14th National Electricity Plan is aiming to achieve 250 GW in renewables sources by March 2027. Further development of renewable sources is expected after 2027 to meet the committed emissions reductions by 2030 as well as even further reductions after 2030.

Nevertheless, the country is facing several additional challenges that must be taken into account when aiming to decarbonize the power sector. On the one hand, the electricity consumption is increasing at high rates and is expected to triple by 2030⁹ (Government of India 2015). The electricity sector is also facing significant regulatory challenges as it has gradually shifted from a vertically bundled and centrally planned industry to an unbundled, market-driven sector. Local pollution, not necessarily correlated with GHG emissions, is also a major problem; seven of the ten most polluted cities in the world are in India (Thornton 2019). Local authorities are pushing to reduce local emissions. Improving reliability is also a significant challenge: power outages and low quality of service have been frequent in the past, and higher standards are expected in the future.

The power system has historically relied on coal plants, and currently, nearly 75% of the electricity generated comes from this source. However, most of the plants to be developed in the following years are variable renewable energy (VRE¹⁰) sources, mainly solar PV plants and wind farms. In the medium-term, CEA expects to have in India 60 GW of wind and 100 GW of solar by 2022, ambitious goals considering that only 12 GW and 32 GW, respectively were installed by March

⁴ This is calculated as the absolute of GHG emissions (measured in CO2 equivalent) divided by the GDP (measured in Indian Rupees).

⁵ Capacity measured in MW, corresponded to installed capacity.

⁶ National Electricity Plan are five year plans elaborated by the Central Electricity Authority and include capacity plans by the end of the five-year period

⁷ The Central Electricity Authority is a statutory organization that advises the government on policy matters and formulates plans for the development of electricity system.

⁸ The target consist in 100 GW of solar PV, 60 GW in onshore wind, 10 GW in biomass plants and 5 GW in mini hydro plants.

⁹ Based on 2012 levels.

¹⁰ Renewable energy sources are defined as solar PV, wind farms, biomass plants and hydro plants under 25 MW.

2017. Including additional solar and wind plants introduce several challenges, mainly because these sources are variable with limited dispatchability. Solar and wind, are variable because their generation will depend on the availability of resources (e.g., solar irradiation and wind blowing) and they have limited dispatchability because plant operators do not have any control on the availability of these resources¹¹. The high variability of irradiation and wind can lead to abrupt changes in the plants' power output in a matter of hours or even minutes. Thus, focusing on developing these technologies provides reliability challenges: how can India maintain or even improve the system's reliability and at the same time, promote variable sources?

Finally, India is a country with a long way to achieve economic wealth and has limited resources. Finding a cost-effective solution to decarbonize the power sector and achieve multiple other goals is necessary. Every penny saved in the power sector can be allocated to education, healthcare, security, etc. The role of policymakers is crucial. How can policy help shape a future power system that is clean, efficient, and reliable?

1.3 Research question

This thesis explores and compares different future scenarios for the Indian power sector. The research evaluates and compares long-term decarbonization with business-as-usual scenarios under different technological assumptions. In particular, the thesis attempts to answer the following questions:

- What optimal energy mix can meet the future load, considering different cost assumptions and emissions targets?
- What different policies could be implemented to achieve the long-term emissions goals? How feasible are these policies?

The objective of this study is to provide an extensive analysis of different pathways that can lead to the decarbonization of the power sector. The study aims to help Indian policymakers in their design of future regulations by providing a broad analysis of how the future power system will work under different scenarios and how it will be influenced by the technological development.

1.4 Thesis organization

The structure of the thesis is as follows. First, **Chapter 2** describes the Indian electric power sector, outlining the main technical and regulatory changes in the past decades and discusses the future challenges that lie ahead.

Then, **Chapter 3** reviews the literature investigating the decarbonization of power systems around the world. While most research analyzes North American and European markets, only a few studies have analyzed the Indian power sector. The latter reports have mostly focused on short- and medium-term analyses and have not discussed the challenges in fully decarbonizing the Indian network in the long term.

Chapter 4 includes an analysis of the operation of the Indian power sector in the last decade. The Indian interconnected system has unique characteristics that differentiate it from other power

¹¹ However, plant operators can reduce the power output of VRE sources.

systems in the United States or the European Union. Analyzing these characteristics is crucial to establishing the main assumptions and defining the different scenarios expected in the future.

Chapter 5 details the methodology used, the scenarios defined in the analysis, and the main model, and data assumptions. The results are presented in **Chapter 6** and the sensitivity analyses in **Chapter 7** . **Chapter 8** discuss the results and its policy implications and includes discussion of future lines of research.

2 Indian power sector: past, present and future challenges

2.1 Description of the Indian power system

2.1.1 Indian power sector

India is a federal republic consisting of 29 states and 7 union territories. Around 1.3 billion people live in India (Central Intelligence Agency 2018), placing the country as the second most populated in the world. Despite the high population, the total electricity consumption is lower than in the United States and Europe. In fact, according to the International Energy Agency (IEA) estimates in (International Energy Agency 2018), Indian electricity consumption per capita in 2017 was around 1,000 kWh, significantly lower than in the United States or large European countries, (e.g., UK, Spain, and Italy) countries with a range between 4,000 and 5,000 kWh per capita. Total capacity by December 2018 was 350 GW, where nearly 60% came from coal plants. The installed capacity almost doubled the peak load, which was slightly over 160 GW during 2018.

The power system is divided, for planning and operational purposes, into five interconnected regions¹², where each region covers multiple states. Interregional transmission links interconnect the regions with each other. The five regions, shown in Figure 2-1 are named Northern, Western, Southern, Eastern, and Northeastern regions. Most states within each region have their own system operator, named State Load Dispatch Centers (SLDC). Each region has a Regional Load Dispatch Center that coordinates the different State Load Dispatch Centers included in the region as well as operating the intraregional links. On a national level, regions and interregional links are coordinated by the National Load Dispatch Center, controlled by Power System Operation Corporation (POSOCO), a central government-owned company. Moreover, POSOCO operates the international transmission links that trade energy between India and neighboring countries. Currently, India has transmission links with Bhutan, Bangladesh, and Nepal, while interconnections with Pakistan and Sri Lanka are in discussion (Government of India, Ministry of Power 2109) (Central Electricity Authority 2018a).

Although the Indian power grid is a single interconnected system, it is operated in a decentralized manner. Distribution companies (DISCOMs) and State Load Dispatch Centers (SLDCs) schedule plants only within the boundaries under their control, and there is little coordination among DISCOMs/SLDCs across states.

¹² In addition, there are small non-interconnected regions (mainly Andaman & Nicobar Islands and Lakshadweep) which have a small share of the total load. The five interconnected grids during the financial year 2016-2017 covered nearly 99.97% of total electricity load in the country (Central Electricity Authority 2008-2018a).



Figure 2-1: Map of the Indian power system showing the five interconnected regions.
 Source: Maps of India (Maps of India 2016).

Figure 2-2 shows the annual electricity demand¹³ per region for the period between fiscal years 2008-09 and 2017-18. Around 90% of the total load is concentrated in three main regions (North, South, and West). Around 80% of the electricity consumption comes from residential, industrial, and irrigation sectors, a percentage that is expected to remain stable in the following years (Central Electricity Authority 2017c).

¹³ The values shown correspond to the electricity requirement and not the demand met. There is a percentage of demand not met due to several reasons that will be explained in the following sections, a gap that has been reduced in recent years.

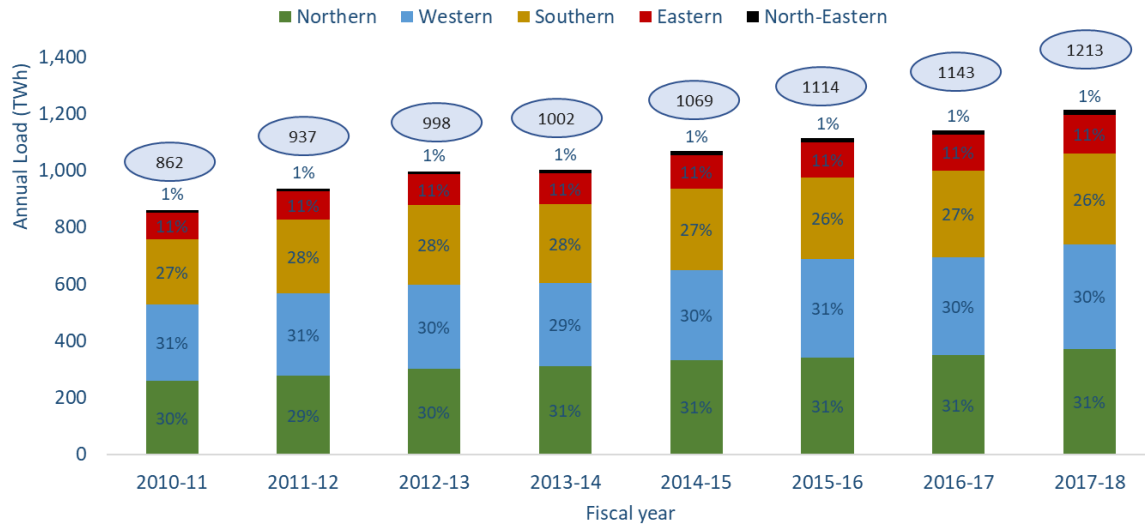


Figure 2-2: Annual electricity demand per region for the period 2008-09 to 2017-18.
Source: (Central Electricity Authority 2008-2018a).

2.1.2 Indian generation mix: actual capacity and potential development.

Coal¹⁴ has dominated the power mix in recent years. Figure 2-3 shows that coal represented on average around 57% of the total installed capacity in the period between the years 2008-09 and 2017-18, while, as shown in Figure 2-4, coal plants accounted on average for over 71% of the total generation mix per year¹⁵. Most of the coal used is domestic coal, according to CEA (Central Electricity Authority 2018a), in the fiscal year 2017-18 around 92% of total coal electricity generation was expected to be produced with domestic coal¹⁶. The potential for further increase in

¹⁴ Within the coal category, coal and lignite plants are included. Lignite is the lowest grade coal with the least concentration of carbon. Lignite capacity represented 3% of the total installed coal capacity as of March 2017 (Central Electricity Authority 2008-2018b).

¹⁵ The aggregated capacity and generation figures presented do not consider either captive plants or behind-the-meter backup diesel generators. Industrial firms install captive plants for their own consumption and inject the excess energy not consumed into the grid. By year 2015, the CEA estimated around 44.6 GW in installed captive plants (Central Electricity Authority 2017c). Behind-the-meter diesel generators are backup plants that small business and residential consumers install as a response to frequent blackouts experienced in many Indian cities. By 2014, the Central Advisor of the Central Electricity Regulatory Commission counted 90 GW in installed backup diesel generators (Central Electricity Regulatory Commission 2014). The presence of these generators will be addressed in the following sections.

¹⁶ Coal is a regulated industry in India and has traditionally been controlled by state and federal governments.

coal plants is high, considering that a substantial share is met by domestic sources and taking into account that coal is a commodity with many global suppliers¹⁷.

Hydro¹⁸ has lost share in the total capacity and generation mix, caused by a slow development in new plants and a reduction in capacity factors. According to CEA in (Central Electricity Authority 2018a) and (Central Electricity Authority 2018b), there is a vast potential for further development of hydro plants. While by March 2017 there were nearly 40 GW of run of river and reservoir plants, and 11 GW were under construction, CEA estimated 95 GW of additional potential development. Regarding pumped hydro storage plants, 5 GW were operating by the end of the year 2016-17, 1 GW were under construction, and CEA estimates 97 GW in additional pumped storage potential at 63 different sites.

VRE sources have slowly gained share, mainly fostered by the development of solar PV plants (rooftop and utility-scale) and onshore wind farms. Indian authorities are pushing to develop the two latter technologies, in order to meet the goals set in the INDC. There is huge potential for solar and wind; the latest estimates indicate that there is potential for total development of over 700 GW of solar PV capacity¹⁹ (Central Electricity Authority 2018a) and 300 GW of onshore wind capacity (Jethani 2017). The actual and future reductions in the investment costs of both solar panels and wind farms can continue to bolster further deployment of these technologies.

Gas-based plants, mainly combined cycles²⁰, have reduced their contribution to the total electricity generated, although experiencing a less drastic reduction in the capacity mix. This combined effect has resulted in major reductions in the capacity factors; an effect that will be described in the following sections. The main challenges this technology faces in the future are the development of gas infrastructure, either liquefied natural gas (LNG) terminals or gas pipelines, for the power sector as well as alternative uses for gas such as the fertilizing and the petrochemical industry.

Finally, nuclear plants have remained practically stable in the total generation mix, but significantly low compared to the other sources. Nuclear plants in India are either constructed with domestic equipment or imported mainly from Russia and have resulted in significantly lower capital costs in comparison to nuclear plants in western countries (Lovering, Yip and Nordhau 2016). However, the ability to develop and construct nuclear plants in reasonable timelines seems challenging. Currently, there are nearly 6.8 GW of plants under operation and 5.4 GW under construction. Although the (World Nuclear Association 2019) has estimated that between proposed and planned

¹⁷ India currently imports coking coal, mainly from Australia. Coking coal is used in the steelmaking industry (Varadhan 2019).

¹⁸ Values shown consider hydro plants over 25 MW, including run of river plants, reservoir plants and pumped hydro storage plants.

¹⁹ In addition, according to (Sharma, Tiwari and Sood 2012), an area of 35,000 km² in the Thar Desert has been specifically set aside for solar projects; a potential between 700 GW and 2,100 GW has been estimated in this area.

²⁰ By March 2017 of the 25,330 MW of gas-based capacity, only 350 MW were open-cycle plants. (Central Electricity Authority 2018a).

projects, additional 80 GW of nuclear capacity could be installed in the long term, other studies²¹ are more conservative to the degree of feasible capacity that could be deployed.

Even though India has interconnections with Bhutan, Bangladesh, and Nepal, the energy traded through the existent links is low. In 2017-18, net imports only accounted for 1% of total electricity generated, coming mainly from Bhutan.

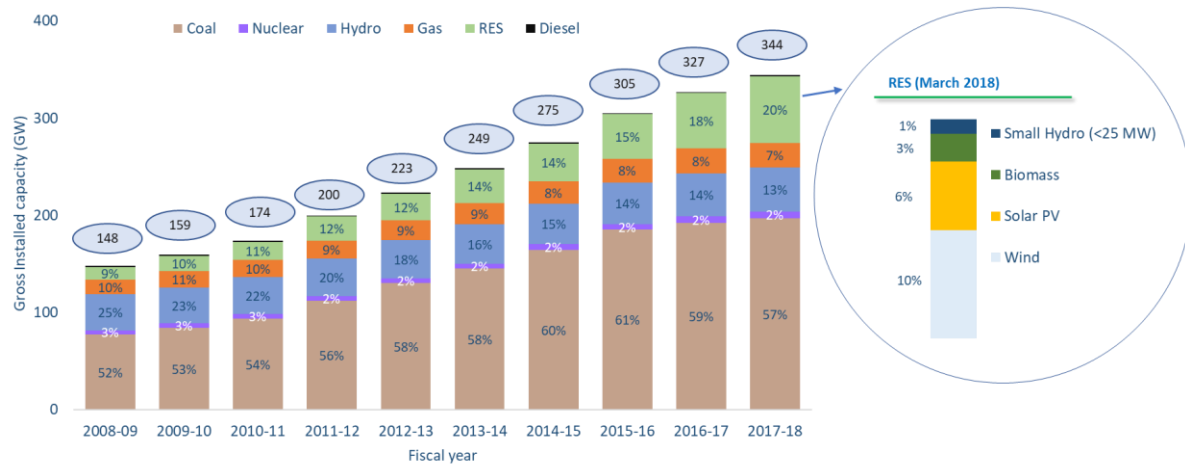


Figure 2-3: National installed capacity at the end of each fiscal year in the period between years 2008-09 and 2017-18. Source: (Central Electricity Authority 2008-2018b).

Note: Values are from March of every fiscal year. Values do not consider captive plants and behind-the-meter diesel generators.

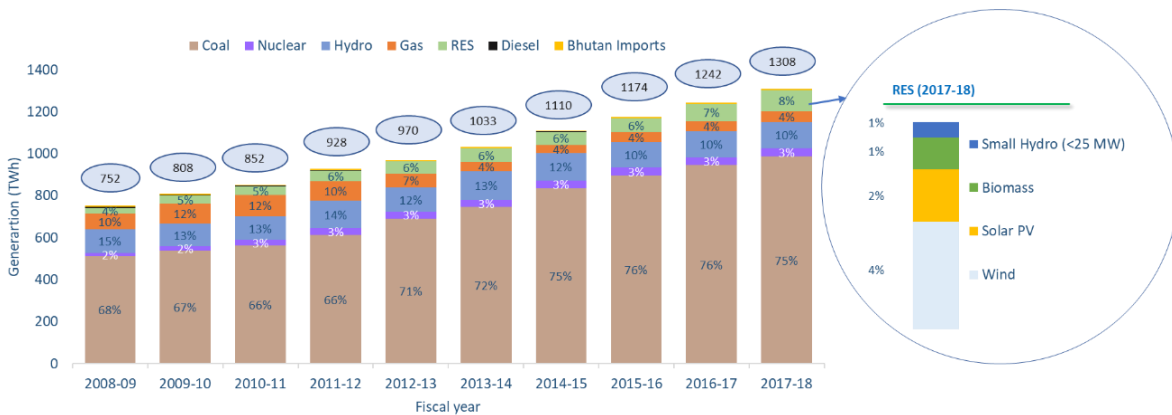


Figure 2-4: Generation per source for the years 2008-09 to 2017-18.

Source: (Central Electricity Authority 2008-2018b).

Note: Values are annual, starting from March of every fiscal year. Values do not consider captive plants and behind the meter diesel generators.

²¹ According to researchers in the Council of Energy, Environment and Water.

2.2 Transforming the Indian power sector: regulatory changes in past decades

The Indian Power sector historically consisted of largely independent regional power grids, with state-owned vertically integrated firms, named State Electricity Boards (SEBs) operating in each region. Driven by the poor performance of SEBs and financial difficulties of DISCOMs²², several regulatory modifications, beginning in the early 90s, gradually changed the existing power system structure. Privatization and unbundling began, separating the transmission, generation, and distribution businesses and allowing the participation of independent power producers. However, the process of unbundling is still being undertaken, with some states lagging behind. In addition, central authorities pushed for integrating the independent regional grids, forming one national integrated system.

The Electricity Act (2003) enabled the introduction of competitive power markets in India. The act established competition at the wholesale level and among many changes, delicensed thermal generation, established open access to transmission and enabled power trading. As Figure 2-5 shows, the Indian power sector is in gradual evolution. Since the promulgation of the Electricity Act in 2003, several new regulations have been approved, changing different stages of the electricity chain.

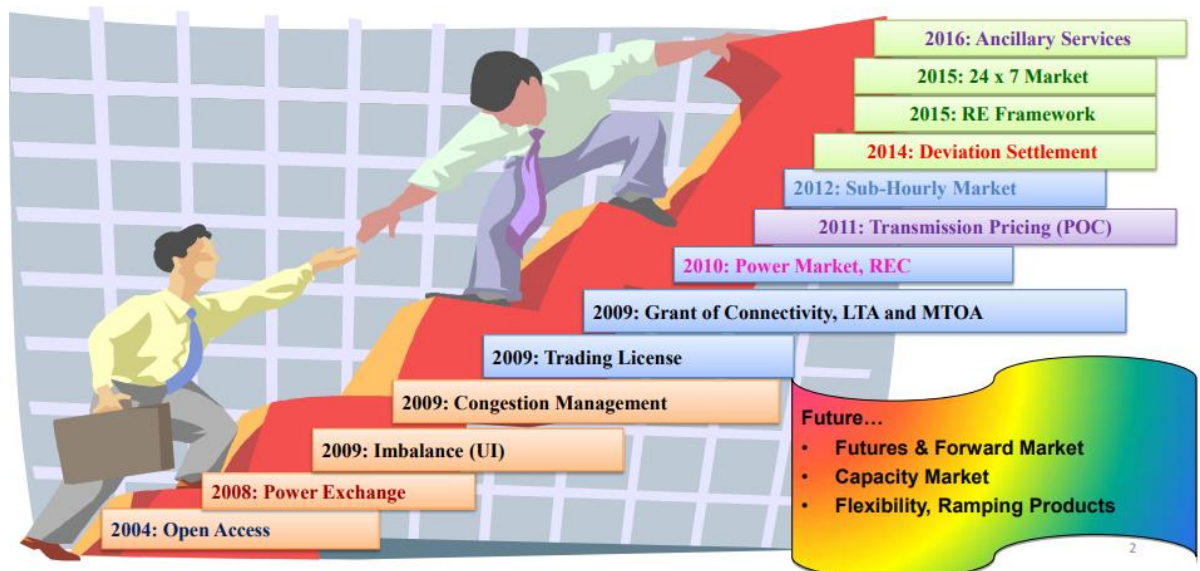


Figure 2-5: Milestones in the development of power markets in India.
Source: (Saxena 2017).

Figure 2-6 shows the different players in the Indian sector. Policymaking is delegated to the Central Government, the Central Electricity Authority (CEA), and each State Government, while the regulatory role is assumed by the Central Electricity Regulatory Commission (CERC) and the State Electricity Regulatory Commissions (SERCs). CEA is the authority at the federal level, assisting the Ministry of Power and elaborating the National Electricity Plans every 5 years. Additionally, it

²² The main reasons behind distribution financial struggles were high wholesale supply costs due to legacy PPAs and, regulated tariffs that are below-cost recovery levels (especially for agricultural customers) and high technical and commercial losses (in 2003-04 in some states losses surpassed 60%).

advises in the elaboration of the National Electricity Policy and elaborates the grid standards. The CERC, and SERCs, among other responsibilities, are in charge of awarding and revoking of licenses, setting tariffs consistent with National Electricity Policy, defining and enforcing performance standards and quality of service.



Figure 2-6: Structure of the Indian Electricity Market.
Source: (Power System Operation Corporation Ltd. 2017).

Investment in the generation and transmission sectors have been mainly driven by federal and state governments. Power generation plants have been historically financed through cost-plus schemes. Once the National Tariff Policy was established in 2006, new power plants were developed by participating in competitive bidding processes to sign long-term agreements. In recent years, power exchanges with Day-Ahead and Intraday markets have developed in some states. However, the total percentage of energy traded through power exchanges is still low, as shown in Figure 2-7.

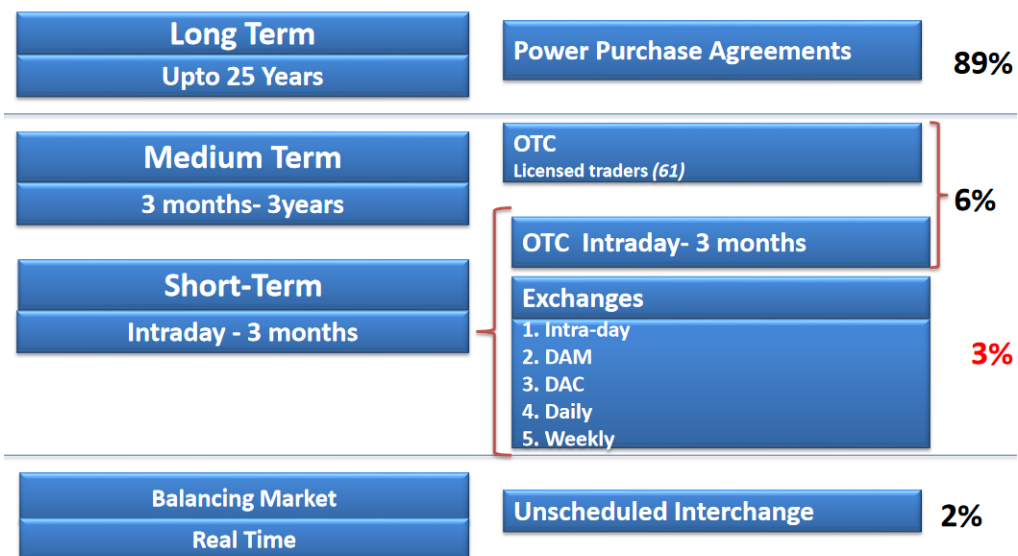


Figure 2-7: Type of contracts in the wholesale market.

Source: (Indian Energy Exchange 2018).

Renewables are incentivized in India through supply-side and demand-side incentives. Renewable Purchase Obligations (RPOs) have been imposed for load-serving entities and other end users, which can be met by purchasing Renewable Energy Credits (RECs). Renewable generators can either sell energy at a feed-in tariff, sell through bilateral agreements (including RECs), or sell energy and RECs in a separate basis and through power exchanges. Feed-in tariffs, previously set by regulators, are now being more commonly determined by competitive bidding processes.

2.3 National Electricity Plans: authorities are pushing for VRE sources

Every 5 years, the CEA publishes a National Electricity Plan. This electricity plan considers the suggestions of licensees, generating companies and the public and is under the approval of the Central Government. This plan includes the planning of interstate transmission systems as well as intrastate transmission systems (up to 66kV). Central Transmission Utilities (CTUs) and State Transmission Utilities (STUs)²³ have the key responsibility of network planning and development based on the National Electricity Plan in coordination with all concerned agencies as provided in the Act. Previous National Electricity Plans focused on developing baseload capacity, mainly coal plants, to improve energy security and reduce the non-served energy. During the period between 2012 and 2017, 99 GW of new plants were installed, 85 GW of them, coal capacity. Following the goals set in the INDC, the CEA is focused now on encouraging renewables. Figure 2-8 shows the current National Electricity Plan with an end date of March 2022. The aims of the plan are set for

²³ Transmission ownership is dispersed among a Central Transmission Utility, State Transmission Utilities, and Private Transmission Licensees. The Central Transmission Utilities is Power Grid Corporation of India Limited (PGCIL), a Government-of-India enterprise and is responsible for interregional and international links while, State Transmission Utilities (STUs) own intrastate transmission networks.

renewable energy sources (RES²⁴) share to double, bolstered by the development of nearly 88 GW of solar and 28 GW of onshore wind. Coal plants would still continue to develop while large hydro, nuclear, and gas capacity would lose share with small development. Figure 2-9 shows that new wind capacity has achieved the targeted additions, while solar additions are falling behind the goals.

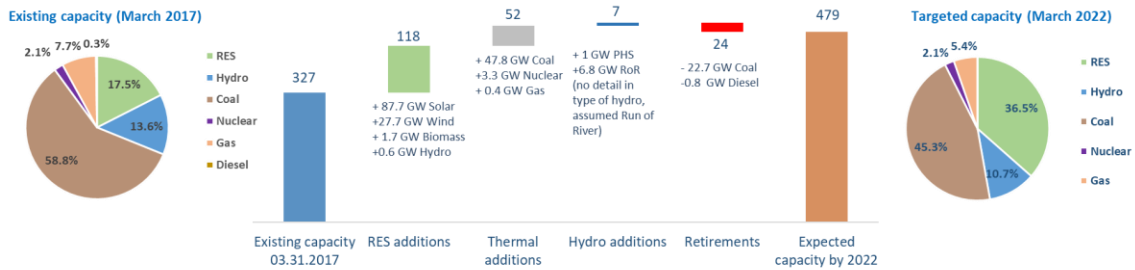


Figure 2-8: 13th National Electricity Plan: 2017-2022. Source: (Central Electricity Authority 2017c).

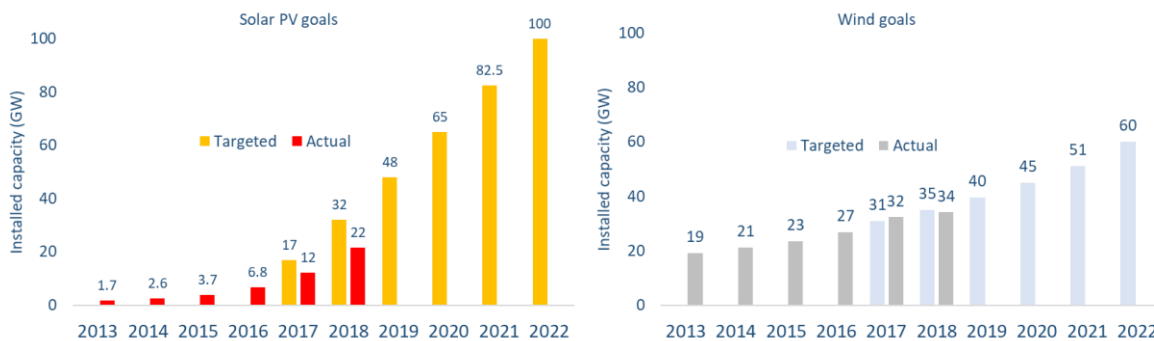


Figure 2-9: Targeted v/s installed solar and wind capacity. Source: (Central Electricity Authority 2017c) and (Central Electricity Authority 2008-2018b).

²⁴ CEA defines solar, wind, biomass and hydro plants under 25 MW as RES.

2.4 Moving forward: major challenges ahead

Besides coping with the ambitious renewables goal, central authorities in India have to deal with several struggles when planning the future power system. The dilemmas are related to the following factors:

1. Electricity load is expected to increase by threefold in the next 20 years.
2. The power mix will shift from coal-based to one more dependent on VRE generation.
3. The power system has experienced reliability problems and provided a low quality of service.
4. Local pollution in several cities is a significant problem, and authorities are pushing to reduce local emissions, directly affecting several fossil fuel technologies.

On the one hand, as shown in Figure 2-10, electricity consumption is expected to nearly triple in the next two decades. The additional load will be driven by an increase in electricity coverage and a rise in electricity consumption per capita. The central government has focused on increasing electricity coverage: during the last five years, the government electrified 100% of all Indian villages²⁵ (BBC news 2018). Many challenges arise with the inclusion of the new customers; most of them did not consume electricity before they were connected to the grid, so there is no information regarding their expected electricity consumption and load profile. Additionally, electricity consumption per capita is expected to increase following the forecasted growth in GDP per capita. An example is the adoption of air conditioning units, which increases as the population becomes wealthier, and that would increase load and even shift peak load intervals. Electrifying sectors that have traditionally been fossil fuel-based, such as transportation and heating, would influence further load growth²⁶. Meeting high load growth rates would require considerable investments in the power and transmissions sectors. The required capacity to meet the future load and replace those plants that would age and retire in the future years is equivalent to the current total installed capacity in India. This is added to the fact that there is some uncertainty regarding future load: how much electricity is expected to be demanded, and what would the load profile be?

²⁵ The central government defines that a village is electrified if 10 percent of its households, as well as public places such as schools and health centers, are connected.

²⁶ Official forecasts include only 6 million electric vehicles by 2022 and do not specify forecasts in the following years.

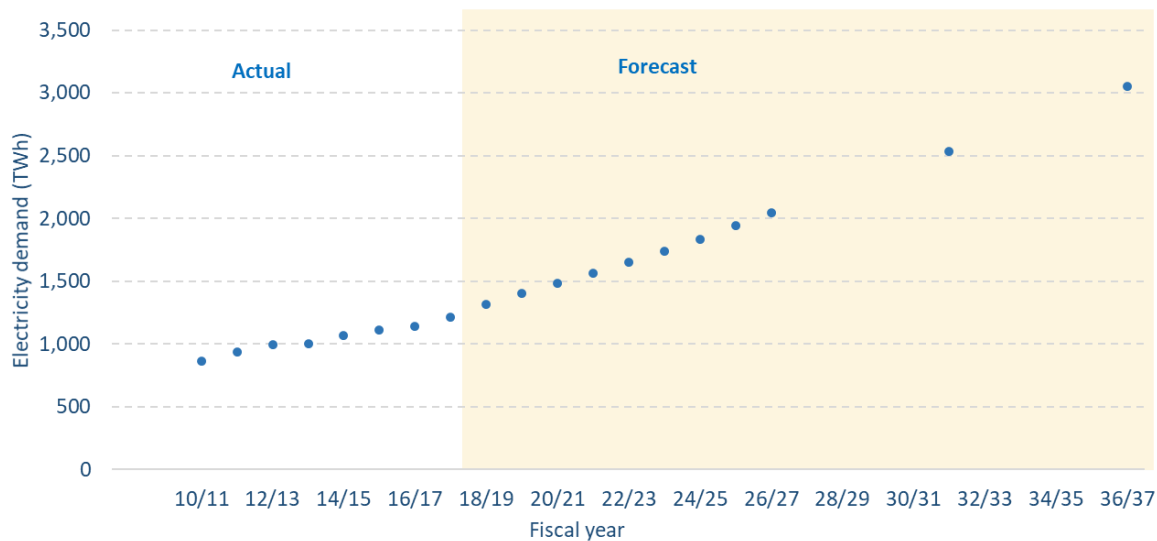


Figure 2-10: Actual and forecasted electricity demand.

Source: Actual values from (Central Electricity Authority 2008-2018a) and forecasts from (Central Electricity Authority 2017c).

On the other hand, achieving the VRE goals by 2022 and more ambitious targets by 2026 and further would involve shifting from a generation mix based on coal generation to one with a high share of variable renewables. State and regional load dispatch operators, used to dealing with predictable thermal plants, will face higher uncertainty and variability in the output of thousands of power units. Managing high amounts of variable capacity would require flexible units, able to ramp up or ramp down in order to cope with abrupt changes in VRE generation. Most of the existing coals plants do not satisfy the flexibility needs the system would demand in the future. The CEA forecasts that by 2022 the coal plants will only able to be dispatched down to 55% of nameplate capacity while ramping up and down at a maximum of 1% per min (Authority 2019b). Investment in more flexible capacity would probably be required in the future. Moreover, considering that VRE capacity is spread all over the country, reinforcements to the transmission and distribution grids and better coordination between DISCOMs, State, and Regional system operators would be vital. Many investments, as well as technical and regulatory changes, must be done to operate the power system under reliable standards.

However, operating a reliable system has been a constant headache for Indian system operators. Historically, the country has experienced frequent power outages and low quality of service. Transmission and distribution infrastructure investments have not keep up with the high growth rates in electricity consumption, due mainly to the weak financial status of electricity firms²⁷. Figure

²⁷ On the one hand there is a financing gap: revenues recollected from tariffs paid by regulated users are not sufficient to cover distribution, transmission and generation costs. On the other hand, a significant share of electricity is not paid or is stolen by end users, generating losses that are borne mainly by DISCOMs. This creates a vicious cycle: the weak financial health of electricity firms cause them to underinvest in network reinforcements, leading to a reduction in the quality of

2-11 shows the average daily power cuts in some major Indian cities during 2015-2016; it is common for citizens of major cities to experience daily power outages, some of them lasting for hours. As a response to frequent power outages, many residential, commercial and industrial customers invested in their own backup diesel generators. CERC estimated in 2014 that there were around 90 GW of behind-the-meter backup diesel generators, increasing by between 5,000 and 8,000 MW per year (Central Electricity Regulatory Commission 2014),

Although the percentage of total energy and peak load not supplied has been steadily decreasing in recent years, as shown in Figure 2-12, there are still some regions with high percentages of unserved load. For instance, during the fiscal year 2017-18, 20% of the required electricity load was not supplied in the state of Jammu & Kashmir, while 9% of unserved energy was observed in Adaman & Nicobar (Central Electricity Authority 2008-2018a). New VRE capacity would only provide additional obstacles to reliability performance. VRE capacity would exert further pressure on the already weak financials of incumbents and will require additional network upgrade investments.

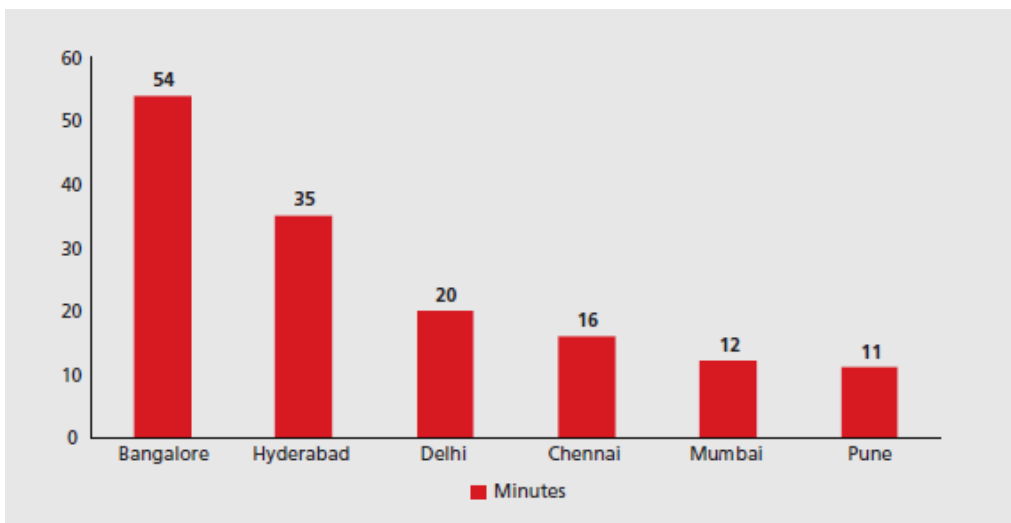


Figure 2-11: Average daily power outages in Indian cities between November 2015 and October 2016. Source: (Bhati and Kalsotra 2017).

service. Then more users feel they should not pay for the poor service provided and lower revenues are collected by DISCOMs increasing the financing gap.

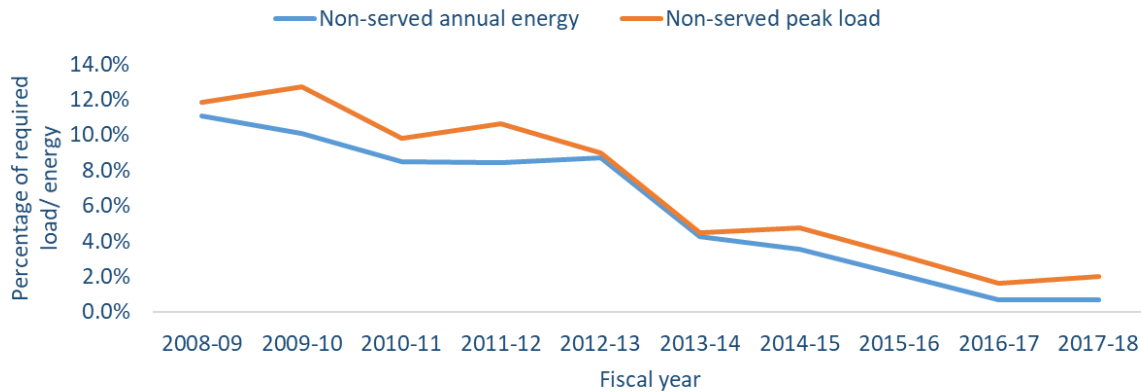


Figure 2-12: Percentage of non-served energy and non-served peak load.
Source: (Central Electricity Authority 2008-2018a).

Finally, local pollution is a primary concern among local authorities, considering that seven out of the ten of the most polluted cities in the world are in India (Thornton 2019). Some large-scale thermal plants, operating nearby new large cities have increased the level of SO₂, NO_x and PM emissions. This is complemented with the usage of backup diesel units, not only emitting a loud noise when operating but contributing to PM_{2.5}, PM₁₀, SO₂, NO_x, and CO₂ total emissions²⁸. To avoid this, authorities have raised emissions standards for SO_x and NO_x emissions for utility-scale power plants (Center for Study of Science, Technology & Policy 2018) while imposing restrictions to the use of behind-the-meter diesel generators²⁹ (Central Electricity Regulatory Commission 2014).

The central authorities, system operators, policymakers and state and private actors would have to deal with all these challenges. Is the Indian power system prepared for all these changes? What is needed to change in the regulatory framework in order to achieve the local and global emission goals in an efficient and reliable way?

²⁸ According to (Bhati and Kalsotra 2017), diesel generation sets contributed to 6% of PM 2.5, 4% of PM₁₀, 4% of SO₂, 25% of NO_x and 7% of CO total levels in the Union Territory of Delhi.

²⁹ For instance, the Government of Delhi banned the use of diesel generators with capacity greater than 4 kW between 10 pm and 6 am (Bhati and Kalsotra 2017).

3 Studies of decarbonization plans in India and the world

This chapter summarizes a few different studies that have analyzed and quantified decarbonization plans for power systems. Most studies focus on mature power systems in developed countries, with high reliability standards and low electricity growth rates. Most of the challenges come from electrifying fossil-fuel-based sectors, such as transportation and heat, instead of experiencing additional growth in electricity consumption. Some reports have analyzed the Indian power sector; however, these studies either analyze the system operation in the short- and medium-term, or evaluate a single scenario in the long-term. None of the studies address the uncertainty in future decarbonization pathways as they fail to explore multiple scenarios that will depend on the different technical, economic, and regulatory assumptions. Finally, to reduce computational challenges, existing research often considers simplified models of power systems, misrepresenting or neglecting key characteristics that exist in power mixes with a high share of variable renewables.

3.1 Studies of decarbonization in developed countries

Several studies have been published evaluating different roadmaps to achieve a drastic reduction in GHG emissions. For instance, (Jenkins, Luke and Thernstrom 2018) and (Sepulveda, et al. 2018) examine different pathways to achieve zero emissions in grids resembling existing power systems in developed countries. Both studies compare the path of relying mainly on VRE sources and flexible capacity with the alternative of developing a broader range of technologies, including low-carbon firm resources³⁰. The authors conclude that policymakers should consider the latter technologies to achieve ambitious emissions reduction goals in a cost-effective way. While (Jenkins, Luke and Thernstrom 2018) conduct a literature review of several studies analyzing deep decarbonization with a global scope or focused in developed countries, (Sepulveda, et al. 2018) simulate multiple scenarios in a fictitious system based on the western US. Other studies have examined the transition from fossil-fuel based to renewable generation mixes in Great Britain (Zeyringer, et al. 2018), Denmark (Lund and Mathiesen 2009), Norway (Hagos, Gebremedhin and Zethraeus 2014), Iceland (Duenas, et al. 2018), Australia (Riesz, Vithayasrichareon and MacGill 2015), South Korea (Koo, et al. 2011), and Portugal (Fernandes and Ferreira 2014). None of these studies analyze the case of India, a developing country with high economic growth rates.

The Deep Decarbonization Pathways Project in its 2015 report (Deep Decarbonization Pathways Project 2015), provides global guidelines to maintain the global temperature rise below 2°C by 2050. The study promotes three main pillars for deep decarbonization: energy efficiency, decarbonizing electricity and fuels, and switching to low carbon sources in energy end-uses. The study proposes recommendations for several countries, including India, although these are general.

Finally, the IEA in its latest World Energy Outlook (International Energy Agency 2018) evaluates three different global policy scenarios to provide insights and inform government and decision-makers about the main outcomes. The main findings, although they include specific recommendations for countries like India, do not provide technical and operational details of how the future grid would behave.

³⁰ Among low-carbon firm sources the authors refer to nuclear, geothermal, biomass and fossil fuel with carbon capture and storage.

3.2 Studies of decarbonization in India

Following CEA's 13th National Electricity Plan announcement, several independent studies have been published analyzing the future operation of the Indian system and evaluating the impact of including 175 GW of installed VRE capacity in the Indian grid. These studies are contrasted with two official reports elaborated by the CEA that provide a technical and operational description of the system by 2022 and 2030, respectively.

On the one hand, the CEA in its official document describing the 13th National Electricity Plan evaluates the main effects of incorporating the VRE goals by 2022. Considering the demand projection, committed capacity of gas, hydro and nuclear plants, and expected thermal retirements, the CEA predicts that around 6 GW of new coal plants would be required. This number is smaller than the nearly 48 GW of new coal capacity that would likely be operating by 2022. CEA predicts an increase in capacity factors for the coal fleet and forecast that VRE sources would represent around 20% of the generation mix. By 2022, the country would comply with its non-fossil-fuel capacity share established in its INDC³¹. The central authority also provides an analysis of the tentative 14th plan, that is aiming to have 250 GW of VRE by the fiscal year 2026-27. VRE would represent around 24% of the total generation mix and to successfully accommodate the additions, the system would require additional peaking power plants and/or energy storage devices.

On the other hand, the CEA recently published a report (CEA 2030 report) estimating the optimal capacity mix for the Indian power system by 2030, considering the specific technical and economic feasibility of different technology options (Central Electricity Authority 2019a). As a first step, the expected installed capacity by 2022 is used as an input, and the least cost option for system expansion for the period between 2022-23 and 2029-2030 is calculated. Then, hourly generation dispatches are simulated for critical days (e.g., peak load day, maximum wind, and solar day) to verify if the optimal mix is adequate to meet the forecasted load at every hour. As a novelty, the study includes battery energy storage as a candidate technology that can be deployed by 2030; currently there is no significant utility-scale storage capacity installed in the Indian power system. Among the main findings, the report concludes that coal capacity will represent around 32% and 50% of the capacity mix and energy mix, respectively, reducing both shares in comparison to 2022 levels. Expected non-fossil-fuel capacity will represent nearly 65% of the total installed capacity, complying with the goals committed in the INDC. Solar and wind will represent approximately 35% of the energy mix, and renewable energy curtailment peaks at 17% of the energy available. Moreover, the report includes sensitivity analysis, showing that increasing flexibility of coal plants can help gradually reduce renewable energy curtailment. Finally, GHG emissions in absolute terms are expected to rise from 2022 to 2030, but only by 12%.

In contrast, three independent studies have quantified the impacts of including 175 GW of VRE in the system's operation by 2022. The independent studies are the study published by National Renewable Energy Laboratory (NREL) (Palchak, et al. 2017), the study elaborated jointly by General Electric and the Shakti Foundation (General Electric & Shakti Sustainable Energy

³¹ The share as indicated before is 40% by 2030. CEA expects that by 2022, non-fossil fuel capacity would already represent 49% of the total installed capacity.

Foundation 2018), and the study conducted by Lawrence Berkeley National Laboratory (Phadke, Abhyankar and Deshmukh 2016).

The NREL study, among many conclusions, finds that CEA's expected generation and transmission infrastructure by 2022 would be sufficient to meet the expected load and accommodate the VRE generation with low levels of renewable curtailment³². The study authors conclude that the expected capacity mix would have enough flexibility to manage the ramping requirements due to changes in variable generation, and would not require additional investment in storage and/or flexible capacity; instead, the system could deal with the retirement of around 46 GW of the old coal fleet without negatively affecting its operation. The study expects that VRE generation, mainly solar and wind, would represent around 22% of the total energy mix, peaking at 54% in certain hours. Among the key recommendations proposed to allow further VRE adoption are to improve the coordination among states, reduce minimum generation levels of large coal plants, and give a more significant role to flexible hydro plants.

General Electric and the Shakti Foundation (General Electric & Shakti Sustainable Energy Foundation 2018) evaluates CEA's 13th National Electricity Plan and focus on specific performance metrics. Among the key findings, the study concludes that including 175 GW in VRE sources would lead to a higher number of starts and stops of the coal fleet, and changes in coal capacity factors, that will depend on the region if they are upward or downward. Interstate and interregional transmission links would likely experience congestion, as electricity exchange among regions, exports mainly from the western to the northern and southern regions would increase. Moreover, some states, mainly in the northern and southern region, would still experience load shedding, due to the inability to import electricity from other regions at peak intervals.

Finally, the authors of Berkeley National Lab's study estimated that coal capacity required by 2022 would be lower than CEA's estimates, while additional flexible gas-based capacity would be needed. While renewable sources provide support during peak hours during monsoon and summer seasons, during winter, flexible dispatchable capacity would be required to ramp up to meet the peak loads. The authors advocate for developing additional gas infrastructure, considering evaluating demand response options and reinforce interregional transmission networks.

While the CEA's National Electricity Plan, NREL, and GE & Shakti studies consider intrastate transmission networks, the Berkeley Lab study is limited to a regional analysis. The CEA 2030 report simulates a single node system and does not consider any transmission congestion. Most studies include detailed analysis of how the system would operate by 2022; nevertheless, they limit their analysis the short- and medium-term. Most studies fail to address its main challenges in the next 20 years: electricity demand will almost triple, a significant share of the existing power capacity would have to retire due to its age, and more stringent emissions limit would be enforced. The CEA in its interregional transmission report (Central Electricity Authority 2016) conducts a long-term assessment (2036) of the transmission operation performance estimating the requirements of transmission capacity under indicative capacity plans; however, it does not include a thorough analysis of how the system would work under more aggressive VRE penetration. The only report that conducts a thorough long-term analysis is the recent CEA 2030 report. Nonetheless, this study considers fix assumptions for the main capacity expansion drivers (e.g., VRE capital costs, storage costs) and fails to explore different scenarios to address the uncertainty in these assumptions. In

³² The study expects only 1.4% of renewable energy curtailment at the national level.

addition, the CEA 2030 first estimates the optimal generation mix and then verifies if the optimal mix is sufficiently adequate to meet the expected load, failing to explore how the firmness of different generation resources can affect long-term capacity expansion decisions. Moreover, the CEA 2030 report does not allow any further gas-based capacity deployment. Gas plants can act as a flexible capacity and compete with storage technologies, and they are a viable technology that should be considered as a candidate for the future power system.

3.3 Optimization tools often used in power systems modeling

Capacity expansion models are the most common tool used by policy-makers and researchers to evaluate future least-cost power mixes under different scenarios. As described by the Department of Energy, a “capacity expansion model simulates generation and transmission capacity investment, given assumptions about future electricity demand, fuel prices, technology cost and performance, and policy and regulation.” (Department of Energy – Office of Energy Policy and Systems Analysis 2016).

However, power systems are extremely complex and have multiple characteristics that are difficult to model into a computer software. Existing tools have to deal with the tradeoff between representing power systems with great detail and running optimization problems under reasonable time periods. Figure 3-1 shows some of the different dimensions that are considered when designing a capacity expansion model.

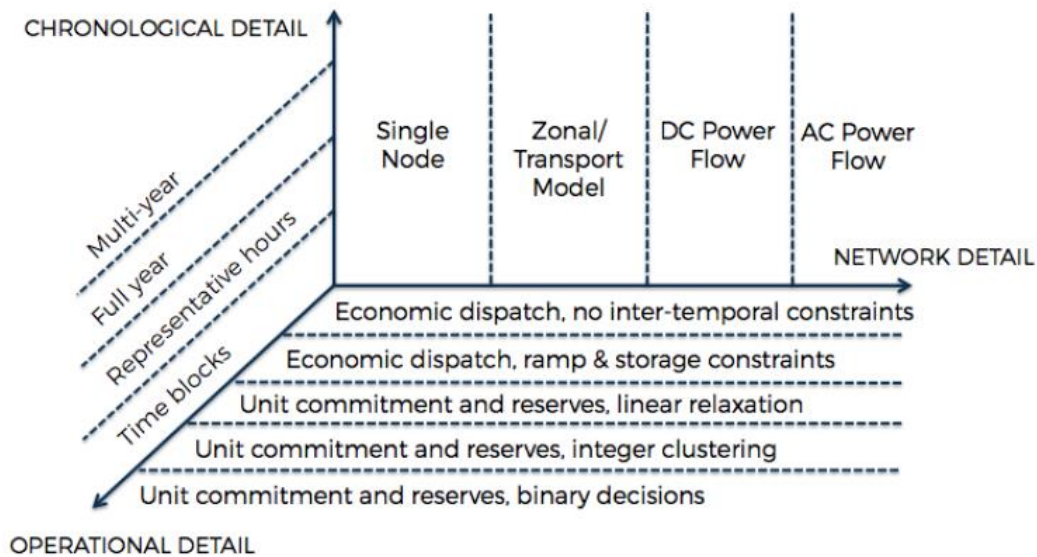


Figure 3-1: Examples of model resolution options for capacity expansion models. Source: (Jenkins and Sepulveda 2017).

One important dimension is the chronological detail: the operation of a power system can experience significant changes within minutes, if not seconds, an effect that has been increased with the expansion of VRE that may experience drastic changes in their power output in minutes. However, to reduce computational time, capacity expansion models have usually simplified

chronological details by aggregating time intervals into time blocks or time slices; this simplification does not take into account the variability within hours. On the other hand, the use of representative hours of days can capture part of the variability in-between hours, without sacrificing computational efficiency, although, this simplification can tend to misrepresent the behavior along more extended time periods such as a year. Another tradeoff is choosing between a single year and multi-year optimization problems³³.

Defining the network detail is another relevant dimension, considering that power systems usually consist of meshed networks with multiple transmission lines with limited capacity subject to congestion. As shown in Figure 3-1, some capacity expansion tools allow the user to model networks with multiple nodes with different degrees of detail, but similarly to the chronological dimension, the higher complexity would lead to a longer time in solving the optimization problem.

The last dimension shown in the figure above is the operational detail. Some power plants have operational constraints that are important to consider in capacity expansion tools, such as startup and shutdown costs, minimum downtime and uptime intervals, ramping and minimum output constraints, among others. These constraints often involve Unit Commitment (UC) decisions³⁴ and can define the type of problem to be solved, being either linear, mixed-integer linear or mixed-integer nonlinear. As said before, including detailed constraints would better represent real power systems, but would sacrifice computational efficiency. Models can be further complicated, by replacing deterministic parameters with stochastic inputs, e.g., trying to adequately represent the uncertainty in load and VRE generation.

Table 3-1 summarizes the models and main dimensions considered in the CEA, NREL, GE & Shakti, and Berkeley lab studies.

³³ Power infrastructure investments are not undertaken over one year but are planned, developed and operated over long term periods making multi-year models more suitable to represent power systems; however modelling multi-year capacity expansion models can significantly increase the computational time.

³⁴ In (Saravanan, et al. 2013) a Unit commitment analysis is defined as “an optimization problem used to determine the operation schedule of the generating units at every hour interval with varying loads under different constraints and environments”.

Table 3-1: Model resolution adopted in existing Indian studies.

Publisher	Study title	Model used	Target year	Capacity expansion?	Chronological detail	Network detail	Generation detail
CEA	Draft Report on Optimal Generation Capacity Mix for 2029-2030	ORDENA	2029-30	Yes (excepting gas)	Multi year - Hourly detail for critical days	Single node	Economic dispatch / Ramp and storage constraints
CEA	13th National Electricity Plan	Electric Generation Expansion Analysis System (EGEAS) and validated with ORDENA	2021-22 / 2026-27	Yes (only thermal)	Hourly detail - One year	State level	Economic dispatch / Ramp and storage constraints
NREL	Greening the grid: Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid	Production Cost and Capacity Expansion Model (PLEXOS) used in three stages: i) Capacity expansion model ii) Day ahead model economic dispatch model iii) Real time economic dispatch model	2022	No	Hour commitment - 15 minute VRE & Load profile - One year	State level	Unit commitment and reserves / Binary decisions
GE & Shakti	Integrating renewable energy modelling with power sector planning for India	Two models were considered: i) GE Multi Area Production Simulation (MAPS) ii) GE Multi Area Reliability Simulation (MARS)	2022	No	Hourly detail - One year	State level	Plant detail/ Unit commitment with binary decisions and some reliability measures (LOLL)
Berkeley National Lab	Techno-Economic Assessment of Integrating 175 GW of Renewable Energy into the Indian Grid by 2022	Production Cost and Capacity Expansion Model (PLEXOS) used in three stages: i) Capacity expansion model ii) Day ahead model economic dispatch model iii) Real time economic dispatch model	2022	Yes (only coal and gas)	Hourly detail - One year	Regional level	Plant detail/ Unit commitment without reserves

4 Understanding the Indian system's operation

Before defining a proper framework to explore future power systems, it is essential to first understand the current system, how it operates, and the main characteristics that differentiate it from other power systems. Figure 4-1 shows the evolution of installed capacity and peak load in the period between 2008-09 and 2017-18. Installed capacity has increased over twofold while peak load has increased by nearly 50%. New coal plants represented 61% of the total new capacity, plants defined as RES by the CEA represented 28%, and the rest of the increase came from all the other technologies.

The higher increase in capacity has led to an apparent overcapacity in the system. By March 2017, the ratio between installed capacity and peak load was 2.1 times. Excluding solar PV, wind, small hydro, and biomass plants from the overall capacity (a conservative simplification of firm capacity³⁵), given that they may not provide output coincident with peak load, there is nearly 70% of more capacity than peak load. This metric, which can be used as a proxy for planning reserves is far higher than planning reserves in US and European markets³⁶, indicating substantial overcapacity in the Indian power system. Considering the forecasted capacity by 2022, after the 13th plan, planning reserves, although they are reduced significantly, are still high in comparison to other power systems.

Considering the current oversupply, why are central authorities pushing for capacity additions in the following years? Existing capacity in an efficient and well-coordinated system should be enough to meet the additional load in the medium term. What are the reasons behind the overcapacity? This chapter analyzes and describes several reasons that could partially explain the current and expected overcapacity in India

³⁵ The firmness of a given plant is defined in (Rodilla and Batlle 2013) as “the amount of capacity that is available to generate when needed, during the required interval of time”. The firmness will depend on the availability of the resource and the economic conditions, among others factors. RES are assumed that they do not provide firm capacity. Firm capacity is usually estimated by calculating the historical generation of each plant and evaluating the coincidence with peak loads. Hence, completely excluding sources like solar PV and wind is not a correct assumption; in many cases, they can produce in coincident time intervals with peak loads. However, for simplification purposes, RES are assumed to not generate coincidentally with peak load. This simplification will only lead to an underestimation of the amount of planning reserves available, maintaining the point described in the section.

³⁶ Target reserve margin in ERCOT is 13.75% (The Brattle Group 2018), while in Spain they expect a reserve margin between 6% and 12% by 2019-2020 (Comisión Nacional de los Mercados y la Competencia 2017). In contrast, planning reserves in UK are nearly 40% (Department of Energy – Office of Energy Policy and Systems Analysis 2016).

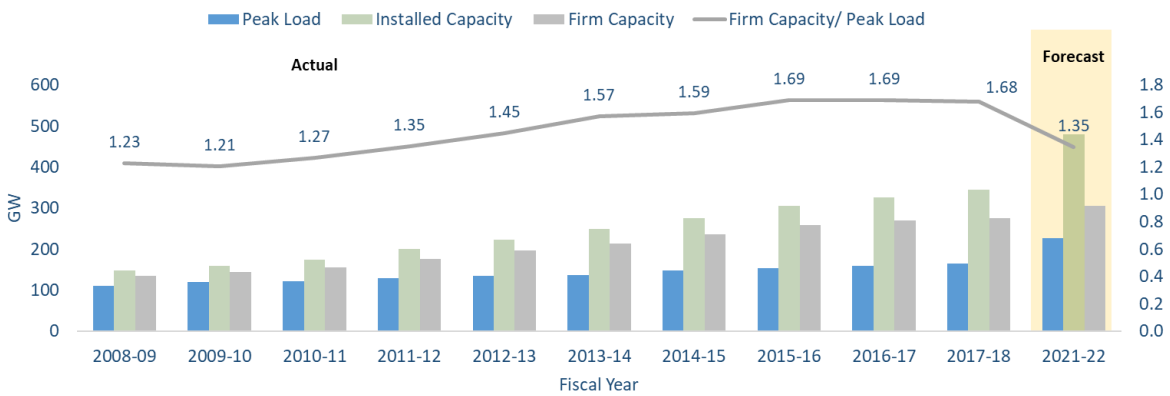


Figure 4-1: Peak Load, Installed Capacity, and Firm Capacity at the end of each fiscal year between 2008-09 and 2017-18. Note: Total capacity values do not consider captive plants and behind the meter diesel generators. Firm capacity is calculated as total capacity excluding RES (hydro under 25 MW, biomass, solar PV, and wind).

4.1 Thermal fleet operation: below international standards

One reason behind the oversupply is the underutilization of the thermal fleet. Figure 4-2 shows the evolution of the installed capacity and capacity factors³⁷ of coal, nuclear, and gas plants in the period from the year 2008-09 and 2017-18. Coal- and gas-based plants, while registering an increase in installed capacity over the years, have almost steadily reduced their capacity factors. The trend in nuclear plants' capacity factors is not that clear; however, recent capacity factors in nuclear plants (71%-72%) are significantly lower than the peak values registered in 2013-2014 (91%). Recent capacity factors for coal and nuclear plants are significantly lower than international references, considering they are both baseload technologies. For instance, NREL assumes in its capacity expansion model named Regional Energy Deployment System (National Renewable Energy Laboratory 2018) 85% and 92% capacity factors for new coal and nuclear plants, respectively. Furthermore, the CEA in its 2019 tariff regulations established an 85% capacity factor for all thermal plants, except in some specific cases. Gas plants will depend on the price of gas consumed and hence, depending on the market, will operate as baseload or intermediate plants. Nonetheless, the steady reduction in capacity factors for gas-based plants is worth analyzing.

³⁷ Capacity factors are calculated by dividing the total electricity generation in a fiscal year by the product of the installed capacity by March (last month) of each fiscal year and 8760 hours. This calculation tends to distort estimates when capacity increases throughout a year. Nevertheless, capacity factors are also calculated using average capacity throughout the year and conclusions did not change significantly.

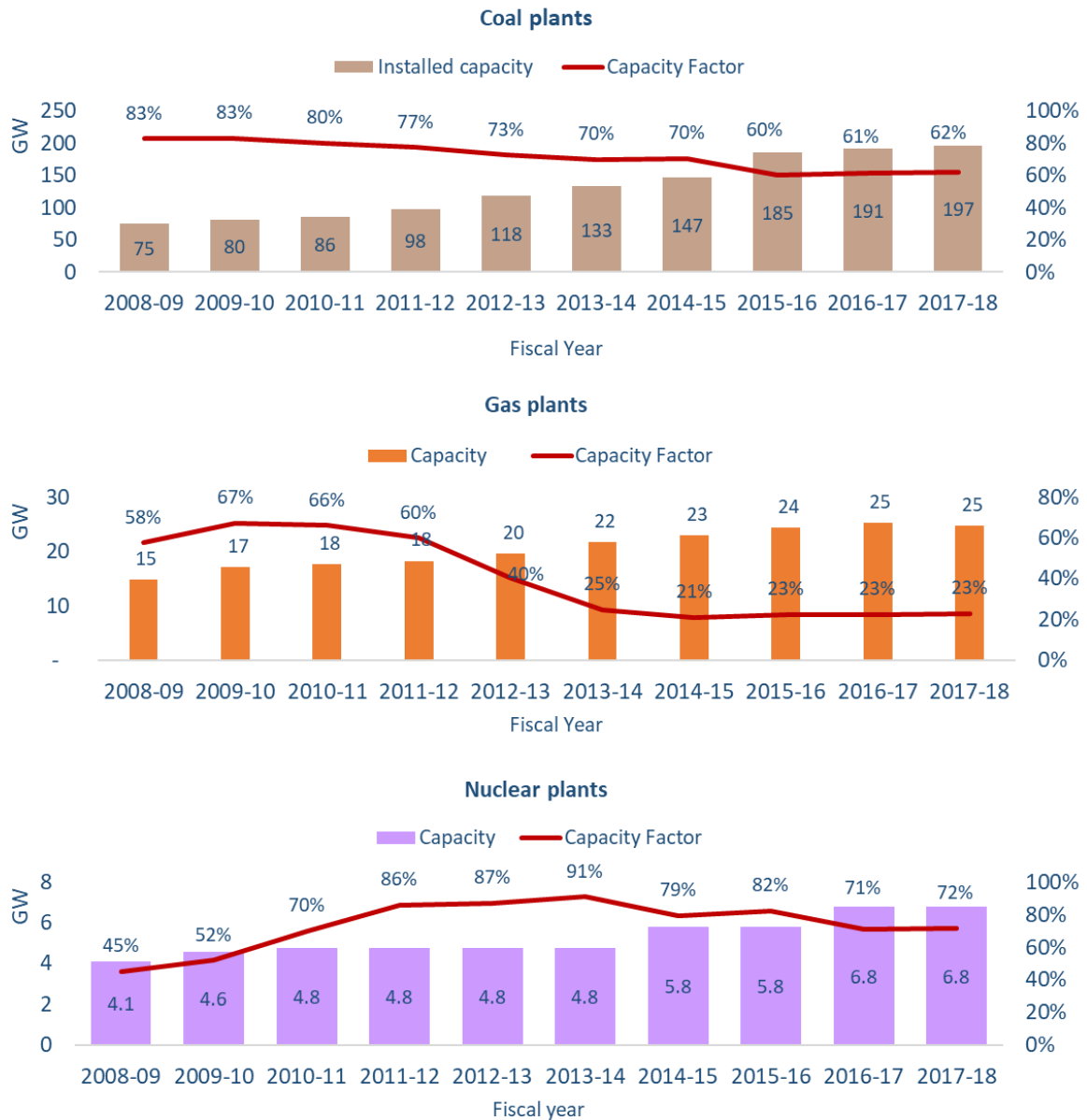


Figure 4-2: Evolution of installed capacity and capacity factors for thermal plants.

Source: (Central Electricity Authority 2008-2018b).

Note: Capacity factor is calculated by dividing the total electricity generation in a financial year and dividing it by the product of the installed capacity by March (last month) of each financial year and 8760 hours.

Figure 4-3 shows the forced outages, planned outages, and availability of the coal fleet for the period between 2009-10 and 2014-15. The decrease in availability from 85% in 2008-09 to 76% in 2014-15, is driven by an increase in forced outages. Planned outages shown are lower than international standards (NREL defines a 10% planned outage rate in its report (National Renewable Energy Laboratory 2018)); however, forced outage rates are high. Forced outages, as defined by the CERC, are driven “by faults or other reasons which have not been planned” (Central Electricity Regulatory Commission 2010). The high increase in forced outages is due to technical as well as economic reasons. According to CEA daily outages reports (National Power Portal 2018), among many reasons, forced outages have been caused by coal supply problems, transmission constraints,

problems operating the equipment, water scarcity, and reserve shutdown events. The last cause is an event when a unit is available for load but not synchronized due to lack of demand. Using this cause to notify a forced outage event is a common technique used by coal plants operators to avoid generating, due to the uncertainty in receiving payments for the energy generated³⁸. Coal supply problems seem to be solved, but other problems are expected to continue in the medium term. Lower availability of the coal fleet does not fully explain the decrease in capacity factors, as shown in Figure 4-2 and Figure 4-3. Other reasons explaining the reduction are the steep increase in VRE capacity. VRE plants (and some thermal plants) are assigned a must-run³⁹ status, preventing system operators from curtailing them, and forcing coal plants, most of them inflexible units, to cope with the changes in net load. Finally, low capacity factors create a vicious cycle as they contribute to the current overcapacity that then causes a further reduction in the utilization of thermal plants.

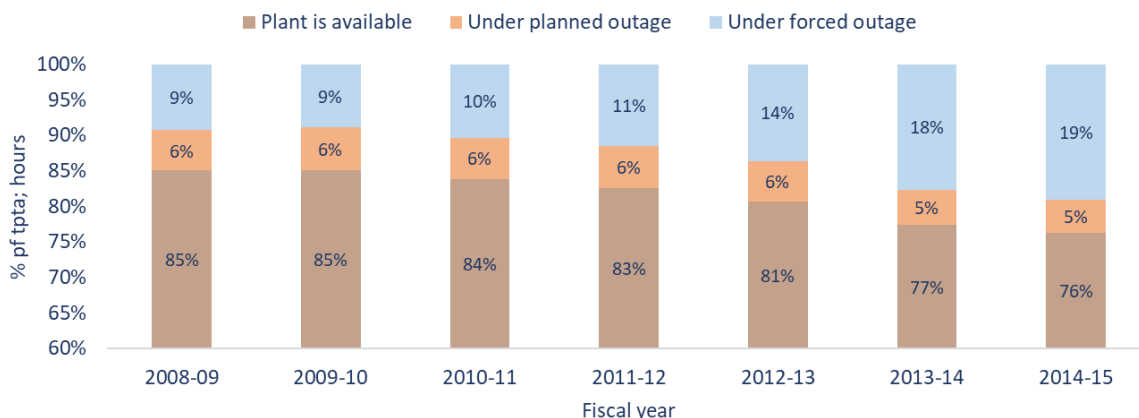


Figure 4-3: Planned outages, forced outages, and availability of the coal fleet. Source: (Central Electricity Authority 2015).

Nuclear plants have experienced higher forced and planned outages rates. Daily analysis of outages during the first ten months of 2018 shows that the availability of the nuclear fleet was under 70%, mainly caused by reactor maintenance and other routine maintenance (National Power Portal 2018).

Low capacity factors in the gas-based fleet are mainly due to supply shortages. Figure 4-4 shows the evolution of gas supplied over gas required, decreasing from over 70% to 25%. Domestic gas is allocated by the government to the different sector per policy guidelines, while imported gas can be freely sold by importers to customers. Natural gas has three main alternative uses in India: power plants, fertilizing plants and petrochemical plants; however, the priority is given to the fertilizing industry due to the importance of the agricultural industry in the country. With the discovery and development of the Krishna Godavari Dhirubhai 6 gas field, there was a high expectation for an

³⁸ Financial weakness of distribution companies has generated fragility in the payment chain. In recent years, generators do not have complete certainty if that they will receive payments for the energy their plants generated.

³⁹ When dealing with variable sources (VRE) combined with inflexible sources (coal and nuclear fleet), system operators must deal with abrupt changes in resources availability by either curtailing VRE or changing the output of the inflexible sources. When VRE are assigned a must-run status, system operators do not curtail VRE but instead instruct other plants to modify their output.

increase in domestic gas supply and new combined cycle plants were developed. However, the production of gas from the new field did not reach the expected target and instead had been decreasing in recent years, affecting the supply of existing plants. On the other hand, the low price affordability of imported gas has led to stranded gas-fired power assets. Because of this reason, the central government has advised developers not to plan new gas-based plants and has implemented different initiatives to promote new gas production sites as well as importing additional LNG (Central Electricity Authority 2018a). **Appendix A** includes additional data regarding forced and planned outages of the thermal fleet.

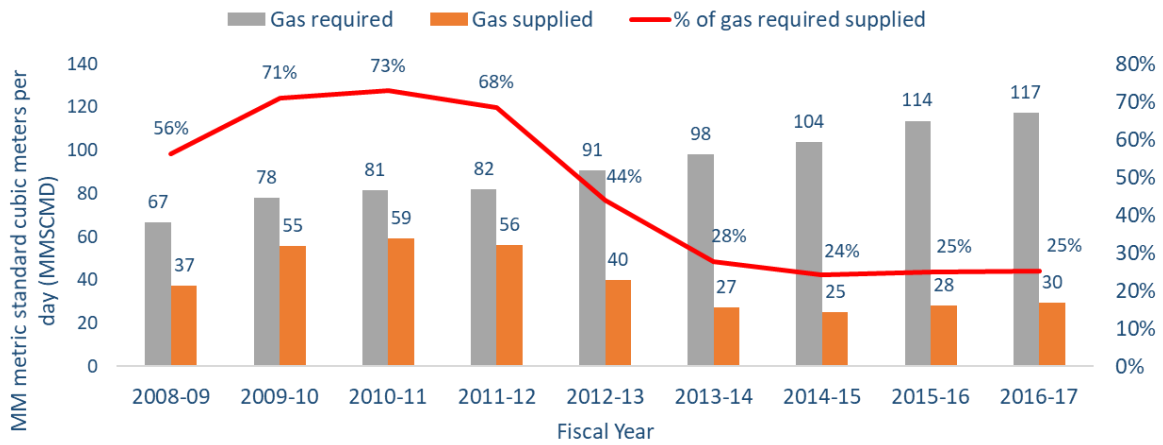


Figure 4-4: Gas supplied to gas-based plants v/s gas required.

Source: (Central Electricity Authority 2018a).

Note: Gas requirements were estimated by CEA considering a capacity factor of 90%.

As described, while the coal and nuclear fleets are operating well below their full capabilities, the gas fleet is operating at much lower capacity factors. Finally, there are coordinating reasons and regulatory inefficiencies that also contribute to efficient plants not operating at its fullest. For instance, there is little coordination among DISCOMs/SLDCs across states, leading to inefficient plants operating in some states while other more efficient plants are idle or operating at part load (Palchak, et al. 2017).

4.2 Hydro sources: declining contribution to the generation mix

Hydro generation, once the primary electricity source in India, has lost share in the generation mix in recent years. Figure 4-5 summarizes the generation of the run of river plants in the past ten years. Capacity factors of run of river plants have averaged 38% in the past ten years, although it has decreased in recent years. In contrast to other countries, hydrology tends to behave similarly throughout the years. Figure 4-6 shows that excluding some anomalies during some years, the capacity factor of these plants tends to peak between July and August, coincident with the monsoon season, while it reaches their minimum on around December and January.

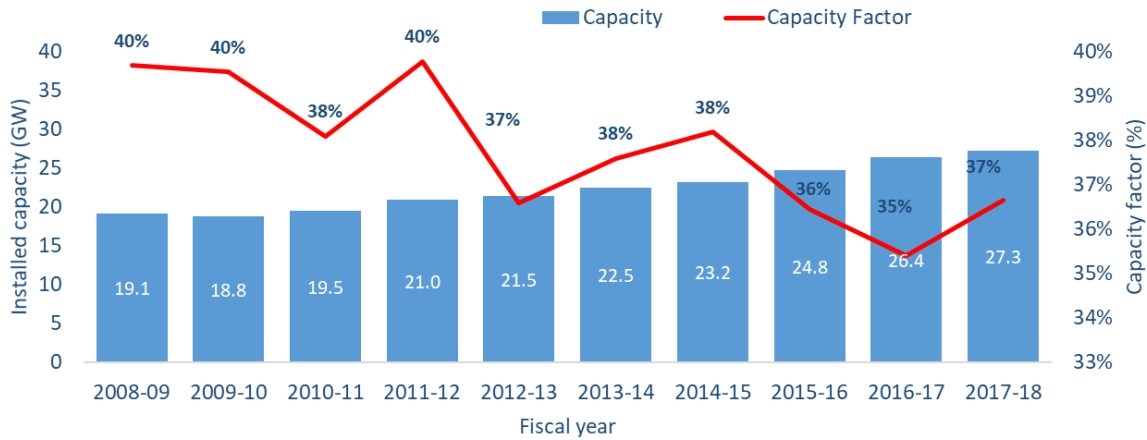


Figure 4-5: Evolution of installed capacity and capacity factors of run of the river plants. Source: (Central Electricity Authority 2008-2018b).

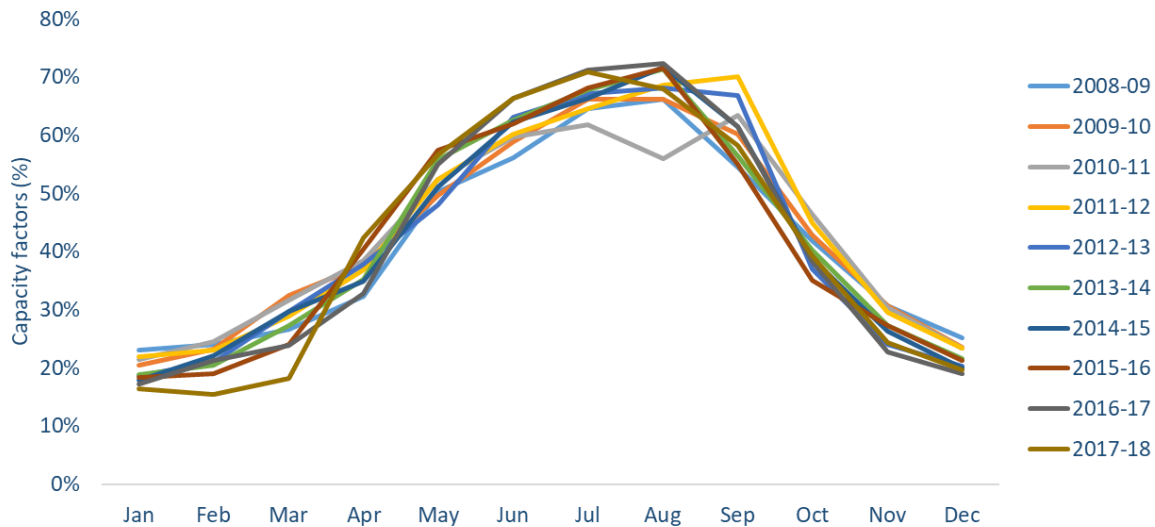


Figure 4-6: Seasonality of run of river plants. Source: Own assumptions on a sample of 64 hydro plants and based on (National Power Portal 2008-2018a).

On the other hand, Figure 4-7 shows that capacity factors for major reservoir hydro plants have averaged 30%, although with high variability among the years. Most of the largest reservoirs are multipurpose, and water besides withdrawing for electricity generation is used for irrigation and consumption. With an increase in irrigation, water will be saved to irrigation rather than used for generation. Figure 4-8 shows the daily evolution of the Bhakra⁴⁰ reservoir between September 2017 and August 2018. The reservoir level reaches its minimum just before the monsoon season begins, and from that moment, the reservoir has a steep rise.

⁴⁰ Bhakra reservoir has an installed capacity of 1,325 MW and can store over 17,000 GWh

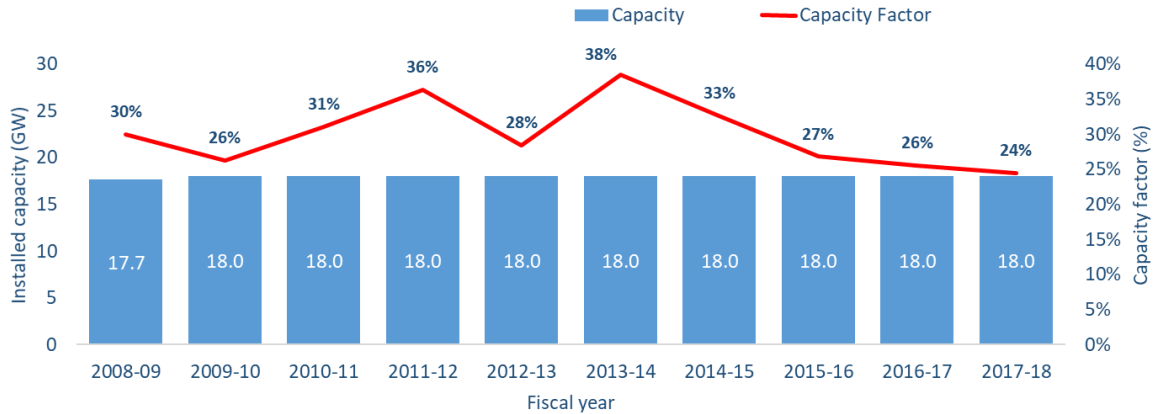


Figure 4-7: Evolution of installed capacity and capacity factors for reservoir plants
 Source: (Central Electricity Authority 2008-2018b)

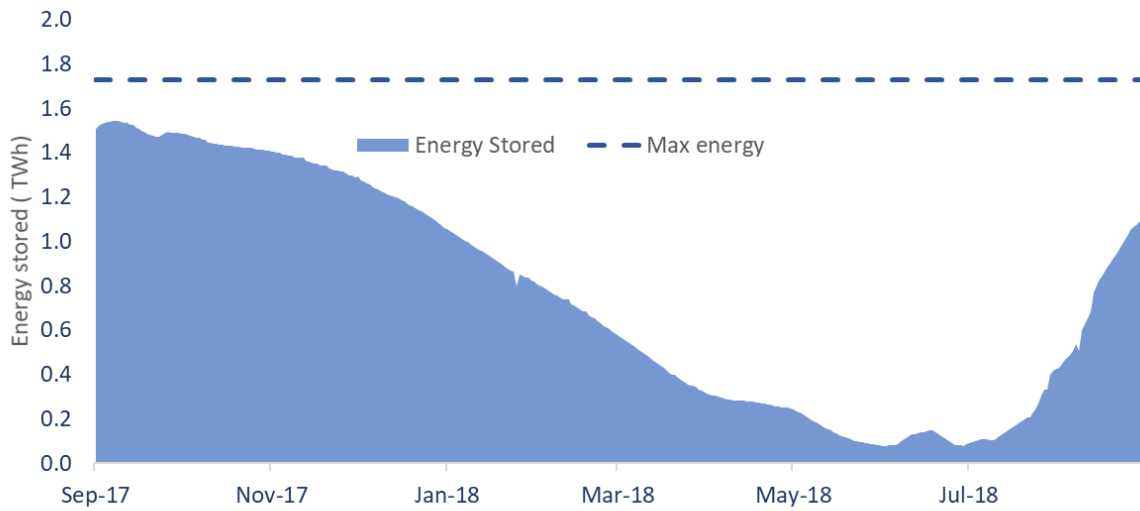


Figure 4-8: Daily evolution of energy stored in the Bhakra reservoir in the period between September 2017 and August 2018.
 Source: Own assumptions based on (National Power Portal 2008-2018b).

Why are no new hydro plants being developed, considering that these resources, especially hydro reservoirs, are a natural complement for variable sources? Reservoirs are flexible enough and can ramp from 0 to 100% output in minutes if not seconds, adapting to the sudden changes in VRE generation. Reasons behind the slow development of new hydro plants include environmental concerns, resettlement and rehabilitation issues, land acquisition problems, long clearance and approval procedures, among others (PricewaterhouseCoopers 2014).

4.3 VRE sources: spread out and with low capacity factors

Finally, as discussed before, most of the new plants under development are VRE. Figure 4-9 shows the operation of wind, solar PV, biomass, and small hydro plants in the last 4 years⁴¹. There is substantial variability in biomass plants' capacity factors, while overall capacity factors are significantly lower than those of large-scale hydro plants, coal, and nuclear plants. Most of these resources are scattered all around the country. For instance, small hydro plants are “generally used as standalone power systems in remote areas” (Central Electricity Authority 2018a). Moreover, a high share of new solar PV plants are rooftop units that generally have lower capacity factors than utility-scale plants; in fact, the CEA aims that 40 GW of the expected 100 GW solar PV plants that will be operating by 2022 should be rooftop solar. Wind farms are scattered around three main regions (north, west, and south). Investment in transmission and distribution added to efficient coordination among all local and national system operators must be in place, to successfully integrate the renewable sources scattered all around the country. As described before, the Indian integrated system has historically lacked both: i.e. limited coordination among state and regional load dispatch centers, and insufficient investment in network reinforcements, especially in distribution networks.

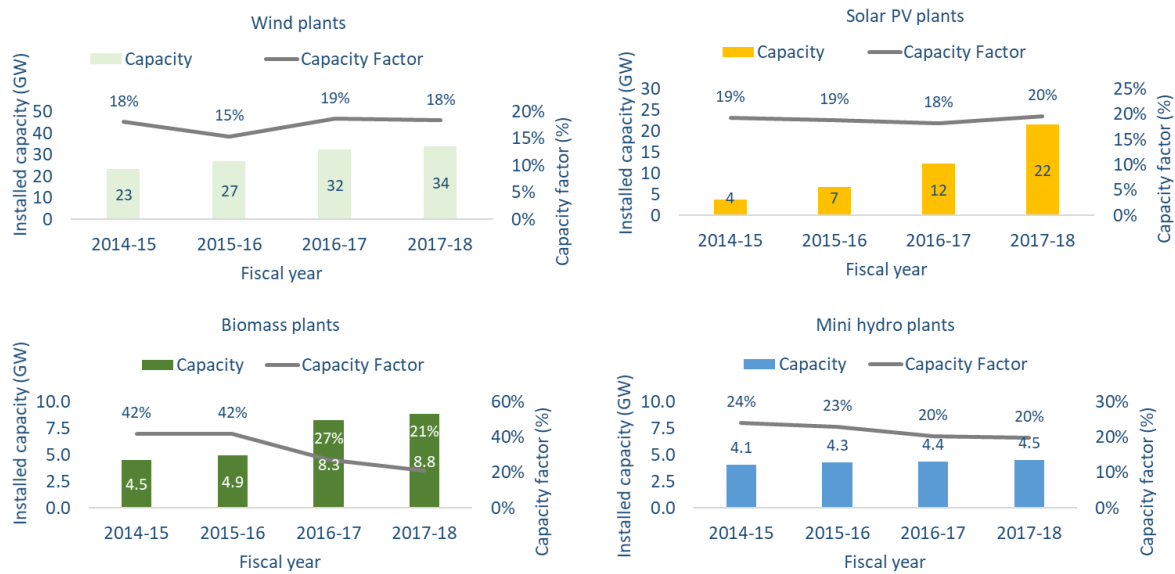


Figure 4-9 : Evolution of installed capacity and capacity factors for wind, solar PV, biomass, and small hydro plants. Source: (Central Electricity Authority 2008-2018b)

⁴¹ Considering there is not sufficient public data detailing VRE generation, a summary for only the last four years is included.

5 Methodology used

This chapter details the methodology used to explore and evaluate future power system scenarios, including the design of the different scenarios, the computer software used to estimate the optimal mix, and the model's main data assumptions.

5.1 Optimal generation mix under centralized decision-making.

This study estimates an optimal generation mix under different scenarios considering centralized decision-making. Under the central planner approach, all decisions, such as planning, development, and investment, are assumed to be taken by a central authority aiming to maximize social welfare. The methodology behind capacity expansion analysis assumes that social welfare maximization is reached by minimizing the total costs of operation and investment incurred in the power system. An alternative approach, decentralized decision-making, emulates competitive markets and considers individual decisions of each agent that participates in the power sector. Under perfect competition, investment decisions considering optimal conditions should be the same under centralized and decentralized decision-making (Botterud, Ilic and Wangensteen 2005).

To calculate the optimal generation mix, only one future target year is modeled. As described in (Sepulveda, et al. 2018), choosing a one-year target produces a “static long-run equilibrium outcome” considering that it does not solve at what point in time investments should be made, but instead, produces a snapshot of an optimal generation mix for a target year. The fiscal year 2036-2037 is chosen as the target year as this is, the last year with available load forecasts (Central Electricity Authority 2017c).

5.2 Definition of scenarios

5.2.1 Defining base scenarios

Modeling power systems 20 years ahead introduces many challenges: there is uncertainty regarding which technologies will be predominant in the future, the cost of commodities and the policies and regulations that will be enforced. Figure 5-1 shows the main dimensions that are pivotal for this research. The cost of generation sources is one of the key drivers for the composition of future generation resources. The changes in the cost of different power generation technologies have dramatically changed in the last decade: technologies such as solar PV were cost-prohibitive a decade ago are now cost-competitive, and further cost reductions are expected in the future. Commodity prices, including fossil fuels, also have uncertainty as they have experienced high volatility in the past: natural gas is a great example, after the shale gas boom; prices in the USA have reduced more than 60% (Feng, et al. 2019), bolstering the deployment of combined cycle power plants. Finally, the implementation of different policies can lead to different energy pathways: the type of policy and how ambitious the policy is will have a great impact on the type of technologies that will be developed.

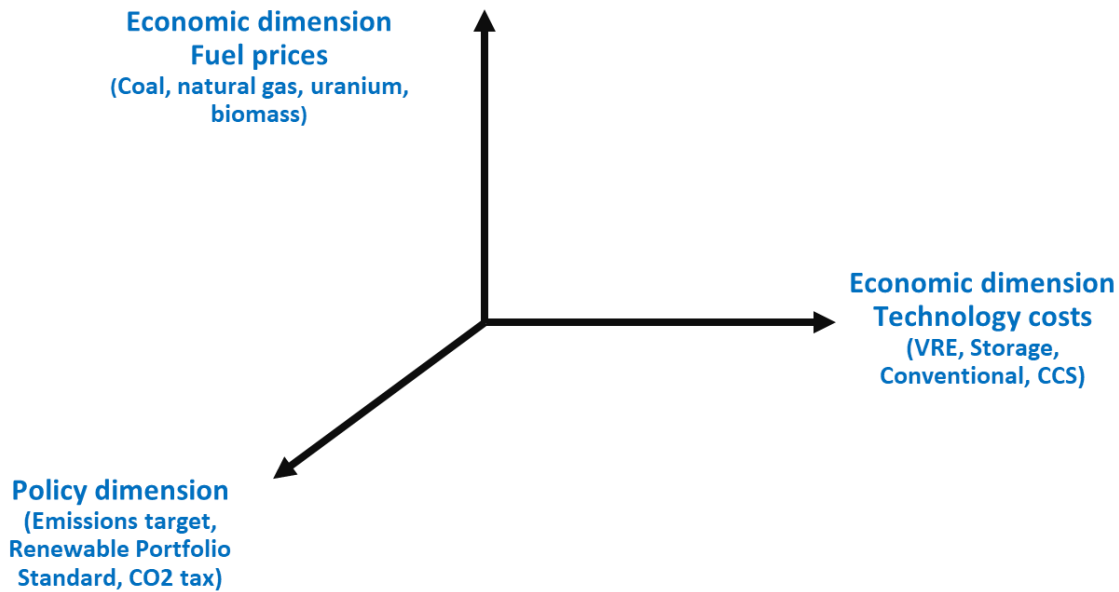


Figure 5-1: Pivotal dimensions to define future power systems.

In this case study of the future Indian power system, four main factors are considered, summarized in Figure 5-2: three economic assumptions and one policy variable. Future capital costs of VRE⁴² have a major effect on the future system’s cost considering that a considerable share of new capacity coming online is solar and wind plants. A system operating with a high share of VRE would require flexible capacity; hence the cost of storage technologies and the future price of gas will influence the type of flexible sources that will accompany the future development of VRE. Relying on gas generation requires not only the development of gas-based plants, but also constructing gas infrastructure, either through the construction of gas pipelines or liquefied natural gas terminals. Different gas price scenarios are defined that consider all costs related to the extraction, transport, import, and delivery to the plant. Finally, emissions limits are defined as a policy factor. Much has been debated in recent UNFCCC meetings regarding the level of emissions goals countries should commit. Some experts say that keeping the average temperature rise under 2°C is not enough, and a more ambitious goal should be set, limiting the increase below 1.5°C. Setting emissions limits consistent with i) business-as-usual scenario (no emissions limit), ii) keeping increase in temperatures below 2°C and iii) below 1.5°C is critical to understand how policy will affect the deployment of future technologies. Emissions according to the different temperature rise scenarios are obtained from (International Energy Agency 2018). The combination of the different assumptions under each dimension makes up 24 different scenarios. The references behind each assumption are detailed in Table 5-1, Table 5-2, Table 5-3, and Table 5-4.

⁴² VRE scenarios are built only from solar and wind capital costs, considering that other VRE sources are not the main focus in CEA’s plans.

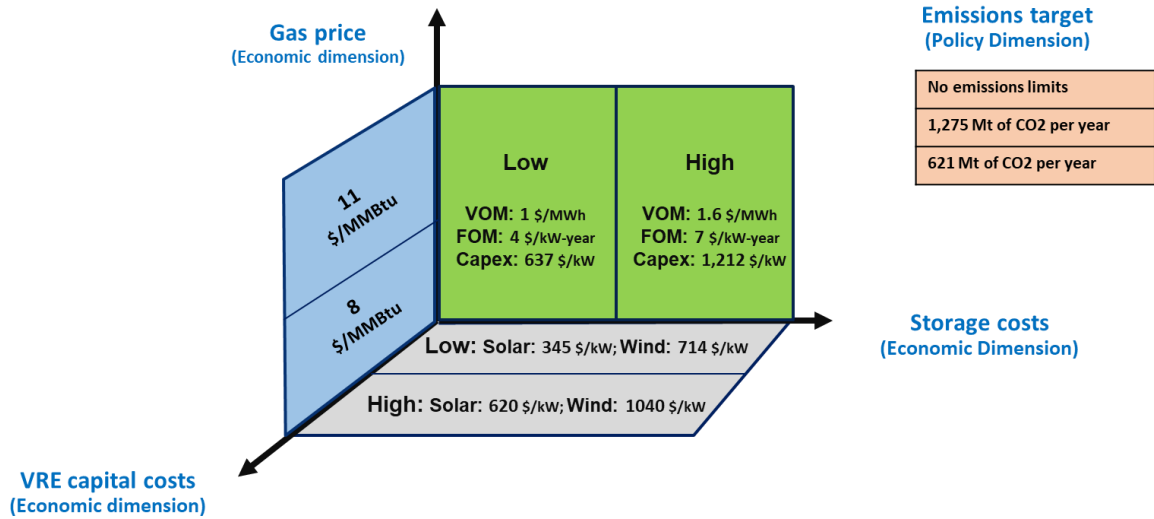


Figure 5-2: Dimensions considered in the study.

Table 5-1: VRE capital cost scenarios: Assumptions for low and high VRE capital costs.

Source: Low scenario assumptions from (Chaturvedi, Koti and Chordia, Sustainable Development, Uncertainties, and India's Climate Policy: Pathways towards Nationally Determined Contribution and Mid-Century Strategy 2018) and high scenario from (International Energy Agency 2018).

Note: Solar PV capital costs consider inverter from DC to AC.

Technology	Overnight capital costs [\$/kW]	
	Low	High
Solar PV	345	620
Onshore wind plants	714	1040

Table 5-2: Gas price scenarios: Assumptions for low and high gas prices.

Source: Own assumptions based on Exxon Mobil recommendations.

Note: Prices consider fuel price, transport, and other related costs.

	Price delivered at plant [\$/MMBtu]	
	Low	High
Gas price	8	11

Table 5-3: Storage scenarios: Assumptions for low and high batteries costs.

Assume storage plants are 4-hour lithium-ion batteries.

Source: Low and medium forecasts by 2035 from (National Renewable Energy Laboratory 2018).

Scenario	Capital cost [\$/kW]	Fixed O&M cost [\$/kW-yr]	Variable O&M cost
Low	637	4.0	1.0
High	1,212	7.0	1.6

Table 5-4: Policy scenarios: Assumptions for emissions limits.
 Source: Own assumptions based on (International Energy Agency 2018).

Scenario	Emissions limits (Mt CO ₂ eq)
Business as Usual	-
Temperature rise under 2°C	1,275
Temperature rise under 1.5°C	621

5.2.1 Additional scenarios: different policies to achieve emissions targets

Setting emissions limits is not an easy task. How can we enforce that the targets are achieved? The assumption behind the base scenarios is that system operators and/or regulators have detailed knowledge of the heat rates of each plant and the pollutant content in every unit of fuel used in each plant. Then, the system operator takes into account the emissions rates, technical constraints, and operating costs when dispatching each plant. However, information asymmetries between plant operators and system operators and/or regulating authorities could lead to inefficient dispatch and/or emissions over the targets.

As an alternative, additional scenarios are defined, depicting alternative policies that would aim to achieve similar emissions limits under a carbon tax policy. The scenarios that will be simulated are summarized in Table 5-5. Literature proposes setting a carbon tax as an optimal policy to reduce GHG emissions (Pearce 1991). However, there is no consensus regarding the value in which the tax should be set; it will depend, among many variables, in the amount of GHG emissions which is want to be avoided. In fact, some European Union countries have applied taxes higher than 20 \$/ton while others have set taxes higher than 100 \$/ton (World Bank 2016)

Another policy, often defined as a “second best” solution is to establish renewable portfolio standards. As defined by the United States Energy Information Administration (U.S. Energy Information Administration 2012), renewable portfolio standards “require or encourage electricity producers within a given jurisdiction to supply a certain minimum share of their electricity from designated renewable resources.” For this analysis, an alternative portfolio composed of non-fossil fuel standards is defined, which are all sources excepting coal, gas plants, and backup diesel generators. Non-fossil fuel standard is defined as a minimum percentage of the total electricity demand that must come from non-fossil fuel sources. In this case, the total demand includes load plus roundtrip losses experienced in storage charging and discharging.

Table 5-5 : Additional scenarios: Implementing different policies.

Policy scenario	Target		
	Low	Moderate	High
Carbon tax [\$/ton]	40	60	80
Non-fossil fuel Portfolio Standard [%]	40	60	80

5.3 Using GenX, a capacity expansion model

5.3.1 Description of the original existing model

GenX is a deterministic capacity expansion planning model that optimizes generation, storage, and transmission capacity expansion decisions and dispatch of generation and storage resources on an hourly basis to meet the electricity demand in a year, at the lowest cost possible. The model minimizes the total cost incurred in operation and investment over a target year.

The model, written in Julia⁴³ and using JuMP⁴⁴, allows the user to define different technical and policy-related constraints. The user can include unit commitment decisions for thermal plants as well as operational constraints for all power plants. The user can also set CO₂ emissions or predefine generation shares to a subset of technologies.

Moreover, the user can choose among different levels of model resolution. For instance, the user can define whether to solve a single node or a multi-nodal transmission system or choose between modeling only the transmission level or include distribution assets. The user can also predefine a transmission system or allow the model to jointly solve a generation and transmission expansion problem.

Furthermore, the user can include a variety of different technologies, including demand-side resources and storage plants. The latter technologies can be modeled as units that can either charge by withdrawing energy from the grid or discharge by injecting energy into the grid. Moreover, hydro reservoir plants are receiving exogenous flows of water that would increase the energy stored in the reservoir.

In addition, the user can choose between modeling generation resources at an individual plant level or aggregate similar plants into clusters. Aggregating plants into clusters, each of them representing a group of identical plants, can considerably reduce the solution time, by transforming binary into integer variables as explained in (Palminier and Webster 2011) and further discussed in (Delarue, Mues and Poncelet 2018) and (Sepulveda, et al. 2018). The model also allows the commitment of regulating and spinning reserves. Further information of the model can be found in (Jenkins and Sepulveda 2017).

In order to find an optimal solution, the model uses the Gurobi commercial optimization solver⁴⁵. GenX, as programmed, allows the model to be solved as either a Mixed Integer Linear Programming (MILP) problem or as a Linear Programming (LP) problem. The latter approach relaxes the integer and binary variables to be continuous, reducing the complexity of the problem to be solved. Nevertheless, using LP does not take fully into account the UC constraints, which

⁴³ Julia is a programming language designed for high-performance numerical analysis and computational science (Bezanson, et al. 2017).

⁴⁴ JuMP is “a domain-specific modeling language for mathematical optimization embedded in Julia”. It supports solvers for several problem classes, including linear programming, mixed-integer programming, non-linear programming, among others (Dunning, Huchette and Lubin 2017)

⁴⁵ Gurobi is a mathematical programming software that solves Linear Programming (LP), Quadratic Programming (QP) and Mixed Integer Programming (MIP) problems (Gurobi Optimization 2019).

may be a substantial simplification, especially when modeling power systems with high VRE generation (Mallapragada, et al. 2018). Different approaches were tried in this study, but after considering the high number of scenarios to be simulated, an LP approach was chosen, to reduce the computational running time. Studies such as (Zhang, Capuder and Mancarella 2015) have found significant computational efficiencies by running LP instead of MILP problems. Additionally, they found out that LP problems approximate flexibility requirements that are more commonly suitable for MILP models, with high precision. It is possible to accelerate the MILP solution process via decomposition algorithms (see, e.g., (Flores-Quiroz, et al. 2016) and (Lara, et al. 2018)), but this was beyond the scope of this project. **Chapter 7** compares the optimal mix by using LP and MILP formulations of the capacity expansion problem and find that the differences are negligible.

5.3.2 Adjustments to original GenX code considered in this study.

Minor adjustments to the GenX formulation are included in this study that were not considered in the original GenX model (Jenkins and Sepulveda 2017). The previous version did not consider that reservoir plants can spill water when having excess energy stored. Formulas 70, 71, and 75 in (Jenkins and Sepulveda 2017) include spillage variables and are modified as follows:

Equation 5-1: Updated constraints for reservoir hydro including spillage variables.

$$70) \Gamma_{y,t,z} = \Gamma_{y,t-1,z} - \left(\frac{\Theta_{y,t,z}}{\eta_{y,z}^{down}} \right) + \left(\frac{\rho_{y,t,z}^{max} \times (\bar{\Delta}_{y,z} + \Omega_{y,z} - \Delta_{y,z})}{\mu_{y,z}^{stor}} \right) + \varrho_{y,t,z}$$

$$71) \Gamma_{y,1,z} = \omega_{y,z}^{level} \times \left(\frac{(\bar{\Delta}_{y,z} + \Omega_{y,z} - \Delta_{y,z})}{\mu_{y,z}^{stor}} \right) + \varrho_{y,t,z}$$

$$75) \Theta_{y,t,z} + \varrho_{y,t,z} \geq \rho_{y,z}^{min} \times \left(\frac{(\bar{\Delta}_{y,z} + \Omega_{y,z} - \Delta_{y,z})}{\mu_{y,z}^{stor}} \right)$$

for every generator y , time t , node z , where:

$\Gamma_{y,t,z}$ = energy stored in MWh

$\Theta_{y,t,z}$ = generation (MWh)

$\eta_{y,z}^{down}$ = generator efficiency (%)

$\rho_{y,t,z}^{max}$ = hourly water inflows as a % of max energy storage

$\mu_{y,z}^{stor}$ = power to energy storage ratio

$\bar{\Delta}_{y,z}$ = Existing capacity (MW)

$\Omega_{y,z}$ = New capacity (MW)

$\Delta_{y,z}$ = Retired capacity (MW)

$\varrho_{y,t,z}$ = Water spilled in MWh

$\omega_{y,1,z}$ = Energy stored in hour 1

$\rho_{y,z}^{min}$ = min generation per hour as a percentage of capacity

5.4 Data assumptions

This section summarizes the data used in the research and the main modeling assumptions.

5.4.1 Modeling the Indian system

The scope of this study considers a regional detail; interstate transmission links within a region are neglected, and only interregional links are modeled. Each region is modeled as a transmission node. Load curves from states are aggregated into regional load curves. Power plants within a region are aggregated representing regional clusters of plants per technology type. Moreover, the analysis does not consider the interconnections between India and its neighboring countries. The assumptions considered in this study are contrasted with the study published by National Renewable Energy Laboratory (NREL) (Palchak, et al. 2017) and the study elaborated jointly by General Electric and the Shakti Foundation (General Electric & Shakti Sustainable Energy Foundation 2018); both NREL and GE-Shakti model state-level detailed load profile and generation sources and consider interstate transmission links. However, these two latter studies only simulate the Indian system by 2022 and do not consider capacity expansion decisions. Figure 5-3 shows the transmission system modeled by the year 2037. The capacity for each interregional transmission link is modeled before running GenX, and are based on the peak import and export requirements estimated by the CEA by the fiscal year 2035-36 in (Central Electricity Authority 2016)⁴⁶. Finally, transmission losses are considered in this model, assuming that they are 3% of flows⁴⁷.

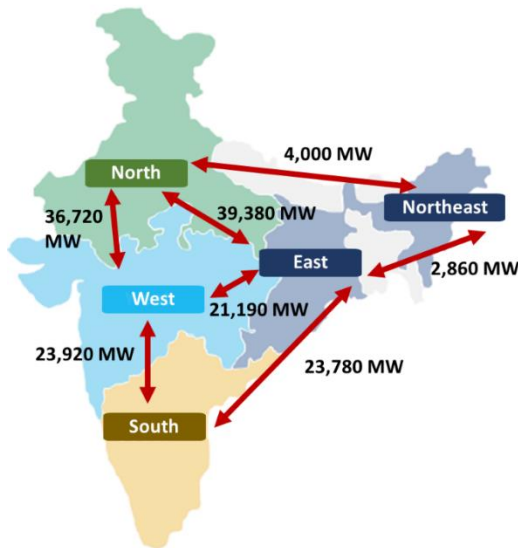


Figure 5-3: Indian transmission system in 2037 modeled in the analysis.

⁴⁶ Forecasted peak import and export power requirements by fiscal year 2035-36 were included in (Central Electricity Authority 2016). A transmission system able to accommodate the forecasted import and exports by year 2035-26 is considered in this study, taking into account the existing transmission links and assuming the least transmission capacity upgrade possible.

⁴⁷ Own assumptions. 1% of transmission losses per 100 miles are assumed in (Blair, et al. 2015).

5.4.2 Load profiles used

Five load profiles are modeled, one for each region, including load values for each of the 8760 hours in the target year. A 2015 baseload profile is assembled for each region by aggregating the load profiles available for every state in that region. State load profiles from 2015 were derived from the General Electric Study (General Electric & Shakti Sustainable Energy Foundation 2018) and originally obtained from multiple sources, some of them public (state load dispatch centers) and some private (paid databases). Load profiles from some states and union territories were not provided, such as Chandigarh (Northern Region), Pondicherry (Southern Region) and all states in the Northeastern region⁴⁸. Due to the lack of available data in some states and taking into account the approximations made in the load profiles from some states, there are differences in the max demand and total annual demand obtained by summing the state load profiles, and between the actual demand and load met reported by the CEA in (Central Electricity Authority 2008-2018a). The original sources, as well as a comparison between the estimated load and actual load in 2015, are detailed in **Appendix B**.

Table 5-6 and Table 5-7 show a comparison between the load estimates (peak and total) derived from (General Electric & Shakti Sustainable Energy Foundation 2018), actual loads and load forecasts included in the 19th Electric Power Survey (Central Electricity Authority 2017c). The fiscal year 2036-2037 is chosen as the target year, as it is the last year with available load forecasts. The annual national load and peak load are expected to increase by 2.7 and 2.8 times, respectively, over the values observed in the fiscal year 2016-17.

Load profiles are estimated in the target year, by scaling up the load of each hour per region, following Equation 5-2. Under this methodology, the national system's peak load is underestimated by around 5% compared to the forecasted values in (Central Electricity Authority 2017c), although in two regions this difference is over 10%⁴⁹.

Equation 5-2: Scaling 2015 load profiles.

$$Load_{r,t,2037} = Load_{r,t,2015} \times \frac{Annual\ load_{r,2037}}{Annual\ load_{r,2015}}, \text{ for each region } r \text{ and hour } t$$

⁴⁸ The load profile in the Northeastern region is assumed to be the same as in the Eastern region.

⁴⁹ The estimates in the southern region are 10.5% under CEA's forecasts while in the northeastern region, 11.6% lower.

Table 5-6: Total load: 2015 estimates, actual load in 2016-17, and forecasts for 2021-22 and 2036-37. Values in TWh.

Source: Load estimates from (General Electric & Shakti Sustainable Energy Foundation 2018) , actual load from (Central Electricity Authority 2008-2018a) and expected loads from (Central Electricity Authority 2017c).

Note: Load estimates do not include data for the northeastern region. Values for all India do not include the isolated regions.

Region	Load estimates	Actual load	Expected load	Expected load
	2015	2016-17	2021-22	2036-37
Northern	322	349	468	918
Western	341	345	482	933
Southern	275	306	421	825
Eastern	99	128	171	318
Northeastern	-	15	24	56
All India	1,037	1,143	1,542	3,048

Table 5-7: Peak load: 2015 estimates, actual load in 2016-17, and forecasts for 2021-22 and 2036-37. Values in MW.

Source: Load estimates from (General Electric & Shakti Sustainable Energy Foundation 2018) , actual load from (Central Electricity Authority 2008-2018a) and expected loads from (Central Electricity Authority 2017c).

Note: Load estimates do not include data for the northeastern region. Values for all India do not include the isolated regions.

Region	Load estimates	Actual load	Expected load	Expected load
	2015	2016-17	2021-22	2036-37
Northern	51,195	53,372	73,770	144,161
Western	49,676	48,531	71,020	142,355
Southern	38,355	42,232	62,975	128,655
Eastern	15,725	18,908	28,046	51,420
Northeastern	-	2,487	4,499	10,007
All India	145,034	159,542	225,751	447,702

Figure 5-4 shows a summary of the load profile considered in the study for the target year. The graph shows a quintile distribution of the system's load⁵⁰ for each hour of the day. Figure 5-5 shows the average daily load per month. Considering the estimated data, electricity demand is on average, higher in September and lower in March. In addition, load tends to peak at 8 pm and register its minimum value between 3 and 5 am. The max value in the whole time series is registered on September 9 at 8pm, while the minimum load value occurs on March 2, at 3 am. The regional load profiles are included in **Appendix B**.

⁵⁰ Load values for each region are summed to form a national load.

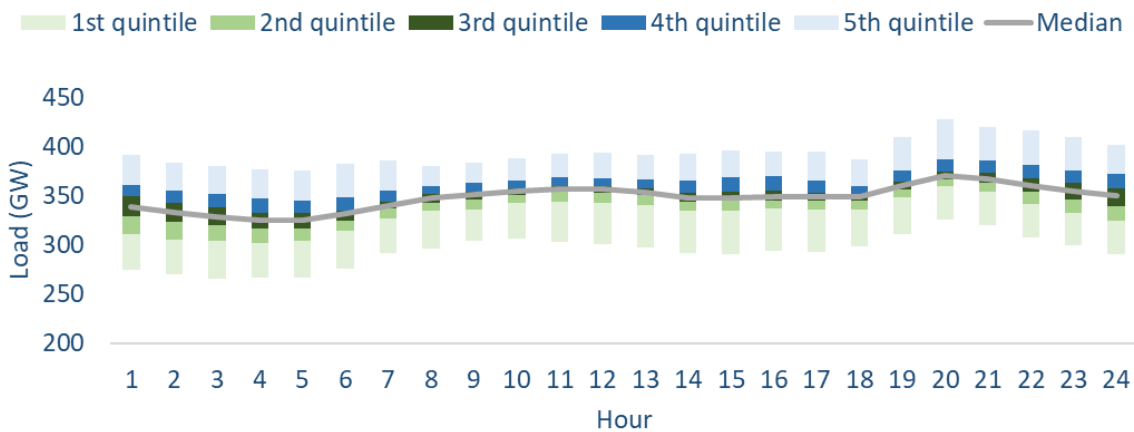


Figure 5-4: Estimated distribution of electricity demand per hour of the year 2036-37. Source: Own assumptions based on scaling up 2015 load estimates.



Figure 5-5: Estimated average daily load for the system per month in the year 2036-37. Source: Own elaboration based on scaling up 2015 load estimates.

5.4.3 Technologies considered in the analysis and potential development

Table 5-8 shows eleven different technologies considered in this study, classified into three main resource categories: Dispatchable, VRE, and Storage. As defined previously, VRE resources are technologies whereby potential generation depends on the underlying resource; there is uncertainty and variability in the generation that will depend on the availability of the resource. GenX allows curtailment of these technologies in scenarios when there is an oversupply of generation. Solar PV, wind, and run of river hydro plants⁵¹ are included in this category.

⁵¹ Run of river plants generation profiles are generally less variable and more predictable. However to simplify the model, they are considered as VRE.

Dispatchable technologies are those technologies for which one can control power output and when to generate or not. GenX allows defining unit commitment constraints for these technologies, such as ramping rates, startup costs, or minimum output levels, among others. This category considers fossil fuel technologies, nuclear plants, biomass plants, and behind-the-meter diesel generators. The latter technology entails sources owned and operated by residential, commercial and industrial customers, as a backup source used when facing blackouts in the grid. Biomass plants, usually considered as VRE, are classified as dispatchable considering the similar characteristics to the other technologies included in the category.

Storage technologies can either generate now or store energy for later. This study considers three types of storage technologies according to the functionalities provided by GenX. Pumped hydro plants⁵² and batteries can either charge by withdrawing energy from the grid, or discharge by injecting energy into the grid, while reservoir hydro⁵³ receive exogenous water inflows.

This research does not consider open-cycle gas turbines, diesel engines, or carbon sequestration technologies. CEA does not include the former two technologies in their national electricity plan⁵⁴, while the latter technology has low potential due to limited sequestered CO₂ storage capacity (Holloway, et al. 2009).

⁵² CEA specifies pumped hydro storage in (Central Electricity Authority 2018a) as power plants that store energy by pumping water from a lower to a higher reservoir and converting the potential energy back into electricity.” In this study, pumped hydro storage plants can only withdraw energy from the grid and do not receive exogenous water inflows.

⁵³ CEA defines reservoir hydro plants in (Central Electricity Authority 2018a) as storage hydro plants that take advantage of large reservoirs with natural inflow of water and the possibility to reduce or increase the water outflow instantaneously.

⁵⁴ Although there were diesel plants operating in March 2017, they are expected to be retired by 2022.

Table 5-8: Technologies considered in the analysis.

Note: Solar PV includes rooftop solar and utility-scale solar plants, and are both modeled the same way. Run of river hydro plants consider units over and under 25 MW. Reservoir hydro plants are considered as only those units considered as major reservoirs in (Central Electricity Authority 2018b).

Technology	Dispatchable sources	Variable Renewable Energy	Storage
Coal plants	X		
Nuclear plants	X		
Gas powered CCGT	X		
Backup diesel generation sets	X		
Biomass power plants	X		
Solar PV		X	
Onshore wind plants		X	
Run of river hydro		X	
Reservoir hydro			X
Pumped hydro storage			X
Lithium-ion batteries			X

Table 5-9 summarizes the national aggregated installed capacity per technology, the expected capacity by 2022, and the potential deployment limits. The installed capacity per technology by 2017 comes from CEA’s official sources (Central Electricity Authority 2017a), with some reclassifications according to (Central Electricity Authority 2018b). In addition, 10 GW of backup diesel generators are used as a proxy of customer-owned behind-the-meter diesel generators, although this number is well below the 90 GW⁵⁵ estimated by CERC (Central Electricity Regulatory Commission 2014). The 2022 capacity considers CEA’s expected additions and retirements in (Central Electricity Authority 2018a). The installation limits come mostly from (Central Electricity Authority 2017c), except for specific technologies (wind, nuclear, hydro and backup diesel generators). The development of additional reservoir hydro plants is not allowed, only allowing for additional hydro deployment of run of river and pumped hydro storage plants. **Appendix C** shows detailed information regarding the installed capacity and installation limits per technology for each region.

⁵⁵ 10 GW out of 90 GW are assumed, considering that not all customers’ diesel generators can be effectively coordinated by a centralized dispatch.

Table 5-9: Installed capacity and total installation limits
Values in GW.

Note: Installed capacity in isolated regions is not considered.

1a, 1b, 1c, 1d, 1e, 1f, 1g, 1i, 1j & 1k from (Central Electricity Authority 2017a) and (Central Electricity Authority 2018b).

Hydro reservoir values correspond to the major reservoirs included in (Central Electricity Authority 2018b). 1.9 GW of pumped hydro storage plants are reclassified into reservoir plants according to (Central Electricity Authority 2018b).

1h: assume 10 GW of 90 GW existing plants (Central Electricity Regulatory Commission 2014).

2a, 2b, 2c, 2d, 2e, 2f, 2g, 2i, 2j & 2k: consider CEA's expected additions and retirements by 2022 in (Central Electricity Authority 2018a).

3a & 3i from (Central Electricity Authority 2018a). 3b from (Jethani 2017). 3j from (Central Electricity Authority 2019a).

3f: own assumptions based on a list of proposed and planned projects (World Nuclear Association 2019).

3c, 3d, 3e, 3g, 3h & 3k: own assumptions.

Technology	3/1/2017 ¹	3/1/2022 ²	Total potential ³
Solar PV ^a	12.2	99.5	748.2
Wind ^b	32.3	59.4	299.0
Reservoir Hydro ^c	18.0	18.0	18.0
Run of River Hydro ^d	28.0	34.2	54.2
Coal ^e	192.1	212.5	Unlimited
Nuclear ^f	6.8	10.1	32.7
CCGT ^g	25.3	25.7	Unlimited
Backup DG sets ^h	10.0	10.0	10.0
Biomass ⁱ	8.3	0	24.1
Pumped Hydro ^j	2.9	3.9	8.9
Lithium-ion batteries ^k	0	0	Unlimited

5.4.4 Definition of power plant clusters

Thermal plants with unit commitment decisions are aggregated into clusters. In GenX, plants within a cluster are assumed to have the same operational and technical characteristics, such as heat rate, ramp rates, and minimum power output, among others. Table 5-10 shows the 24 different clusters considered. Three types (coal, gas, and nuclear) are differentiated based on age (i.e., existing vs. new plants), and the region they are or can be installed. For existing plants, the operational and technical characteristics for each cluster are taken as the weighted average of the existing plants in each region⁵⁶ and are derived from (General Electric & Shakti Sustainable Energy Foundation 2018).

⁵⁶ Some regions do not have clusters because either they do not have existing plants of a specific technology, or no additional development is allowed.

Table 5-10: Clusters considered in the analysis.

Technology	Northern region	Western region	Southern region	Eastern Region	Northeastern Region
Existing coal	X	X	X	X	X
New Coal	X	X	X	X	
Existing Nuclear	X	X	X		
New Nuclear	X	X	X	X	
Existing Gas	X	X	X		X
New Gas	X	X	X	X	

5.4.5 Economic and technical assumptions for generation plants

Table 5-11 details economic assumptions for each technology considered. Overnight capital costs are considered and converted into annual amortizations payments, using the asset life for each technology and a real discount rate of 9%, used by the CEA in its National Electricity Plan (Central Electricity Authority 2018a). Construction and financing costs are not included in the investment amortizations. Capital costs and asset life are shown only for those technologies that have additional potential development. Capital costs for wind and solar and costs for lithium-ion batteries are detailed in Table 5-1 and Table 5-3, respectively and depend on the scenario simulated. While inputs for existing plants are mainly derived from CEA and GE reports, inputs for new plants are mainly taken from IEA, NREL, CEA and CERC studies. Most values, unless otherwise stated, are in 2018 Indian rupees (INR), and an exchange rate of 66 INR per US dollar is used. Unless otherwise stated, values reported in years prior to 2018 are not adjusted for inflation.

Table 5-11: Investment and operational cost assumptions.

Note: assume backup generators' only costs is fuel consumption at a variable cost of 500 \$/MWh.

1d, 1f, 1h & 1k from (Central Electricity Authority 2018a), forecast for the year 2018-19, originally in 2017 nominal INR.

1j, forecast for 2040, in 2017 real dollars from (International Energy Agency 2018). 1l: high bound from (Jason Deign 2019), originally in 2016 nominal INR.

2a, 2b, 2d, 2k & 2l from (Central Electricity Regulatory Commission 2018).

2f, 2h & 2j from (National Renewable Energy Laboratory 2018).

3a & 3b, forecast for 2016-17, originally in 2016 nominal INR, from (Central Electricity Regulatory Commission 2016).

3k from (Central Electricity Regulatory Commission 2018), for the year 2018-19, originally in 2018 nominal INR.

3c corresponds to the average of existing plants, while 3d is the percentage of the capital costs for plants over 200 MW. Use the same values in 3l as in 3c. All values for the year 2019-20 from (Central Electricity Regulatory Commission 2019), originally in 2019 nominal INR.

3e: base costs are own assumptions from (National Renewable Energy Laboratory 2018) in 2016 real dollars and considering additional costs (own assumptions based on Exxon Mobil recommendations) due to the installation of scrubbers.

3f & 3j assuming proxy costs from (National Renewable Energy Laboratory 2018) for 2040 in 2016 real dollars.

3g, 3h, 3i, 4e, 4f, 4g, 4h, 4i & 4j from (General Electric & Shakti Sustainable Energy Foundation 2018) in 2015 dollars.

Technology	Overnight cost per gross MW [\$/kW] ¹	Asset life [years] ²	Fixed O&M cost [\$/kW-yr] ³	Variable O&M cost [\$/MWh] ⁴
Solar PV ^a	Table 5.1	25	11	0.0
Wind ^b	Table 5.1	25	17	0.0
Reservoir Hydro ^c	-	-	35	0.0
Run of River Hydro ^d	1,576	40	55	0.0
Existing Coal ^e	-	-	55	0.9-1.1
New Coal ^f	1,024	30	30	0.9
Existing Nuclear ^g	-	-	75	0.6
New Nuclear ^h	1,576	40	75	0.6
Existing CCGT ⁱ	-	-	9-12	1.2-1.9
New CCGT ^j	700	30	10	1.5
Backup DG sets	-	-	0	0.0
Biomass ^k	864	20	38	0.0
Pumped Hydro ^l	1,200	40	35	0.0
Lithium-ion batteries	Table 5.3	Table 5.3	Table 5.3	Table 5.3

Table 5-12 through Table 5-14 summarize the technical assumptions per type of technology considered. High (forced and planned) outages are assumed for coal and nuclear plants, simulating the historical performance of both fleets, as shown in Figure 4-2, Figure A-1, and Figure A-4. The forced and planned outage for each technology is spread uniformly along the 8760 hours⁵⁷. Minimum output per plant is de-rated by its availability. On the one hand, no technical constraints are assumed for backup diesel generators, as they are considered as a type of demand response. On the other hand, nuclear plants are not allowed to operate at output levels below 100% of de-rated nameplate capacity.

⁵⁷ Considering that clusters are being modelled, representing a fleet of several plants, spreading out the outage uniformly along the year is equivalent to modelling that in average a specific percentage of plants is not available at every hour.

VRE are considered as fully flexible with instantaneous ramping rates and no minimum output constraints. In addition, any continuous amount of VRE sources are allowed to be deployed into the grid. Capacity factor for solar and wind plants are taken from the GE study (General Electric & Shakti Sustainable Energy Foundation 2018), while run of river capacity factors are based on own assumptions considering (General Electric & Shakti Sustainable Energy Foundation 2018), (Central Electricity Authority 2008-2018b) and (National Power Portal 2008-2018a). Production profiles for VRE sources are fully explained in **Section 5.4.8**.

Finally, storage technologies are modeled as continuous and fully flexible. Hydro reservoir assumptions are mostly taken from official CEA statistics (Central Electricity Authority 2018b), adjusted to reflect the actual operation taken from (National Power Portal 2008-2018b).

Table 5-12: Technical assumptions for dispatchable plants.

Note: Backup DG sets and Biomass plants are modeled as continuous sources meaning that any linear amount can be dispatched and if possible, installed. Heat rates of backup diesel generators are adjusted to reflect a 500\$/MWh variable costs. Existing plants forced and planned outage rates of coal plants are penalized to include the effect of the installation of scrubbers (own assumptions based on Exxon Mobil recommendations).

1a, 1c, 1e, 2a, 2c, 2e, 4a, 4c & 4e from (General Electric & Shakti Sustainable Energy Foundation 2018). Consider the installation of scrubbers for existing coal plants.

1b, 1d, 2b, 2d & 2f from (Central Electricity Authority 2018a). 1f from (Sepulveda, et al. 2018).

3e & 3f from (Central Electricity Regulatory Commission 2019).

2g, 3g & 4g from (Central Electricity Regulatory Commission 2018).

4b from (Central Electricity Authority 2018a), 4d from (General Electric & Shakti Sustainable Energy Foundation 2018), 4f from (International Energy Agency 2016).

5: De-rated values in 5a & 5b from (Palchak, et al. 2017) and in 5c & 5d from (National Renewable Energy Laboratory 2018).

6a, 6b, 6e, 6f, 7a, 7b, 7e, 7f, 8a, 8b, 8e & 8f from (Palchak, et al. 2017); costs values originally in 2016 nominal INR.

7c, 7d, 8c & 8d from (Sepulveda, et al. 2018), cost values in 2017 dollars.

Technology	Power plant gross capacity [MW] ¹	Auxiliary consumption [%] ²	Forced and planned outage rates [%] ³	Heat Rate [MMBtu/MWh] ⁴	Min stable output [% Cap] ⁵	Hourly ramp rates [% Cap/hour] ⁶	Min Up/Down times [hours] ⁷	Startup cost [\$/Start-MW Cap] ⁸
Existing Coal ^a	250-465	6.1%-11.3%	20.9%-21.3%	9.2-10.9	43.3%-43.5%	60%	24	237
New Coal ^b	660	5.8%	19.0%	9.5	44.6%	60%	24	215
Existing Nuclear ^c	300-425	10.2%-11.3%	25%	10.0-10.2	75.0%	0%	36	1000
New Nuclear ^d	540	10.2%	25%	10.1	75.0%	0%	36	1000
Existing CCGT ^e	140-460	0.8-3.4%	15%	6.1-7.8	25.5%	100%	8	107
New CCGT ^f	500	2.50%	15%	6.6	25.5%	100%	8	107
Backup DG sets	-	0.00%	0%	27.8	0%	100%	-	0
Biomass ^g	-	10%	20%	16.7	0%	100%	-	0

Table 5-13: Technical assumptions for VRE sources.

1: Own assumptions.

2: Show the upper bound and lower bound among all regions, from (General Electric & Shakti Sustainable Energy Foundation 2018), capacity factors for hydro plants are adjusted to reflect recent operation.

Technology	Auxiliary consumption [%] ¹	Capacity factor [%] ²	Min stable output [% Cap]	Hourly ramp rates [% Cap/hour]
Solar PV	0%	19%-23%	0%	100%
Wind	0%	18%-26%	0%	100%
Run of river hydro	0%	23%-45%	0%	100%

Table 5-14: Technical assumptions for storage technologies.

1a from (Central Electricity Authority 2018b), 1b from (Shin-Ichi 2009), 1c from (Lazard 2018).

2a: Show the upper bound and lower bound of hourly inflows among all regions, own assumptions based on (Central Electricity Authority 2018b) and (National Power Portal 2008-2018b).

3b is within range included in (Rogers, et al. 2014). 3c from (National Renewable Energy Laboratory 2018)

4c: Own assumptions.

Technology	Energy storage [hours] ¹	Average hourly inflows [% Cap] ²	Auxiliary consumption [%]	Cycle efficiency [%] ³	Self discharge rate [% max output/day] ⁴	Ramp rates [% max output/hour]
Reservoir Hydro ^a	1,764-2,681	0.01%-0.03%	0%	100%	0%	100%
Pumped Hydro Storage ^b	12	-	0%	75%	0%	100%
Lithium-Ion Batteries ^c	4	-	0%	90%	5%	100%

5.4.6 Fuel costs, emissions, water consumption, and water withdrawal assumptions

Table 5-15 details the fuel and emissions assumptions undertaken in the analysis. Emissions considered in this study are CO₂, SO₂, and NO_x. Gas prices are specified in Table 5-2 and will depend on the scenario simulated. CO₂ emission rates are derived from (Central Electricity Authority 2018c). SO₂ and NO_x emission rates for gas, diesel, and biomass plants were taken from (Eurek, et al. 2016) while SO₂ and NO_x emissions rates for coal plants are own estimates⁵⁸ based on (Center for Study of Science, Technology & Policy 2018), and (Central Electricity Authority 2018c).

Table 5-15: Fuel cost and emissions assumptions.

Note: Diesel fuel cost was adjusted to reflect a 500\$/MWh

Source for fuel costs: coal within range in (Center for Study of Science, Technology & Policy 2018) initially in 2017 INR, uranium from (Sepulveda, et al. 2018) in 2017 dollars, and biomass from (Central Electricity Regulatory Commission 2018), originally in 2018 nominal INR.

Fuel	Fuel Cost [\$/MMBTu]	CO ₂ emissions [kg/MMBTu]	SO ₂ emissions with abatement [kg/MMBTu]	SO ₂ emissions without abatement [kg/MMBTu]	NO _x emissions with abatement [kg/MMBTu]	NO _x emissions without abatement [kg/MMBTu]
Coal	3.0	95.7	0.033	0.772	0.042	0.355
Gas	Table 5.2	52.2	0.001	0.001	0.009	0.009
Diesel	18	73.0	0.136	0.136	0.078	0.078
Uranium	1.0	0	0	0	0	0
Biomass	3.7	0	0.036	0.036	0	0

Water withdrawal and consumption rates for coal, nuclear, and gas are derived from (Chaturvedi, Nagarkoti, et al. 2017), while from biomass, hydro, solar PV and wind sources come from (Srinivasan, et al. 2018). As described in (Macknick, et al. 2012) and according to USGS, water withdrawal is “the amount of water removed from the ground or diverted from a water source for

⁵⁸ Rates in g/kWh from (Center for Study of Science, Technology & Policy 2018) are converted to kg/MMBTu using each coal plant characteristic included in (Central Electricity Authority 2018c).

use”, while water consumptions is the amount of water that is evaporated, transpired, incorporated into products or crops, or otherwise removed from the immediate water environment”.

Table 5-16: Water withdrawal and consumption rates.

Technology	Water withdrawal [m3/MWh]	Water consumption [m3/MWh]
Existing Coal	3.50	2.40
New Coal	2.50	1.70
Existing Nuclear	3.50	2.08
New Nuclear	2.50	1.49
Existing CCGT	1.62	1.62
New CCGT	1.09	1.09
Backup DG sets	0.00	0.00
Biomass	3.30	2.10
Hydro	0.00	17.00
Solar PV	0.0	0.02
Wind	0.0	0.00

5.4.7 Reserves requirements and contribution per technology

Table 5-17 show the reserves requirements imposed on a national level, and the unserved load parameters. ERCOT’s⁵⁹ value of lost load (VOLL) was used as the cost of load shedding (Potomac Economics 2018). Regulating and spinning reserves⁶⁰ requirements assumed are similar to those defined in (Cole, et al. 2018). Regulating reserves, as defined in GenX, must always be met, while the penalty cost of not meeting spinning reserves is defined as an intermediate value between the cost of load shedding and the variable cost of the most expensive generation unit (500 \$/MWh).

Table 5-17: Reliability requirements.

Note: Same requirements are set for upward and downward regulating reserves. Minimum level required showed for spinning reserves corresponds to upwards reserves; downward reserves do not consider the 3,000 MW contingency.

Type of reliability requirement	Minimum level required	Unmet costs
Load shedding	-	9000 \$/MWh
Regulating reserves	1% Load + 0.5% VRE	Binding
Spinning reserves	3% Load + 3,000 MW	1000 \$/MWh

⁵⁹ ERCOT stands for Electric Reliability Council of Texas and is the system operator of the Texas interconnected system.

⁶⁰ To define regulating reserves, solar PV and wind requirement is replaced in (Cole, et al. 2018) by the VRE requirement, while 3,000 MW are added as contingency to the spinning reserves requirements.

Table 5-18 shows the reserves contribution per technology and the cost of providing reserves. Regulating and spinning reserves contributions, as well as the cost of providing regulating reserves, are mostly obtained from (Cole, et al. 2018). As a conservative assumption, VRE and backup diesel generators are assumed to be unable to provide reserves and that there is no cost for providing spinning reserves⁶¹.

Table 5-18: Reserves contribution and cost for providing regulating reserves.
 Note: Assumed that values for pumped hydro storage plants apply for lithium-ion batteries.
 Costs values were originally in 2013 real dollars.

Technology	Contribution to regulating reserves [% of max output]	Contribution to spinning reserves [% of max output]	Cost of providing regulating reserves [\$/MWh]	Cost of providing spinning reserves [\$/MWh]
Solar PV	0%	0%	-	-
Wind	0%	0%	-	-
Run of river hydro	0%	0%	-	-
Reservoir Hydro	100%	100%	2	0
Pumped Hydro Storage	100%	100%	2	0
Lithium-Ion Batteries	100%	100%	2	0
Existing Coal	20%	40%	10	0
New Coal	20%	40%	15	0
Existing Nuclear	0%	0%	-	-
New Nuclear	0%	0%	-	-
Existing CCGT	25%	50%	6	0
New CCGT	25%	50%	6	0
Backup DG sets	0%	0%	-	-
Biomass	20%	40%	4	0

5.4.8 VRE production profiles and hydro reservoir inflows

Solar and wind production profiles are derived from (General Electric & Shakti Sustainable Energy Foundation 2018). The GE-Shakti study estimates the solar and wind production profiles per state for the expected capacity by 2022. The 2022 state production profiles are aggregated into regional production profiles and use them as a proxy for the 2036-37 production profiles.

Figure 5-6 shows the distribution for each hour of the day for solar PV capacity factors in the Western region. Solar production starts at around 6 am peaks at 1pm in the southern region and tends to go to zero sometime between 6pm and 7pm. This trend is similar in most regions⁶². On the other hand, as shown in Figure 5-7, solar PV production tends to be higher during the first two quarters and lower during the third quarter, although it will depend on the region.

On the other hand, Figure 5-8 and Figure 5-9 show that wind capacity factors are highly volatile and will depend on the season. In fact, wind production profiles will depend on the region, with lower variability in the southern region and higher variability in the northern region. Figures with production profiles for solar and wind plants of the other regions are shown in **Appendix D**.

⁶¹ VRE can provide reserves.

⁶² Excepting the northeastern region: the production profile is completely shifted to one hour before.

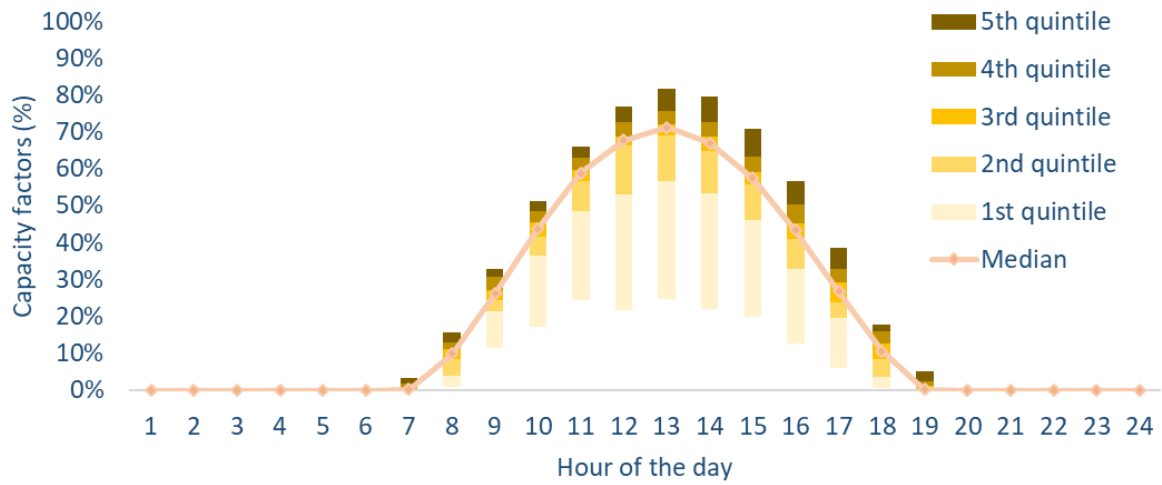


Figure 5-6: Distribution of solar production profile in the western region for each hour of the day.
Source: (General Electric & Shakti Sustainable Energy Foundation 2018).

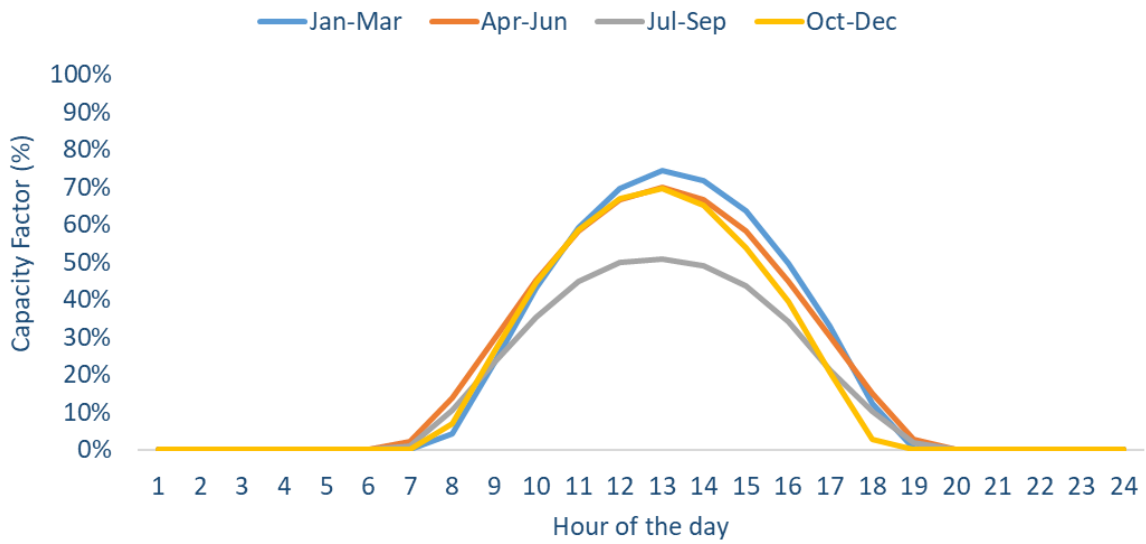


Figure 5-7: Average hourly solar profile per trimester in the western region.
Source: (General Electric & Shakti Sustainable Energy Foundation 2018).

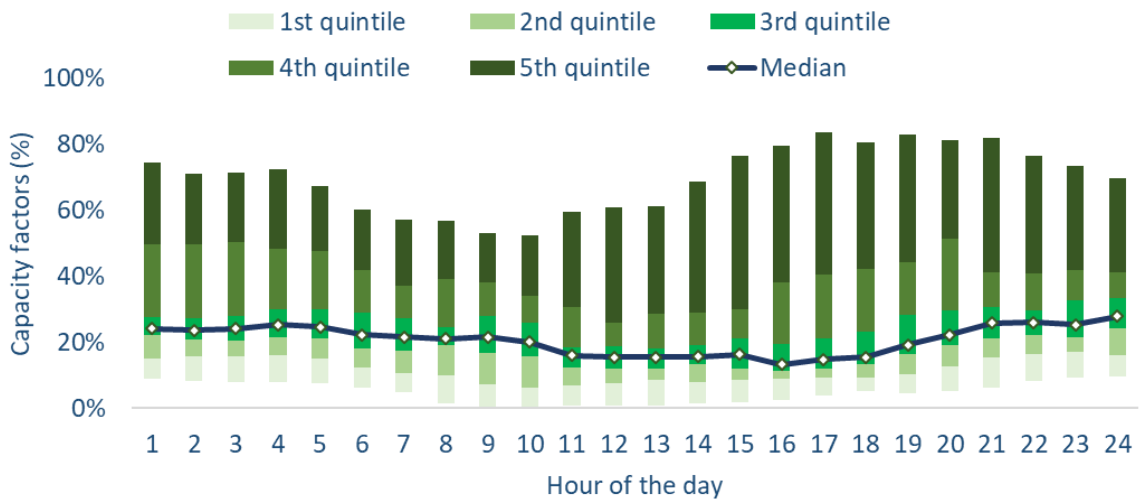


Figure 5-8: Distribution of wind production profile in the western region for each hour of the day.
 Source: (General Electric & Shakti Sustainable Energy Foundation 2018).

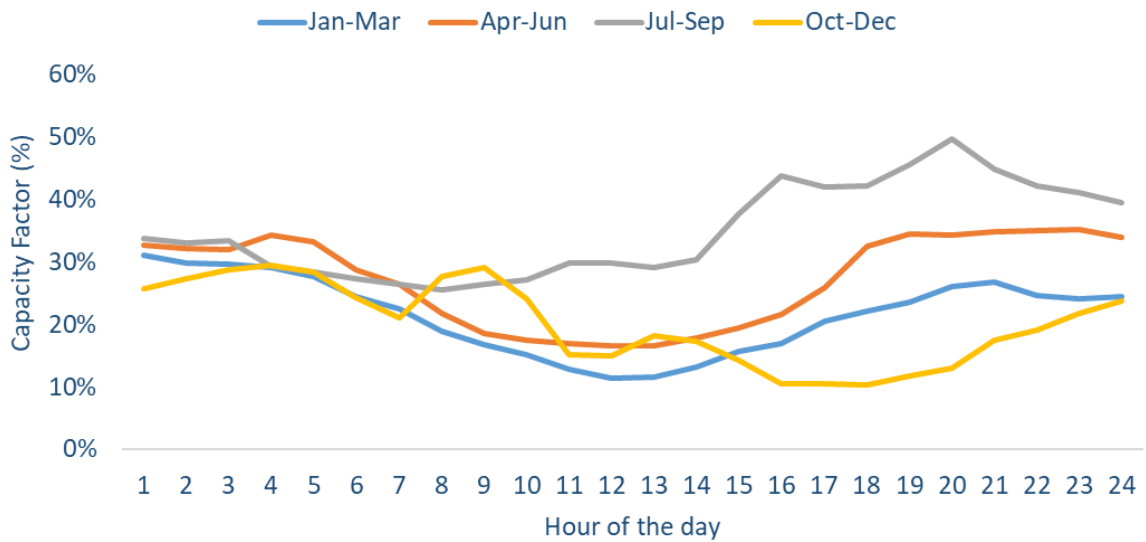


Figure 5-9: Average wind profile per trimester in the western region.
 Source: (General Electric & Shakti Sustainable Energy Foundation 2018).

Finally, Figure 5-10 shows the capacity factors of run of river plants, while Figure 5-11 shows the water inflows of reservoir hydro plants. This study assumes only monthly variability and no variation in hours within a month in capacity factors and water inflows of run of river plants, and reservoir hydro plants, respectively.

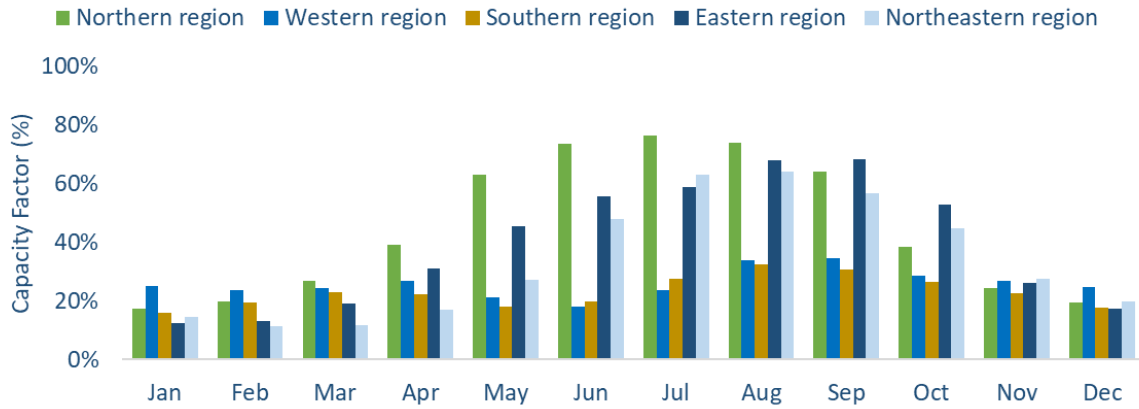


Figure 5-10: Capacity factor used for run of the river plants.
 Source: Own assumptions, based on (General Electric & Shakti Sustainable Energy Foundation 2018) and (Central Electricity Authority 2008-2018b).

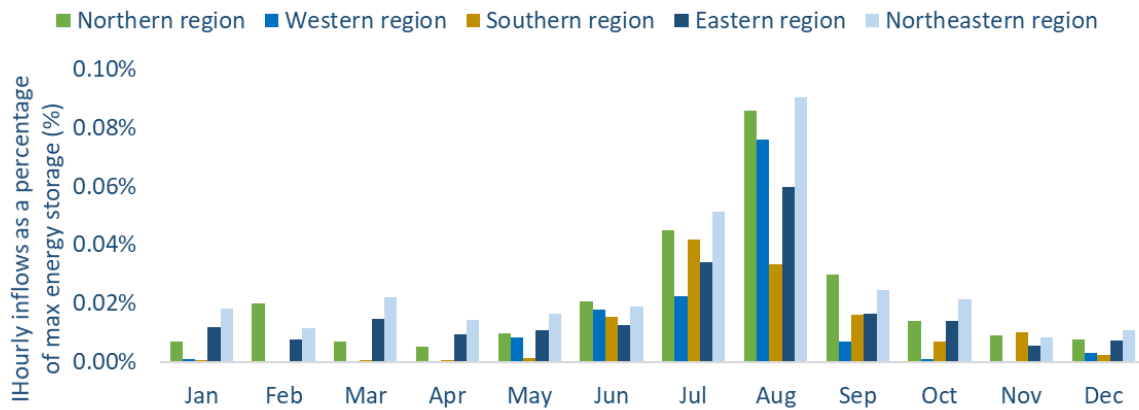


Figure 5-11: Hourly inflows used for reservoir plants.
 Source: Own assumptions, based on historical information from (Central Electricity Authority 2018b) and (National Power Portal 2008-2018b).

6 Results

6.1 2037 results under 24 base scenarios

6.1.1 Optimal generation mix for 24 base scenarios

Figure 6-1 shows capacity additions and retirements, while Figure 6-2 summarizes the capacity mix across all scenarios. All scenarios include retirements of coal and gas power plants, corresponding to plants expected to be retired by the CEA by 2027 and plants that will meet their life term by 2037. Additional coal is installed in all scenarios with no emissions and the medium emissions limit (1,275 million tons), while further retirements are seen when imposing the stringent emissions limit (621 million tons).

In the absence of an emissions target and when VRE capex is high, there is no further deployment of solar and wind capacity, an effect that does not hold true when imposing medium or stringent emissions targets. In scenarios with emissions limits, wind additions are often capped by its potential deployment (240 GW). The maximum potential of nuclear is deployed in all scenarios (additional 20 GW), while hydro development varies across scenarios.

Although storage capacity is added in all scenarios, its deployment depends mainly on its costs, a dependence that is magnified when imposing emissions limits. Installed storage capacity peaks at nearly 440 GW⁶³, representing nearly a quarter of the installed capacity by 2037. Gas competes directly with storage; in scenarios with high storage adoption, gas development tends to be lower. Gas installed capacity peaks at over 200 GW under stringent emissions⁶⁴, representing almost 20% of the installed capacity mix.

The non-fossil fuel target established in the INDC⁶⁵ is not always met across scenarios with no emissions limit⁶⁶. However, as emissions limits are imposed, the target is always fulfilled, peaking at 87% in the stringent emissions scenarios⁶⁷.

⁶³ In the scenario with low VRE capex, low Storage costs and gas price at \$11/MMBtu.

⁶⁴ In the scenario with high VRE capex, high Storage costs and gas price at \$8/MMBtu and emissions limit of 621 million tons.

⁶⁵ As described in Chapter 1, as a part of the efforts to reduce the emissions intensity, India established a renewable portfolio target, stating that at least 40% of total power capacity must be non-fossil fuel based by 2030.

⁶⁶ In some scenarios with high VRE capex and storage costs the capacity share of non-fossil fuel is under 40%.

⁶⁷ In the scenario with low VRE capex, low Storage costs and gas price at \$11/MMBtu. Storage is included.

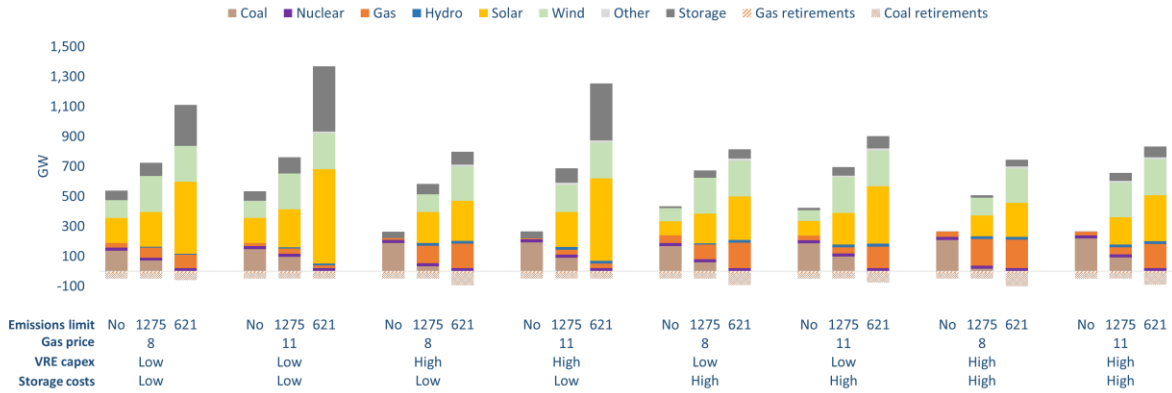


Figure 6-1: 2037 capacity additions and retirements by generator type across different scenarios.

Note: Values in net GW.

Hydro includes run of river and reservoir plants, Storage includes pumped hydro storage plants and lithium-ion based batteries, and Other include biomass plants and backup diesel generators.

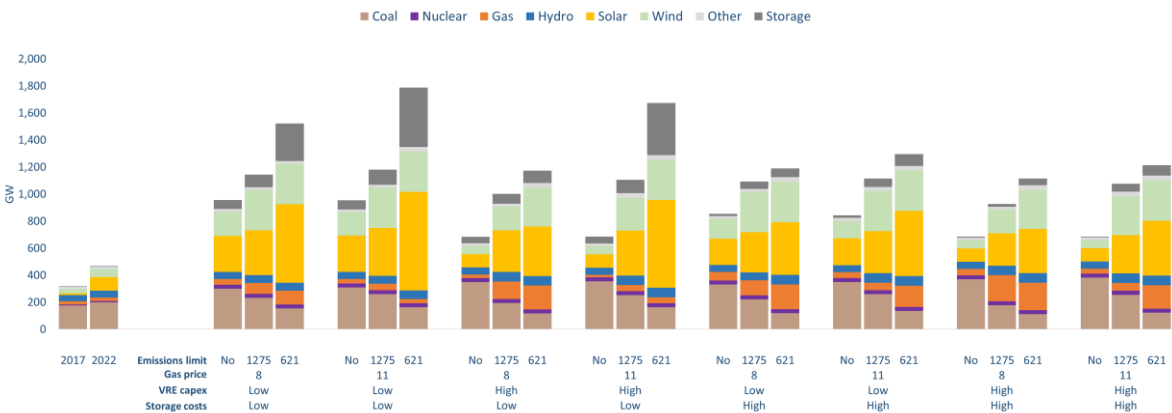


Figure 6-2: 2037 total installed capacity by generator type across different scenarios.

Note: 2017 values are in gross GW while 2022 and 2037 values are in net GW.

Hydro includes run of river and reservoir plants, Storage includes pumped hydro storage plants and lithium-ion based batteries, and Other include biomass plants and backup diesel generators.

Figure 6-3 and Figure 6-4 summarize the generation mix across the 24 scenarios. With no emissions limits, coal remains the main source in the generation mix, increasing its absolute generation in comparison to 2017 and 2022. In these scenarios, the coal generation share in the total mix ranges from 58% to 78%⁶⁸. Setting moderate emissions limits (1275 million tons) do not reduce absolute coal generation in comparison to 2022 levels while imposing stringent emissions limits (621 million tons) reduce coal generation in all scenarios with a max reduction of nearly 70%⁶⁹. Under medium emissions limits, coal represents between 37% and 45% of the total mix, while under stringent emissions limits, coal share is reduced to between 10% and 22%.

⁶⁸ Peaking in the scenario with high VRE capex, low Storage costs and gas price at \$11/MMBtu.

⁶⁹ Scenario with high VRE capex, low Storage costs and gas price at \$11/MMBtu.

In the absence of emissions policies, the combined contribution of solar and wind to the generation mix varies significantly across scenarios, ranging from 10% to 30%. When imposing emissions limits, solar and wind sources increase their share, ranging from 40% and 64% in stringent emissions scenarios.

Nuclear and hydro have a minor contribution in the scenarios analysis, as their additional deployment was capped in order to match viable future development. Nuclear contribution is limited to 6%, while hydro ranges between 5% and 7%. Gas contribution, as described before, depends mainly on the emission limits and storage costs, peaking at 32% of total injections⁷⁰. Only in a small subset of scenarios (mainly with high storage costs and stringent emissions limits), gas is the largest source in the generation mix. The inclusion of storage plants requires additional energy into the grid, due to the losses in the charging and discharging process, in scenarios with high storage penetration, in some cases, nearly 3% of additional generation is required for storage operation⁷¹. Finally, non-fossil fuel share⁷² in the generation mix varies across all scenarios, peaking at nearly 77% in scenarios with the stringent emissions target.

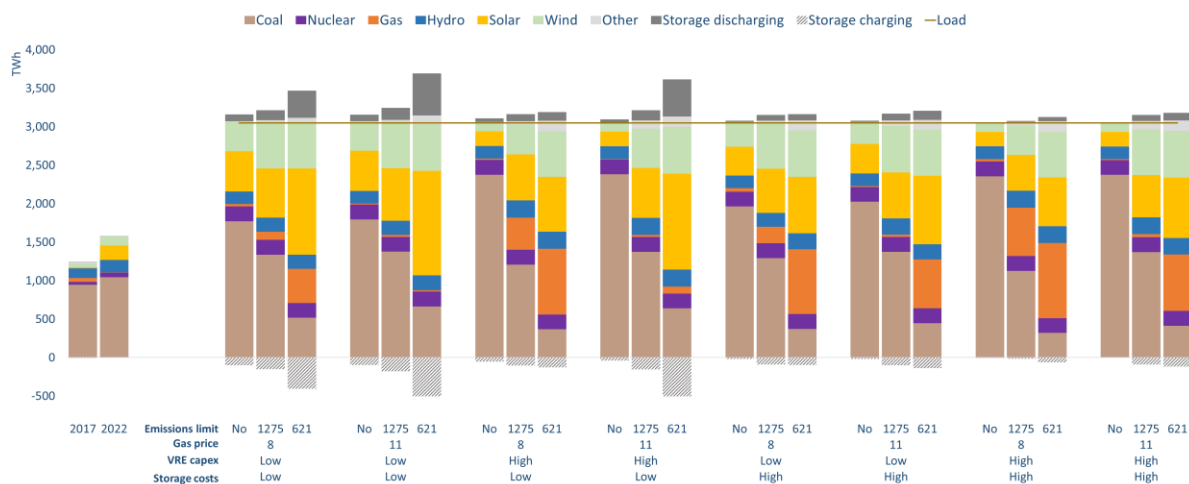


Figure 6-3: 2037 generation by generator type across different scenarios.

Note: 2017 generation mix taken from official CEA statistics (Central Electricity Authority 2008-2018b) while 2022 and 2037 generation mix are own assumptions using Gen X. 2017 values are in gross TWh while 2022 and 2037 values in net TWh. Category Hydro includes run of river and reservoir plants, category Storage includes pumped hydro storage plants and lithium-ion based batteries, and category Other include biomass plants and backup diesel generators.

⁷⁰ In the scenario with high VRE capex, high storage costs and gas price at \$11/MMBtu.

⁷¹ Considering energy required in charging minus energy discharged into the grid.

⁷² Nuclear is included in non-fossil fuel share.

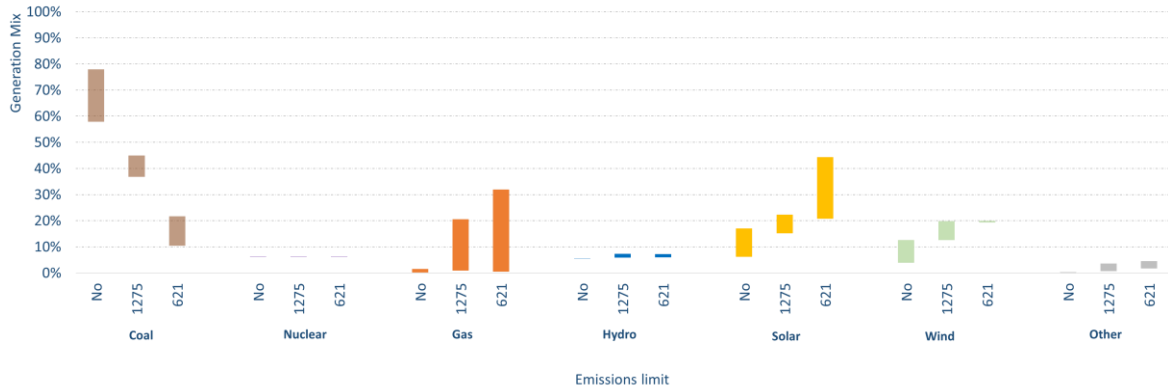


Figure 6-4: 2037 generation share per generator type across different emissions limits scenarios. Notes: Shares are estimated based on injections. Storage was not included because it has negative net injections. Hydro includes run of river and reservoir plants, and Other include biomass plants and backup diesel generators.

Figure 6-5 summarizes total costs incurred for investment⁷³, fuel, operation, maintenance, and considered costs of unserved energy and unmet spinning reserves in 2037. In the absence of an emissions policy, costs only vary around 3% in all scenarios, ranging from 122 to 127 billion dollars. However, total costs can rise from 16% to over 40% when imposing stringent emissions goals. The majority of the costs come from new investment, fuel and fixed O&M costs, while in some scenarios with stringent emissions limits, startup costs become relevant, mainly due to the increase in the number of starts of gas power plants.

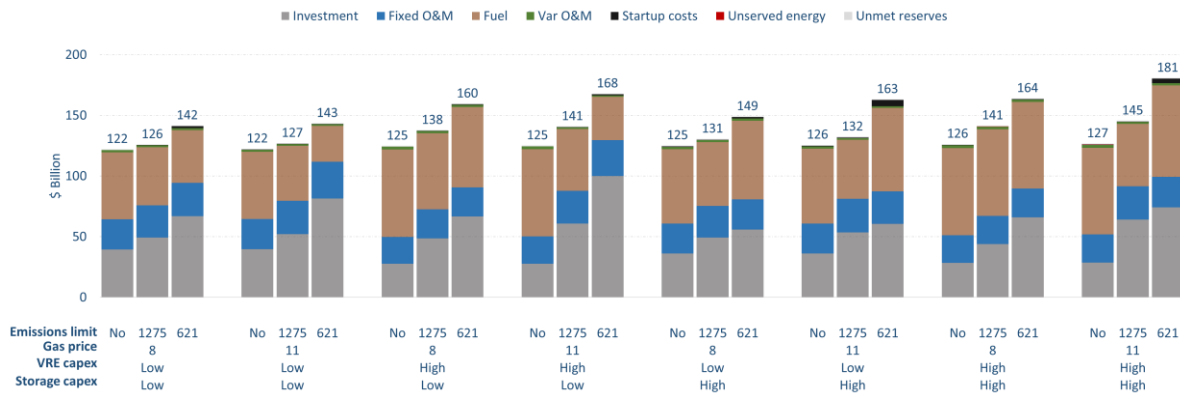


Figure 6-5: 2037 total costs across different scenarios.

6.1.1 Energy curtailment, unserved energy, and provision of reserves

Figure 6-6 shows renewable generation curtailment across all scenarios. Without enforcing emissions targets, renewable energy curtailed is low: in all scenarios, less than 0.5% of the total VRE energy available for injection is curtailed, while the maximum hourly curtailment represents less than 20% of the energy available. Imposing stringent emissions limits leads to higher curtailment to over 6% of the total annual VRE available and peaking at nearly 40% on an hourly basis. Figure 6-7 shows a histogram summarizing the renewable curtailment in a scenario with high

⁷³ Considering only annual payments of investment.

VRE penetration⁷⁴. Although in most hours there is no curtailment, there are some hours where curtailment represent a substantial share of the hourly load, reaching 37% of the load when imposing stringent emissions limits.

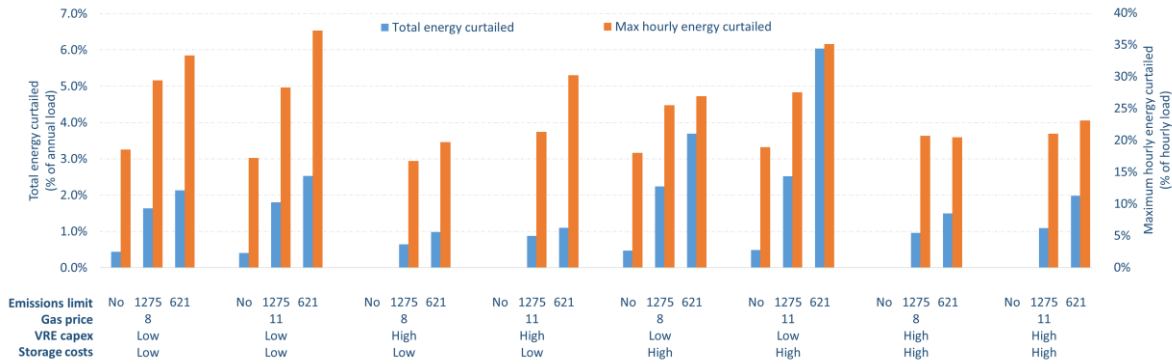


Figure 6-6: Renewable energy curtailment across all scenarios.

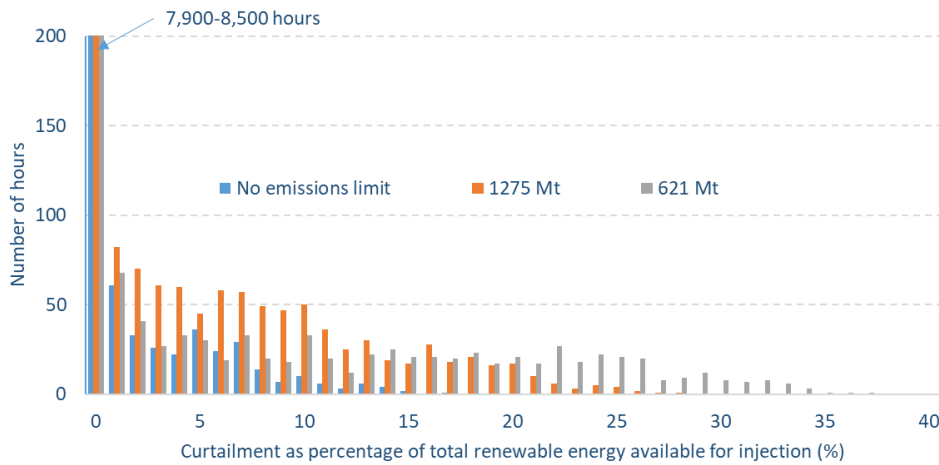


Figure 6-7: Histogram summarizing hourly renewable generation curtailed, for the scenario with Low VRE capex and Low Storage costs and gas price at \$11/MMBtu.

Unserviced energy, in comparison to annual load, is low in most scenarios, as shown in Figure 6-8, ranging from 0 to 18 GWh. The unmet energy represents less than 0.001% of the energy required, significantly lower than the 0.7% unmet energy in the fiscal year 2017-18, as shown in Figure 2-12. However, the peak percentage of unmet load is higher than the percentage of peak load non-supplied in 2017-18. The unmet load is significantly lower in scenarios with low storage costs.

⁷⁴ In the scenario with low VRE capex, low storage costs and gas price at \$11/MMBtu.

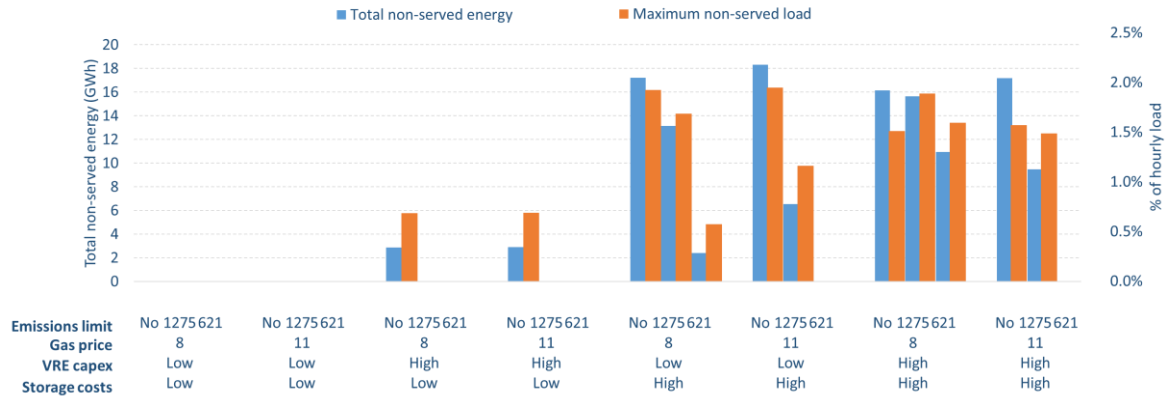


Figure 6-8: Total non-served energy and maximum non-served load across all scenarios.

Finally, Figure 6-9 and Figure 6-10 show the provision of regulating and spinning reserves per technology. While regulating reserves are mostly provided by storage, coal and in some cases, and gas-based plants; storage and hydro reservoirs are the main contributors to spinning reserves. Even in cases with low storage adoption, storage capacity is used to provide spinning reserves.

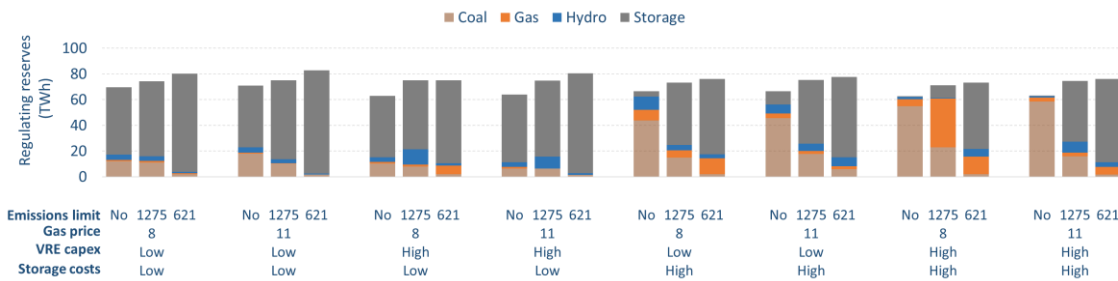


Figure 6-9: Total regulating reserves (up and down) contributed throughout the year per technology across all scenarios.

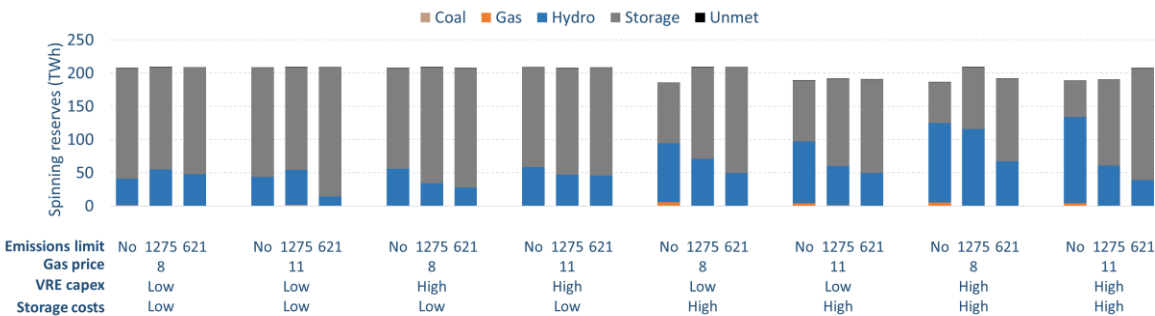


Figure 6-10: Total spinning reserves (up and down) contributed throughout the year per technology across all scenarios.

6.1.2 CO₂, NO_x and SO₂ emissions

Figure 6-11, Figure 6-12, and Figure 6-13 show total CO₂, NO_x, and SO₂ emissions, respectively, across all scenarios. Without an emissions target, CO₂ emissions range between 1.6 and 2.2 billion tons, showing that in the absence of any policy, GHG emissions would increase in the following years in comparison to 2017 and 2022. In contrast, SO₂ and NO_x emissions are reduced in all 2037 scenarios in comparison to 2017 levels. This is mainly because of the abatement technologies that must be installed in all coal plants by 2022, as coal is the main SO₂ and NO_x emitter among all technologies. According to the Center for Study of Science, Technology, and Policy, with the installation of scrubbers, SO₂ and NO_x emissions can be reduced between 96% and 88% respectively (Center for Study of Science, Technology & Policy 2018) . In Figure 6-12 and Figure 6-13 the shaded bars with patterns in the year 2022 show the emissions avoided due to the abatement technologies.

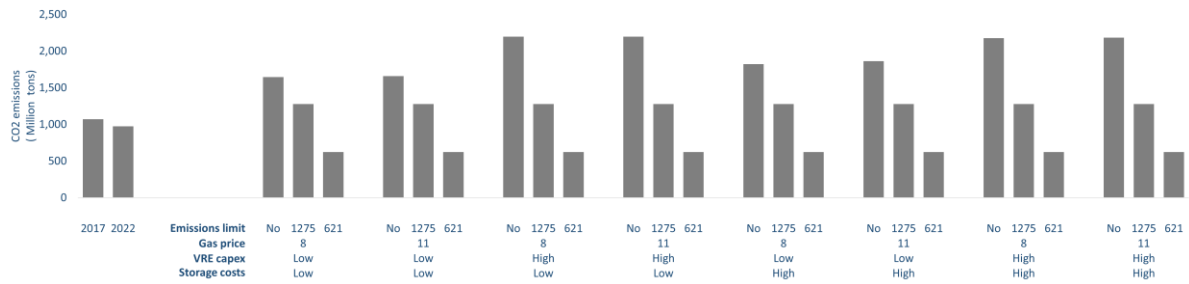


Figure 6-11: 2037 CO₂ emissions across all scenarios.

Note: 2022 values are own assumptions considering expected generation, while 2017 CO₂ emissions come from (International Energy Agency 2018).

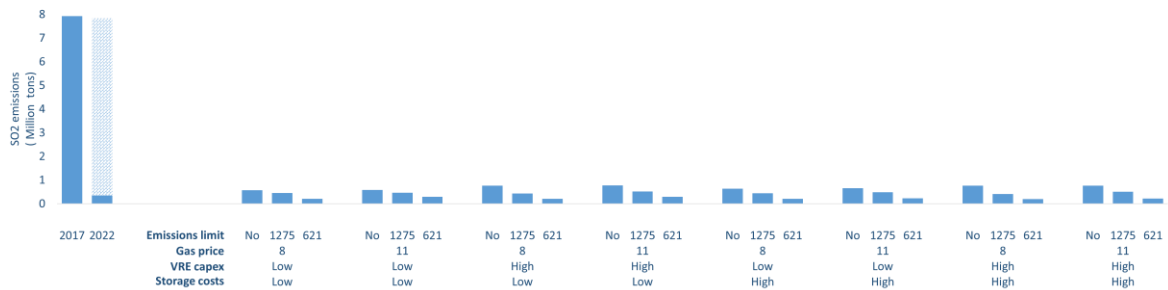


Figure 6-12: 2037 SO₂ emissions across all scenarios.

Note: 2017 and 2022 values are own assumptions considering either past generation (2017) or expected generation (2022).

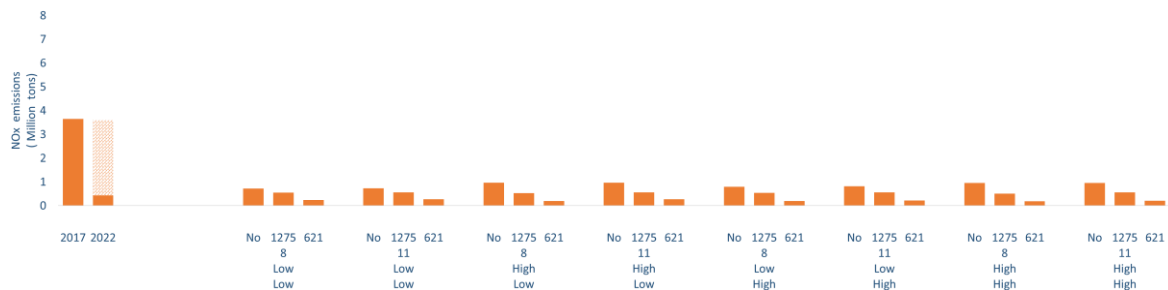


Figure 6-13: 2037 NOx emissions across all scenarios.
 Note: 2017 and 2022 values are own assumptions considering either past generation (2017) or expected generation (2022).

The CO2 abatement costs can be calculated by comparing the total system cost with and without emissions limits. Figure 6-14 and Figure 6-15 show the marginal and average abatement costs incurred by imposing emissions targets. On the one hand, the average abatement costs are calculated as the quotient between the increase in total costs and the decrease in total CO2 emissions. On the other hand, the marginal abatement cost is the shadow price of the total emissions constraint, calculated by GenX. When imposing medium emissions limits, marginal abatement costs range between \$14 and \$36/ton, while with stringent emissions limits, marginal abatement costs range from \$36 and \$70/ton, depending on the scenario.

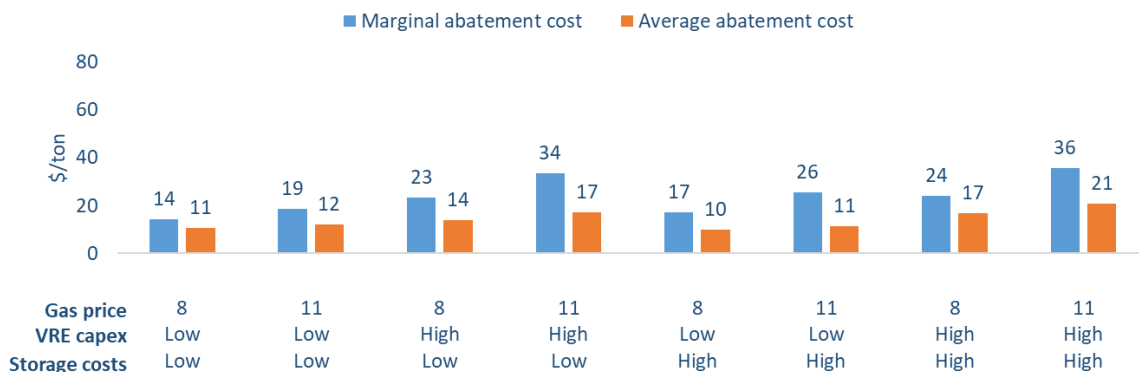


Figure 6-14: Marginal and average CO2 abatement costs - 1,275 million tons emissions limit.

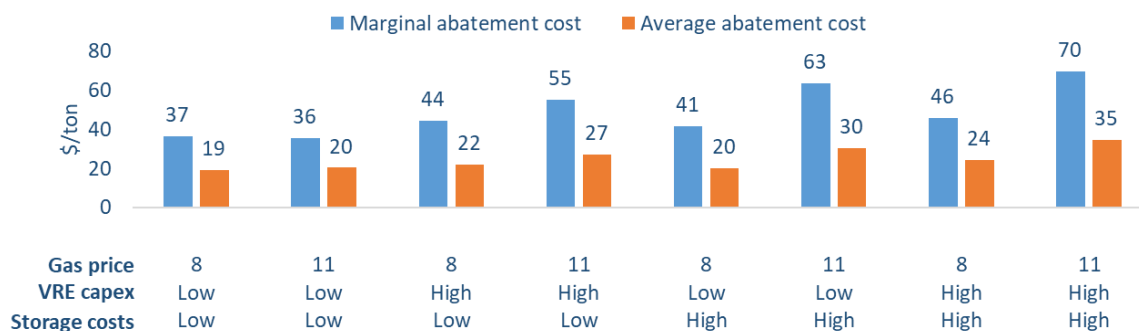


Figure 6-15: Marginal and average CO2 abatement costs - 621 million tons emissions limit.

Finally, Figure 6-16 shows the emissions intensity across all scenarios. Emissions intensity decreases in all scenarios, including those without any emissions constraint. However without emissions targets, emissions intensity range from 0.54 and 0.72 tons of CO₂/MWh, significantly higher than 2016 emissions in USA and the European Union (0.4 and 0.33 tons/MWh), according to (International Energy Agency 2018). With medium emissions limits, emissions intensity is reduced to 0.42 tons/MWh while with stringent emissions targets, it reaches 0.2 tons/MWh.

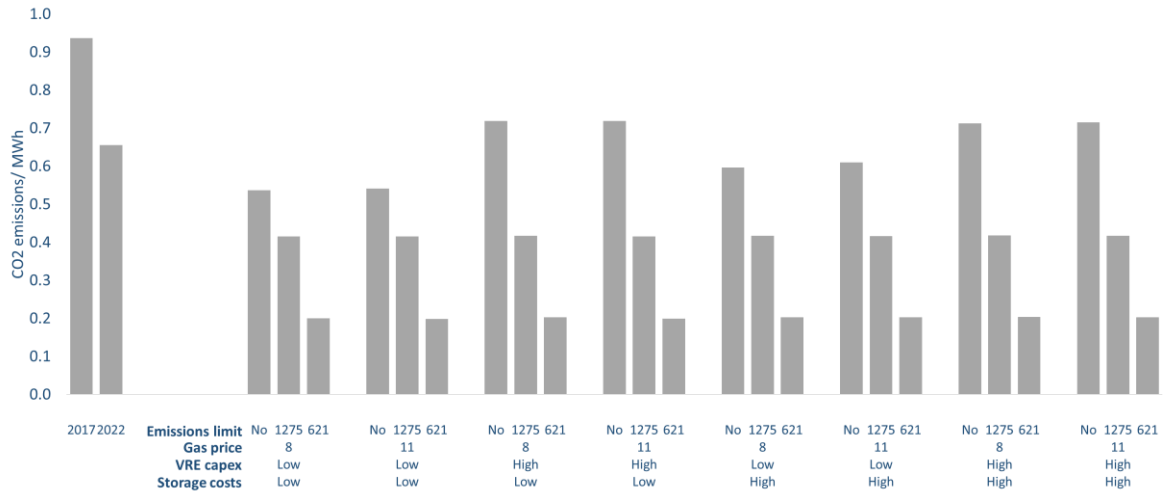


Figure 6-16: CO₂ emissions over total generation across all scenarios.

Note: 2022 values are own assumptions considering expected generation, while 2017 CO₂ emissions come from (International Energy Agency 2018).

6.1.3 Gas consumption, water withdrawal and water consumption

Gas consumption will depend on the amount of power generation from gas power plants. As shown in Figure 6-17, in scenarios with high gas share, gas consumption can increase up to 17 times in comparison to gas consumption in 2017. Gas consumption peaks at 17 billion cubic feet per day, which is roughly two thirds the natural gas consumed for power electricity generation during 2017 in the United States (U.S. Energy Information Administration 2019). Figure 6-18 shows that water withdrawal and consumption will also tend to increase, even in scenarios experiencing a reduction in coal generation. Water consumption increases mainly due to the addition of hydro run of river plants and pumped hydro plants, that are assumed to consume approximately 5 times more than thermal plants (Eurek, et al. 2016).

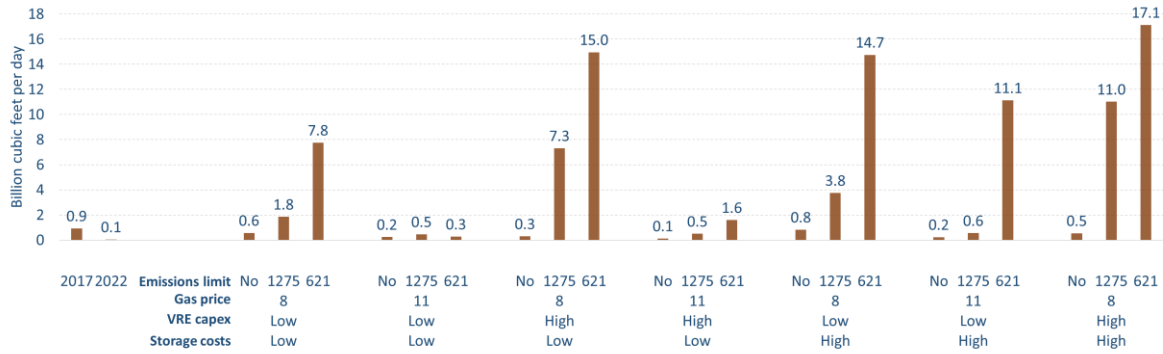


Figure 6-17: 2037 gas consumption across different scenarios.
 Note: 2017 and 2022 values are own assumptions considering either past generation (2017) or expected generation (2022).

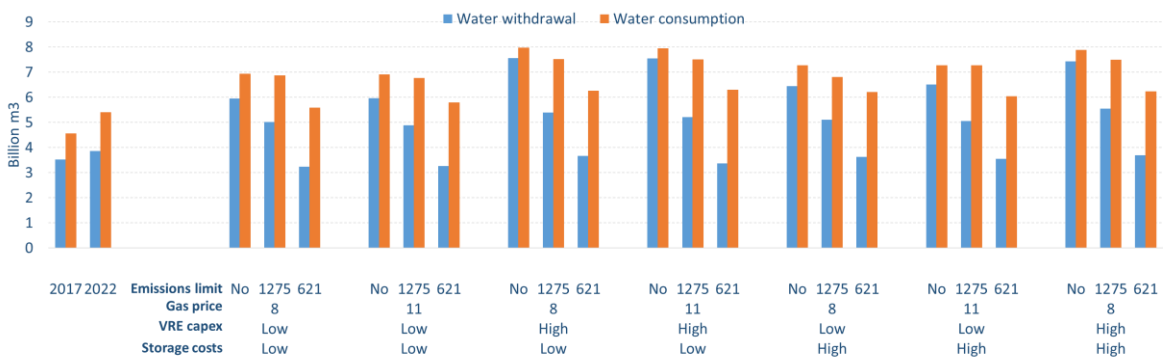


Figure 6-18: 2037 water withdrawal and consumption across all scenarios.
 Note: 2017 and 2022 values are own assumptions considering either past generation (2017) or expected generation (2022).

6.1.4 Hourly generation dispatch on critical days

This section shows hourly generation dispatch graphs for “critical days” under different scenarios. In contrast to the annual snapshots provided by the preceding figures, these figures illustrate the hour-to-hour generation of dispatchable, storage, and VRE sources as well as the intricate interplay between them under different penetration levels.

On the one hand, Figure 6-19 shows the system dispatch on the peak net load day (October 16th) in a scenario with high VRE penetration. Peak load and net peak load on this day reach 421 GW and 381 GW, respectively. During the peak net load hour (8pm), the contribution of VRE is limited: solar generation is null, while the wind capacity factor is at 8%. In fact, wind contribution is low during the entire day, given that wind production tends to be lower during October. Dispatchable sources are operating at full capacity during peak hours, storage discharging and backup generators are also required to operate. Storage capacity is not fully discharged in the peak net load hours, but instead, keep storing for the next hours with low VRE generation as well as providing reserves. Due to natural variability in the VRE generation, over 270 GW of non-VRE capacity is required to ramp up in a period of 4 hours to meet the increase in load, i.e., a number equivalent to turning on the entire projected 2022 CCGT fleet in the United States (U.S. Energy

Information Administration 2019). This ramping mainly comes from storage discharging. Almost no ramping is done by coal, and nuclear units as these plants are operating at full capacity over most of the day. Nearly 430 GWh of energy is curtailed in a period of 4 hours, mainly from solar generation and peaking at over 172 GW at 2pm, representing over 45% of the hourly load. However, storage charging mitigates this energy loss as over 1,800 GWh of otherwise curtailed energy is charged in storage units, mainly during daytime hours.

On the other hand, Figure 6-20 shows the system dispatch on the minimum net load day (April 28th) in the same scenario as the previous figure. While load peaks at 360 GW, the VRE contribution is higher, specifically for wind, which has a capacity factor between 12% and 34% throughout the day. No gas generation is required, as load can be supplied by VRE, storage, nuclear and coal generation. The load is less “peaky” than in the net peak load day, requiring less ramping requirements, mainly supplied by storage discharging. Energy curtailment is much higher on this day; over 700 GWh of energy is curtailed in a period of 5 hours, peaking at nearly 225 GW at 2pm, representing over 70% of the hourly load.

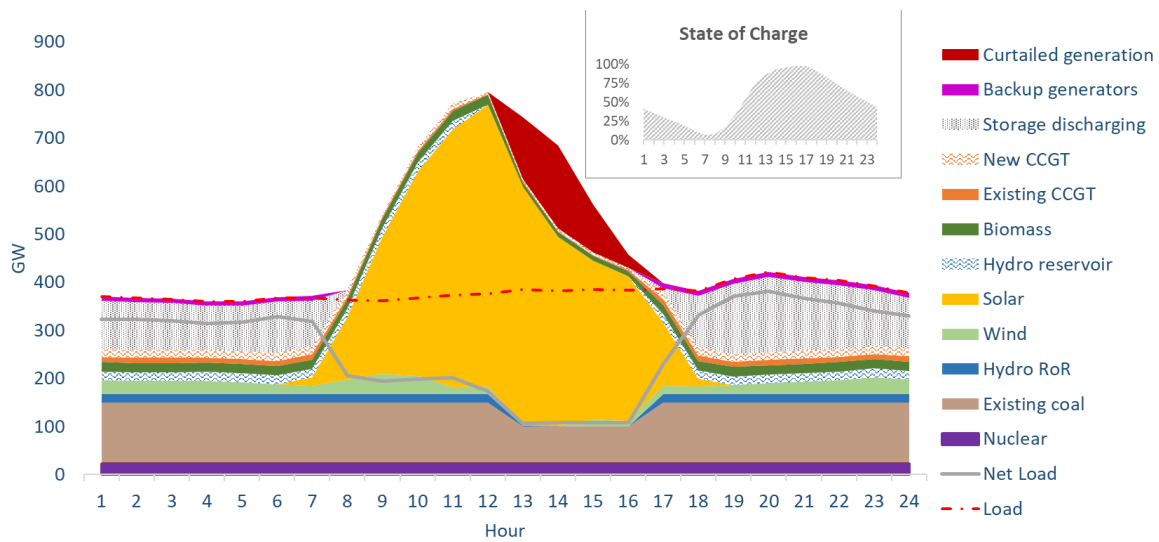


Figure 6-19: Dispatch example on peak net load curve day (October 16th) for a scenario with an emissions limit of 621 million tons of CO₂, Low VRE capex, Low Storage costs and gas price at \$11/MMBtu.

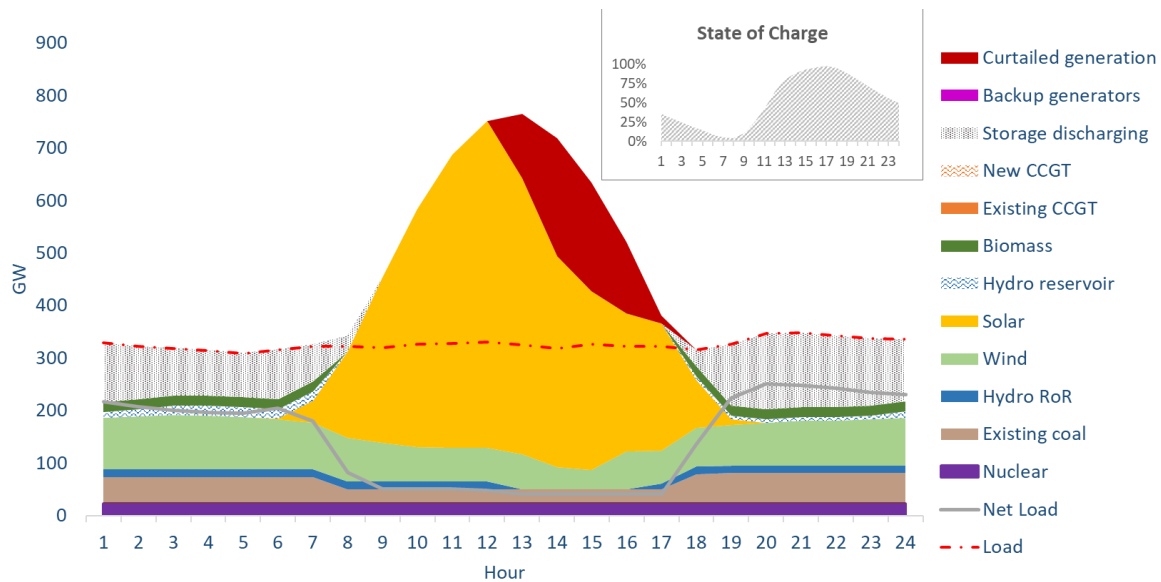


Figure 6-20: Dispatch example on minimum net load curve day (April 28th) for a scenario with an emissions limit of 621 million tons of CO₂, Low VRE capex, Low Storage costs and gas price at \$11/MMBtu.

In contrast, Figure 6-21 and Figure 6-22 show the system's operation during the peak net load day and minimum net load day, respectively, in a scenario with lower VRE and storage penetration and high development of gas-based plants.

On the peak load day, while in daytime hours there is over 125 GWh in curtailed renewable energy, at peak hour, existing capacity is not enough to supply load, leading to diesel back up generation and unserved load. Unserved load peaks at 2 GW at 8pm, almost 0.6% of total load, while backup generators reach their max output (10 GW). There is no contribution of solar at peak load, while wind has only a 8% capacity factor. Over 260 GW is required in ramping capacity in a period of 7 hours, which is mainly covered by gas plants and storage units.

On the minimum net load day, the peak hour (9pm) coincides with a high wind capacity factor (53%). The 163 GW in ramping requirement is mainly covered by an increase in gas generation and some storage discharge. Nearly 300 GWh of energy curtailment is registered in a period around noon, with a peak of over 87 GW (27% of load) at 2pm.

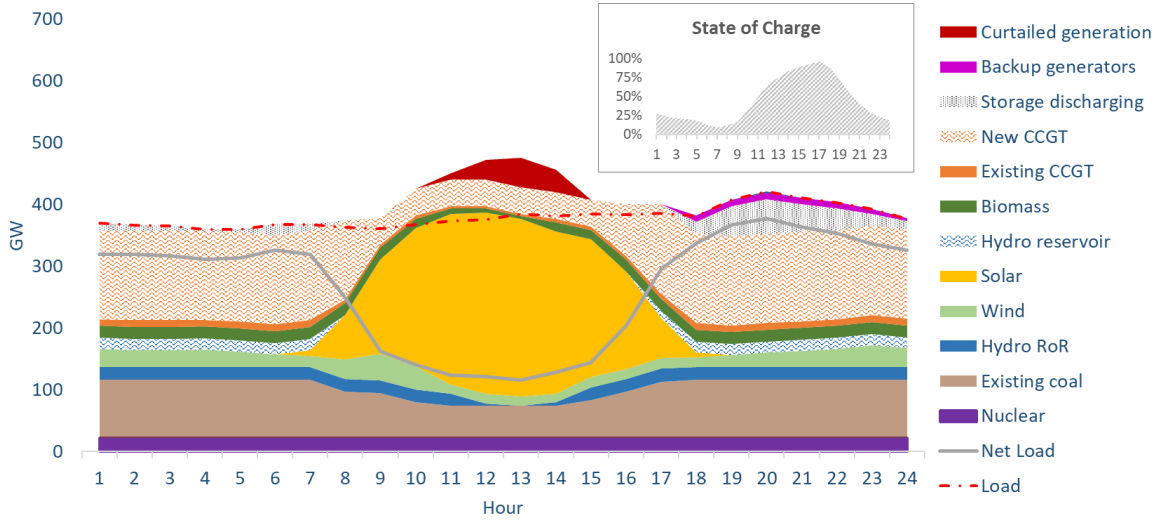


Figure 6-21: Dispatch example on peak net load curve day (October 16th) for a scenario with an emissions limit of 621 million tons of CO₂, Low VRE capex, High Storage costs and gas price at \$8/MMBtu.

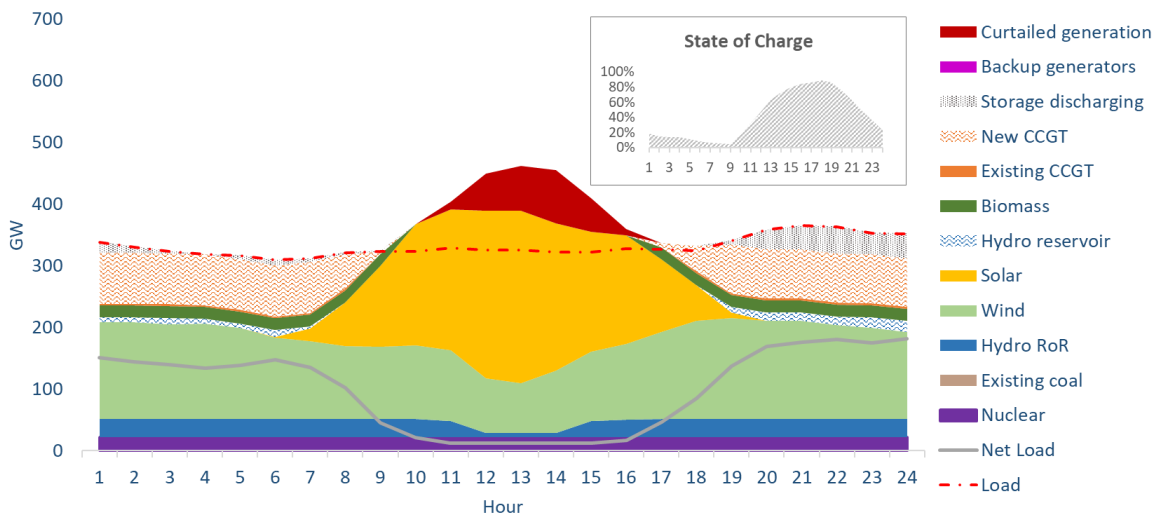


Figure 6-22: Dispatch example on minimum net load curve day (June 22th) for a scenario with an emissions limit of 621 million tons of CO₂, Low VRE capex, High Storage costs and gas price at \$8/MMBtu.

Finally, Figure 6-23 shows a day where coal plants ramp over 100 GW in only 4 hours. This requires the power output of the available⁷⁵ coal fleet to double from 50% to 100% to meet the rise in net load. A total of 67 previously offline coal plants (12% of the entire coal fleet), must start operating

⁷⁵ As discussed in Chapter 5, unavailability due to forced and planned outages are assumed to be spread uniformly through the 8,760 hours, equivalent to that in average, a specific percentage of plants is not available in every hour.

to meet the 100% output. Significant coordination will be likely to be needed to start such a high number of plants and double the power output of a fleet of over 550 plants in a couple of hours.

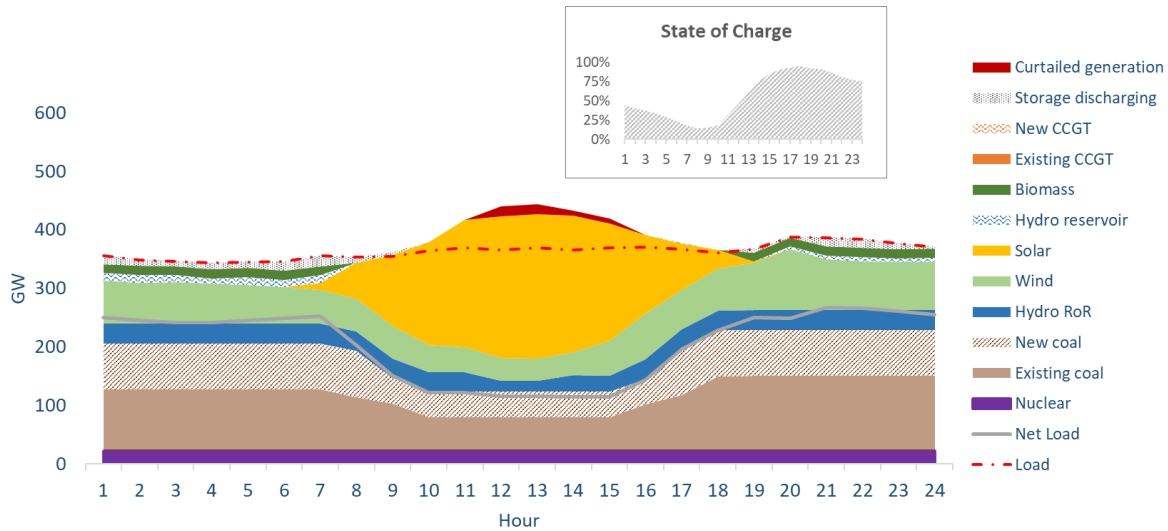


Figure 6-23: Dispatch example on coal maximum ramp day (August 24th) for a scenario with an emissions limit of 1,275 million tons of CO₂, Low VRE capex, High Storage costs and gas price at \$11 /MMBtu.

6.1.1 Operation of thermal fleet

Figure 6-24 summarizes the capacity factors of dispatchable plants across all scenarios. Without emissions limits, coal plants tend to operate near their maximum available output. Once emissions limits are imposed, coal plants decrease their capacity factors to nearly 30% in the lower range. Low variable costs and null ramping rates keep nuclear plants at a constant 75% capacity factor in all scenarios, a bound capped by its availability. Gas-based plants have a high range of generation across all scenarios. Without an emissions limit, gas plants continue to be underutilized. When imposing stringent emissions limits, gas capacity factors increase, although still significantly lower than coal and nuclear plants. In addition, when imposing emissions limits, gas plants' capacity factors vary significantly across scenarios increasing the uncertainty in their utilization. Finally, diesel backup plants operate at under 1% of capacity factors, showing they are only required in peak hours when existing capacity is not sufficient to meet the load.

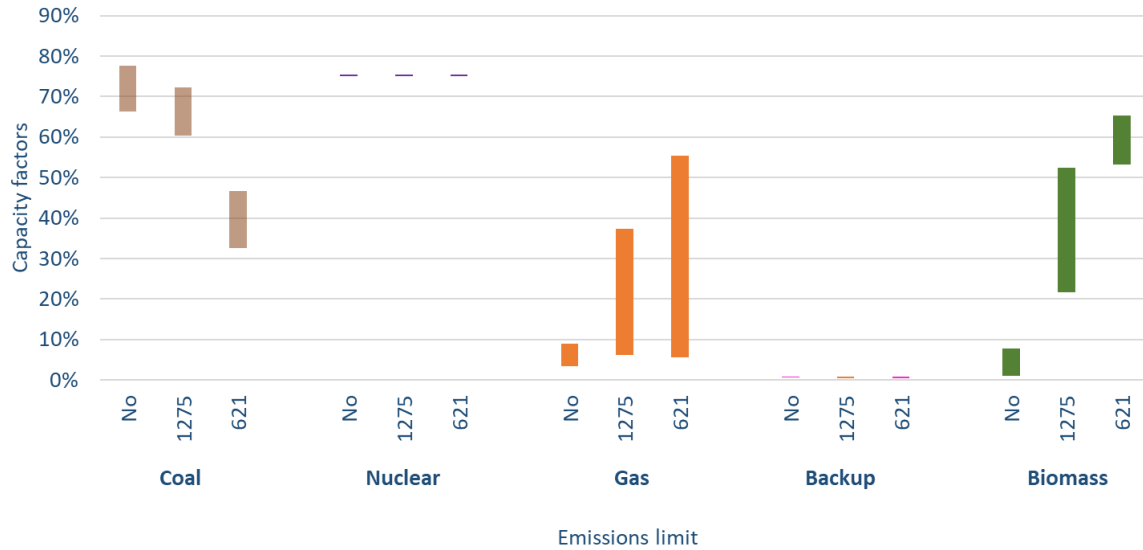


Figure 6-24: Capacity factors for dispatchable technologies across all scenarios.

Figure 6-25 summarizes the capacity factors for a scenario with a high share of coal generation. In the absence of an emissions target, the coal fleet operates between 36% and 80%, bounds near the minimum dispatch levels (~43%) and maximum availability (~80%). Nevertheless, when emissions limits are enforced, coal plants (mainly existing plants) tend to go offline more frequently, reducing the fleet’s capacity factor.

Figure 6-26 and Figure 6-27 show scenarios that illustrate the range in which the gas fleet and backup diesel generators operate. On the one hand, in the absence of emissions enforcement, gas plants operate under a broad range of utilization levels, remaining completely idle for several hours. The high uncertainty in gas-based plant capacity factors and the several hours with plants being idle imply important risks to decide whether to develop gas infrastructure to supply these plants. Under emissions limits, the gas-based fleet increases its power output and register more hours at full capacity (85%). On the other hand, Figure 6-27 shows that backup generators are either idle or operating at full capacity (100%) and there are only a few hours with intermediate power output levels, behavior that is not significantly affected by the imposition of emissions targets. In total, backup generators only operate between 70 and 80 hours per year, depending on the emissions limit enforced.

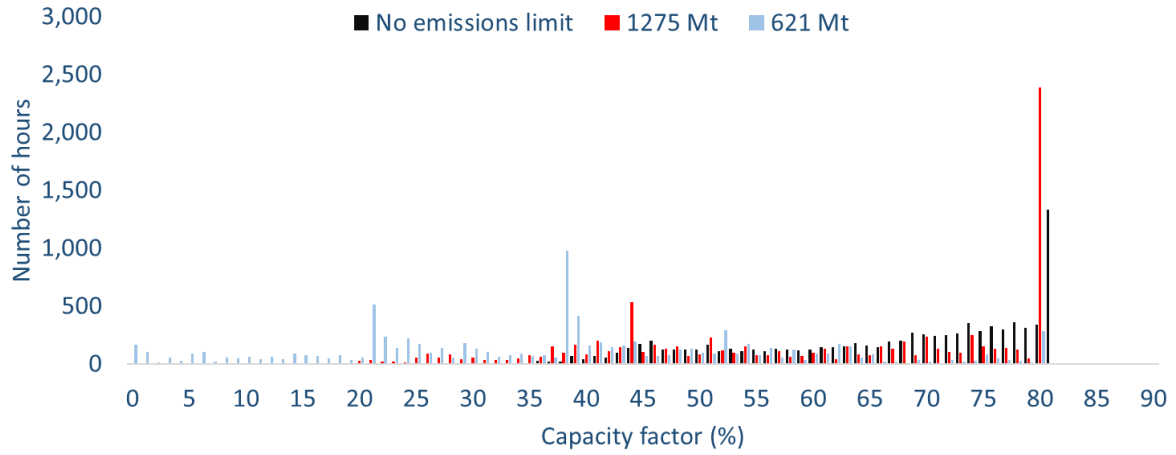


Figure 6-25: Histogram summarizing coal fleet capacity factors over 8,760 hours. Scenarios with Low VRE capex, High Storage costs, and gas price at \$11/MMBtu.

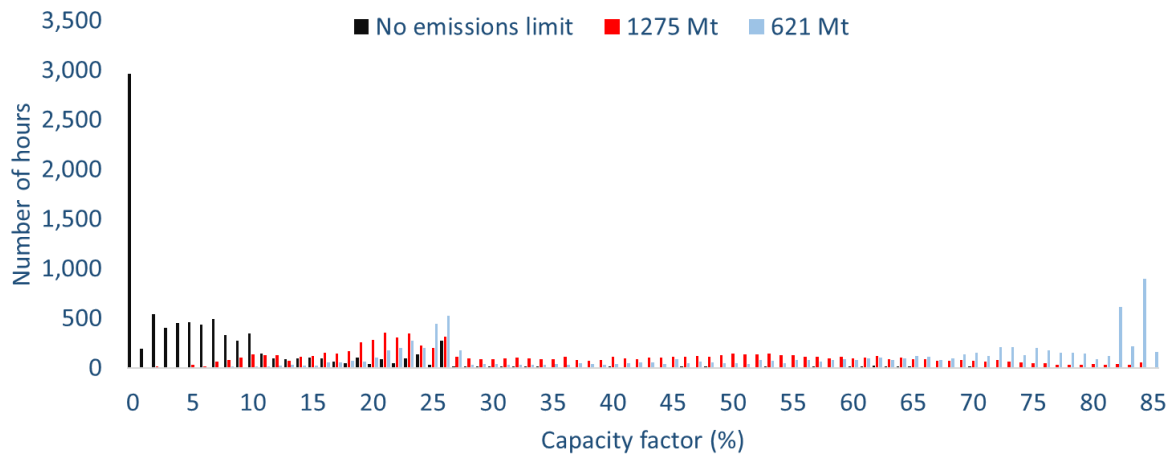


Figure 6-26: Histogram summarizing gas fleet capacity factors over 8,760 hours. Scenarios with High VRE capex, High Storage costs, and gas price at \$8/MMBtu.

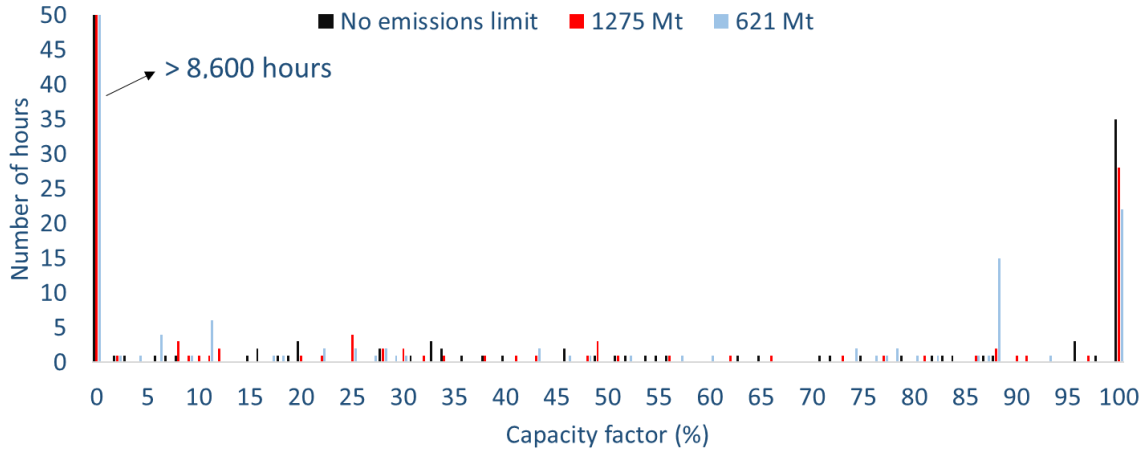


Figure 6-27: Histogram summarizing behind-the-meter backup generators capacity factors over 8,760 hours. Scenarios with Low VRE capex, High Storage costs, and gas price at \$11/MMBtu.

Finally, Figure 6-28 and Figure 6-29 show the average number of starts per coal plant and gas plant, respectively, across all scenarios. Coal plant startups are infrequent, peaking at 14 starts per plant in a year. In contrast, the gas fleet has a high number of starts, surpassing 100 starts per plants in some emissions-limited scenarios. The high number of starts for gas plants may create operational challenges: significant cycling can reduce their average life and increase operation and maintenance costs (Kumar, et al. 2012).

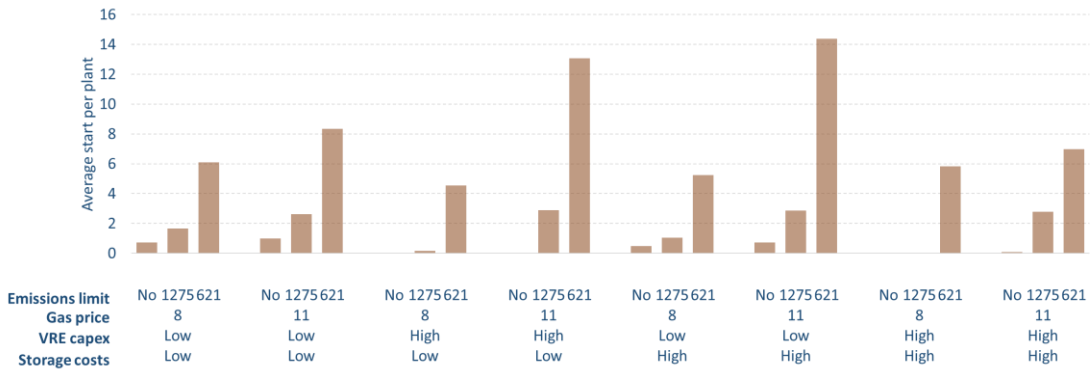


Figure 6-28: Average number of starts per coal plant per year across all scenarios.

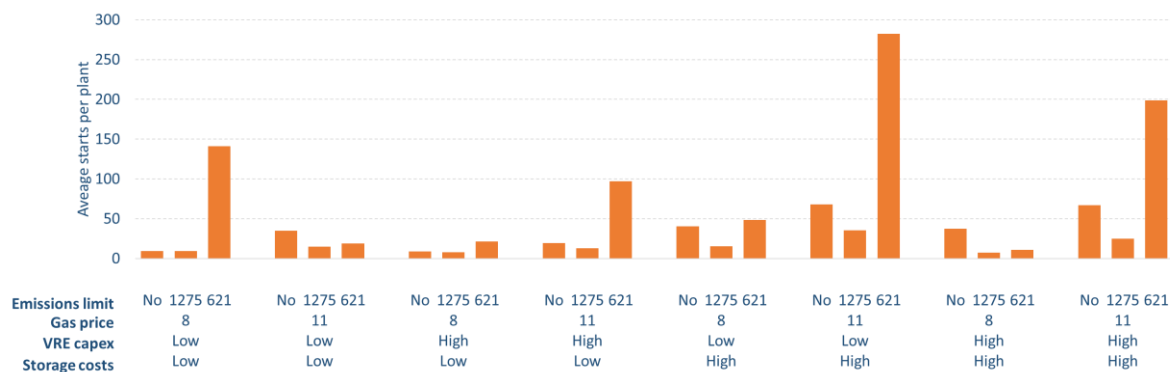


Figure 6-29: Average number of starts per gas-based plant per year across all scenarios.

6.2 Results under additional policy scenarios

6.2.1 Designing a carbon tax

Figure 6-30 and Figure 6-31 summarize the capacity mix and generation mix, respectively, when imposing different CO₂ taxes for a low-, mid- and high-cost scenario. Gas and storage play a prominent role in most high carbon tax cases as they complement the variability that comes with high VRE penetrations. As the carbon tax increases, VRE adoption rises as coal is replaced by gas generation, whose share peaks at 35% in the mid-cost scenario. Wind deployment reaches its maximum potential with a carbon tax of \$40/ton in all scenarios, while solar PV reaches its maximum potential only in the low-cost scenario.

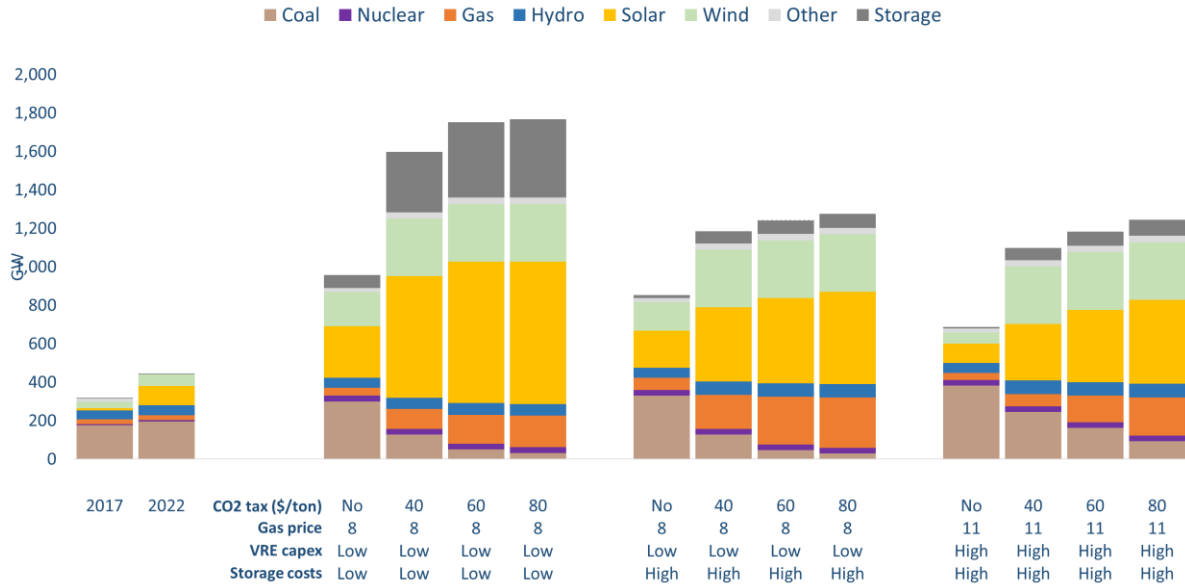


Figure 6-30: 2037 installed capacity by generator type under different cost scenarios and CO₂ taxes.
 Note: 2017 values are in gross GW while 2022 and 2037 values are in net GW.

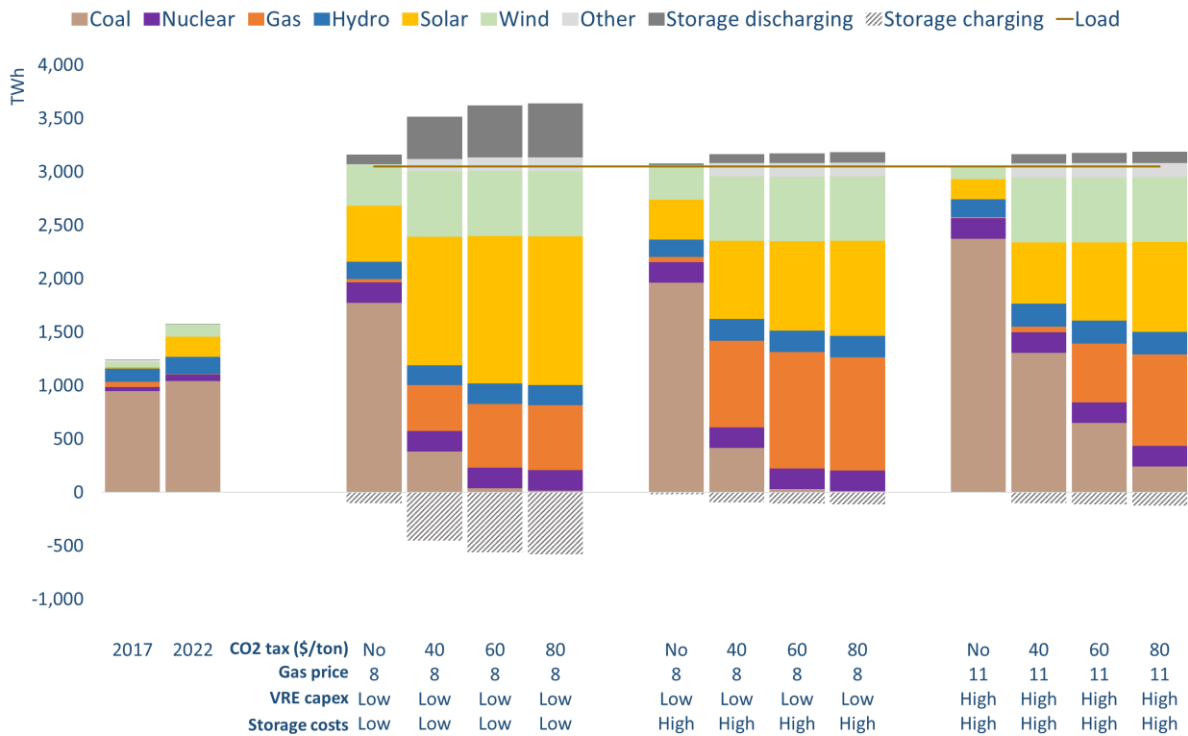


Figure 6-31: 2037 generation by generation type under different cost scenarios and CO₂ taxes.
 Note: 2017 generation mix taken from official CEA statistics (Central Electricity Authority 2008-2018b) while 2022 generation mix are own assumptions using Gen X. 2017 values are in gross TWh while 2022 and 2037 values in net TWh

Figure 6-32 shows the CO2 emissions and total costs under the different CO2 tax scenarios. A \$40/ton tax would be enough to meet the medium emissions target in all scenarios, while an \$80/ton tax would be required to meet the stringent limit. Imposing a carbon tax at \$40/ton causes a spike in total costs, increase that is slowed down when rising carbon tax towards \$80/ton. The results indicate that with the right carbon tax, India could meet its targeted emissions. However, there are challenges associated with estimating the ideal carbon tax: underpricing the carbon tax would fail to meet the emissions goal while overpricing it could lead to added costs that would not necessarily reduce emissions.

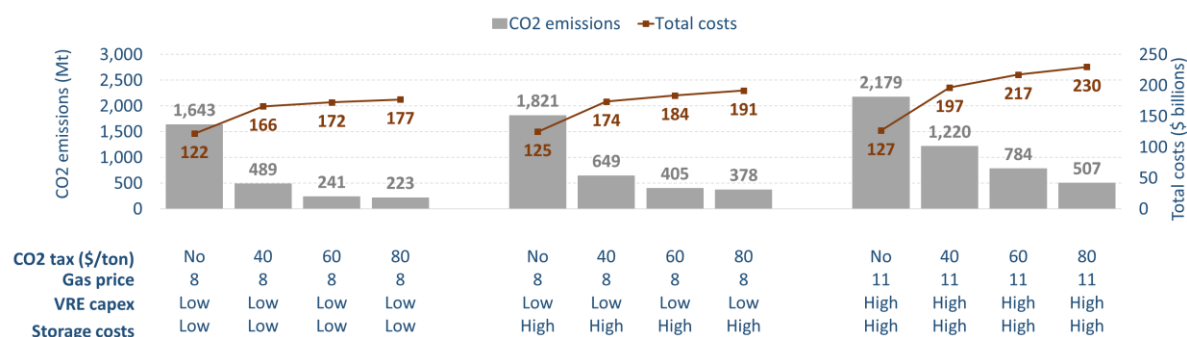


Figure 6-32: 2037 CO2 emissions under different costs scenarios and CO2 taxes. Total costs are in \$Billions and include CO2 tax.

6.2.2 Setting non-fossil fuel portfolio standards

Figure 6-33 and Figure 6-34 summarize the capacity mix and generation mix, respectively, when imposing non-fossil fuel standard in a low, mid, and high-cost scenario. As described, non-fossil fuel shares are imposed as a percentage of load plus roundtrip losses incurred in storage charging and discharging. The results are surprising: even though there is an increase in VRE and storage deployment, coal generation in absolute terms only decrease when imposing 80% of non-fossil fuel shares, when comparing to 2017 and 2022 levels.

Gas generation remains practically unchanged as higher non-fossil fuel shares are imposed, even when storage costs are higher. In contrast, even though coal generation decreases when higher non-fossil fuel shares are imposed, it remains higher than if emissions limits were directly imposed. In fact, by comparing Figure 6-34 and Figure 6-3, coal generation in scenarios with high non-fossil fuel shares is between 20% and 60% higher than in scenarios with stringent emissions limits. Considering that with a non-fossil fuel standard the goal is to reach a specific generation mix rather than meeting an emission target, the share that is left for fossil-fuel sources will be met by the most cost-effective source (coal) instead of the least emitting source (gas). This effect is illustrated in Figure 6-35 and Figure 6-36 that compares the emissions and non-fossil fuel shares under i) policy that sets a non-fossil fuel standard and ii) policy that sets an emissions limit. While total emissions remain similar under both policies, non-fossil fuel shares are significantly lower when imposing emissions targets.

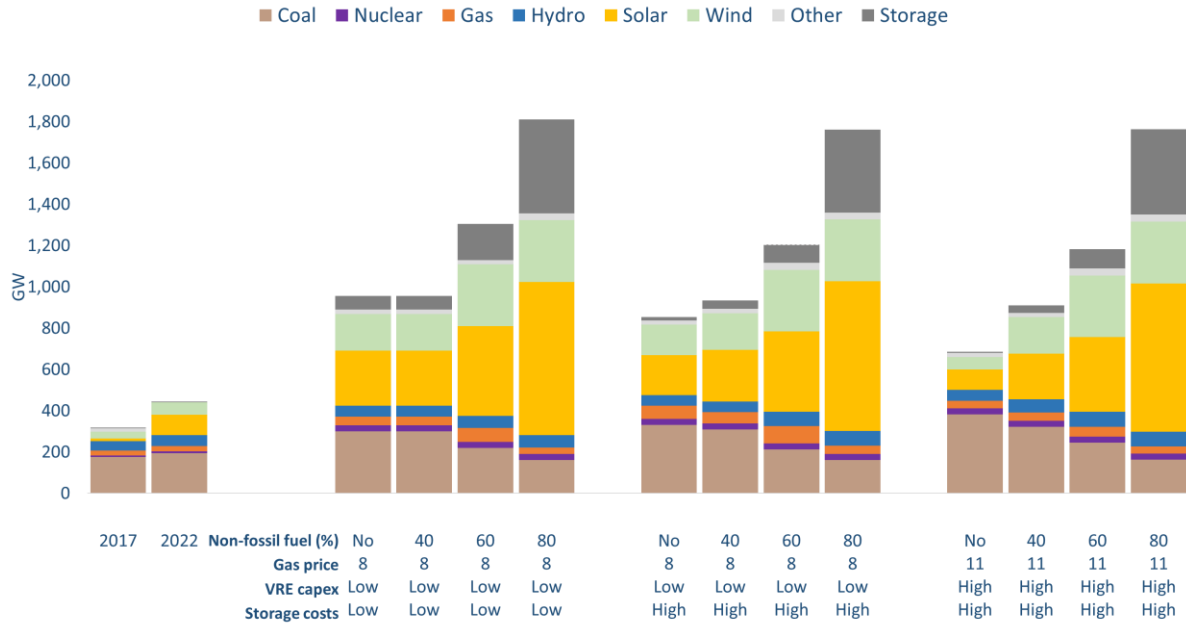


Figure 6-33: 2037 installed capacity by generator type under different cost scenarios and non-fossil fuel shares. Note: 2017 values are in gross GW while 2022 and 2037 values are in net GW.

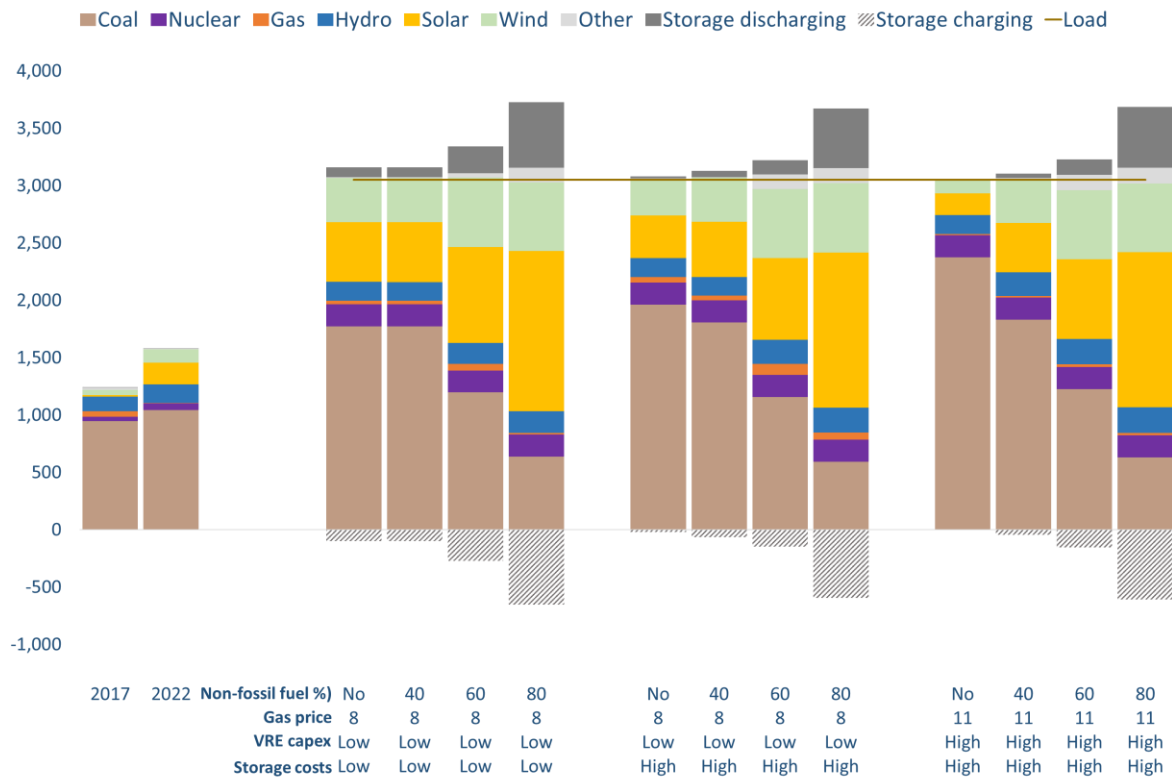


Figure 6-34: 2037 generation by generation type under different cost scenarios and non-fossil fuel shares. Note: 2017 generation mix taken from official CEA statistics (Central Electricity Authority 2008-2018b) while 2022 generation mix are own assumptions using Gen X. 2017 values are in gross TWh while 2022 and 2037 values in net TWh.

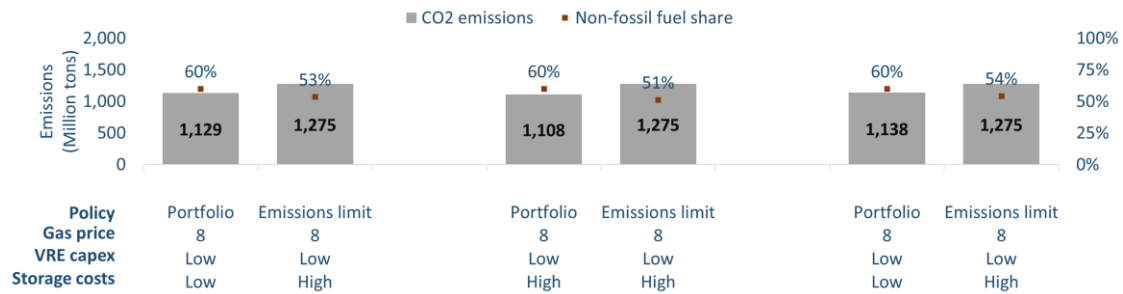


Figure 6-35: Comparing CO2 emissions and non-fossil fuel shares when imposing moderate emissions limits (1,275 million tons) and moderate non-fossil fuel share (60%).

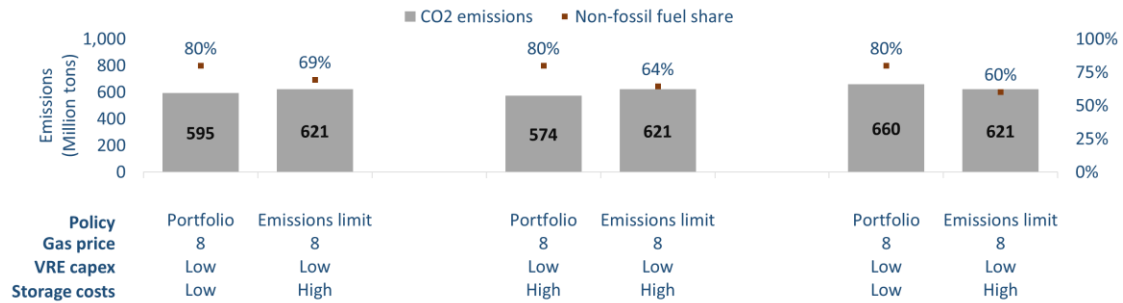


Figure 6-36: Comparing CO2 emissions and non-fossil fuel shares when imposing stringent emissions limits (621 million tons) and high non-fossil fuel share (80%).

Finally, as shown in Figure 6-37, stringent emissions limits (621 million tons) are only met when imposing a high non-fossil fuel share (80%) and not in all scenarios. In fact, in the scenario with High VRE capex, High storage costs and gas prices at \$8/MMBtu, while total CO2 emissions are over 621 million tons, the total costs are 11% higher than if stringent emissions were directly imposed. It seems that designing a portfolio standard would not necessarily lead to the desired emissions target.

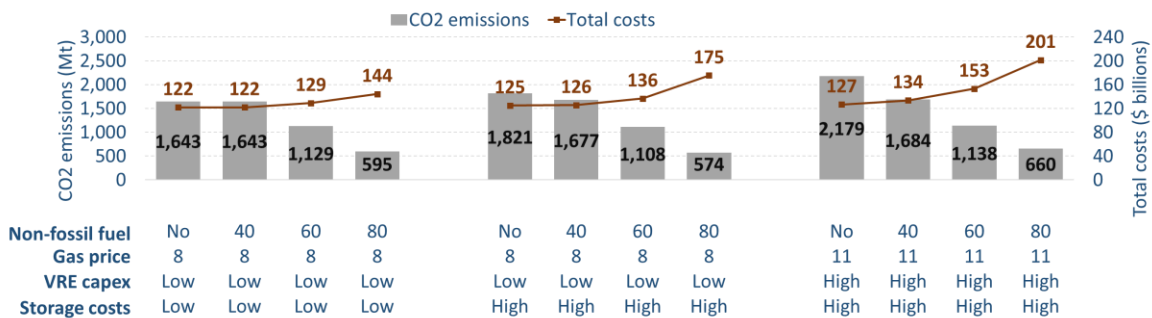


Figure 6-37: 2037 CO2 emissions under different costs scenarios and non-fossil fuel shares. Total costs are in \$Billions.

7 Sensitivity analysis

This chapter includes several sensitivity analyses to explore the sensitivity of the results to different modeling and data assumptions. The conclusions of the different sensitivity scenarios will be described in the following sections.

7.1 Modeling with integer UC (MILP approach)

As described in Chapter 5, an LP approach was chosen by using linearized unit commitment (UC), to reduce the computational running time⁷⁶. Figure 7-1 and Table 7-1 summarize a comparison between using integer UC (MILP approach) and linear UC for two scenarios. In terms of generation and capacity mixes, there are minor differences, mainly in coal generation, while total costs and emissions have a difference of under 1% in both scenarios. This error is within the tolerance usually considered in integer optimization problems. These results indicate that using the linearized UC representation is a reasonable approximation.

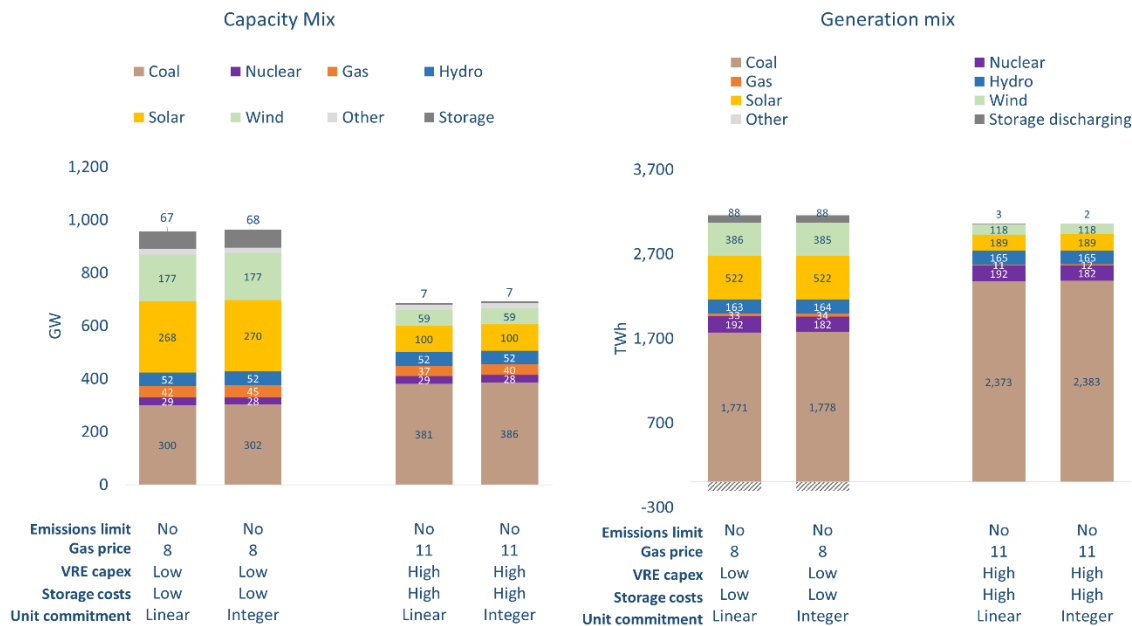


Figure 7-1: Using Integer UC v/s Linear UC. Comparing the generation mix and capacity mix.

⁷⁶ Most of scenarios were solved using Intel Xeon E5-2650 processors with 64 GB of ram. In one of the scenarios shown, the running time by using Linearized UC was reduced from 14 hours to 9 hours, while in the other scenario, from over 23 hours to 18 hours.

Table 7-1: Using Integer UC v/s Linear UC. Comparing total costs and CO₂ emissions.

Gas price @ \$8/MMBtu, Low VRE capex, Low Storage costs and no emissions limit			
Unit commitment	Linear	Integer	Difference (%)
Total costs (\$ billions)	121.9	122.4	0.40%
CO ₂ emissions (million tons)	1,643	1,649	0.40%

Gas price @ \$11/MMBtu, High VRE capex, High Storage costs and no emissions limit			
Unit commitment	Linear	Integer	Difference (%)
Total costs (\$ billions)	126.6	127.5	0.66%
CO ₂ emissions (million tons)	2,179	2,187	0.37%

7.2 Including gas-based OCGT as a potential generation source

As detailed in Chapter 5, open cycle gas turbines (OCGT) are not considered among the possible technologies that can be developed in the Indian power system. Open cycle plants are usually peaking plants and can burn either gas or diesel. These plants are flexible, have high ramping rates, and almost no minimum output level and downtime (National Renewable Energy Laboratory 2018). This source is neglected mainly because of i) there is only one open cycle operating in the India grid today, ii) CEA does not consider the development of these technologies in the future and iii) open cycles are being scarcely built in the world since combined cycles can operate in open cycle mode⁷⁷. The effect of including open cycle plants in the system is analyzed, considering a scenario where there is a high share of gas generation. Figure 7-2 shows the optimal mix under the three emissions scenarios. In the absence of an emissions limit, open cycles take the role of combined cycles as peaking plants and reduce the development of combined cycles, coal plants, and storage. Gas generation, including CCGT and OCGT, is reduced by nearly 50%. When imposing emissions limits, open cycles continue to reduce the investments in coal and storage but fosters gas consumption. Although combined cycle deployment decreases, their utilization increases, and added to OCGT deployment, lead to a rise in the gas share of the generation mix. This effect is also shown in Figure 7-3 as CCGT capacity factors increase under all emissions limits. Table 7-2 shows that including OCGT leads to a reduction in total costs of more than 1%, although this decrease is reduced as emissions are capped at lower values. Finally, Figure 7-4 shows the effect of including OCGT in a peak net load day under the stringent emissions scenario. Open cycle plants reduce combined cycle generation at peak load hours and decrease the need for storage discharges, reducing the amount of energy required for charging in daytime hours.

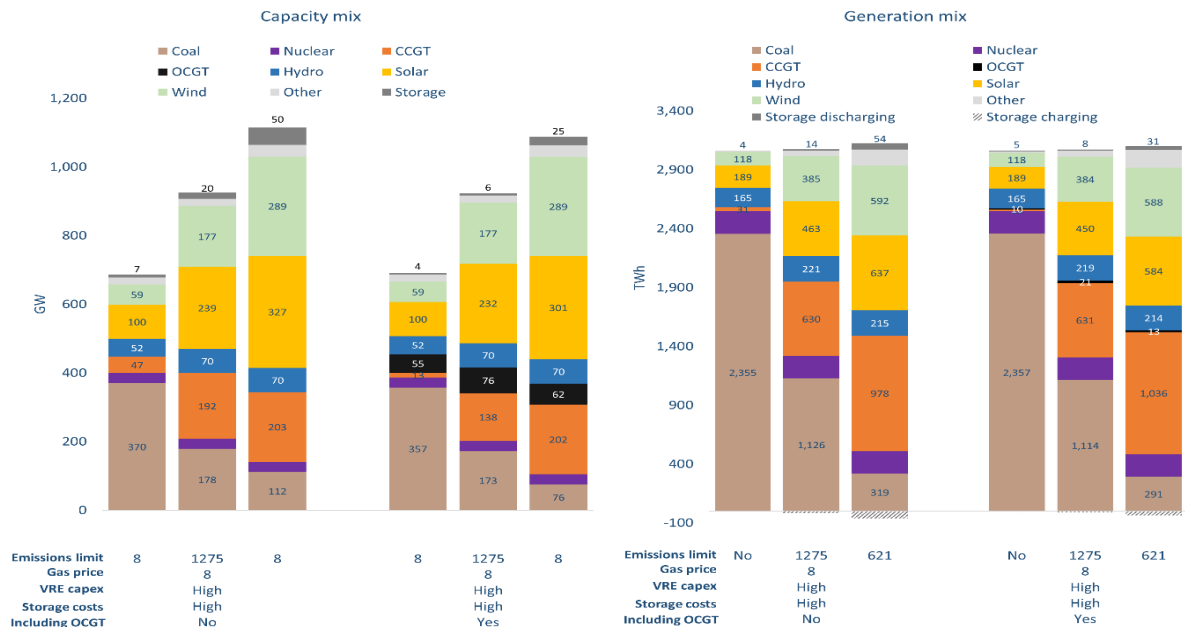


Figure 7-2: Including OCGT as a potential source. Comparing the generation mix and capacity mix.

⁷⁷ In 2015, combined cycles accounted to roughly three quarters of 46 GW new plants installed in OECD countries (International Energy Agency 2017).

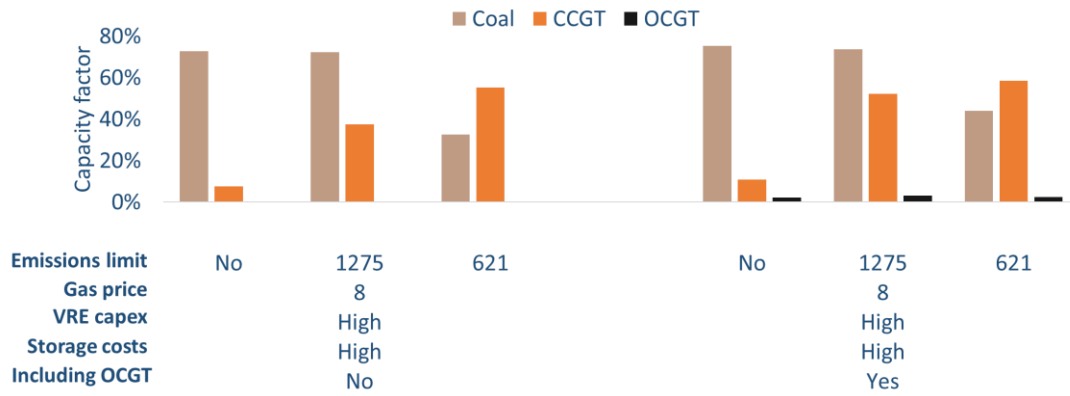


Figure 7-3: Including OCGT as a potential source. Comparing capacity factors of coal, CCGT, and OCGT fleet.

Table 7-2: Including OCGT as a potential source. Comparing total costs.

Emissions limit	Total costs (\$ billions)		
	Without OCGT	With OCGT	Difference (%)
No emissions limit	126.3	124.6	-1.35%
1,275 Mt	141.4	139.6	-1.27%
621 Mt	163.9	163.4	-0.33%

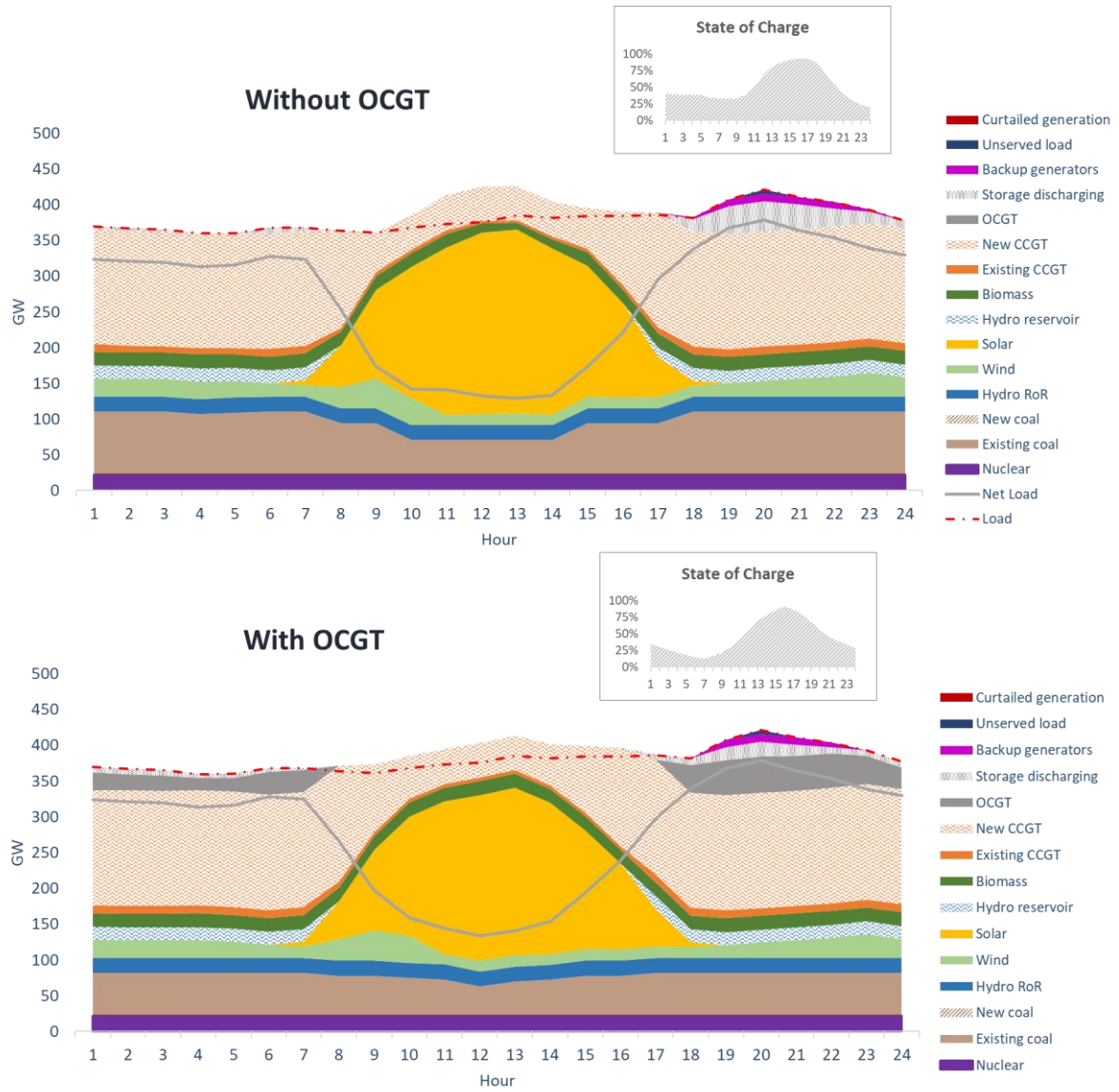


Figure 7-4: Comparing the effect of including OCGT. Dispatch example on peak net load curve day (October 16th) for a scenario with an emissions limit of 621 million tons of CO₂, High VRE capex, High Storage costs and gas price at \$8/MMBtu.

7.3 Changes in load growth

The load forecast is a crucial parameter in determining the future Indian power system. The uncertainty regarding the future annual load and load profile could affect the optimal power generation mix. The effect of increasing the compound annual growth from 5% to 6.4% is analyzed, resulting in a 30% load increase by 2037 in comparison to the base scenario. This could be the case, for instance, if there is a higher degree of electrification of various sectors than what the baseload forecast accounts for. Figure 7-5 and Table 7-3 summarize the effects of the load increase in the optimal mix, CO2 emissions, and total costs. Depending on the emissions limit, gas or coal play a more significant role. In both scenarios analyzed, total costs increase by far over 30%.

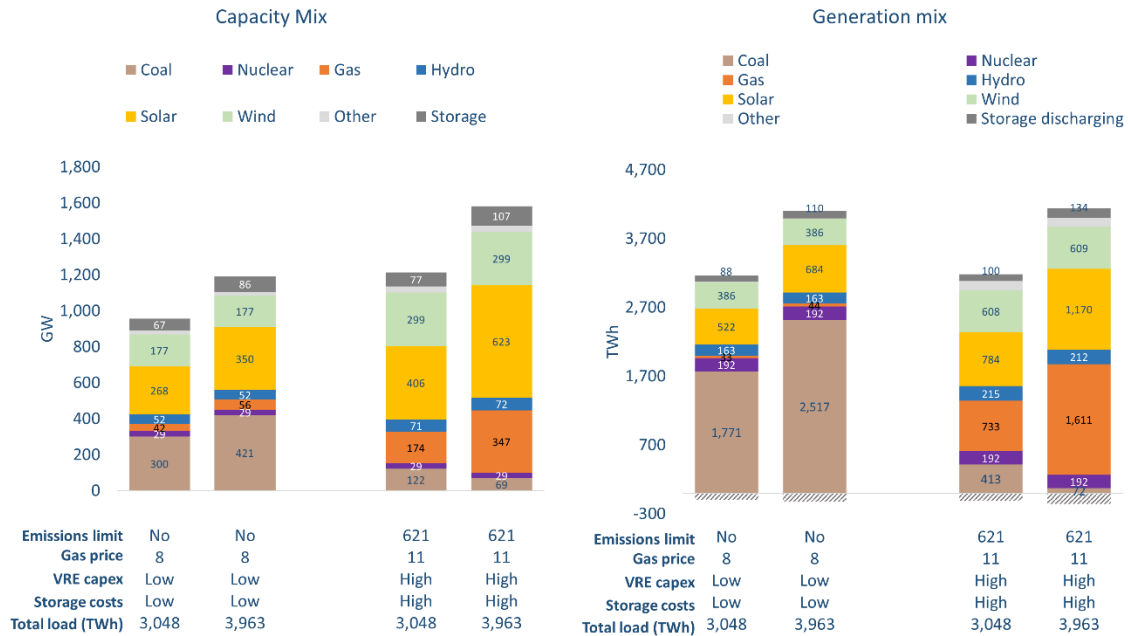


Figure 7-5: Increasing 2037 load by 30%. Comparing the generation mix and capacity mix.

Table 7-3: Increasing 2037 load by 30%. Comparing total costs and CO2 emissions.

Gas price @ \$8/MMBtu, Low VRE capex, Low Storage costs and no emissions limit			
Load (TWh)	3,048	3,963	Difference (%)
Total costs (\$ billions)	121.9	167.4	37.31%
CO2 emissions (million tons)	1,643	2,322	41.35%

Gas price @ \$11/MMBtu, High VRE capex, High Storage costs and 621 Mt limit			
Load (TWh)	3,048	3,963	Difference (%)
Total costs (\$ billions)	180.7	271.9	50.44%
CO2 emissions (million tons)	621	621	0.00%

7.4 Eliminating transmission constraints

Figure 7-6 and Table 7-4 summarize the effect of eliminating transmission constraints in the least and highest cost scenarios. VRE generation increases slightly mainly due to a reduction in renewable curtailment, and coal observes a small increase, and gas generation a small reduction. Finally, the cost reduction is negligible in both scenarios.

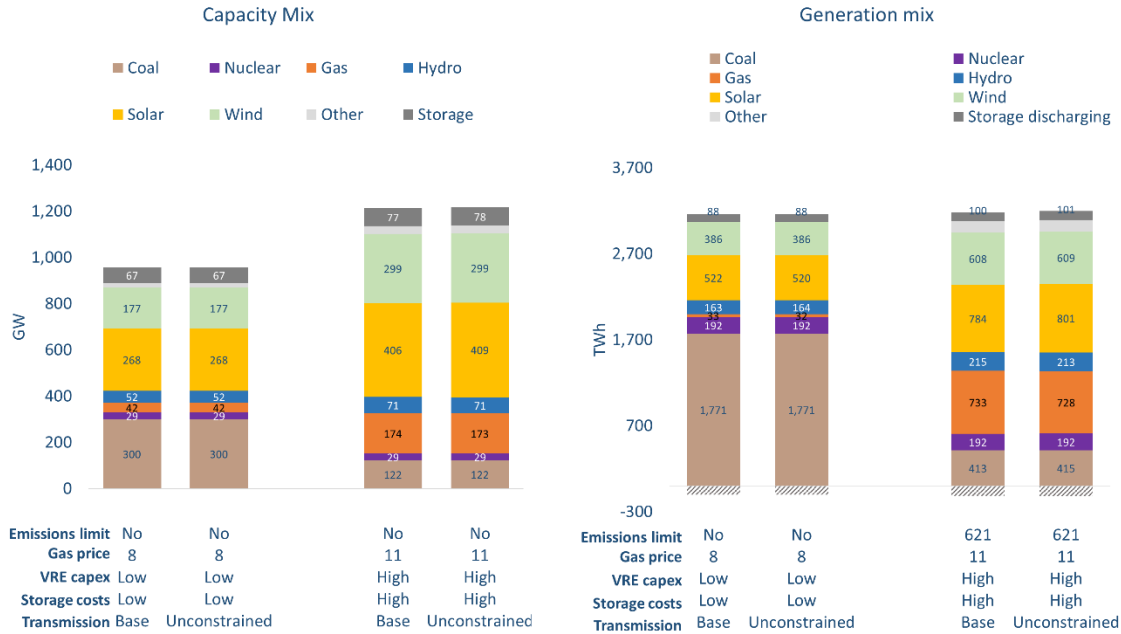


Figure 7-6: Eliminating transmission constraints. Comparing the generation mix and capacity mix.

Table 7-4: Eliminating transmission constraints. Comparing total costs and CO₂ emissions.

Gas price @ \$8/MMBtu, Low VRE capex, Low Storage costs and no emissions limit			
Transmission system	Base case	Unconstrained	Difference (%)
Total costs (\$ billions)	121.9	121.9	0.00%
CO ₂ emissions (million tons)	1,643	1,643	-0.01%

Gas price @ \$11/MMBtu, High VRE capex, High Storage costs and no emissions limit			
Transmission system	Base case	Unconstrained	Difference (%)
Total costs (\$ billions)	180.7	180.7	-0.02%
CO ₂ emissions (million tons)	621	621	0.00%

7.5 Reducing long term gas price

Gas prices are one of the key drivers in the composition of an optimal mix. Figure 7-7 and Figure 7-8 summarize the effect of reducing the gas price from 8 to \$6/MMBtu. As a result, gas increases its share considerably, becoming the main source in medium and stringent scenarios. Gas capacity factors are shown in Figure 7-8 increase considerably in comparison to the base case shown in Figure 6-26, although they remain lower than for nuclear plants.

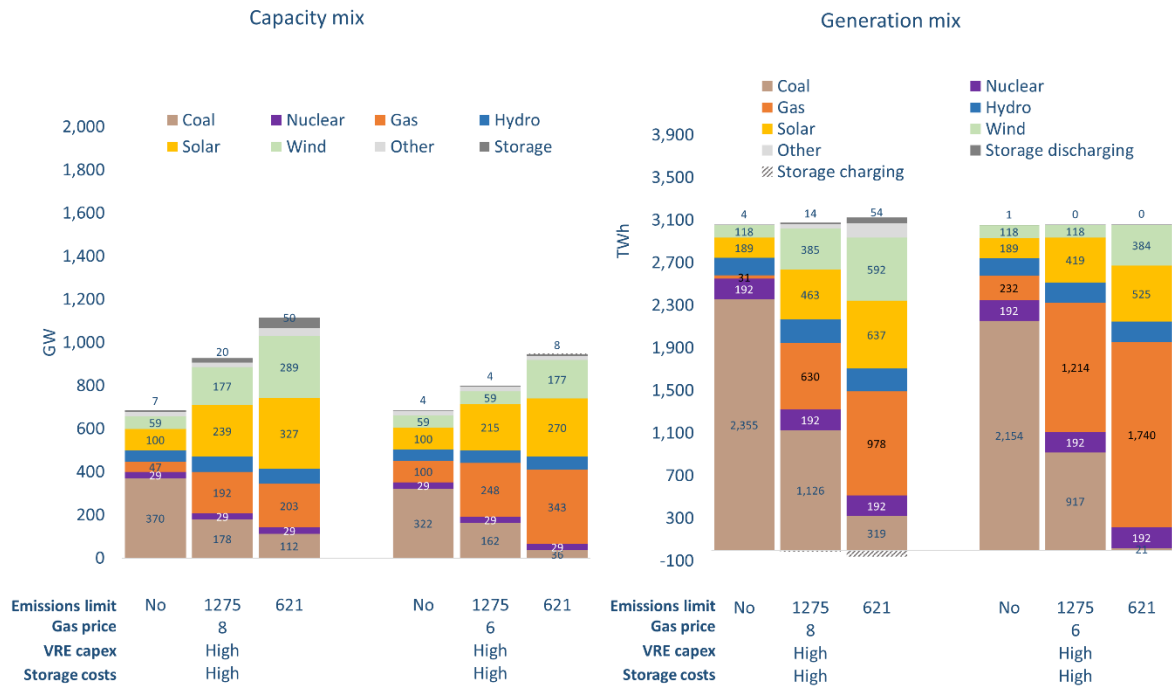


Figure 7-7: Reducing long term price to \$6/MMBtu. Comparing the generation mix and capacity mix.

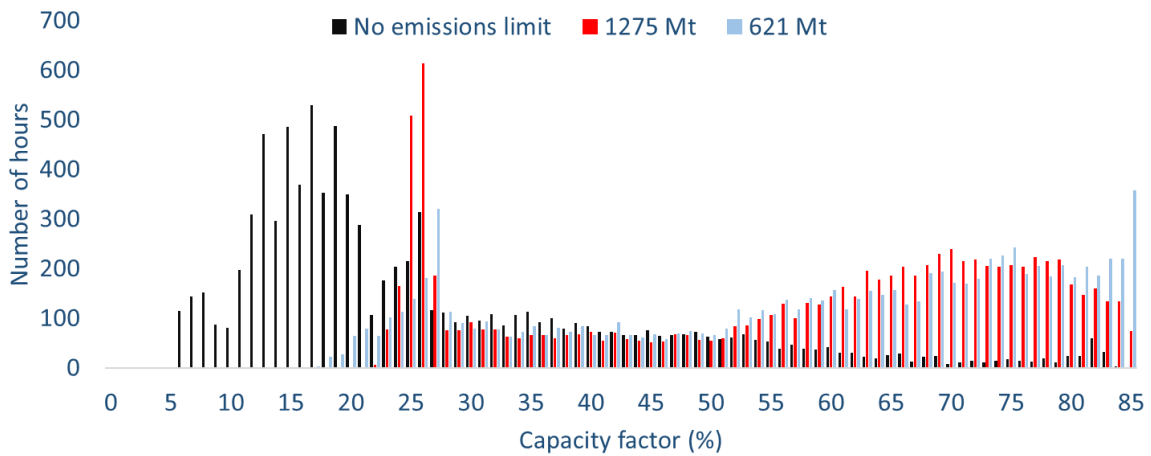


Figure 7-8: Histogram summarizing gas fleet capacity factors over 8,760 hours. Scenarios with High VRE capex, High Storage costs, and gas price at \$6/MMBtu.

7.6 Modeling 90 GW of behind-the-meter diesel generators

Behind-the-meter backup generators have been installed by end-users to avoid power outages and can be used in the future as demand response. As described before, around 90 GW in diesel backup generators were recorded in 2014, according to (Bhati and Kalsotra 2017), but only 10 GW are considered in the study. The effect of considering 90 GW of diesel generation capacity is analyzed in a scenario with the highest utilization of this resource. Figure 7-9 indicates that the impacts of capacity and generation are modest and reduced as more stringent emissions limits are imposed. Figure 7-10 shows that additional backup capacity reduces the use of storage, with corresponding effects on the dispatch. Finally, the effects on total costs and emissions are minimal.

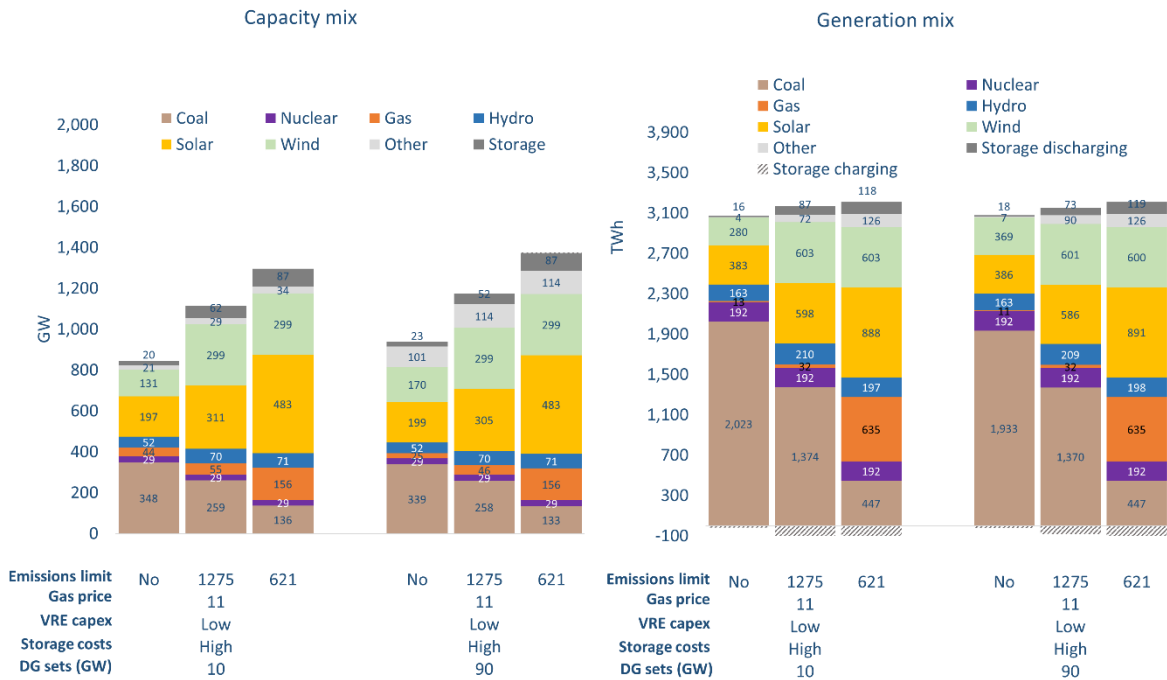


Figure 7-9: Modelling 90 GW in behind-the-meter backup generators. Comparing the generation mix and capacity mix.

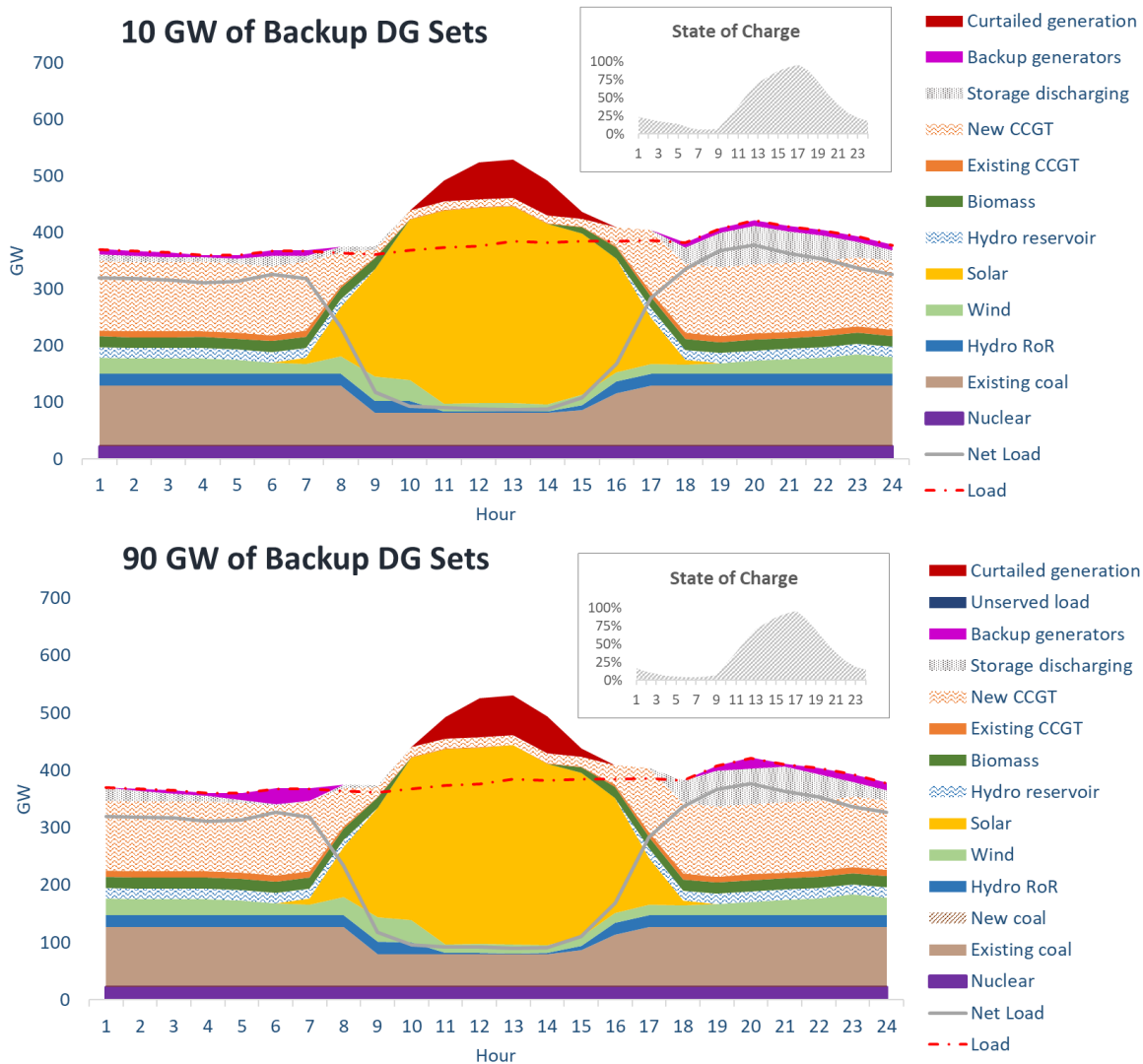


Figure 7-10: Comparing generation dispatch when including 10 and 90 GW of backup generators. Dispatch example on peak net load curve day (October 16th) for a scenario with an emissions limit of 621 million tons of CO₂, Low VRE capex, High Storage costs and gas price at \$11/MMBtu.

7.7 Evaluating the effect of a monsoon

The rainy season, also named “monsoon” occurs almost every year in India from June to September. During this timeframe, there are heavy rainfalls that start in the southwest of the country and spread all over the Indian territory. The heavy rainfalls are considered in hydro inflows and capacity factors but are not considered in the solar production profiles. This sensitivity analysis shows the scenario of reducing solar production to zero during a two week period in July, an extreme analysis considering that rainy season that does not coincide all around the country but spreads gradually around the regions. Figure 7-11 shows including a time period without sun lead to less solar deployment and generation, although minor, while Figure 7-12 shows that in days without solar production, coal generation replaces solar and storage generation.

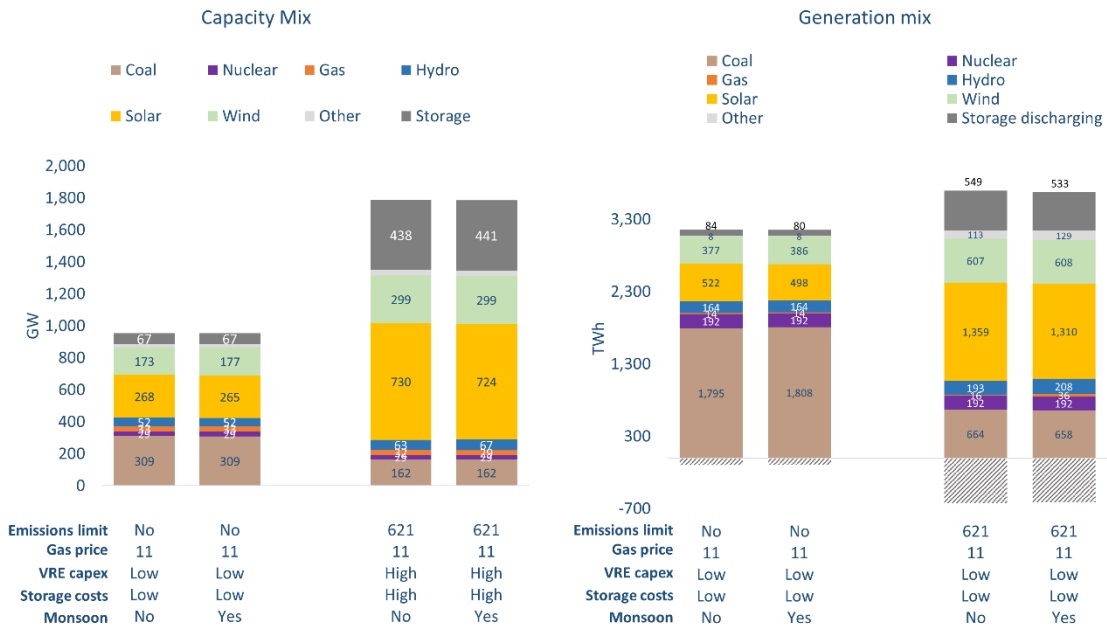


Figure 7-11: Evaluating the effect of a monsoon season on solar production. Comparing the generation mix and capacity mix.

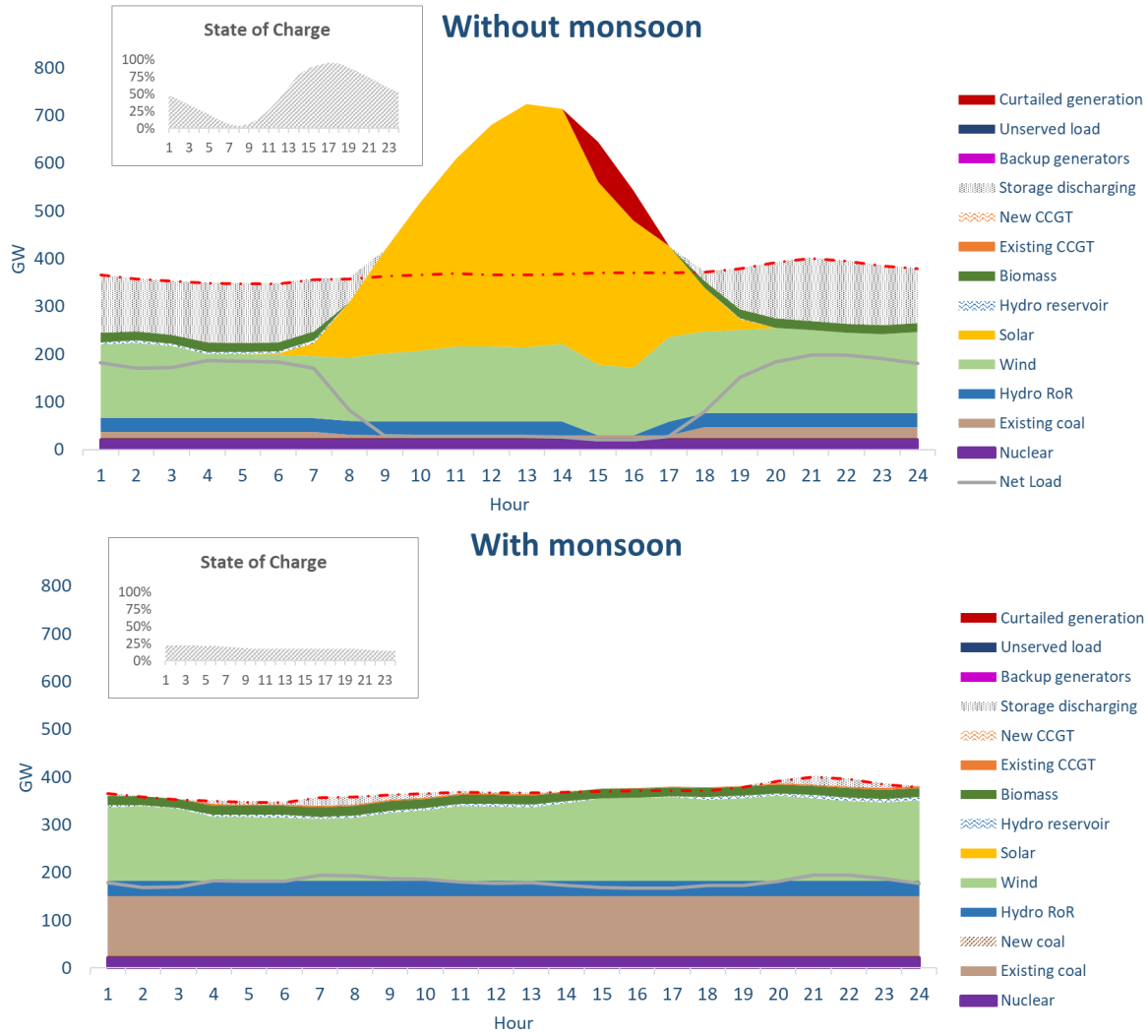


Figure 7-12: Comparing generation dispatch when including the effect of a monsoon season on solar production. Dispatch example on July 3rd for a scenario with an emissions limit of 621 million tons of CO₂, Low VRE capex, Low Storage costs, and gas price at \$11/MMBtu.

8 Conclusions and discussion

8.1 Main results

Indian authorities are pushing for ambitious renewables development to meet their INDC targets while they are facing several other challenges, such as high load consumption growth rates, poor quality of service, and local pollution. A considerable amount of new power capacity is required to meet the load growth, expected to be tripled in the next 20 years, and replace existing assets that will be retired in the future. Additional problems regarding the operation of the Indian power system need to be solved: thermal capacity is currently underutilized, there is lack of efficient coordination among state, regional, and national system operators and several electricity companies are under financial stress.

This thesis explores 24 different scenarios, considering different VRE capital costs (low and high), storage costs (low and high), gas price (\$8 and \$11/MMBtu) and emissions targets (no limit, 1275 million tons, and 621 million tons). GenX, a capacity expansion model developed internally at MIT, is used in the analysis. The results obtained from the scenario analysis, although broad in nature, lead to several specific conclusions. Without imposing emissions limit, coal remains the most competitive technology increasing its generation in comparison to 2017 levels; GHG emissions continue to increase if no policy is enforced despite the historical and expected reduction in VRE and storage costs. Although scenarios with low VRE and storage costs tend to mitigate the emissions growth, they fail to give rise any carbon emissions reduction. In contrast, SO₂ and NO_x emissions are reduced in all scenarios, mainly due to the installation of abatement technologies, which is required for all coal plants by 2022.

Imposing CO₂ emissions limits has a significant effect on the capacity and generation mix. As more stringent emissions limits are imposed VRE penetration increases, surpassing 50% in some scenarios. With medium emissions limits, non-fossil fuel capacity is above 40% across all scenarios meeting the goals of the Indian government. Under stringent emissions targets, non-fossil fuel represents roughly between 50% and 80% of the generation mix. Moreover, the low emission limit of 621 million tons leads to a reduction of coal generation in absolute terms across all scenarios.

Hourly generation dispatch graphs show that higher VRE penetration would require additional efforts in coordinating the power system across the country, and flexible capacity would play a vital role in balancing supply and demand. In a low VRE cost and low emissions scenario, over 270 GW of dispatchable capacity would be required to ramp up to meet the changes in net load when the sun sets at the end of the day. Results show significant VRE curtailment, especially during VRE peak hours. Energy storage adds flexibility to the grid, thereby facilitating a higher VRE penetration and less curtailment. Under low storage and VRE cost scenarios, batteries and pumped hydro plants can charge from the grid in hours with low peak net load and discharge in peak load hours, reducing renewable energy curtailment without increasing emissions. However, further reduction in storage costs must occur; under high-cost scenarios, the contribution of storage in the system operation is limited.

Furthermore, gas generation competes directly with storage sources; both technologies are flexible and can adapt to abrupt changes in VRE generation. When storage costs increase, gas-based plants increase their share in the generation mix, along with gas consumption. In fact, natural gas becomes the primary generation source in some strict emissions limits scenarios. However, even with high gas penetration, gas-based plants capacity factors remain under 60%. In addition, under stringent emissions scenarios, gas fleet shows a broad range of utilization. Increasing the frequency of gas-

based plant cycling will also be a major challenge: under some scenarios, the average number of starts per plant would be over 100, almost one start per three days. Increasing the number of starts can reduce the lifetime of combined cycles and increase the operation and maintenance costs (Kumar, et al. 2012).

Quality of service improves in most scenarios. Even though behind-the-meter backup diesel capacity has currently an essential role in assuring reliability, it would have a minor effect in the future, operating mainly in peak hours as a demand response technology. Unserved load continues to be observed in some scenarios; however, it is limited and shows that not supplying load is more cost-effective than developing new capacity.

Different sensitivity analyses were conducted to quantify the effects of changing critical assumptions in the system's operation. Results indicate that using an Integer Unit Commitment approach, relaxing transmission constraints and including a larger amount of backup diesel generators have minor effects on the optimal generation mix. Reducing gas price and including open cycle plants as a potential source tend to favor gas-based adoption. Load growth will depend on the emissions scenario: when emissions limits are imposed, the gas share would see a substantial increase. Including the effect of monsoon has a minor effect on solar deployment, and mainly affects solar generation during rainfall days.

8.2 Policy discussion

The study results provide vital insights that Indian regulators must consider when designing policies. From a carbon perspective, the major challenges are related to how the emissions targets can be met. In the absence of any emissions limit, that scenarios explored show that GHG emissions will continue to grow in the next years. Enforcing an emissions target in a command-and-control approach is challenging. Information asymmetries and coordination challenges would add obstacles in meeting the emissions goals. It is generally agreed that a carbon tax is an ideal policy; however, setting the right carbon tax is not an easy task, and it will depend on the costs of alternative sources. Undervaluing a carbon tax would fail to meet the emissions target while overvaluing the tax could lead to an excessive burden on the power system and could lead to non-optimal generation mixes. Designing a portfolio standard is a “second best” alternative. Nevertheless, imposing a portfolio standard could fail to meet the ultimate goal, if this is to reduce carbon emissions in a cost-effective manner. As shown in this study, designing a portfolio standard based on load would lead to a less drastic reduction in coal generation failing to meet emissions targets in some scenarios, or at higher costs, in other scenarios.

Analyzing hourly generation dispatch graphs provide some critical observations that Indian regulators must consider when designing policies. Managing high VRE penetration requires efficient coordination and operation of multiple plants located in several states. Authorities must incentivize better coordination between state and regional system operators and encourage the development of new transmission links. The current lack of coordination among state system operators, if not improved, will be an obstacle for future VRE deployment and could cause significant renewable energy curtailment. Storage proves to be a great complement to VRE adoption; however, further cost reductions are required for a cost-effective adoption. Policies encouraging the research and development of better storage technologies and how to optimize the use of them in the power grid must continue to be implemented.

Uncertainty in the utilization of the gas fleet is also a significant challenge that needs to be tackled. Authorities would probably debate whether it is necessary to develop gas infrastructure to supply underutilized gas assets that also have high uncertainty in their expected generation. In addition, combined cycles would probably face additional costs due to more frequent cycling. Policymakers must discuss ways how to develop gas infrastructure, by either rewarding the flexibility attribute gas plants provide or by reducing the uncertainty in its utilization.

8.3 Further work

Further analyses are needed to fully understand the future Indian power system. The model used simplifies the Indian grid; a detailed analysis including state transmission systems could provide additional details in how the system would operate, where resources are allocated and which are the main bottlenecks and challenges. VRE potential is not located evenly among all states but concentrated in specific regions, and hence, interstate transmission links can play a major role in VRE generation and curtailment. In addition, VRE was assumed to be deterministic; the role of uncertainty can have a significant effect on how the system is designed, planned, and operated. Running scenarios with different renewable profiles can provide additional insights on how they can affect VRE penetration.

Further work in modeling gas supply must also be done. Operational constraints in gas supply and transport were neglected. Additionally, gas fuel supply was assumed to be a variable cost, ignoring that investments in gas pipelines and/or LNG terminals are made in lump sums, and therefore are fixed costs.

Including other non-emitting generating sources must be explored. CCS technologies were not considered due to the low carbon storage potential in India. However, sequestered carbon could be exported to neighboring countries, where carbon storage potential is higher.

Moreover, the capacity expansion analysis is conducted on a single target year. Power infrastructure investments are not undertaken over one year but are planned, developed and operated over long term periods making multi-year models more suitable to represent power systems; however, modeling multi-year capacity expansion models can significantly increase the computational time.

Finally, as new customers are connected to the grid, aggregated load profiles could change, affecting how power plants are being dispatched. Estimating the future load profile is therefore crucial to understand the operation of the future power system.

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A. Appendix: forced and planned outages

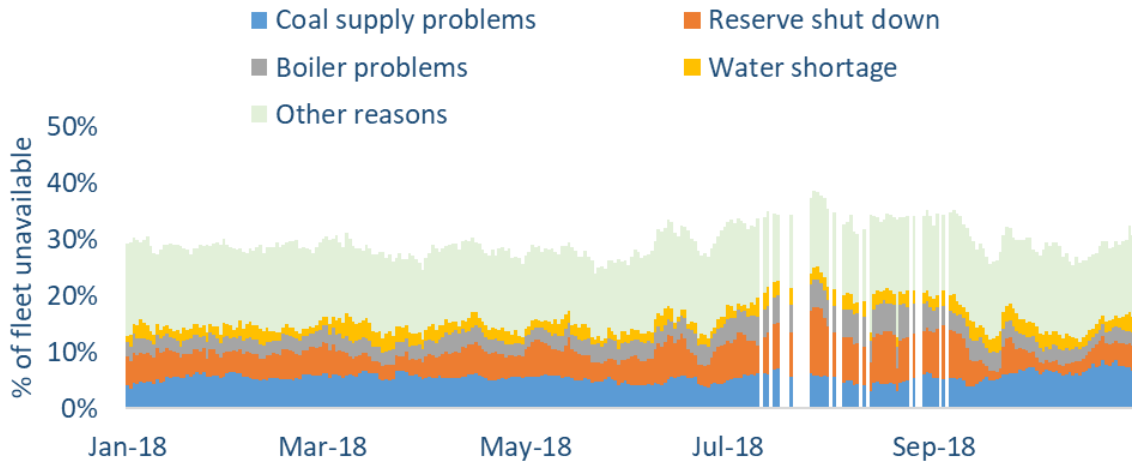


Figure A-1: Causes behind forced and planned outages of the coal fleet.
Source: (National Power Portal 2018) and (National Power Portal 2018).

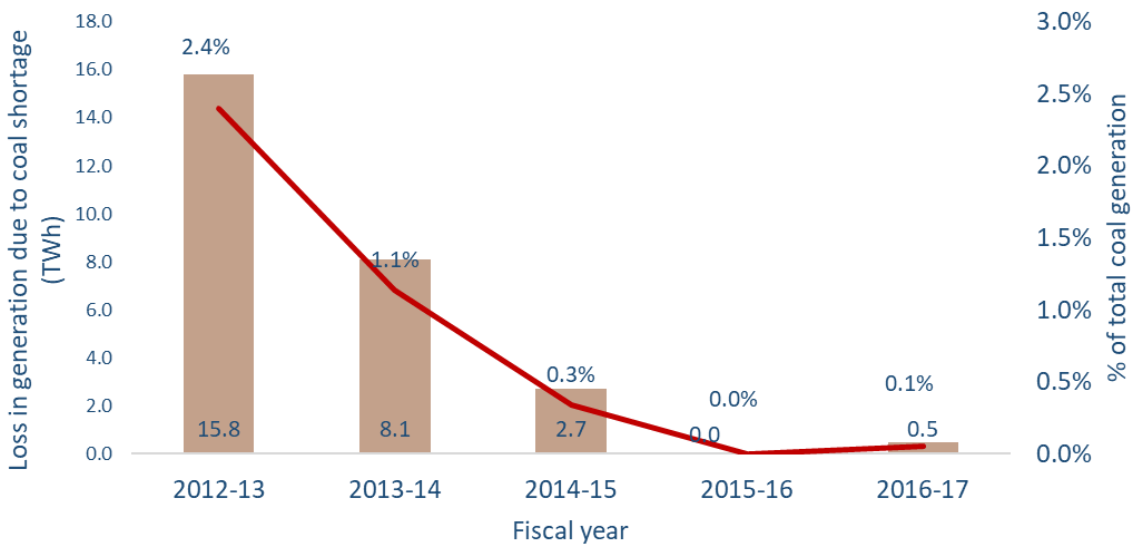


Figure A-2: Coal generation lost due to coal shortage.
Source: (Central Electricity Authority 2018a).

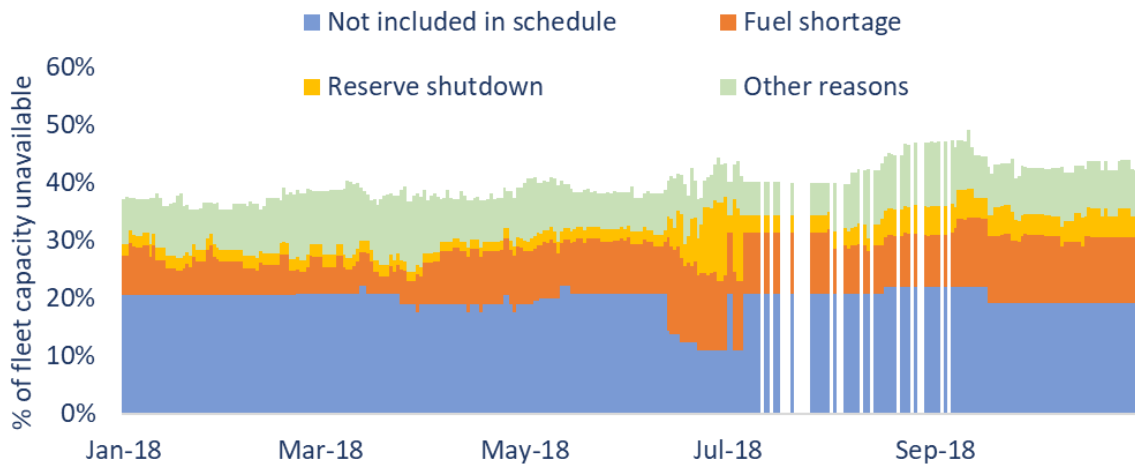


Figure A-3: Causes behind forced and planned outages of the gas fleet.
 Source: (National Power Portal 2018) and (National Power Portal 2018).

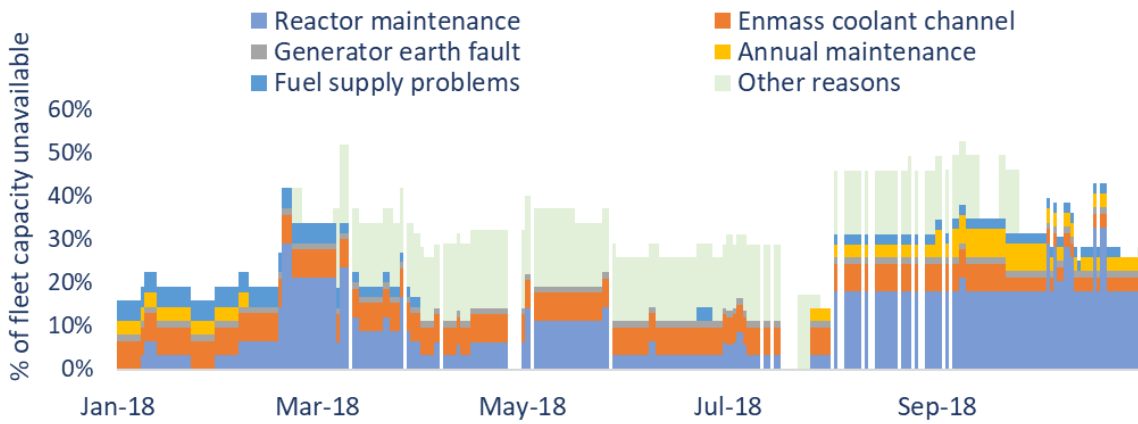


Figure A-4: Causes behind forced and planned outages of the nuclear fleet.
 Source: (National Power Portal 2018) and (National Power Portal 2018).

B. Appendix: load profiles

Table B-1: Original source of load profiles per state.

Note: Some load profiles are based on raw hourly values, while others are estimated from the average peak and off-peak values.

Region	No.	State / Technology	2015 Case (Base Case)
Northern	1	Uttar Pradesh	<ul style="list-style-type: none"> • Peak and off-peak daily shape for each month • Extrapolated hourly profile assuming average day load to be 80% of the peak day and 2 peak days, 8 off-peak days and 20 average load days per month • Daily peak demand values available from paid database subscribed by GE Energy Consulting Group • Scaled hourly demand pattern based on the daily peak demand values
	2	Rajasthan	
	3	Punjab	
	4	Haryana	
	5	Uttarakhand	
	6	Delhi	
	7	Himachal Pradesh	
	8	Jammu and Kashmir	
Western	9	Maharashtra	Hourly state demand is taken from the Maharashtra State Load Dispatch Center Daily systems Report
	10	Gujarat	<ul style="list-style-type: none"> • Peak and off-peak daily shape for each month available from State Load Dispatch Center. • Extrapolated hourly profile assuming average day load to be 80% of the peak day and 2 peak days, 8 off-peak, days and 20 average load days per month • Scaled the hourly demand pattern based on the daily peak demand values
	11	Madhya Pradesh	
	12	Chattisgarh	
	13	Goa	
	14	Union Territory	
15	Karnataka	Hourly values in public domain from the Load Dispatch Center website	
Southern	16	Andhra Pradesh	Hourly values provided by Load Dispatch Center from July 2014 to March 2015. Extrapolated data for April to June 2014 based on the ratio of monthly peaks.
	17	Telangana	Assumed same profile as for Andhra Pradesh with scaling based on peak load
	18	Kerala	Only peak and off-peak daily shape for each month available. Extrapolated hourly profile assuming average day load to be 80% of the peak day and 2 peak days, 8 off-peak days and 20 average load days per month
	19	Tamil Nadu	Hourly values in public domain from the Load Dispatch Center website
	20	West Bengal	<ul style="list-style-type: none"> • Peak and off-peak daily shape for each month available from State Load Dispatch Center. • Extrapolated hourly profile assuming average day load to be 80% of the peak day and 2 peak days, 8 off-peak days and 20 average load days per month • Scaled the hourly demand pattern based on the daily peak demand values
21	Bihar		
22	Jharkhand		
23	Odisha		
24	Sikkim		

Table B-2 : Peak load: comparison between 2015 estimates and actual load.
 Values in MW.

Source: Load estimates from (General Electric & Shakti Sustainable Energy Foundation 2018) and actual values from (Central Electricity Authority 2008-2018a).

Region	Peak load (GE database)	Peak load required (actual)	Peak load met (actual)
Northern	51,195	52,752	50,354
Western	49,676	48,634	48,193
Southern	38,355	38,241	37,047
Eastern	15,725	18,312	18,035
Northeastern	-	2,573	2,352
All India	145,034	151,171	148,092

Table B-3 : Total Load: comparison between 2015 estimates and actual load.
Values in TWh.

Source: Load estimates from (General Electric & Shakti Sustainable Energy Foundation 2018) and actual values from (Central Electricity Authority 2008-2018a).

Region	Total load (GE database)	Total load required (actual)	Total load met (actual)
Northern	322	334	318
Western	341	331	329
Southern	275	284	278
Eastern	99	123	122
Northeastern	-	14	14
All India	1,037	1,086	1,060



Figure B-1: Distribution of regional electricity demand per hour of the day for the year 2036-37.

Source: Own assumptions based on scaling up 2015 load estimates.

Note: the northeastern load profile is not shown, giving that load values in this region are significantly lower than in the rest of the regions.

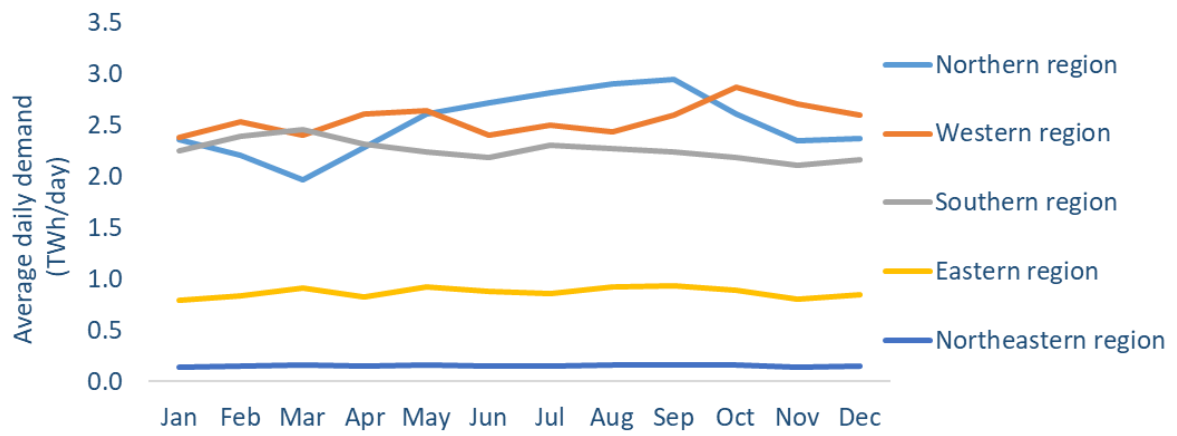


Figure B-2: Regional average daily load per month in the year 2036-37.
 Source: Own assumptions based on scaling up 2015 load estimates.

C. Appendix: installed capacity and installation limits per technology for each region

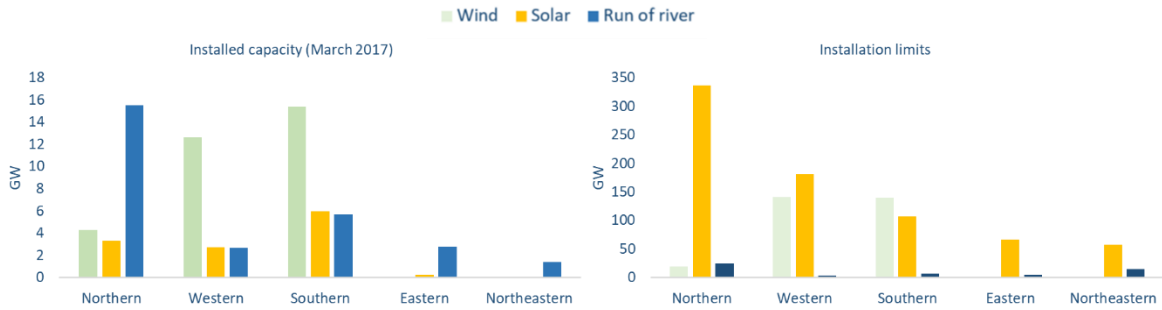


Figure C-1: Installed capacity by 2017 v/s installation limits of VRE sources.
Source: (Central Electricity Authority 2018a), (Jethani 2017) and own assumptions.

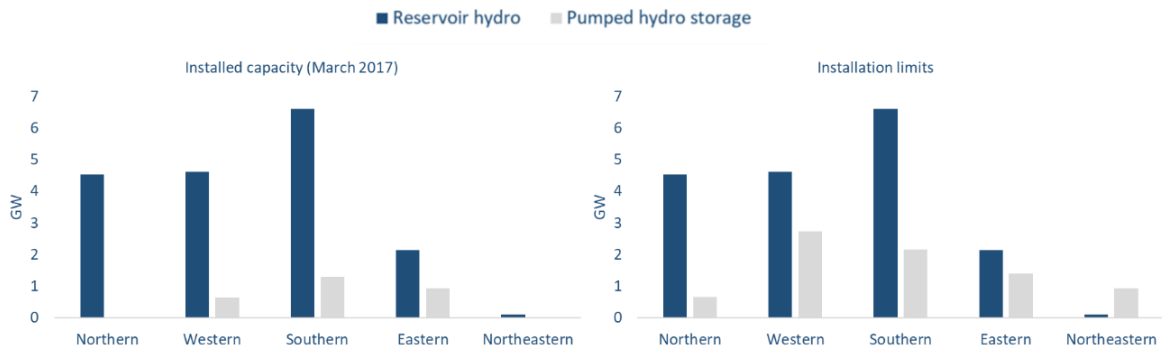


Figure C-2: Installed capacity by 2017 v/s installation limits of storage technologies.
Source: (Central Electricity Authority 2018a), and own assumptions.
Note: Lithium-ion batteries are not included in the graph given that there are currently no batteries installed and unlimited installation limits are assumed.

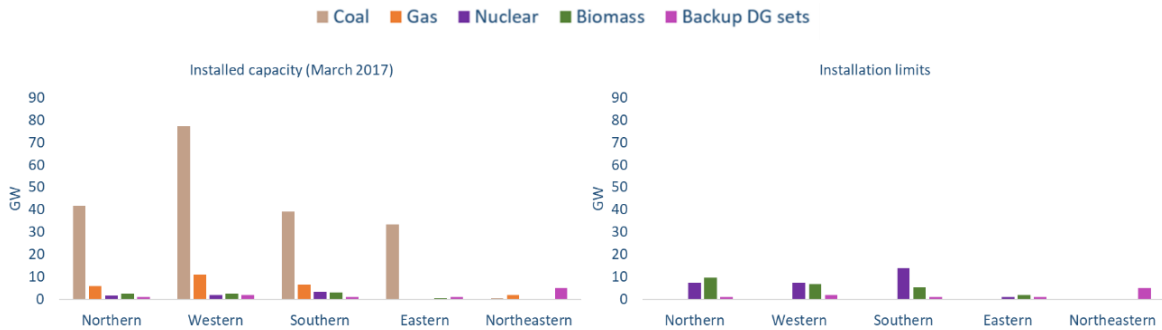


Figure C-3: Installed capacity by 2017 v/s installation limits of dispatchable technologies.
Source: (Central Electricity Authority 2018a), and own assumptions.
Note: No installation limits for coal and gas plants (excepting in the northeastern region where no further development is allowed).

D. Appendix: VRE production profiles per region

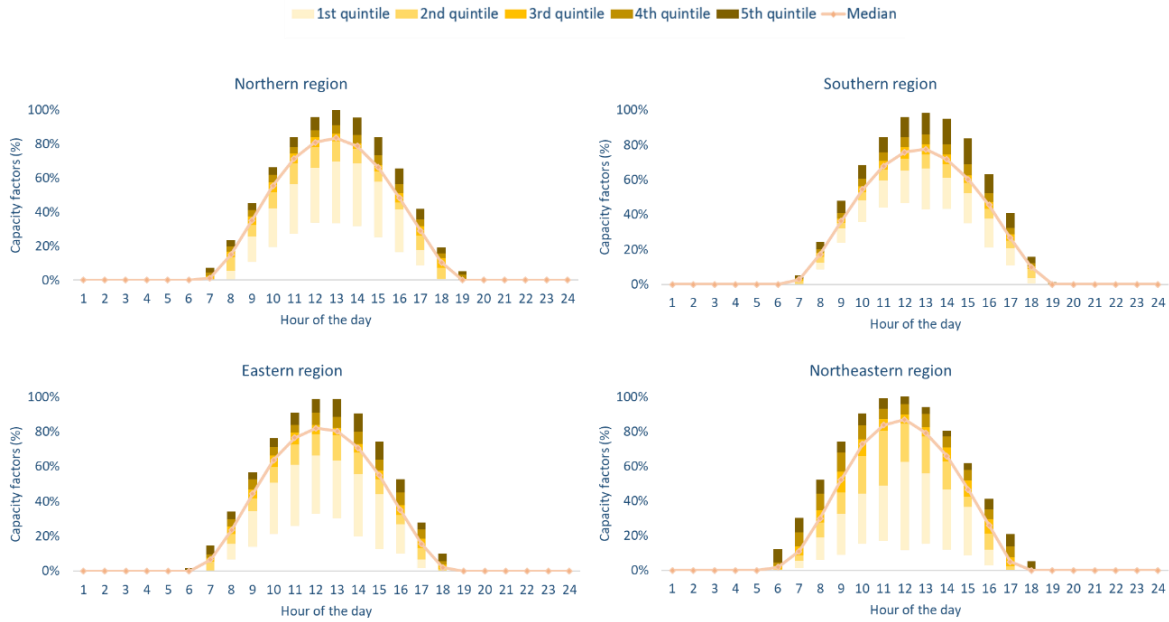


Figure D-1: Distribution of solar production profile per region for each hour of the day.
Source: (General Electric & Shakti Sustainable Energy Foundation 2018).

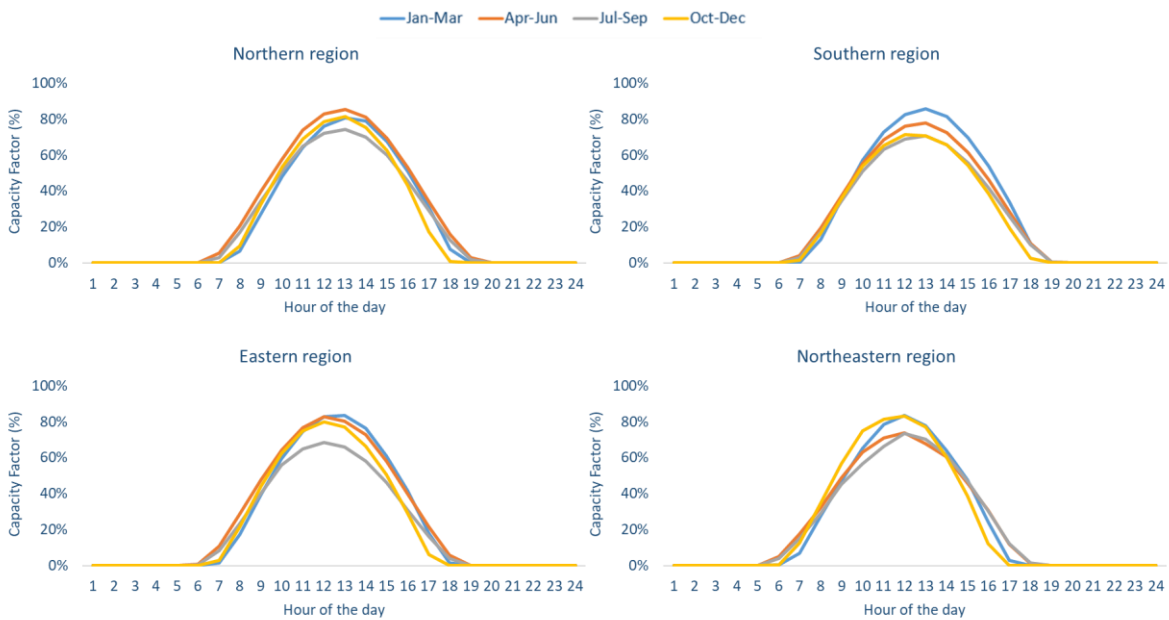


Figure D-2: Average solar profile per trimester for each region.
Source: (General Electric & Shakti Sustainable Energy Foundation 2018).

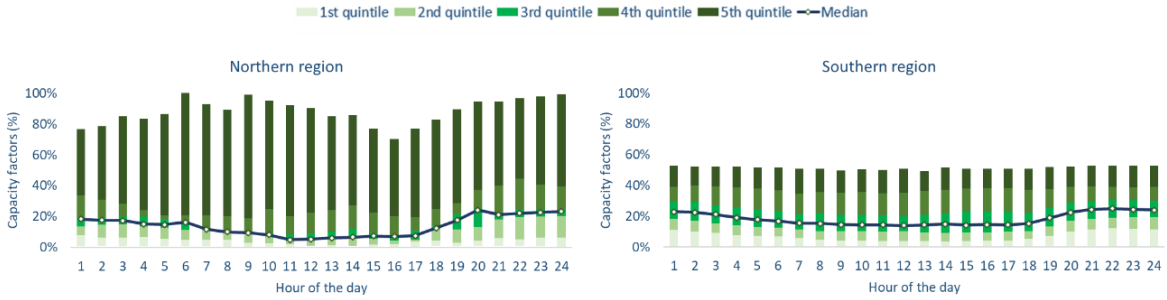


Figure D-3: Distribution of wind production profile per region for each hour of the day.
 Source: (General Electric & Shakti Sustainable Energy Foundation 2018).

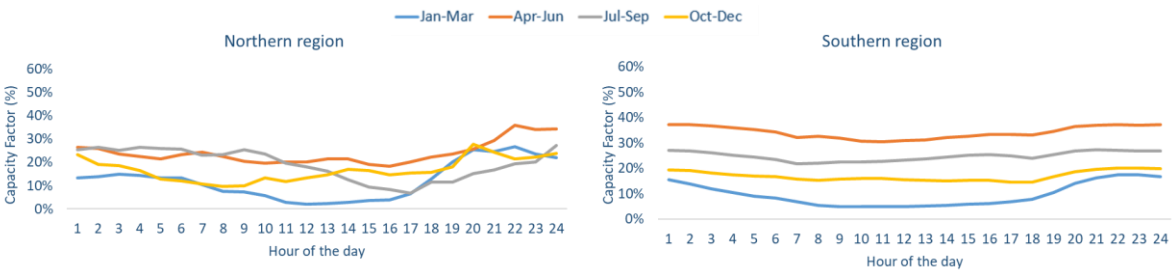


Figure D-4: Average wind profile per trimester for each region.
 Source: (General Electric & Shakti Sustainable Energy Foundation 2018).