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Authors
Phadke, Amol
Abhyankar, Nikit
Deshmukh, Ranjit

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Preliminary Assessment of Renewable Energy Grid Integration in India:

Insights for Power Sector Investment and Costs for Integrating 160GW of Renewable Energy from Grid Planning and Dispatch Analysis

Amol Phadke

Nikit Abhyankar

Ranjit Deshmukh

June 2016

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This analysis is based on significant simplifications and assumptions especially regarding the transmission system as well as deviation settlement mechanism. Our model assumes that there are no intra-regional transmission constraints; also, we assume gross settlement (regional dispatch) within each region. Therefore, the results and conclusions presented in the paper, especially about the generation and transmission system investments should be viewed only as high-level indications of the impacts of the aggressive penetration of renewable energy on the Indian grid. Significant refinement to this analysis would be necessary for actual power system planning purposes. For example, USAID's Greening the Grid project attempts to answer some of the key questions on operational strategies for grid integration of renewable energy using a comprehensive model of the Indian grid.

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Executive Summary

1. Introduction

In 2014, India announced increasing the installed capacity of solar power projects from about 3 gigawatts (GW) in 2014 to 100GW by 2022 and increasing the wind power capacity from nearly 20GW to 60GW in the same timeframe. Given such aggressive targets, there is significant discussion on the policy, regulatory and commercial strategies to integrate renewable energy (RE) in the Indian power system. Although large scale RE grid integration has been analyzed widely in the US and European context, there is very limited literature on this topic in the Indian context. The objectives of our analysis are to assess the technical feasibility of integrating the large renewables capacity in the India electricity grid, ascertain its impact on power sector investments and operations, and quantify the incremental cost of such large-scale RE grid integration.

2. Methodology and Data

We conduct our analysis using Plexos, a power system capacity expansion and production cost model. For various levels of RE penetration, Plexos identifies the least cost investment and operations (power plant dispatch) strategies to integrate the specified level of RE subject to a range of operational constraints. We model the Indian electricity grid using 5 nodes – one node for every region viz. north, east, west, south, and north-east which allows us to broadly assess the transfer capacities across regions. It is important to note that given the regional level resolution of the model, this analysis cannot answer questions on the intra-regional (across states within a region) and intra-state transmission and dispatch issues. Hence, the results can be interpreted as what is needed for RE integration once the interstate transmission constraints are resolved and the balancing area for generation dispatch is expanded to the regional level.

We assess the following three scenarios for RE penetration for the financial year 2022:

(a) ***13th Plan***: This scenario serves as the baseline and uses the generation capacity addition for all technologies as projected in the Government of India's 12th Plan document that include projections up to the 13^{th} Plan period (2022).

(b) ***National Action Plan on Climate Change (NAPCC)***: The scenario models the renewable energy target described in India's NAPCC (2009). NAPCC targets RE to provide 15% electricity (by energy) by 2020 (PMO 2009). If the same trend between now and 2020 is projected up to 2022, RE capacity would provide ~20% electricity (by energy) by FY 2022. Keeping the installed capacity of the other RE (small hydro and biomass) the same as the 13th Plan, we split the rest of the NAPCC target into wind and solar PV using 75:25 ratio (by energy and not capacity). Regional targets are estimated by applying the current ratio of the RE installed capacity.

(c) ***RE Missions***: This scenario models the Government of India's announcement in 2015 to increase the total installed capacity of solar projects to 100GW and wind projects to 60 GW by FY 2022. MNRE has also specified individual state level installed capacity targets for each technology.

The following table shows the total installed capacity of RE technologies by 2022 in GW for each scenario.

	13th Plan	NAPCC	RE Missions
Wind	41	~107 (13% by energy)	60
Solar	22	~58 (4% by energy)	100
Small Hydro	6.6	6.6 (1.5% by energy)	6.6
Biomass	7.7	7.7 (1.5% by energy)	7.7

Our key assumptions are summarized below:

1. *Demand*: We project demand for each hour of FY 2022 based on the historical hourly demand for FY 2010 through 2013, projected urbanization, and the projected load growth based on the CEA's 18^{th} Electric Power

Survey (EPS). By 2022, the national peak demand is projected at 287GW and total energy consumption is projected at 1906 TWh/yr (both at bus-bar).

2. *RE Generation*: Hourly profiles of wind energy generation have been forecasted using the actual historical generation data for FY 2010 through 2013 from the states of Tamil Nadu, Karnataka, Maharashtra, and Gujarat. For estimating the hourly generation profile of solar PVs, we chose 100 sites spread over all 5 regions with best quality solar resource (measured in Direct Normal Irradiance and Global Horizontal Irradiance kWh/m2) using the national solar energy dataset for India developed by the National Renewable Energy Laboratory. Simulated hourly PV output profiles of the sites in each region were averaged to arrive at the regional solar PV generation profile.
3. *Generator characteristics:* Generator characteristics such as unit size, heat rates, ramp rates, and minimum stable level of the power plants have been estimated using the historical dispatch data, outage and other performance data, regulatory orders on heat rates and costs, other relevant literature.
4. *Generator costs:* Capital costs and fixed O&M costs for each technology have been taken from CERC's tariff norms for 2014-2015. Future trends in the capital cost of wind and solar have been taken from the literature. We assume that the solar prices continue to drop and reach Rs 3.4/kWh in 2022 from the current price of nearly Rs.5.1/kWh, resulting in average cost of solar for 100 GW of capacity addition to be Rs 4.0/kWh. Further, we assume that highest quality wind resource is used in future capacity additions leading to an average capacity factor of 30% (for new capacity) that leads to an average wind cost of Rs 3.3/kWh.
5. *Fuel prices and availability*: We take the current year fuel prices and use historical trends to project the fuel prices in 2022. Domestic coal availability for the power sector has been taken from the Ministry of Coal's projections in the 13th five-year plan up to 2017; the same trend has been projected up to 2022. We have assumed that the domestic gas availability for the power sector in the future remains the same as the current quantity. No quantity restrictions are assumed on imported fuels.
6. *Transmission*: We assume that there are no transmission constraints within a region. Our model gives a high-level assessment of the power transfer capacity needed across regions in order to minimize the total generation and transmission costs.

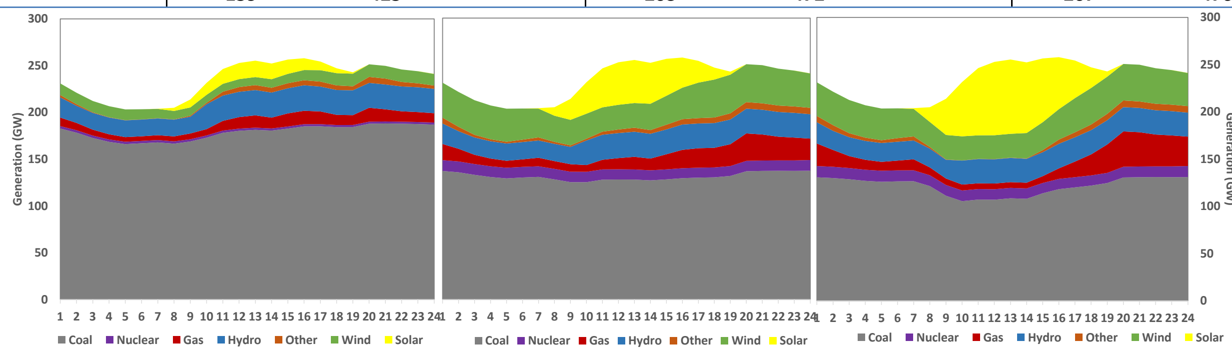
3. Results

Table 1 shows the total (national) capacity additions, installed capacities, and capacity factors (i.e. PLF) of each technology. In NAPCC and RE Missions scenarios, much lower coal capacity is needed compared to the 13th Plan scenario (the baseline). Instead, significant gas based capacity is needed in both scenarios, which serves as the major source of additional flexibility for integrating RE. Figure 1-Figure 3 show the average hourly national dispatch in each season for all scenarios. In all scenarios and seasons, coal provides the base load support. RE can provide significant support during afternoon peak demand period during summer (mainly solar) as well as monsoon (mainly wind). In both seasons, gas based generation (or other flexible source) is needed for evening ramp-up support and meeting evening peak demand. In Winter, when solar and wind generation both drop, gas based generation provides round the clock energy and load following support despite lower demand. Note that although significant gas based capacity is needed, it primarily is required to generate during evening peak hours, especially during winter and early summer, when there is neither solar nor wind generation, leading to a low (7-9%) capacity factor. The total gas required is 3.6-6.2 bcm/yr which can be met by domestic sources requiring no LNG imports.

One of the key enablers of the reliable grid integration is the transmission network. In order to integrate 160 GW of variable renewable energy, the additional power transfer capacities (relative to the 13th Plan) are moderate as shown in Table 2; the only significant increases in the transfer capacities are West-South (increase by 3000 to 4000 MW relative to the 13th Plan) and East-South (increase of 6000 to 8000 MW relative to the 13th Plan). Note that these are power transfer capacities; actual transmission capacity investments may be significantly higher.

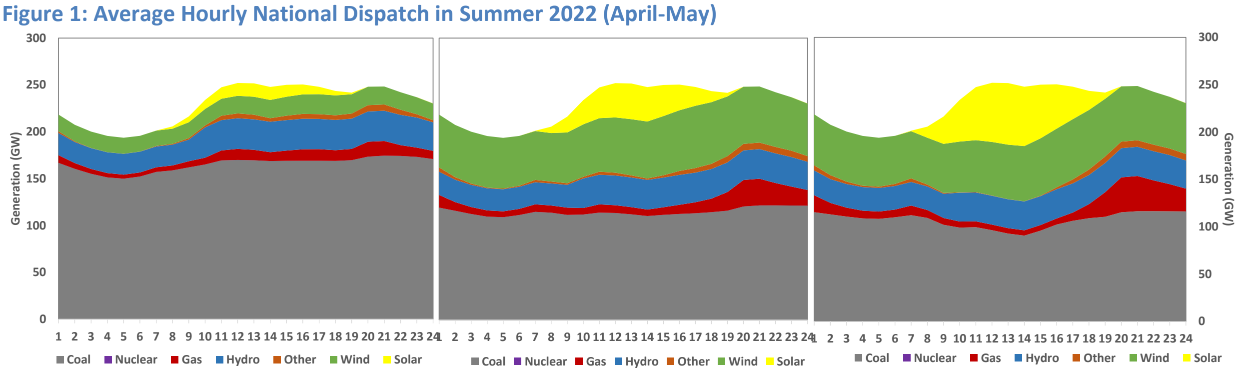
Table 1: Capacity Built (GW), Installed Capacity (GW), and Capacity Factors (%) in Each Scenario by FY 2022

	13th Plan			NAPCC			RE Missions		
	Capacity Built (2015-2022)	Installed Capacity in 2022 (GW)	Capacity Factor (%)	Capacity Built (2015-2022)	Installed Capacity in 2022 (GW)	Capacity Factor (%)	Capacity Built (2015-2022)	Installed Capacity in 2022 (GW)	Capacity Factor (%)
Coal	79	243	65%	17	182	71%	17	182	73%
Gas	0	19	0%	6	25	7%	14	33	9%
Diesel	0	1	0%	0	1	0%	0	1	0%
Nuclear	19	25	89%	19	25	89%	19	25	89%
Hydro (Reservoir)	9	30	35%	9	30	35%	9	30	34%
Hydro (Run of the River)	7	23	38%	7	23	38%	7	23	38%
Hydro (Pumped Storage)	2	6	5%	2	6	12%	2	6	15%
Small Hydro	2	6	37%	2	6	37%	2	6	37%
Biomass	4	8	0%	4	8	2%	4	8	2%
Solar	18	22	20%	55	58	19%	97	100	19%
Wind	18	41	25%	85	108	29%	39	62	29%
Total	**159**	**425**		**203**	**472**		**207**	**476**	



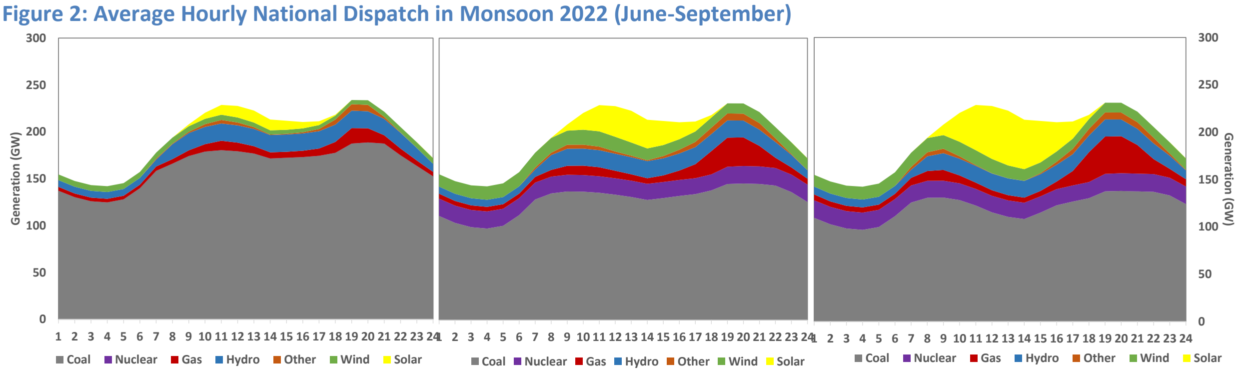
(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

Figure 1: Average Hourly National Dispatch in Summer 2022 (April-May)



(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

Figure 2: Average Hourly National Dispatch in Monsoon 2022 (June-September)



(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

Figure 3: Average Hourly National Dispatch in Winter 2022 (December – February)

Table 2: Inter-regional Power Transfer Capacities (MW) Required by FY 2022 in Each Scenario

	East-North	East-South	East-West	NorthEast-East	North-West	West-South
13th Plan	15124	8656	9171	2914	23173	10896
NAPCC	11215	16563	8717	2907	17315	14731
RE Missions	11588	14218	7488	2907	15865	13462

In NAPCC and RE Missions scenarios, some of the inter-regional transmission interfaces would have to be used in both directions because of the seasonal and diurnal RE generation patterns. For example, during summer and monsoon seasons, RE generation from the west and the south flows to the east and the west; during evening peak demand periods in all seasons, especially winter, the coal based power from north and the east would have to flow to the south and the west. This implies that an appropriate policy and regulatory framework for moving power across regions more freely (for example intra-day and ancillary services markets) is crucial.

The incremental cost of generation in NAPCC and RE Missions scenarios is not significant relative to the 13th Plan as shown in the following chart, which plots the total annual generation cost. There are three reasons for such moderate increase (a) low cost RE (b) avoided coal capacity and imports as a result of increased RE penetration, and (c) limited balancing requirement given the seasonal complementarity of solar and wind generation in India.

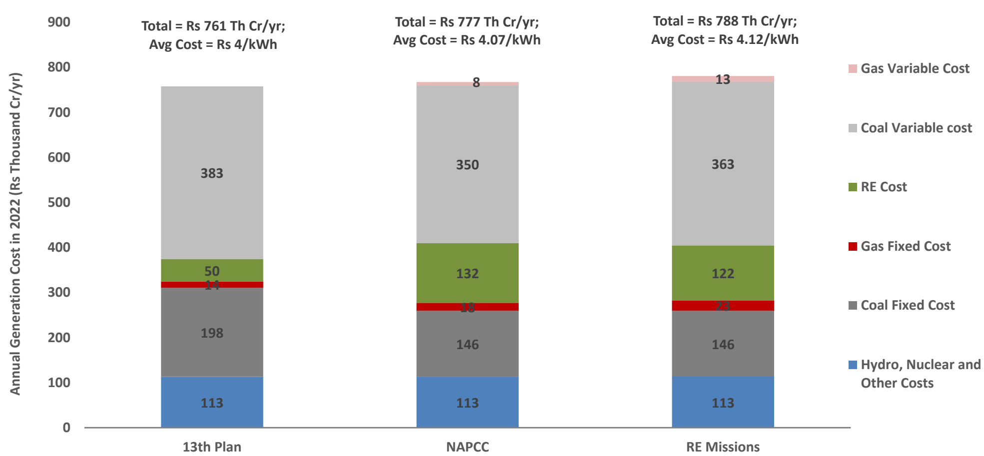


Figure 4: Annual Generation Cost in 2022 (Rs Thousand Cr/yr) and Average Cost of Generation (Rs/kWh)

Please note that cost estimates shown above already include the majority of the RE integration cost such as additional investments in flexible capacity (such as gas, CT, etc.) or operation of the expensive gas or diesel-based power plants, etc. What it does not include is the cost for procuring additional reserves (spinning, contingency, or otherwise) or other ancillary services. However, in other such studies in the US or Europe, such incremental ancillary services cost are found to be minor (5-10% of the RE generation cost). In our forthcoming analyses, we do assess the incremental ancillary services costs for RE integration in the Indian context. Also, the coal investment costs in all scenarios have been estimated without considering the new norms for Particulate Matter, SOx, and NOx emissions (2015), which may require additional investments; such investments may increase their fixed costs by over 10% and reduce the cost-differential between the 13th Plan and RE Dominant scenarios further.

We conducted sensitivity analysis to assess the impact of key parameters on generation investments and cost. Note that if solar costs do not reduce further and if the highest resource quality wind is not accessed, RE costs will increase by Rs 30,000 Cr/year by 2022 in case of RE Missions scenario (increase in the average cost of generation by ~ 4%). If the generation capacity is optimally planned in the 13th Plan (or slippage in the capacity addition targets), the average cost of the 13th Plan portfolio reduces by 2.1% increasing the cost differential in the NAPCC and RE Missions scenarios to 4.0% and 5.3% respectively. To the contrary, if the coal capacity addition in the RE Missions scenario stays the same as originally planned in the 13th Plan (high coal and high RE scenario), the capacity factor of the coal capacity drops to 56% (national average) resulting in an increase in the average cost of generation; however, despite such an inflexible system, RE curtailment is not found to be necessary. Average cost of generation in both these RE dominant scenarios is significantly less sensitive to the fuel price and supply risks; if by 2022, imported fuel prices are 25% more expensive than their projected prices, average cost of generation for the 13th Plan increases by 2.7% while that for the RE Missions and NAPCC scenarios increases by 0.4% and 0.1% respectively.

4. Conclusion

In both NAPCC and RE Missions scenarios, coal capacity requirement is much lower than the 13th Plan; however, significant gas based capacity needs to be added, which serves as the major source of additional flexibility. During summer and monsoon, renewable energy can provide significant support during afternoon peak demand periods; however, in winter, when solar and wind generation both drop, gas based generation provides round the clock energy and load following support despite lower demand. This implies that the flexible resource used for grid integration in India should be able to provide cross-seasonal support. Hydroelectric projects (reservoir type) would be able to offer such support – however, there are significant barriers to their timely construction. Gas based projects would also be ideal for such cross-seasonal support - however, gas availability in India is a major concern. One solution to that could be building on-site gas storage facility so gas power plants do not have to always have to depend on the pipeline gas for power generation; importing LNG could help; however, that may involve significant price and supply risks.

The regional diversity in RE generation and its complementarity with demand and other RE resources help reduce the impact of extreme events such as sudden loss of RE generation or over-generation, etc. on the system. But RE forecasting is absolutely crucial for utilizing such complementarities. With newer state-of-the-art forecasting techniques, forecast errors have been reducing rapidly especially with the use of the real-time generation data. With installation of Renewable Energy Management Centers and the new forecasting regulations for the interstate RE generators, India has already started creating a robust framework for RE forecasting.

One of the key enablers of the reliable grid integration is the transmission network. While the additional power transfer capacities are found to be moderate, some of the inter-regional transmission interfaces would have to be used in both directions because of the seasonal and diurnal RE generation patterns. This implies that appropriate policy and regulatory framework for moving power across regions more freely is crucial. This could be achieved by creating robust markets and other measures such as intra-day and ancillary services market, imbalance markets or balancing area coordination etc. in addition to the transmission investments.

The incremental cost of generation in NAPCC and RE Missions scenarios is found to be moderate; also, it is found to be significantly less sensitive to fuel price and supply risks, which is crucial for ensuring energy security of the country. Given the large RE potential and aggressive targets, studies that quantify their operational and economic impacts as well as discussions on the potential policy/regulatory frameworks for achieving such targets are crucial. This study serves as the first one of our forthcoming series on RE grid integration in India. However, note that **this analysis is based on significant simplifications and assumptions regarding the transmission system and the deviation settlement mechanism. Therefore, the results and conclusions presented in the paper, especially about the generation and transmission system investments should be viewed only as high-level indications of the impacts of the aggressive penetration of renewable energy on the Indian grid. Significant refinement to this analysis would be necessary for actual power system planning purposes.**

Preliminary Assessment of Renewable Energy Grid Integration in India:

Insights for Power Sector Investment and Costs for Integrating 160GW of Renewable Energy from Grid Planning and Dispatch Analysis

Amol Phadke, Nikit Abhyankar, Ranjit Deshmukh

1 Introduction

Recently, several planning and policy initiatives have been proposed in India for large scale deployment of renewable energy (RE). For example, in 2009, India announced its National Action Plan on Climate Change setting a target of sourcing 15% of its electricity requirement (by energy) by 2020 from renewable sources (PMO 2009). In 2014, India announced increasing the installed capacity of solar power projects from about 3 gigawatts (GW) in 2014 to 100GW by 2022 and increasing the wind power capacity from nearly 20GW to 60GW in the same timeframe.[1] The government and the private sector have already shown significant commitment to achieve these targets. For example, the government has approved setting up over 20GW of solar capacity in 25 "Ultra-Mega Solar Parks" spread across the country and has also offered a financial support of nearly US$650 million (MNRE 2014; PIB 2014).

Given the proposed addition to the renewable capacity, there is significant discussion on the policy, regulatory and commercial strategies to integrate RE in the Indian power system. Large scale RE grid integration has been analyzed widely in the US and European context (see for example: (Palchak and Denholm 2014; Cochran et al. 2015; Milligan et al. 2013; A. D. Mills and Wiser 2013; Andrew D. Mills 2014; Orans et al. 2013) etc.). However, there is limited literature in the Indian context. Few studies have assessed the variability and capacity value of renewable energy in India (Hummon et al. 2014; Phadke, Abhyankar, and Rao 2014; George and Banerjee 2009; Chattopadhyay and Chattopadhyay 2012); but they do not deal with the grid integration issues in detail.

Very few studies have conducted comprehensive grid dispatch modeling and investment planning analysis. The Report on Green Energy Corridors analyses the flexibility of the Indian power system for integrating a total of 72,400 megawatts (MW) of RE by 2022 (POWERGRID 2012). However, the analysis in that report is limited to the typical day per month and therefore, does not capture the entire range of annual hourly load and renewable generation variability. The Asian Development Bank, as a part of their technical assistance to the government of India, conducted a comprehensive cost-benefit analysis study of six major electric power interconnection projects in South Asia (ADB 2013). However, their analysis was primarily focused on assessing the cross-border energy trade and transmission investments using power flow modeling (to assess the actual power transfer capabilities). (Shakti 2013) analyzes the economic impact of integrating renewable energy in the Indian grid using grid dispatch modeling. That study, however, does not consider very aggressive RE penetration and there is no significant variation in the RE

[1] India's peak electricity demand in 2014 was about 150 GW and the total installed capacity was about 230GW (CEA 2015d).

penetration numbers across multiple scenarios e.g. in their most aggressive scenario they assume an RE penetration of 25% by energy by 2031; while the baseline penetration is assumed to be 16% by energy. The government of India has released a few reports that broadly assess the strategies to integrate RE most notably by CEA and NITI Aayog. India's Central Electricity Authority published a document in 2013 that laid out the key issues in RE grid integration and assessed the strategic solutions (CEA 2013a). NITI Aayog released a roadmap for accelerating the deployment of renewable energy in India that highlights the key issues facing RE deployment in India ranging from financing costs to integration risks (NITI 2015). These analyses, however, do not assess the technical feasibility or quantify the economic impacts of RE integration.

The objectives of our analysis are to assess the technical feasibility of integrating the large renewables capacity in India that has been planned for the near future, ascertain its impact on power sector investments and operations, and quantify the incremental cost of generation. More specifically, we intend to answer the following questions:

a) What is the impact of integrating RE on the capacity addition and capacity factors of conventional generators?
b) Are there any additional ramp requirements and if so how can they be met in a least cost fashion?
c) How do regional transmission flows and investment requirement change?
d) What is the impact on the cost of generation?

We conduct the analysis by modeling the least cost generation investments and simulating economic dispatch for the financial year 2022 using PLEXOS for a variety of renewable energy penetration scenarios.[2] We use a five node model of the Indian electric grid (one node per region), which allows us to broadly identify transmission corridors across regions. We believe that our results would inform two important decisions. First, cost of integrating RE would be borne by certain players (primarily utilities) in the power sector. Quantifying these costs is essential for designing potential commercial arrangements to mitigate the adverse impact on any particular stakeholder. Second, our analysis will identify least cost investment and operational solutions to integrate large scale RE in India. Creating an appropriate policy and regulatory framework for such solutions would be crucial for achieving the RE deployment targets.

It is important to note that given the regional level resolution of the model, this analysis cannot answer questions on the intra-regional (across states within a region) and intra-state transmission and dispatch issues. Hence the results can be interpreted as what is needed for RE integration once the interstate transmission constraints are resolved and the balancing area for generation dispatch is expanded to the regional level.

The rest of the paper is organized as follows. Section 3 describes our methodology, data, and assumptions followed by section 4 that discusses the key results and sensitivity analysis. In section 6, we conclude the paper with key policy recommendations for integrating the aggressive RE targets and discuss the

[2] PLEXOS is a production cost and capacity expansion model that optimizes the investments and economic dispatch of power plants considering unit commitment etc. used widely by the utilities and system operators/planners across the world.

opportunities for future work. Annexure and the supplementary material provide more details on the assumptions and results.

2 Overview of the Indian Power Sector

With peak electricity demand of 150 GW and the total installed capacity of about 230GW, India has one of the largest electricity transmission and distribution systems in the world (CEA 2015d). More than half of existing installed generation capacity is owned by state government companies, and a third is owned by central (federal) government corporations. The remainder is owned by the private sector. By contrast, more than 87% of the distribution sector (by sales) is owned by state-government utilities, and the rest is owned by private and municipal utilities (CEA 2008).

2.1 Renewable Energy

Several studies have shown immense solar and wind energy potential in India. For example, at 20% capacity factor and above, total wind energy potential in India is in excess of 3000 GW (Phadke, Bharvirkar et al. 2012). Similarly, total solar PV potential in India is as high as 11,000 GW (Ramachandra, Jain et al. 2011; Sukhatme 2011; Deshmukh and Phadke 2012).

Almost all key states in India have specified Renewable Purchase Obligation (RPO) that mandate the load serving entities and captive users to purchase a fraction of their annual electricity requirements from renewable energy sources. The following table shows the RPO targets in the key states.

State	RPO Target (2015)
Maharashtra	9%
Gujarat	8% (2015) 10% (2017)
Tamil Nadu	9% (non-solar) 0.5% (solar)
Karnataka	7-10% (non-solar) 0.25% (solar)
Rajasthan	9% (2015) 11.4% (2017)
Andhra Pradesh	4.75% (non-solar) 0.25% (solar)
Madhya Pradesh	6% (non-solar) 1% (solar)

Data source: (MNRE 2015)

In addition to RPO, renewable energy sources are offered feed-in tariffs. Moreover, the central government offers significant financial incentives such as generation based incentive or accelerated depreciation for aggressive deployment of renewable sources. As a result, the RE capacity has increased by nearly eight fold over the last ten years i.e. from 4,155 MW in 2005 to 33,550 MW in 2015 (CEA 2015d; CEA 2009b; CEA 2015a).

2.2 Electricity Grid and Transmission

The Indian power grid is an interconnected 50Hz network. Currently, there are five regional grids (all synchronized) – north, south, west, east and north-east; each region is made up of 5-7 states. In most cases, each state is an independent balancing area. The state grids are operated by the State Load Dispatch Centers, while the interstate transactions within a region (interstate generating stations and the transmission system) are operated by the Regional Load Dispatch Centers. The inter-regional transmission system is operated by the National Load Dispatch Center. India does operate a day-ahead electricity market with the gate closure time of one hour i.e. day-ahead schedules could be updated up to an hour in advance. However, only about 3% of the total annual energy generation is traded on the day ahead market while 95% is based on long term PPAs and short-term bilateral contracts (IEX 2015). Although there is no formal real time market in India, the deviation settlement mechanism acts as the de-facto real time market, where the real time price is dependent on the system frequency. Such real time deviations of each utility relative to the day-ahead schedule are capped at 150 MW or 12% of the schedule, whichever is lower. In April 2016, India has created a framework for ancillary services in market, wherein the un-requisitioned capacity of the central sector generating stations from the day-ahead schedule would be allocated to other utilities.

The following tables show the current installed capacity in each region in India by technology.

Table 3: Installed Capacity (MW) in India by region (March 2015)

	North	West	South	East	North-East	All-India
Coal	39,431	66,220	30,343	28,583	60	164,636
Gas	5,331	10,915	4,963	190	1,663	23,062
Diesel	13	17	939	17	143	1,130
Nuclear	1,620	1,840	2,320	-	-	5,780
Hydro	17,067	7,448	11,398	4,113	1,242	41,267
Wind	3,053	8,517	10,891	4	-	22,465
Solar	962	1,638	416	62	-	3,078
Small Hydro	1,331	490	1,670	238	262	3,991
Biomass + Cogeneration	1,094	1,275	1,555	89	-	4,014
Total	**69,902**	**98,360**	**64,495**	**33,296**	**3,370**	**269,422**

Data source: (CEA 2015c)

With significant capacity additions in the recent years, the power shortage in India has reduced considerably. In the financial year 2014-15 (April 2014 through March 2015), India faced nearly 5% peak shortage and about 3.5% of energy shortage as shown in the following table.

Table 4: Peak (MW) and Energy (GWh) Demand and Availability by Region (for FY 2014-15)

Region	Energy (GWh)		Peak (MW)	
	Demand	Availability	Demand	Availability
North	332,453	311,589	51,977	47,642

West	317,367	314,923	44,166	43,145
South	285,797	274,136	39,094	37,047
East	119,082	117,155	17,040	16,932
North-East	14,224	12,982	2,528	2,202
All-India	**1,068,923**	**1,030,785**	**148,166**	**141,160**

Data Source: (CEA 2015b)

Since all states and regions are synchronized since 2014, the transmission constraints across state and region boundaries have started relieving significantly. The following table shows the existing transmission capacity in June 2015 between the regions in India.

Table 5: Existing inter-regional Transmission Capacity in India (June 2015)

Corridor	Transmission Capacity (MW) (June 2015)
East-North	15830
East-West	10690
East-South	3630
East-North_East	2860
West-North	8720
West-South	5720

Source: (MOP 2015)

Note that the numbers shown in this table are the total transmission capacity. The actual concurrent power transfer capability (considering congestion, reverse flows, and other technical constraints) may be much lower than this.

Over the next 15-20 years, Indian power sector is poised to expand significantly. For example, the peak power demand is expected to nearly double to about 287GW by 2022 and more than triple to nearly 500 GW by 2030 (CEA 2013c).

3 Methodology, Assumptions, and Data

We model the Indian electricity grid using 5 nodes – one node each for every region viz. north, east, west, south, and north-east. We project hourly demand by region in 2022 using the Central Electricity Authority's demand projections in their 18th Electric Power Survey and the hourly demand patterns over the financial years 2010 through 2013 adjusting for rapid urbanization. We then created a variety of scenarios for renewable energy penetration. We use actual hourly generation and solar irradiance (DNI and GHI) data to project the hourly wind and solar generation for 2022. We develop assumptions regarding cost and performance of generation technologies, fuels, and transmission. We use a capacity expansion and production cost model called PLEXOS in order to assess the least cost generation and transmission investments and simulate economic dispatch for the financial year 2022 subject to a range of operational constraints as described in the following sections.[3] We then conduct sensitivity analysis on key parameters to assess the robustness of our findings. The methodology is summarized Figure 5 and the following section describes it in detail.

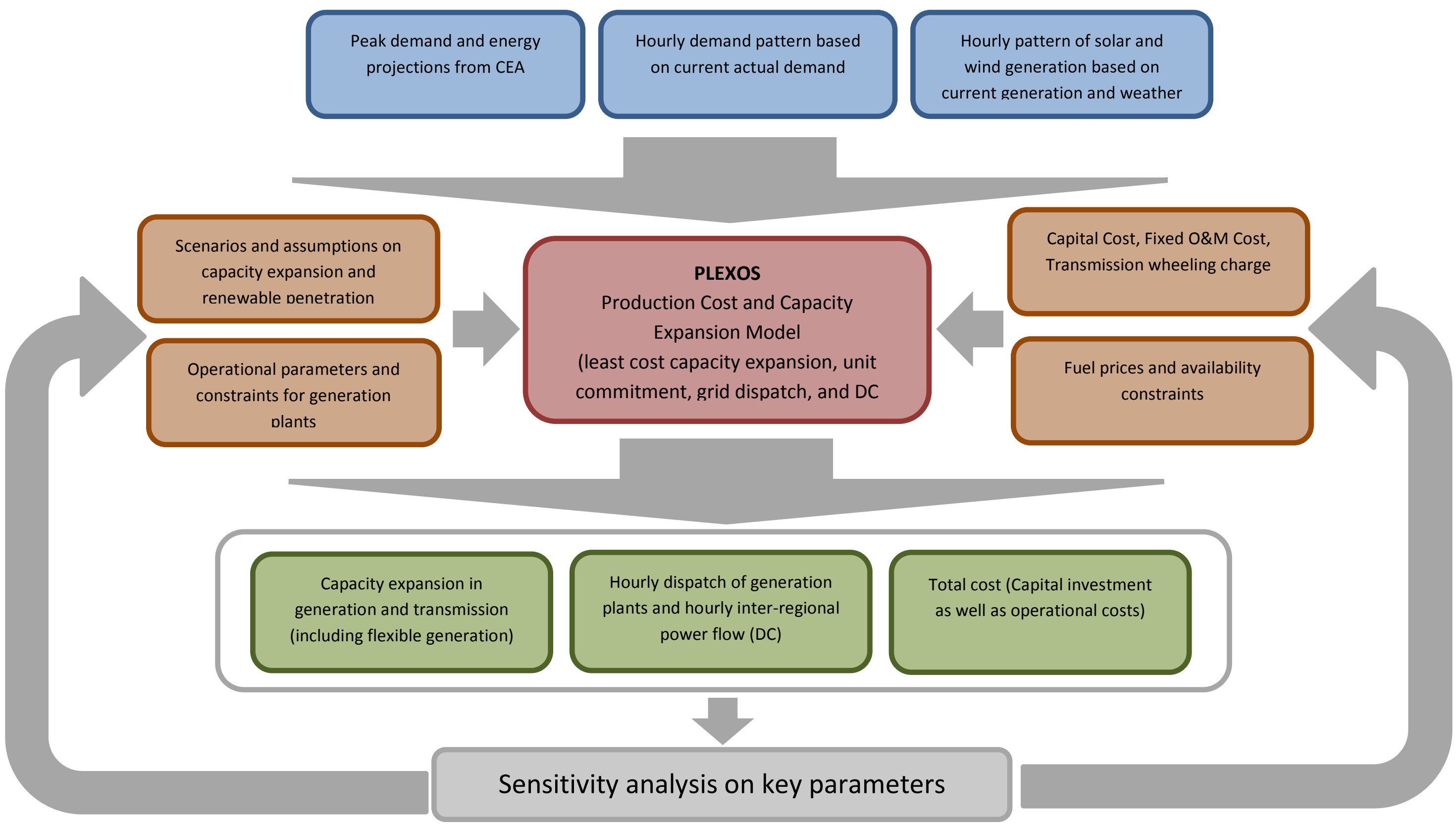


Figure 5: Summary of the Methodology

In Plexos, we run the economic dispatch model in two stages. The first stage is simulation of the day-ahead scheduling and market. In the day-ahead mode, the model takes the day-ahead RE and load forecasts and expected maintenance outages and makes the unit commitment decisions for thermal power plants. These RE and load forecasts are revised up to an hour in advance in order to reduce the forecast errors significantly and potentially revise the unit commitment schedule for the next twenty four hours if feasible. The second stage is simulating the real time grid operation and power plant dispatch. In the real-time mode, the model takes the unit commitment decisions from the day-ahead mode and does the economic dispatch considering the actual (i.e. real-time) RE generation and load.

[3] PLEXOS is a production cost model that optimizes the investments and economic dispatch of power plants considering unit commitment etc. used widely by the utilities and system operators/planners across the world. We are thankful to energy exemplar inc. for providing PLEXOS license to us at research institution rate.

3.1 Scenarios for RE Penetration

We created the following three scenarios for renewable energy penetration for the financial year 2022:

1. ***13th Plan***: This scenario serves as the baseline for this analysis and uses the generation capacity additions for all technologies as projected in the Government of India's 12th Plan up to 2022 (end of the 13th Plan). Although the 12th plan provides detailed capacity addition projections only up to FY 2017, it does estimate the 2022 targets also (Planning Commission 2012). For RE, this scenario assumes the total installed capacity of 41GW of wind, 22GW of solar PV (i.e. India's original National Solar Mission), 14 GW of other RE (small hydro and biomass combined) by FY 2022; the total installed capacity including the conventional technologies is assumed to be about 425GW by FY 2022.

2. ***National Action Plan on Climate Change (NAPCC)***: The scenario models the renewable energy target described in India's NAPCC (2009). NAPCC targets renewable energy to provide 15% electricity (by energy) by 2020 (PMO 2009). If the same trend between now and 2022 is projected up to 2022, RE capacity would provide ~20% electricity (by energy) by FY 2022. Keeping the installed capacity of the other RE (small hydro and biomass) the same as 13th Plan, we split the rest of the NAPCC target into wind and solar PV using 75:25 ratio (by energy and not capacity). Applying the ratio of the current RE capacity in different regions, these national targets are then translated to regional targets. Based on the wind and solar resource potential data, the model then chooses the best solar and wind resources in each region as explained in the subsequent section. The national installed capacity targets by 2022 translate to approximately 100GW of wind, about 60GW of solar, and 14GW of other RE.

3. ***RE Missions***: This scenario models the recent announcement by the Government of India to increase the total installed capacity of solar PV projects to 100GW and wind projects to 60 GW by FY 2022. Note that out of the solar PV target of 100 GW, about 40 GW is expected to be distributed PVs. However, from the overall transmission grid perspective, there is no difference between the utility scale and distributed PV projects. Therefore, in this analysis we have not differentiated the two. It is interesting to note that the total RE targets in the RE Missions scenario are almost the same as those in the NAPCC scenario except the capacity shares of wind and solar are reversed. The other RE capacity targets are assumed to be the same as those in the 13th Plan scenario. For translating these national targets to the regional targets, we have used the state-level targets of the wind and solar capacity by MNRE.

The following table shows the total installed capacity (national) of RE technologies for each scenario.

Table 6: Total RE installed capacity in GW in FY 2022 for each scenario[4]

	13th Plan	NAPCC	RE Missions
Wind	41	~107 (13% by energy)	60
Solar	22	~58 (4% by energy)	100
Small Hydro	6.6	6.6 (1.5% by energy)	6.6
Biomass	7.7	7.7 (1.5% by energy)	7.7
Total RE	77	179 (20% by energy)	175

3.2 Assumptions on Capacity Expansion of Other Technologies

In the NAPCC and RE Missions scenarios, we assume that the hydro and nuclear capacity addition is the same as that in the 13th Plan scenario; capacity addition in coal and gas is optimized by PLEXOS. The following table shows our assumptions on capacity additions under each scenario.

Table 7: Assumptions on Cumulative Capacity Additions in GW between FY 2013 and FY 2022 for non-RE Technologies under each Scenario

	13th Plan	NAPCC	RE Missions
Coal	133	Optimized by model	Optimized by model
Gas	1	Optimized by model	Optimized by model
Nuclear	21	21	21
Hydro	21	21	21

In 2012, the government of India decided that no sub-critical coal capacity would be added after 2017. Our model includes that constraint. Moreover, domestic coal and gas availability has a major bearing on the feasible capacity additions under all scenarios as explained in the following sections.

[4] In order to project how the capacity expansion targets of the renewable technologies be distributed among the states / regions, we compared our approach (distribution based on the ratio of existing installed capacities) with two other studies looking at RE expansion plans in the future viz. (a) study by the Forum of Regulators (India) to assess the impact of the RPS targets on future retail rates (FOR 2012), and (b) Report by PowerGrid Corporation of India on Green Energy Corridors to assess the transmission needs of aggressive RE capacity addition (POWERGRID 2012). Our distribution of RE targets across regions closely matches with both these studies.

3.3 Hourly Demand Forecast by Region

The following table shows the load factors (ratio of the annual average demand to peak demand) over the last seven years in all five regions and key cities that do not face significant power cuts.

Table 8: Annual load factors in key cities and regions (financial years 2008 through 2015)

	2008	2012	2013	2014	2015
Chandigarh	63%	68%	55%	52%	50%
Delhi	65%	61%	52%	54%	56%
Pondicherry	91%	76%	82%	80%	78%
Mumbai	69%	68%	65%	#N/A	#N/A
Northern Region	78%	79%	75%	78%	75%
Western Region	84%	80%	82%	83%	83%
Southern Region	88%	84%	86%	82%	84%
Eastern Region	81%	77%	76%	78%	79%
North-Eastern Region	68%	64%	66%	66%	67%
All India	***87%***	***84%***	***84%***	***84%***	***83%***

Data Sources: (CEA 2015b; CEA 2015d; CEA 2012; CEA 2013b; CEA 2009a)

Across all regions and cities, load factors have been reducing over time; this implies that the demand is becoming peakier in nature. This may be happening due to two reasons viz. (a) availability of power has been increasing resulting in reduced shortages, and (b) due to rapid urbanization, electricity usage pattern and appliance ownership have changed significantly. This has an important bearing while projecting the hourly demand curve for the financial year 2022. We simulated the hourly demand curve for each region based on the historical hourly demand patterns in the country, growing urbanization, and the projected load growth based on the CEA's 18th EPS. One of the key problems in projecting the future demand was accounting for the load curtailment (which was as high as 6% by energy in 2013). To address that, we used a mixed approach. We used the current restricted load data for each region to assess the seasonal load pattern in a region; and used hourly load data of the key load centers that do not experience load shedding (such as Delhi, Chandigarh, Gujarat, Mumbai, Pondicherry etc.) and the load centers that have the load shedding data available (such as Maharashtra, Tamil Nadu etc.) to assess the diurnal demand pattern. For estimating the FY 2022 demand, we apply the regional demand growth rates from CEA's 18th EPS. Next, to account for the growing urbanization in the country, load shapes of the urban load centers (such as Delhi, Mumbai, Pondicherry etc.) are given an additional 20% weight relative to the state level load curves in each region. This would make the resultant 2022 load curve peakier than the current (2015) one. Finally, the regional load curve is uniformly adjusted so that the peak demand and total energy demand match CEA's projections for FY 2022 in their 18th EPS. Demand forecast and load shape assessment is an area where future work is needed using a combination of bottom up and top down approaches.

The following charts show the projected load duration curves for each region for financial year 2022 and the table shows the monthly peak demands and energy consumption in each region.

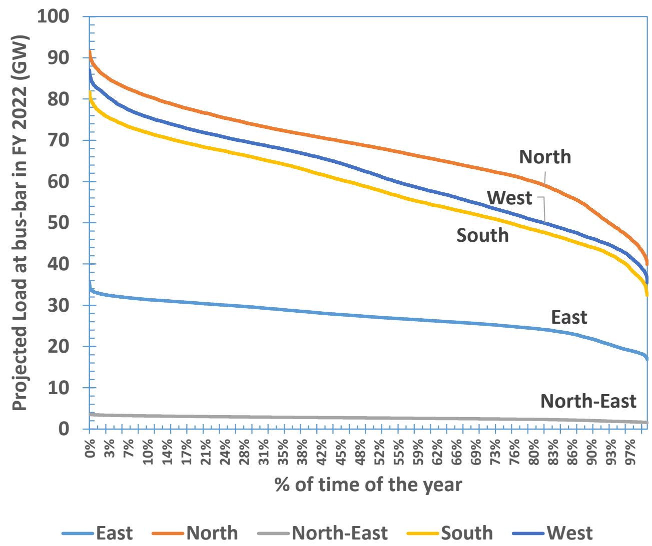


Figure 6: Load Duration Curves for Regions in India for the Financial Year 2022

The following table shows the projected energy demand, peak demand, and load factor for the financial year 2022 in each of the regions.

Table 9: Projected energy demand, peak demand, and load factors for the financial year 2022

Region	Energy Demand (TWh/yr)	Peak Demand (GW)	Load factor (%)
Northern	594	92	78%
Western	540	87	72%
Southern	511	82	71%
Eastern	237	36	75%
North_Eastern	23	4.1	65%
All-India	***1906***	***287***	***77%***

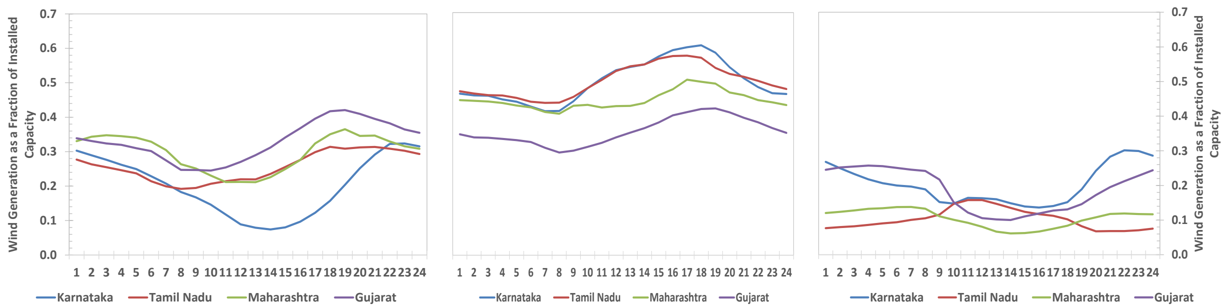
In Annexure 2, we have given the monthly peak and energy demand projections for each region.

3.4 Hourly Solar and Wind Generation Forecast by Region

3.4.1 Wind Energy Generation Profiles

India's current wind installed capacity is more than 21GW and has been growing consistently over the last 10 years or so. Indian wind energy generation is highly seasonal and peaks during monsoon. For FY 2022, Hourly profiles of wind energy generation have been forecasted using the actual historical generation data for the financial years 2010 through 2013 from the states of Tamil Nadu, Karnataka, Maharashtra, and Gujarat. These states together cover over 80% of the existing wind installed capacity and over 75% of the total wind potential in India (CWET 2014; Phadke 2012). Hourly wind generation data was sourced from the websites of the respective state load dispatch centers. We understand that the reported wind generation does not take into account the curtailment. Therefore, actual data may not represent the true profiles of wind generation. Unfortunately, the data on exact amount and timing of curtailment is not available. Secondly, industry experts suggest that wind energy curtailment was quite limited until the financial year 2012-2013 (Phadke, Abhyankar, and Rao 2014).

The following chart shows the seasonal averages of the wind energy generation (as a share of the installed capacity) in the key states mentioned above.



Summer (April-May) Monsoon (June-September) Winter (Dec-Feb)

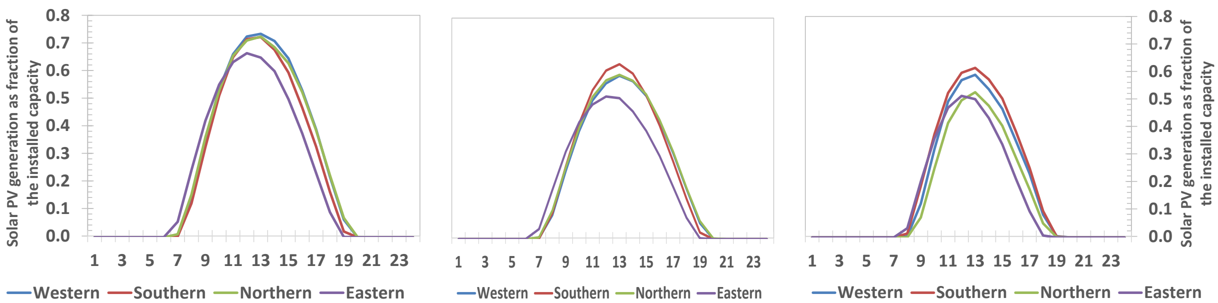
Figure 7: Average daily wind generation curve (of existing capacity) in key states for key states

It can be seen that there is significant seasonal variation in wind generation in all states. Wind generation peaks in monsoon (June through September) and drops significantly in the winter. However the diurnal pattern of wind generation in a season is very similar across all states. In Monsoon and Summer, the wind generation peaks late afternoon or early evening which matches with the overall demand patterns in these seasons.

For future wind capacity addition, we used the wind energy potential numbers in each state from our previous study assessing the wind energy potential in India (Phadke 2012). For estimating the hourly wind generation profile for a future year (2022, in this case), the approach in other studies has been to use time-series data from meso-scale models. But in this study, we are scaling the actual generation data for the current year, which assumes that the additional capacity will be installed in the same regions, and hence will have the same profiles. However, in reality, capacity addition will occur in different areas, which is likely to reduce the overall variability of the wind generation at the regional level due to geographic diversity of the wind installations. However, given that verified hourly wind resource data was not available in the public domain, we could not use wind resource data from undeveloped sites. Thus, wind variability in this analysis would be high and the capacity value conservative; and could be seen as the worst-case scenario of the future wind capacity addition. More detailed analysis (for example using time-series meso-scale resource data) is needed to improve the profiles of wind generation used in this analysis.

3.4.2 Solar Energy Generation Profiles

Unlike wind, total grid connected solar PV capacity in India is only 3 GW albeit it is increasing rapidly given the dropping costs and favorable regulatory and policy environments. The largest capacity of 1.5 GW is operational in the state of Gujarat. However several studies have shown practically infinite solar energy potential in India. For estimating the hourly generation profile, we chose 100 sites spread over all 5 regions with best quality solar resource (measured in Direct Normal Irradiance and Global Horizontal Irradiance kWh/m2) using the national solar energy dataset for India developed by the National Renewable Energy Laboratory that contains hourly irradiance data for every 5kmx5km grid in India. The solar irradiance data was then fed into the System Advisor Model (SAM) also developed by the National Renewable Energy Laboratory to get the solar PV output at the chosen 100 sites. The hourly PV output profiles of the sites in each region was averaged to arrive at the regional solar PV generation profile. The average generation profiles for each season are shown in the charts below.



Summer (April-May) Monsoon(June-September) Winter (Dec-Feb)

Figure 8: Average daily solar generation curves for each region

As can be seen from the charts that the solar resource peaks in the summer and drops in winter. However, the seasonal variation is not as dramatic as that in case of wind. It may appear that there is not much difference in the average resource quality of the western, northern and southern regions; however, resource quality would vary significantly at the individual site level. Most of India's best quality solar resource is concentrated in the western and the northern region. As explained in the previous section on wind energy, we assume that the future solar capacity is added at the sites selected for estimating the hourly generation profile. Therefore, it will not fully capture the benefits of geographic diversity and may overestimate the variability to some extent.

3.5 Operational Parameters of Generators

Table A.1 in Annexure 1 summarizes our assumptions on the operational characteristics (unit size, heat rates, ramp rates, minimum stable level, etc.) of the power plants. The values have been estimated using the actual hourly dispatch data, actual outage and other performance data, regulatory orders on heat rates and costs, other relevant literature, and actual practices in India. Currently, the combined cycle (gas) plants in India are not operated in the open cycle mode (gas turbine only; no waste heat recovery). However, by 2022, we assume that the gas turbines in the combined cycle plants could be operated independently in open cycle mode, which enhances the system flexibility considerably.

3.6 Hydro Capacity and Energy Model

Hydro capacity is modeled using a fixed monthly energy budget. Based on the historical dispatch and minimum flow and spill constraints we estimated the capacity factors of the hydro power plants for every month. Subject to such monthly capacity factor constraints, reservoir based hydro power plants are assumed to be optimally dispatched. The following table shows the monthly capacity factors for hydro plants in each region:

Table 10: Monthly Capacity Factors of Hydroelectric Projects for Each Region

	East	North-East	West	South	North
January	18%	25%	30%	28%	24%
February	18%	23%	27%	32%	29%
March	19%	22%	26%	40%	36%
April	25%	34%	26%	31%	40%
May	18%	49%	26%	27%	62%
June	27%	61%	23%	27%	64%
July	28%	80%	27%	31%	67%
August	27%	83%	47%	37%	67%
September	32%	67%	49%	54%	71%
October	26%	60%	38%	39%	40%
November	16%	40%	26%	29%	29%
December	8%	26%	21%	24%	26%
Annual Average	***22%***	***47%***	***30%***	***33%***	***46%***

Hydro capacity factors depend on a variety of factors including high recharge season (such as summer or monsoon), irrigation and minimum flow requirements, etc.

More than 50% of India's current hydro capacity is run of the river; output of the run-of-the-river plants is assumed to be flat subject to the monthly capacity factor constraint. India has limited pumped storage capacity; they are modeled using a weekly energy balance i.e. the head and tail storage ponds return to their initial volumes at the end of each week. We ran a sensitivity case with daily energy balance but given the small pumped storage capacity, it does not make a large difference to the overall results.

3.7 Costs

The following tables show the assumptions on capital cost and fixed O&M costs for each technology. The current capital costs of renewable technologies have been taken from the Central Electricity Regulatory Commission's (CERC) tariff regulations 2015. CERC's tariff regulations for the conventional projects do not mention the capital cost norms. For coal based power projects, we have used CERC's interim order (2012) on benchmarking the capital costs of thermal projects (CERC 2012). For gas, diesel, and hydro projects, we have used industry norms per our previous report (Abhyankar et al. 2013). Capital and O&M costs of the nuclear projects have been taken from (Ramana, D'Sa, and Reddy 2005).

The following table shows the current year capital and O&M costs for all technologies considered in this analysis.

Table 11: Current year capital cost (overnight; excluding interest during construction) and fixed O&M cost of the generating plants (2015)

Generation Technology	Capital Cost Rs Cr/MW (2015)	Fixed O&M Cost Rs Cr/MW/yr (2015)	Fixed O&M Cost as % of Capital Cost
Coal (>600 MW units)	5.37	0.14	2.7%
Coal (500 MW units)	5.08	0.16	3.1%
Coal (210/250 MW units)	#N/A	0.24	#N/A
Gas CCGT (Combined cycle)	4.80	0.15	3.1%
Gas CT (Open Cycle)	4.20	0.15	3.5%
Diesel	3.60	0.13	3.5%
Nuclear	5.71	0.11	2.0%
Hydro (<200 MW)	8.00	0.32	4.0%
Hydro (>200 MW)	8.00	0.20	2.5%
Small Hydro (between 5 and 25MW) - excluding Himachal Pradesh, Uttaranchal and North-Eastern States	5.93	0.17	2.8%
Small Hydro (between 5 and 25MW) - Himachal, Uttaranchal and North-Eastern States only	7.54	0.21	2.8%
Biomass (for rice straw and juliflora based projects with water cooled condenser)	6.10	0.45	7.3%
Wind (Onshore)	6.19	0.11	1.7%
Solar PV	5.87	0.13	2.2%

Data Sources: (CERC 2012; CERC 2015; CERC 2014; Abhyankar et al. 2013; Ramana, D'Sa, and Reddy 2005)

Note that the capital cost of coal units shown above does not include the additional investment needed to meet the new norms for Particulate Matter, SOx, and NOx emissions (2015); such investments may increase the capital cost of the coal units by over 10% or so.

The economic life of all generation assets has been assumed to be 25 years and the weighted average cost of capital is assumed to be 12.8% (i.e. weighted average of the 14% ROE and 10% interest rate assuming a debt to equity ratio of 70:30).

The solar PV cost in CERC regulations matches up with the prices quoted in the latest solar PV reverse auctions in India. In the state of Madhya Pradesh, a reverse auction concluded in July 2015 received a winning bid of Rs 5.05/kWh (Business Standard 2015). Using CERC's capital cost and O&M cost norms, WACC of 12.8%, and assuming a capacity factor of 21%, the levelized cost of electricity for a solar PV plant comes to Rs 5.07/kWh.

Given that most of the conventional technologies have already matured, their capital costs are not assumed to change until 2022. Renewable technologies especially solar PV still have high learning rates and thus their costs would reduce between 2015 and 2022. Our assumptions for such reduction are shown in the following table.

Table 12: Wind and Solar PV Capital Cost Reduction in Future

	2015 Capital Cost Rs Cr/MW	Average annual price reduction (%)	2022 Capital Cost Rs Cr/MW
Wind	6.19	-	6.19
Solar PV	5.87	4.7%	4.18

For solar PVs, we used the capital cost trajectory projected in the Global PV Market Outlook 2015 by BNEF (BNEF 2015). Based on their capital cost projections, we estimated the average annual reduction in PV prices to be 4.7% between 2015 and 2020. We apply the same annual reduction up to 2022. Lawrence Berkeley National Lab's PV market assessment in the US reports similar cost reductions (Barbose, Weaver, and Darghouth 2014). For wind, we use the historical capital cost data in the US from LBNL's wind technologies assessment report (Wiser and Bolinger 2015). Although there have been significant annual fluctuations in the wind capital cost, the capital cost has not changed much over the last 10 years or so.[5] Therefore, going forward, we have assumed that wind capital cost would stay the same until 2022.

3.8 Fuel Availability and Prices

Domestic gas and coal availability is constrained in India. Coal availability for the power sector has been taken from the Ministry of Coal's projections in the 12th five-year plan up to 2017; the same trend has been projected up to 2022. Domestic gas availability is highly constrained too and several gas-based power plants are stranded because of non-availability of gas. We have assumed that the domestic gas availability for power sector in future remains the same as the current quantity. If the system needs more natural gas, it will have to be imported (LNG) at international prices. We have not assumed any restrictions on imported coal and gas, and other fuels such as diesel and biomass.

[5] Wind PPA prices have dropped significantly in the recent years though; in 2014, the average levelized wind PPA price in the US was $23/MWh including the Production or Investment Tax Credits (Wiser and Bolinger 2015). If the tax credits are excluded, the levelized price would be about $40/MWh (approximately Rs 2.5/kWh).

Table 13: Fuel Availability and Calorific Value Assumptions (2022)

Fuel	Max Availability in FY 2022	Gross Calorific Value
Domestic Coal	750 Million Tons/yr	4000 kCal/kg
Imported Coal	Unlimited	5400 kCal/kg
Domestic Gas	29 bcm/yr	9000 kCal/m^3
Imported LNG	Unlimited	9000 kCal/m^3
Diesel	Unlimited	10000 kCal/lit
Biomass	Unlimited	3000 kCal/kg

Data source for coal and gas availability: (Planning Commission 2012)

Domestic coal price data have been taken from Coal India Limited's annual reports as the average price of coal sold by CIL in that year (CIL 2011; CIL 2015).[6] Historical trends in the imported coal prices have been taken from the BP Statistical Review (Asian marker price) (BP 2015); current international. Domestic natural gas price has been taken from the Ministry of Petroleum and Natural Gas' orders in various years/months. Imported LNG price for the current year (2015) has been taken from the media reports on the international LNG market, while the historical trend in the imported LNG price in India has been taken from (Sen 2015). The fuel prices are assumed to increase at the long-run (10-year) compounded average growth rate. However, note that the historical fuel prices are listed in nominal dollars (or rupees, as the case may be). In order to assess the price trend in real terms, we deflated the nominal prices using the annual inflation rate (Wholesale Price Index); the WPI data was sourced from (OEA 2015). The following table shows the current fuel prices, long-run growth nominal and real growth rates, and the projected 2022 fuel prices expressed as 2015 dollars or rupees.

Table 14: Fuel Price Assumptions

Fuel	Fuel Price in 2015 (FOB)	Escalation in Nominal Price (10-yr CAGR) %	Inflation adjusted (real) escalation rate % p.a.	Fuel Price in 2022 (FOB) (2015 $)
Domestic Coal (Rs/Ton)	1948	7.5%	1.4%	2141
Imported Coal ($/Ton)	77.89	6.9%	0.7%	82
Domestic Gas ($/mmbtu)	4.66	8.8%	2.7%	5.6
LNG ($/mmbtu)	11	6.2%	0.1%	11
High Speed Diesel (Rs/lit)	50	6.2%	0.1%	50

Data Sources: *Ibid*

Note that these are the FOB (free on board) prices and do not include the fuel transportation and LNG regasification etc. costs. Those costs depend on the locations of the plant and the fuel sources. Domestic

[6] Coal India Limited controls more than 80% of India's total coal production and about 80% of its coal is sold to the power sector.

coal transportation costs have been taken from regulatory proceedings and tariff orders of the state and central generation utilities. Imported coal plants are assumed to be located on the shore and therefore would not incur any domestic transportation charge except in cases of northern and eastern regions. The following table shows the coal transportation costs to each of the regions:

Table 15: Average Coal Transportation Costs to Each Region

	Domestic Coal (Rs/Ton)	Imported Coal ($/ton)	
		International transportation	Domestic transportation
North	1200	30	1500
West	1500	30	-
South	1800	30	-
East	1000	30	1500

Data source: Authors' estimates, Regulatory filings

Similarly, imported LNG based plants are not assumed to incur domestic gas pipeline charges, except in cases of northern and eastern regions; all LNG imports are assumed to incur a regasification cost of $0.5/MMBTU. In case of domestic gas, we have assumed two sources viz. (a) Bombay high field (off the western coast) near Mumbai and, (b) KG-D6 field off the eastern coast near Andhra Pradesh. The following table shows the domestic gas and LNG transportation charges from these sources to each of the regions. The following table shows the gas transportation costs to each of the regions:

Table 16: Average Gas Transportation Costs to Each Region

	Domestic Gas ($/MMBTU)		Imported LNG ($/MMBTU)		
	Bombay High	KG D-6	International transportation	Regassification	Domestic Pipeline
North	1.5	2.0	1.0	0.5	1.5
West	0.5	1.5	1.0	0.5	0
South	1.5	0.5	1.5	0.5	0
East	#N/A	1.5	1.5	0.5	1.5

Data source: Authors' estimates, PNGRB website

3.9 Transmission

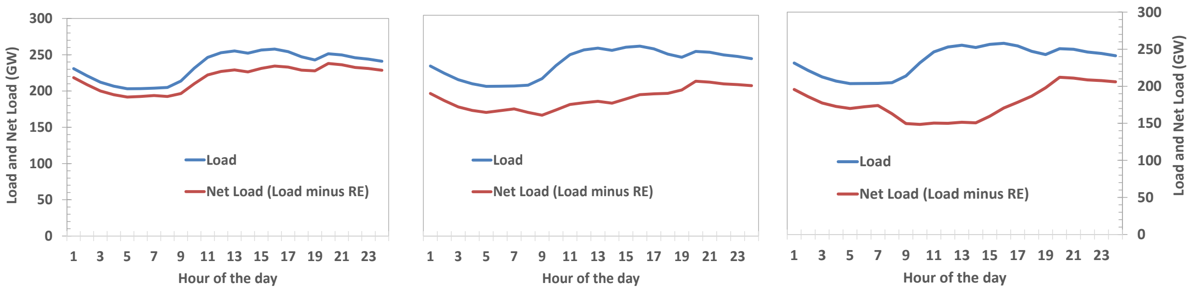
In 2013, southern regional grid in India was integrated with the northern regional grid. Additionally, there have been significant transmission investments planned in the near future. Going forward, we have assumed no constraints on transmission primarily to assess the transmission transfer capability requirements between the regions in future.

4 Results

In this section, we present the key results of our analysis. In order to develop an intuitive understanding of the results and keep them tractable, we are only going to present the results for an average day in each season. Detailed hourly results are presented in the supplementary material.

4.1 Impact on Net Load to be Met by Conventional Generators

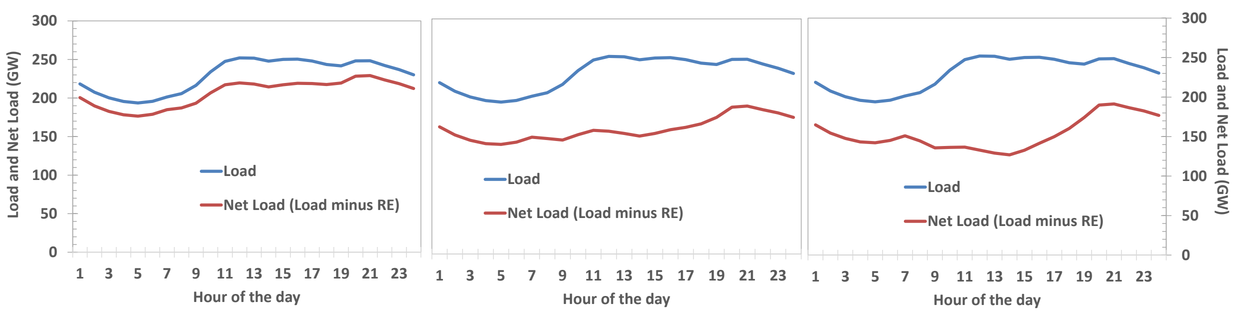
Since we define RE penetration scenarios exogenously, we first compare the characteristics of the net load (residual demand that the conventional generators have to meet) in order to provide an intuitive explanation of our modeling results discussed further. Net load (or the residual load) is estimated by subtracting the variable RE generation from load. The following charts show the national net load curves for an average day in each season. In the supplementary material, we provide detailed results for each region.



(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

Figure 9: Average Daily Load and Net Load Curves (National) during Summer 2022 (April-May)

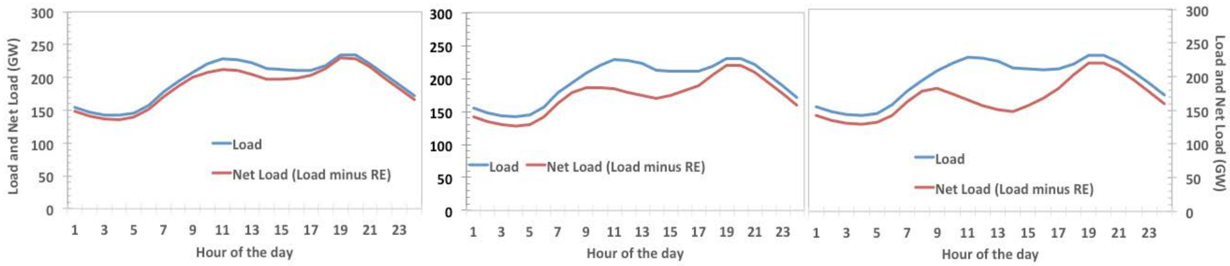
In summer (April-May), load peaks in the afternoon mainly because of the space cooling demand. There is a small peak in the evening because of the lighting demand and the demand remains high at night and early morning mainly due to the residential space cooling demand. Solar PV generation peaks in the summer and correlates well with the diurnal demand pattern especially until early afternoon. In the NAPCC scenario, it removes the afternoon peak and makes the net load look much flatter. In the RE missions scenario, the net load actually dips in the afternoon and introduces significant ramping in the evening when solar PV generation drops rapidly.



(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

Figure 10: Average Daily Load and Net Load Curves (National) during Monsoon 2022 (June-September)

The load curve in monsoon is somewhat similar to that in the summer – afternoon peaking with significant demand in the night/early morning. Although the load in the western and southern region drops, the load peaks in the northern region of the country. Wind generation has a very high correlation with the load (especially in the northern region) in monsoon. In both scenarios – NAPCC and RE Missions, net load curves in monsoon are similar to those in the summer.



(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

Figure 11: Average Daily Load and Net Load Curves (National) during Winter 2022 (June-September)

Winter load curve is significantly different. It has two distinct peaks – one in the morning mainly because of the water heating demand and the other one in the evening primarily because of the lighting demand. Overall, the demand in the winter is much lower than that in the summer or monsoon. Wind generation drops significantly in the winter. There is a drop in solar generation also but not as significant as wind. This drop in RE generation has a major bearing on the energy support that may be needed in winter as explained later. Also, in winter, the ramping requirement in the evening is much higher than the other two seasons due to the rapid drop in solar generation and increase in the evening demand.

4.2 Capacity Addition and Capacity Factors of Conventional Generators

The following table shows the capacity additions required by 2022 under all scenarios and the annual capacity factors of all technologies aggregated at the national level. Please refer to the supplementary material for detailed results by each region. The assumptions governing the additions in nuclear, hydro, and renewable technologies have already been explained in the previous section. Given those assumptions and the operational constraints, the model chooses the least cost investments.

Table 17: Capacity Additions, Installed Capacities and Capacity Factors of All Technologies (National)

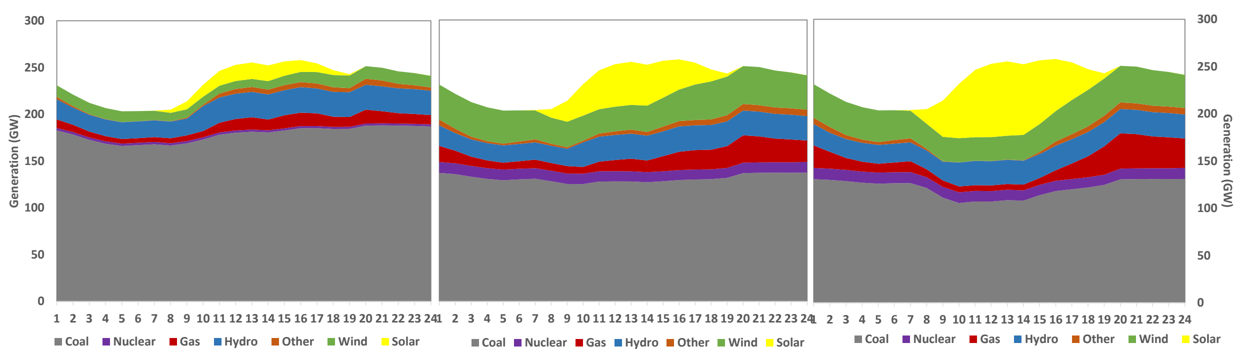
	13th Plan			NAPCC			RE Missions		
	Capacity Addition in GW (2015-2022)	Total Installed Capacity in GW in 2022	Annual Capacity factor (%)	Capacity Addition in GW (2015-2022)	Total Installed Capacity in GW in 2022	Annual Capacity factor (%)	Capacity Addition in GW (2015-2022)	Total Installed Capacity in GW in 2022	Annual Capacity factor (%)
Coal	79	243	65%	17	182	71%	17	182	73%
Gas	0	19	0%	6	25	7%	14	33	9%
Diesel	0	1	0%	0	1	0%	0	1	0%
Nuclear	19	25	89%	19	25	89%	19	25	89%
Hydro (Reservoir)	9	30	35%	9	30	35%	9	30	34%
Hydro (Run of the River)	7	23	38%	7	23	38%	7	23	38%
Hydro (Pumped Storage)	2	6	5%	2	6	12%	2	6	15%
Small Hydro	2	6	37%	2	6	37%	2	6	37%

Biomass	4	8	0%	4	8	2%	4	8	2%
Solar	18	22	20%	55	58	19%	97	100	19%
Wind	18	41	25%	85	108	29%	39	62	29%
Total	**159**	**425**		**207**	**472**		**211**	**476**	

In both the renewable energy dominant scenarios, significant new coal capacity could be avoided relative to the 13th Plan scenario (the baseline). However, significant gas based capacity is added in both scenarios, which serves as the major source of additional flexibility relative to the 13th Plan. Secondly, in both scenarios gas plants operate with an annual capacity factor of only about 10% or so implying that they are used only during the peak demand periods and providing ancillary services like ramping/regulation or reserves. As noted previously, the system needs flexibility and it is not technology specific; if any other sources start providing flexibility to the Indian grid (for example, more flexible hydro dispatch with lesser constraints on monthly discharge, demand response etc.), the need for gas based capacity addition would reduce. The next section describes how each of these plants are dispatched for integrating RE.

4.3 How is the System Operated to Integrate RE

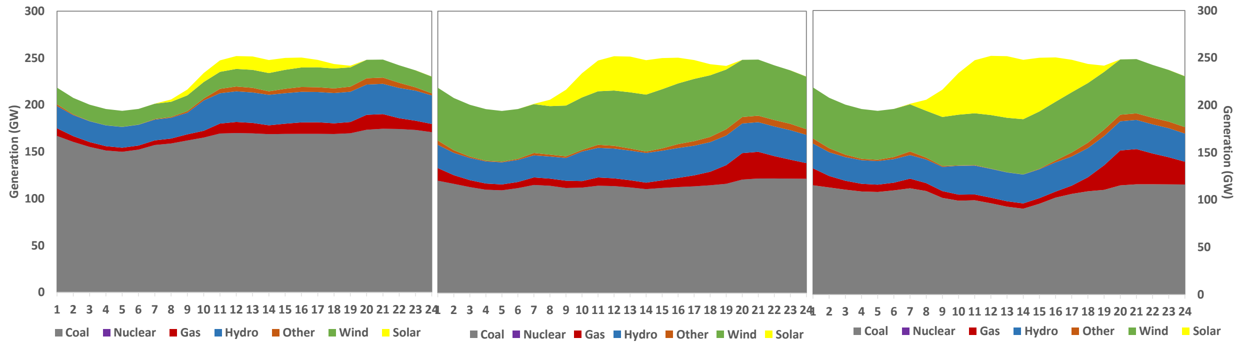
The following charts show how the average hourly dispatch in each season for the national grid (all regions combined).[7] They show how each generation technology contributes towards meeting the demand. For example, nuclear and coal power is used as the base load. Hydro is primarily used as a peaking resource but because of the run of the river plants, a large portion also runs as a base load (subject to the water flow constraints). Solar energy does contribute in the peak demand hours (afternoon cooling peak) while nationally, wind energy contributes equally in peak as well as intermediate demand hours. In the NAPCC and the RE Missions scenarios, it can be seen that there is significant support needed from gas and hydro power plants for grid balancing and also during peak demand periods.



(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

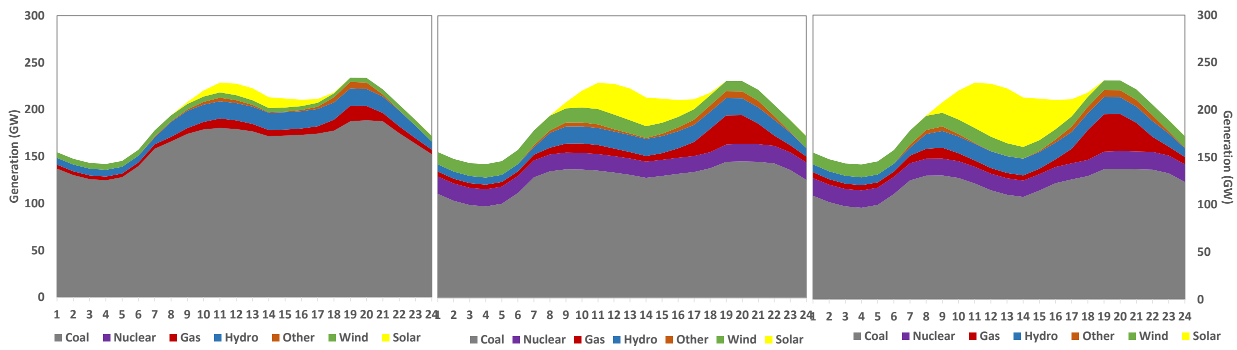
Figure 12: Average Hourly Daily National Dispatch during Summer 2022 (April-May)

[7] Dispatch results for each region are provided in the supplementary material.



(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

Figure 13: Average Hourly Daily National Dispatch during Monsoon 2022 (June-September)



(a) 13th Plan (41GW Wind; 22GW Solar) (b) NAPCC (100GW Wind; 60GW Solar) (c) RE Missions (60GW Wind; 100GW Solar)

Figure 14: Average Hourly Daily National Dispatch during Winter 2022 (December – February)

In all scenarios and seasons, coal provides the base load support. As observed in the previous section, both NAPCC and RE Missions scenarios can avoid the coal capacity addition (and hence generation) significantly. However, as mentioned previously, the 13th Plan scenario overbuilds the coal capacity. Therefore, the avoided coal capacity would be smaller if it were added optimally in the baseline (13th Plan scenario). In order to asses that, we ran the 13th Plan scenario with optimal coal capacity addition, which is explained in the sensitivity analysis section.

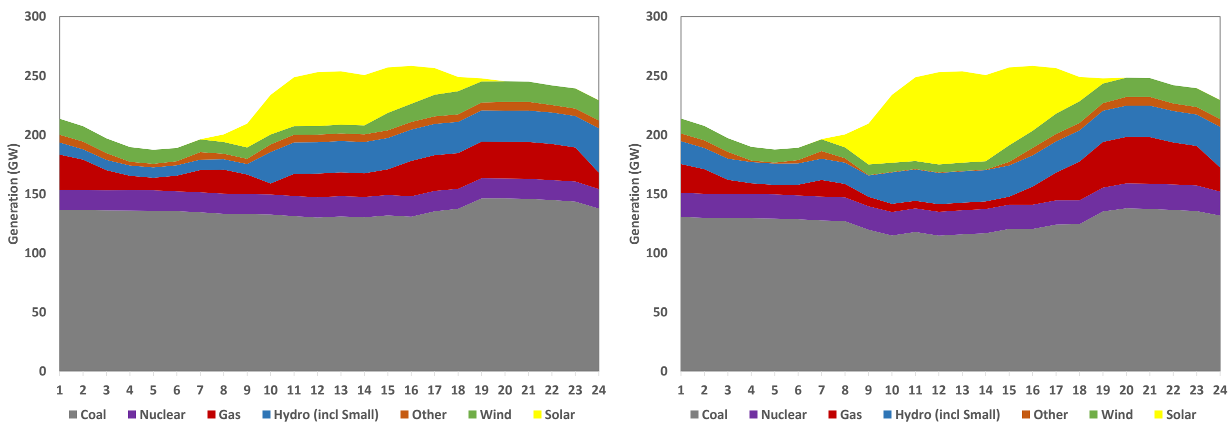
During summer (April-May) and monsoon (June through September) seasons, as seen in the net load charts, renewable energy can provide significant support during afternoon peak demand period during summer (mainly solar) and as well as monsoon (mainly wind). However, in both seasons, gas based generation (or some form of flexible generation) is necessary to provide the evening ramp-up support and meet the evening peak demand especially after the solar generation drops rapidly. In Winter, when solar and wind generation both drop, gas based generation provides round the clock energy and load following support despite lower demand. This implies that the flexible resource used for grid integration in India should be able to provide cross-seasonal support and the energy in winter is crucial for reliable grid service.

4.4 How Would the System be Operated on Extreme Days

The key question relevant to system planners is how the system would be operated in case of extreme events/days such as very low renewable energy generation day, or sudden loss or increase in renewable energy generation (variability) etc. In this section, we present how the system would be dispatched on such events/days . The results shown here are for the national scale; for regional level results, please refer to the supplementary material.

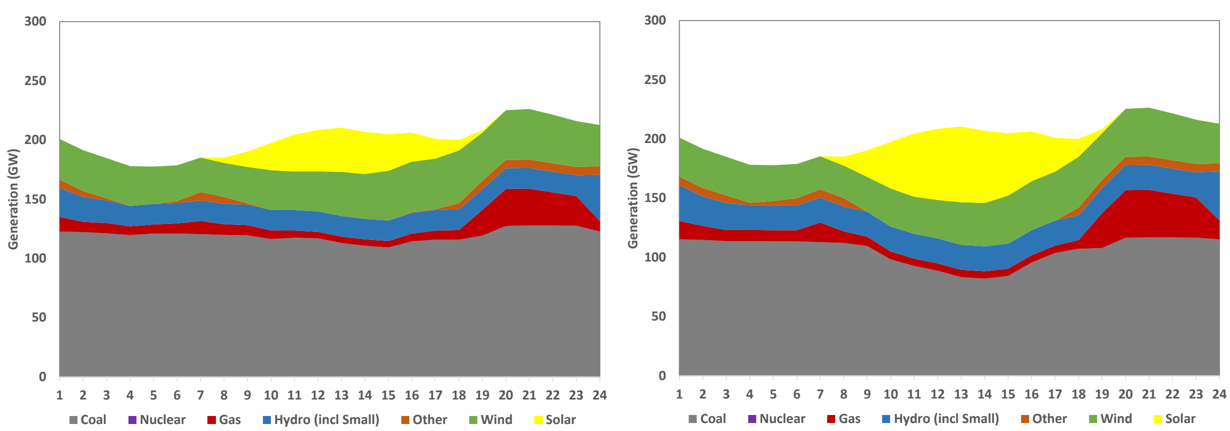
4.4.1 Low RE Generation

The following charts show the national dispatch for minimum renewable energy (nationally) generation day for each season. Given the seasonal nature of wind and solar generation, minimum RE generation in the summer implies minimum solar generation while that in the monsoon implies minimum wind generation.



(a) NAPCC (100GW Wind; 60GW Solar) (b) RE Missions (60GW Wind; 100GW Solar)

Figure 15: Hourly National Dispatch for Minimum RE Generation Day (April 8th) – Summer 2022 (April-May)



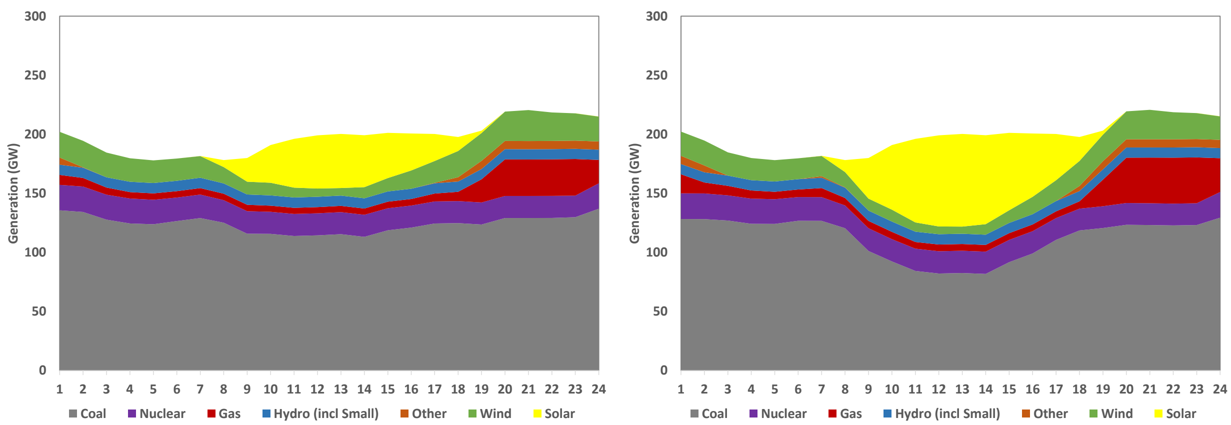
(a) NAPCC (100GW Wind; 60GW Solar) (b) RE Missions (60GW Wind; 100GW Solar)

Figure 16: Hourly National Dispatch for Minimum RE Generation Day (August 22nd) – Monsoon 2022 (June – September)

In summer, the drop in RE generation is compensated primarily by gas and hydro power plants. However, in monsoon, it is interesting to see that on the minimum RE generation day, the demand is also significantly lower than the average.

4.4.2 Low Demand and Potential RE Over-Generation

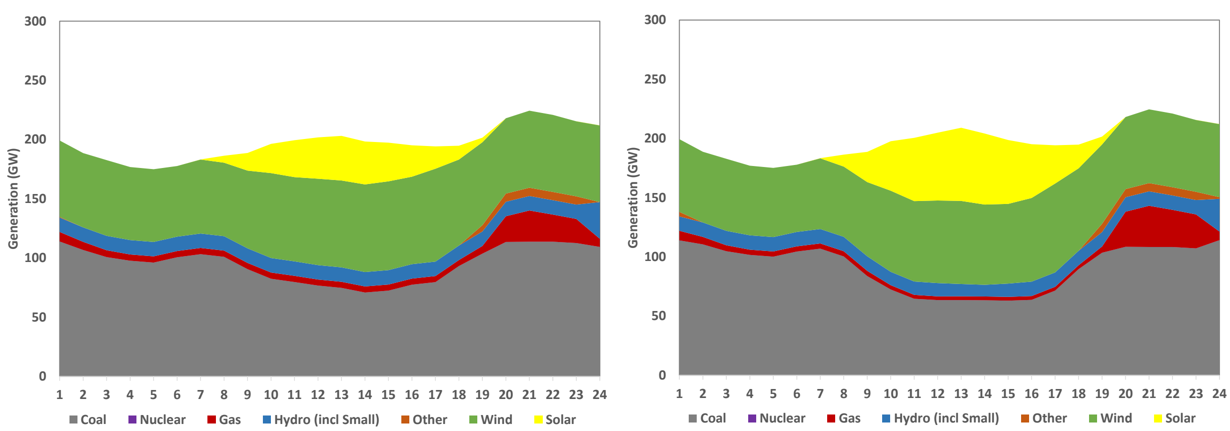
One of the other key concerns regarding RE is potential over-generation. In the following charts, we show the national dispatch for the minimum demand day in each season.



(a) NAPCC (100GW Wind; 60GW Solar)

(b) RE Missions (60GW Wind; 100GW Solar)

Figure 17: Hourly National Dispatch for the Minimum Demand Day (April 4th) – Summer 2022 (April-May)



(a) NAPCC (100GW Wind; 60GW Solar)

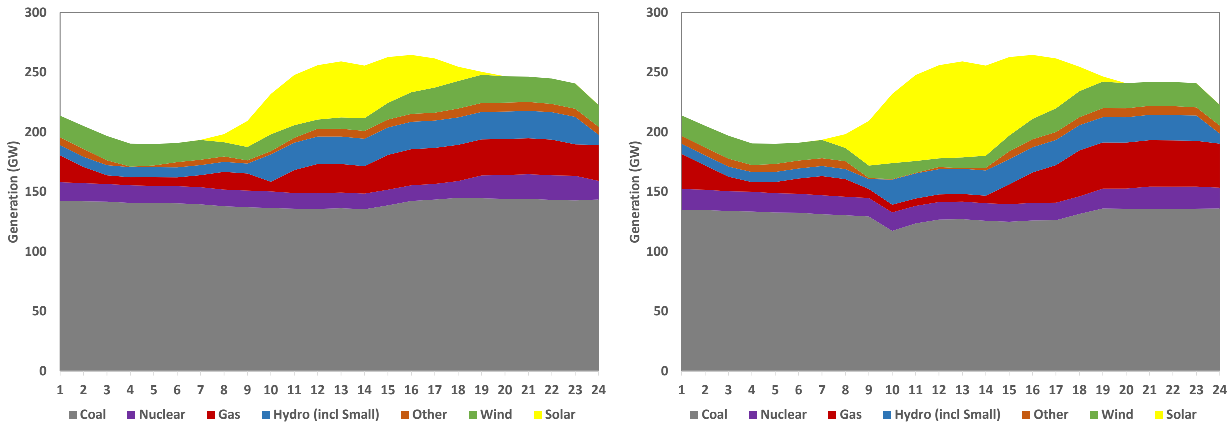
(b) RE Missions (60GW Wind; 100GW Solar)

Figure 18: Hourly National Dispatch for Minimum Demand Day (August 1st) – Monsoon 2022 (June – September)

It is interesting to see that on the minimum demand day in summer, the solar generation also drops. In monsoon, however, wind generation is still very high and the total RE contribution to the afternoon peak demand (1 PM) is as high as 55% in case of the NAPCC and 63% in case of the RE Missions scenario. Due to this, some coal units need to be backed down to 55% level, perhaps violating the current minimum load norm of 70% used by the system operators, but still meeting the norm of 55% specified in the CERC regulations in 2015; hydropower plants and gas plants operate on minimum load in case of both scenarios.

4.4.3 High Variability in RE Generation

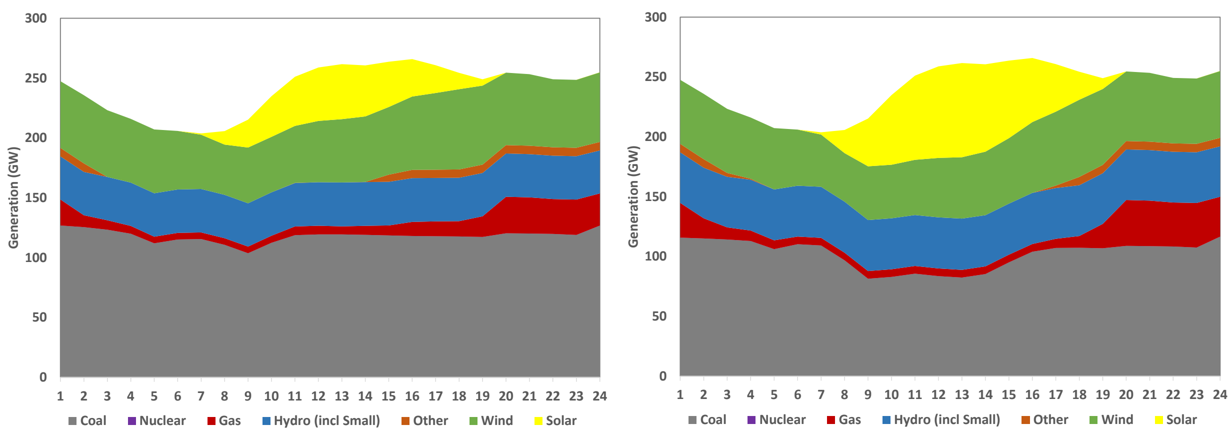
The other major criticism of renewable energy is the high variability. The following charts show the national dispatch in each season on the day with maximum variability (i.e. maximum hour to hour variation) in RE generation.



(a) NAPCC (100GW Wind; 60GW Solar)

(b) RE Missions (60GW Wind; 100GW Solar)

Figure 19: Hourly National Dispatch for the Maximum RE Variability Day (April 13th) – Summer 2022 (April-May)



(a) NAPCC (100GW Wind; 60GW Solar)

(b) RE Missions (60GW Wind; 100GW Solar)

Figure 20: Hourly National Dispatch for the Maximum RE Variability Day (June 5th) – Monsoon 2022 (June – September)

In both seasons and scenarios, ramping up of the solar generation in the morning introduces significant variability in RE generation (9 – 10 AM in the morning). The following table shows the maximum RE variability in each season:

Table 18: Maximum variability in Renewable Energy Generation (National)

	Day and time of the maximum RE variability	NAPCC (100GW Wind; 60GW Solar)	RE Missions (60GW Wind; 100GW Solar)
Summer	April 13th at 9 AM	14,943 MW/hr	25,082 MW/hr
Monsoon	June 5^{th} at 9 AM	16,626 MW/hr	24,931 MW/hr

4.4.4 Load and Net-load Variability (Ramps)

It should be noted that the load is significantly variable as well. For example, the maximum variability in national load in FY 2022 is projected to be 36,646 MW/hr (610MW/min). Therefore, from the system balancing perspective, the incremental variability added due to renewable energy generation is the key. An analysis by LBNL using actual wind generation data showed that the incremental variability added due to wind is fairly small in India i.e. 99^{th} percentile incremental net load variability of 58 MW/hr for total installed wind capacity of 9000 MW in the state of Tamil Nadu (Phadke, Abhyankar, and Rao 2014). Similarly, NREL did analysis of the variability in solar PV generation in Gujarat which was found to be moderate (95^{th} percentile ramp between 37.6 MW/5-min and 57.5 MW/5-min for installed solar PV capacity of 2,900 MW), albeit they did not estimate the incremental net load variability added due to solar (Hummon et al. 2014).

It is important to note that the regional diversity in renewable energy and its complementarity with demand as well as other RE resources help reducing the impact of extreme events. As mentioned previously, we have assumed the future capacity addition in the renewable energy resources happens on the same sites as the current installed capacity. This is a highly conservative assumption for diversity and hence will significantly overestimate the variability in RE generation. Despite such conservative assumptions, we find that the incremental net load variability added due to wind and solar generation is none or only minor as shown in the following table.

Table 19: Maximum Hourly National Net Load Variability (MW/hour) in All Scenarios (2022)

	Max Load Variability – National (MW/hour)	Max Net Load Variability - National (MW/hour)
13^{th} Plan	36,646	36,010
NAPCC	36,646	36,230
RE Missions	36,646	37,538

The following chart shows load ramps and the net load ramps for the entire year for all three scenarios.

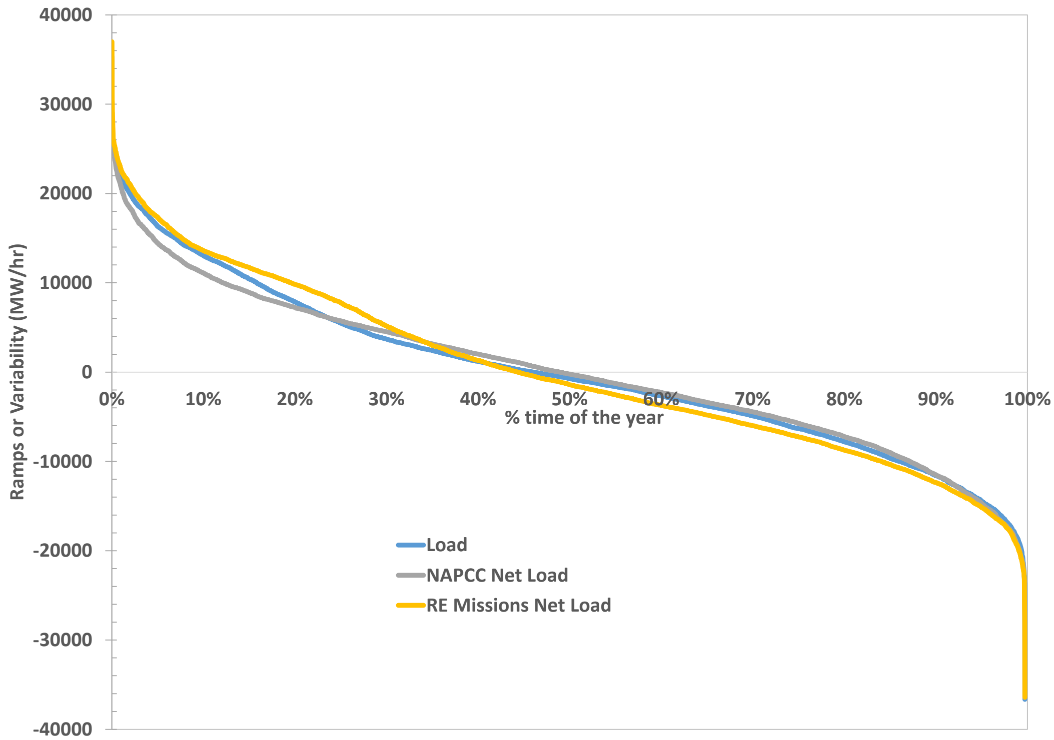


Figure 21: Load and Net-load Ramps (Variability) in 2022

As shown in Table 19, the maximum net load ramps in the RE Missions as well as NAPCC scenarios are almost indistinguishable from the load ramps, implying the maximum additional variability introduced due to the RE generation is relatively minor. However, during the intermediate load periods, the net load ramps in the RE Missions scenario are somewhat higher than the load ramps. In the same period, the net load ramps in the NAPCC scenario are actually lower than the load ramps, implying that the overall renewable energy generation in the NAPCC scenario has a better correlation with demand.

The analysis presented in this section shows that system can handle both extremes in RE – low and high generation and high variability. However, one of the important assumptions in the model is perfect RE forecasting on a day ahead basis, which is crucial for reliable grid integration. But in reality, there will be forecast errors, albeit small with state of the art forecasting techniques. Therefore, utilities will have to incur additional costs to manage such uncertainty. Although quantifying such costs is out of the scope of our analysis, we include such additional costs, based on certain assumptions, under integration cost, which is explained in the subsequent section.

4.5 Inter-Regional Power Transfer

One of the key enablers of the reliable grid integration is the transmission network. The following table shows the inter-regional power transfer capacities estimated in each scenario.

Table 20: Inter-regional Power Transfer Capacities (MW) – Existing and Capacities Required by FY 2022 in Each Scenario

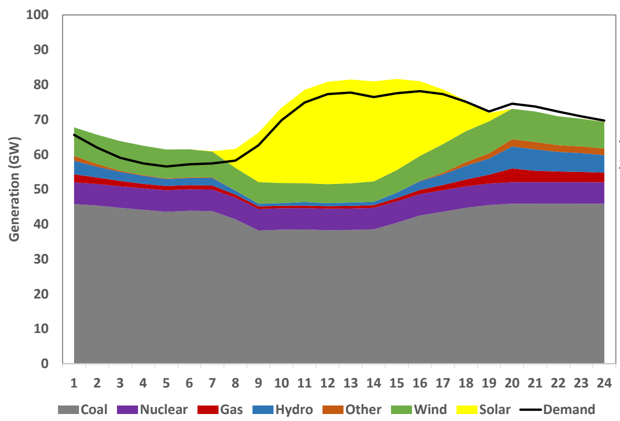
		Power Transfer Capacity requirement (Transmission capacity requirement may be significantly higher)		
	Existing Transmission Capacity (June 2015)	**13th Plan (2022)**	**NAPCC (2022)**	**RE Missions (2022)**
East-North	15830	15124	11215	12489
East-South	3630	8656	16563	18354
East-West	10690	9171	8717	6772
NorthEast-East	2860	2914	2907	3195
North-West	8720	23173	17315	15654
West-South	5720	10896	14731	20285

Note that the existing (June 2015) capacity is the total transmission capacity. The actual concurrent power transfer capacity may be lower due to congestion, reverse flows, and a number of other technical constraints. Similarly, the numbers shown for 2022 represent the power transfer capacity requirement; actual transmission capacity requirement may be higher. Also note that, this study assumes regional balancing, and that there are no transmission constraints within each region. However, in reality, individual states act as the balancing area and there may be several intra-state or intra-regional transmission constraints. Therefore, the results presented in the above table should be viewed as indicative only. Significant refinement in representation of the transmissions system as well as balancing areas would be necessary in order to use the analysis for actual planning purposes.

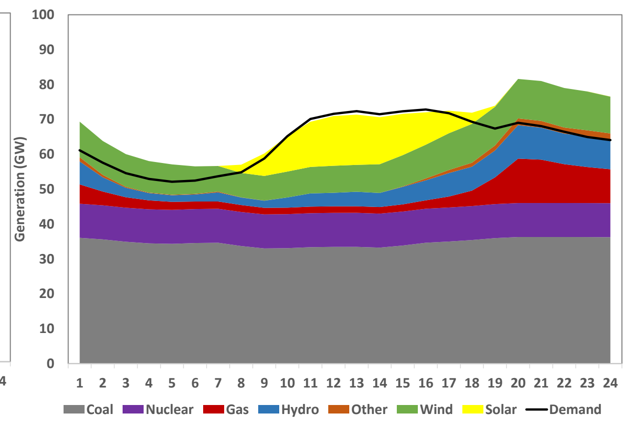
In order to integrate nearly 160 GW of variable renewable energy, the additional inter-regional power transfer capacity requirement (relative to the 13th Plan baseline) is found to be on the West-South (increase by 3000 to 4000 MW relative to the 13th Plan) and East-South (increase of 6000 to 8000 MW relative to the 13th Plan) links. One of the reasons for this is that the renewable resources are well distributed among northern (mostly solar and some wind), western (both solar and wind), and southern (mostly wind and some solar) regions.

Note that in the RE dominant scenarios, some of the transmission lines would have to be used in both directions because of the seasonal and diurnal RE generation patterns. This implies that in order for reliable RE grid integration, it is absolutely crucial to have an appropriate policy and regulatory framework for moving power across regions more freely. For example, deepening the existing day-ahead energy market (i.e. more utilities and generators participating from multiple regions participating in the market) or introducing the ancillary services market. Since 2014, India has started a 24x7 day-ahead energy market, and since April 2016, India has introduced a framework for the ancillary services market, where unrequisitioned share of the central sector generating stations from the day-ahead schedule may be allocated to other utilities.

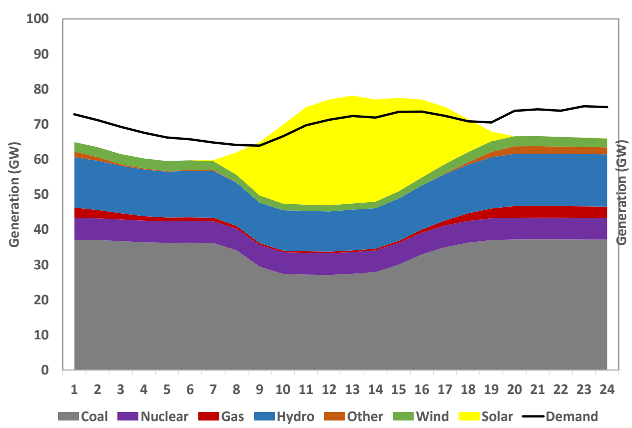
The following charts show the average hourly regional dispatch and transmission flows from one region to the other in Summer of FY 2022 for the RE Missions scenario. The black line in each chart shows the regional demand. Similar results for other scenarios and seasons could be found in the supplementary material.



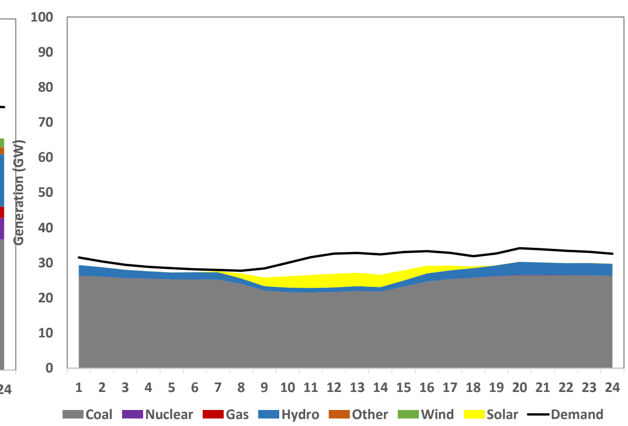
(a) Western Region



(b) Southern Region



(c) Northern Region



(d) Eastern + North Eastern Region

Figure 22: Average Daily Dispatch and Average Hourly Load by Region in Summer FY 2022 (April-May) in the RE Missions Scenario (100GW Solar+60GW Wind)

The difference in the demand (black line) and the total generation is either exported or imported by the region. Note that Western and Northern Regions are net-exporting in the afternoon due to significant solar generation while they are net-importing during other hours. The following chart shows the net transmission flows between regions. Note that positive and negative flow implies the direction of the flow.

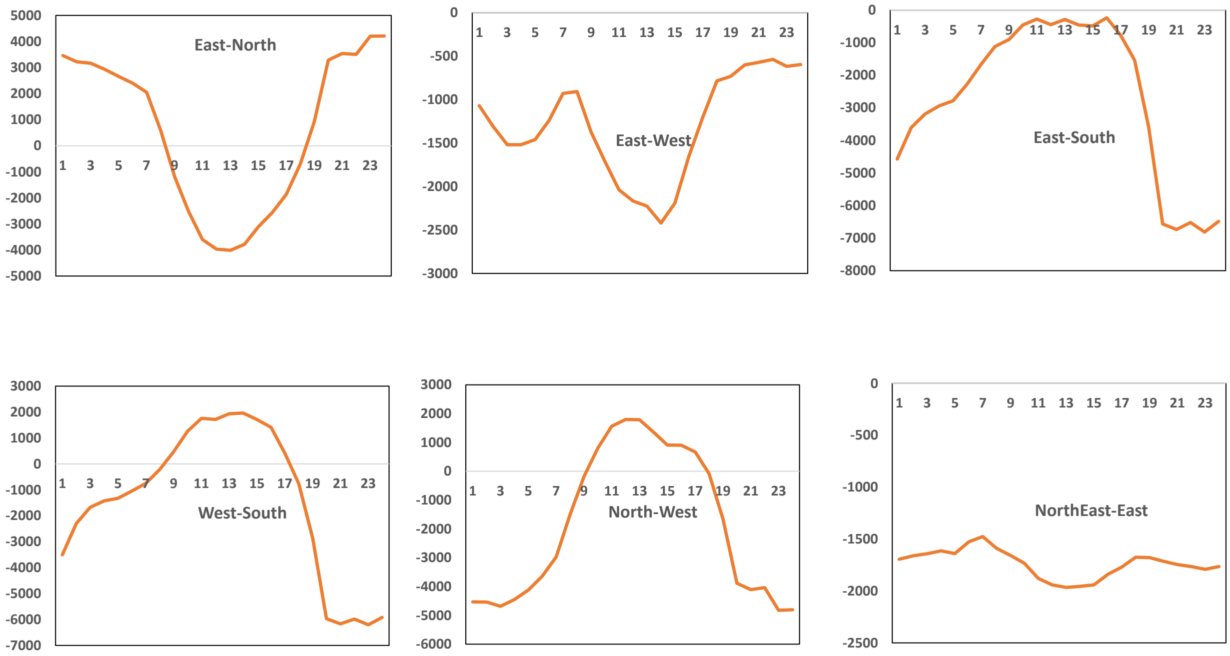


Figure 23: Average Hourly Inter-regional Transmission Flows during Summer 2022 (April-May) in the RE Missions Scenario (100GW Solar+60GW Wind)

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

Because of the renewable energy generation, the flows on inter-regional lines change significantly (including the direction of flow) within a day and therefore, efficient markets or balancing area coordination is required in addition to the transmission investments.

4.6 Cost of Generation

The following chart shows the total annual generation cost and average cost generation in FY 2022 for all the three scenarios.

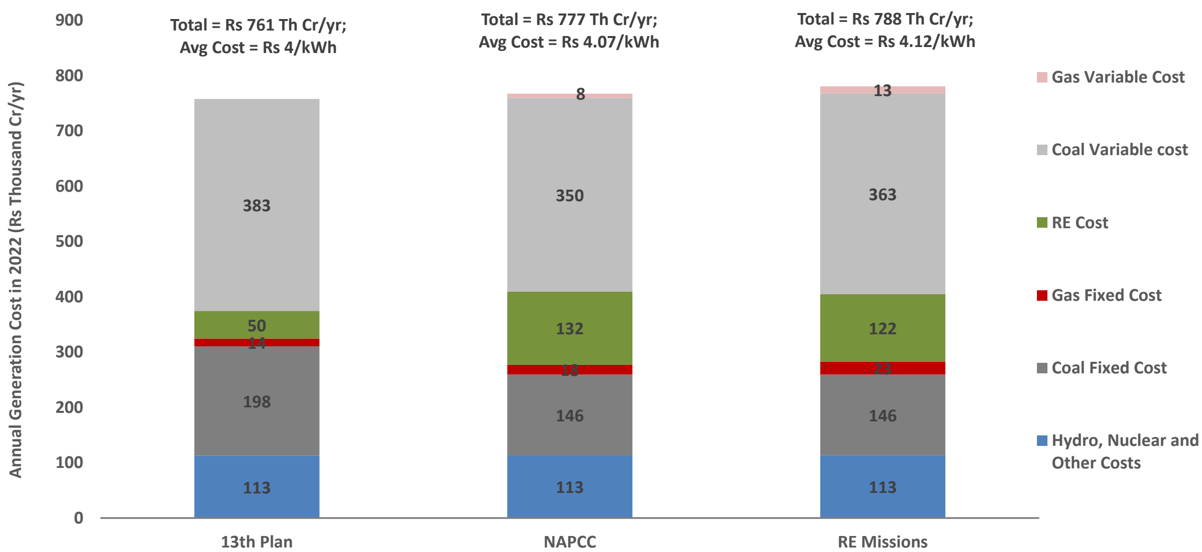


Figure 24: Annual Generation Cost in FY 2022 for all Scenarios

The incremental cost of generation in NAPCC and RE Missions scenarios is 2.1% and 3.5% relative to the 13th Plan.

An intuitive explanation of such cost differential despite 160GW of RE capacity is as follows:

(a) Both NAPCC and RE Missions scenarios would potentially need lower coal capacity resulting in significant saving in fixed costs.
(b) There has been and will be deep reduction in the costs of renewable technologies (especially solar PV). Based on the CERC norms, we have assumed the current capital cost of solar PV to be Rs. 5.87 Cr/MW (average cost of about Rs 5.1/kWh); by 2022, based on the global trends, we assume that it will reduce to Rs 4.18 Cr/MW (average cost of Rs 3.4/kWh). Since most of the solar capacity will be added in later years (post-2017), their incremental cost is minor relative to the new imported coal based plants.
(c) Both the RE dominant scenarios can avoid significant coal consumption and imports. Since imported coal prices are higher than the domestic coal prices, this results in a significant reduction of the fuel cost. The following chart shows the total coal and gas consumption and imports for all scenarios.

Table 21: Coal and Gas: Total Consumption and Imports

		13th Plan	NAPCC	RE Missions
Coal (million tons/yr)	Domestic Coal	715	710	715
	Imported Coal	74	0	17
Gas (bcm/yr)	Domestic Gas	0.0	3.6	6.2
	Imported LNG	0.0	0.0	0.0

(d) Both the RE dominant scenarios need additional investments in gas based capacity. However, the seasonal complementarity between solar and wind generation keeps the need for such additional investments in the flexible capacity (i.e. gas) moderate.

Note that the coal investment costs in all scenarios have been estimated without considering the new norms for Particulate Matter, SOx, and NOx emissions (2015), which may require additional investments; such investments may increase the fixed costs of coal plants by over 10% and reduce the cost-differential between the 13th Plan and RE Dominant scenarios further.

The following chart shows the total coal and gas consumption for all scenarios.

Table 22: Coal and Gas: Total Consumption and Imports

		13th Plan	NAPCC	RE Missions
Coal (million tons/yr)	Total Coal	789	710	732
Gas (bcm/yr)	Total Gas	0.0	3.6	6.2

4.7 Electricity Market Prices

Although we do not simulate the day-ahead and real-time markets per se (mainly due to the lack of the bilateral/IPP contract data), we still estimate the day-ahead and real time prices. Since we do not have all the existing contracts and self-scheduling modeled in the system, these prices are essentially the variable generation cost of the marginal unit on the system in each hour. The following chart shows the real-time prices for each scenario. One can see that in certain instances when the marginal unit on the system is gas CT or diesel CT, the system price is very high. Also, note that we have shown an average electricity price for the entire nation. India does not have locational marginal prices, but instead it operates a zonal market. Therefore, in reality, the wholesale electricity prices would be different in each zone, if there are transmission constraints. However, since we have not assumed any transmission constraints, prices in all zones are almost identical; they only differ by the transmission wheeling charge between the two zones.

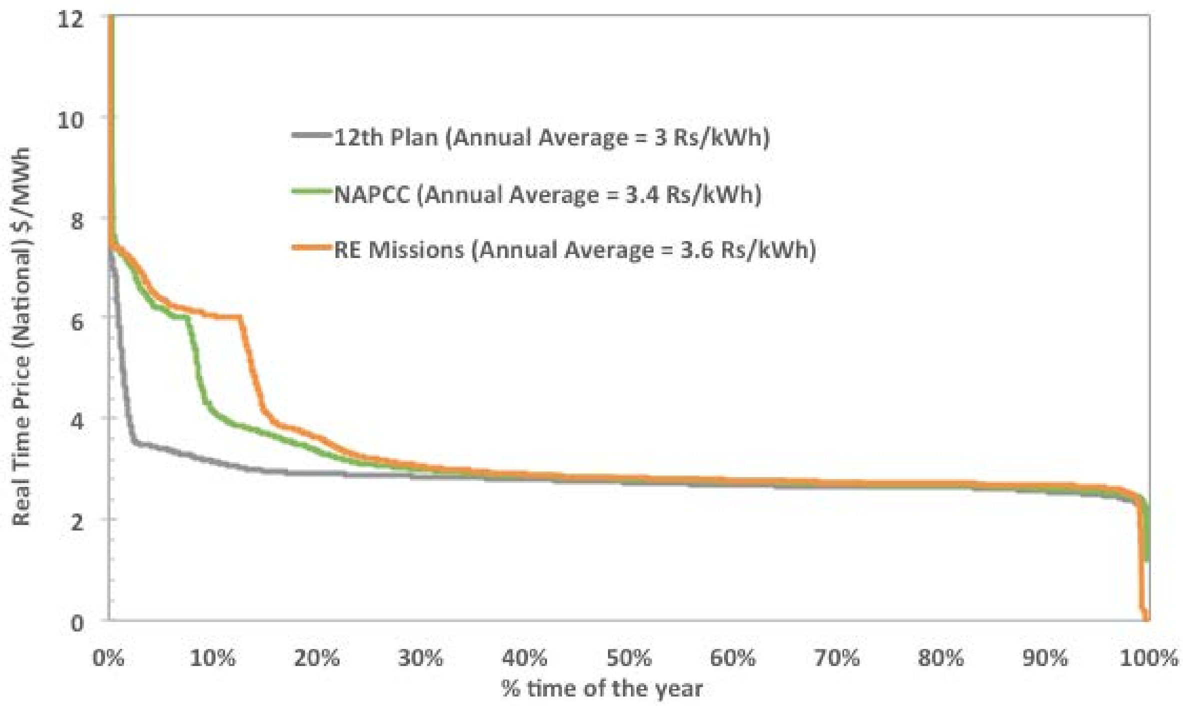


Figure 25: Real-time electricity market price duration curves

Note that the prices should not be confused with the average cost of generation. Prices only reflect the variable cost of generation while the average cost also includes the fixed costs (capital as well as O&M etc.). In both the RE scenarios, there are a few constrained hours on the system where the gas CT or diesel plants need to be operated to balance the additional ramps introduced by RE. In such hours, the prices are significantly higher than the 12th Plan scenario, as seen in the chart. In the RE missions scenario, for a few hours (20 hours) in the year, the real time price actually becomes zero due to excess RE generation. This implies that all the thermal units already committed in the day-ahead market are generating at their minimum stable level and the marginal unit on the system is a renewable energy project or a hydro power plant (i.e. zero marginal cost). However, once the thermal units drop to their technical minimum, RE curtailment is still not necessary.

The following chart shows the day-ahead, intra-day (3-hour ahead), and real time prices in the RE Missions scenario. It can be seen that as expected, real time and the intra-day prices are significantly higher than the day-ahead prices, especially during the peak demand (high price) periods.

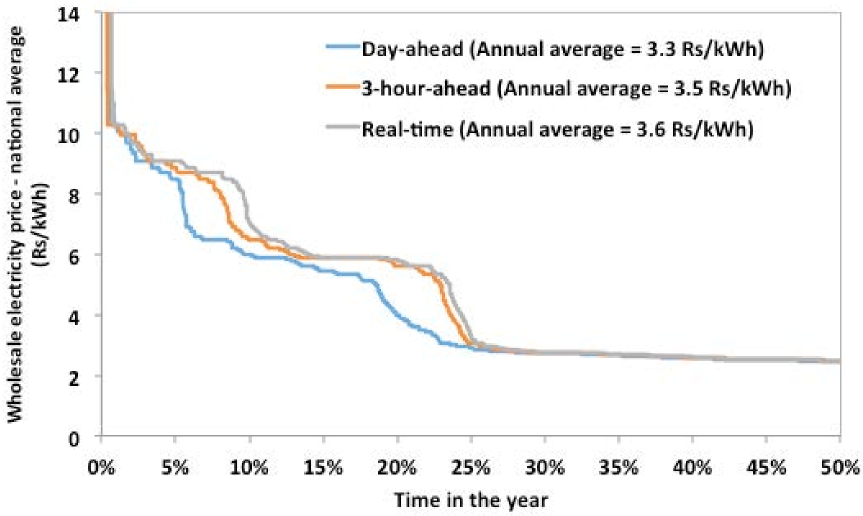


Figure 26: Day-ahead, intra-day, and real-time prices in the RE Missions scenario

For more details, please see Annexure 4.

4.8 Integration Cost

There is no standard definition of "integration cost" in the literature. Generally, integration cost is meant to reflect any additional costs to manage the variability and uncertainty of RE generation. Aggressive RE penetration may require additional investments in flexible capacity (such as gas CT etc.) or operation of the expensive gas or diesel-based power plants, or operating coal power plants at partial loads. All such costs have already been included in the cost results presented so far. Note that in addition to these costs, utilities may have to procure additional reserves (spinning, contingency, or otherwise) or other ancillary services for reliable RE integration. Our analysis does not include such incremental ancillary services cost.

In several studies in the US and Europe, such incremental ancillary services cost for RE integration is found to be minor i.e. only about 5-10% of the RE generation cost. For example, (A. Mills, Phadke, and Wiser 2010) estimate that the incremental ancillary services cost to be $5/MWh of wind generation (Rs 0.3/kWh) for wind power and $2.5/MWh of solar generation (Rs 0.15/kWh) for solar PV power projects. These costs depend on a range of factors including reserve requirements, total RE penetration, forecast errors, loss of load expectation (LOLE), and available conventional as well as flexible generation. Significant further analysis is needed to estimate the incremental ancillary services costs accurately in the Indian context. Our forthcoming paper on RE valuation in India attempts to estimate the total integration cost including the reserves and ancillary services cost.

5 Sensitivity Analysis

We assess the sensitivity of our results on the following key parameters:

1. *<u>Slippage in capacity addition in the 13th Plan</u>*

We assess the impact on costs if the thermal capacity is planned in a least-cost manner in the 13th Plan period. This would imply lower coal capacity than originally planned in the 13th Plan. Therefore, it could also be considered equivalent to slippages in the 13th Plan capacity additions.

2. *High coal and high RE*

   In order to test the impacts of integrating RE in a more inflexible system, we increase the coal generation capacity in the RE Missions scenario to the 13th Plan level i.e. an increase of more than 60 GW.

3. *Transmission Constraints*

   One of the key assumptions in this is that new inter-regional transmission capacity can be freely built. In order to test the importance of transmission, in the NAPCC and RE Missions case, we restrict the inter-regional power transfer capacity to that estimated in the 13th Plan scenario (baseline).

4. *Capital cost of the renewable energy technologies (especially solar)*

   Capital costs of the renewable energy technologies have been falling significantly over the last few years. Although we have assumed a reduction in their capital cost, we assess the impact of a change in that reduction. We create two sensitivity cases viz. (a) capital costs reduce 50% faster than anticipated, and (b) capital costs reduce 50% slower than anticipated.

5. *Fuel prices*

   Fuel prices (especially imported coal and gas) are significantly volatile. In order to address that, we create two sensitivity cases viz. (a) high fuel price case, where fuel prices in 2022 are assumed to be 25% higher than presented before, and (b) low fuel price case, where fuel prices in 2022 are assumed to be 25% lower than presented before.

5.1.1 Slippages in Thermal Capacity Addition or Least Cost Thermal Capacity Addition

In order to assess the impact of slippages in thermal capacity addition, we ran the model to optimize the coal capacity addition by 2022 in a least-cost manner by holding the planned capacity additions in all other technologies constant. If coal capacity addition is optimized, by 2022, the total installed coal capacity by 2022 would be 203 GW. This is equivalent to a slippage of 30% in the coal capacity addition in the 12th and 13th Plan periods. This naturally reduces the total investment costs and also increases the capacity factors (PLF) of the existing as well as newly built plants. As a result the average cost of generation would lower significantly as shown in the following table.

Table 23: Total Coal Installed Capacity and Average Cost of Generation – Sensitivity Analysis on Least Cost Thermal Capacity Addition

	13th Plan (Baseline)	13th Plan (Optimal Thermal Addition Case)	NAPCC	RE Missions
Total Coal Installed Capacity (2022) MW	243,475	203,375	182,375	181,375
Average Cost of Portfolio incl Integration Cost Rs/kWh (bus-bar)	4.00	3.91	4.07	4.12

If one uses the “optimal” coal capacity, the average cost of the portfolio (including the integration cost) in the 13th Plan scenario would be Rs 3.91/kWh i.e. lower than the 13th Plan baseline by about 2.1%. This would in turn make the incremental cost of the NAPCC scenario to be 4.0% and that of the RE Missions scenario to be 5.3% higher.

5.1.2 High Coal and High RE

In order to test the feasibility of integrating the renewable energy in a more inflexible system, we increase the coal generation in the RE Missions scenario to that of the 13th Plan level i.e. an increase in the coal capacity of nearly 60 GW. The following table summarizes the total installed capacity in the original RE Missions scenario and the High Coal sensitivity case.

Table 24: Total installed capacity in 2022 (GW)

	13th Plan (Baseline)	RE Missions	High Coal and High RE case
Coal	243	181	243
Wind	40	60	60
Solar	22	100	100

With additional 60 GW of coal capacity, the system becomes significantly oversized. This implies that the need for the additional gas power plants for flexibility goes away entirely i.e. no additional gas based capacity is required for RE balancing. The system operates the additional coal power plants at reduced capacity to meet the net-load ramps. However, this implies that the capacity factor of the coal power plants drops significantly (as low as 50% in the Southern and Western region due to large RE capacity which implies that many coal units are just shut down for most of the year); as a result the average cost of generation increases by 5% relative to the RE Missions scenario as shown in the following table.

Table 25: Coal capacity factors and average cost of generation

	13th Plan (Baseline)	RE Missions	High Coal and High RE case
Coal Installed Capacity (GW)	243	181	243
Coal Capacity Factor (%)	65%	73%	56%
Average Cost of Generation (Rs/kWh)	4.0	4.12	4.32

During the high RE generation periods, several coal power plants need to be either shut down or operate at their technical minimum levels. This is evident from the coal power generation duration curves shown in the following figure for the 13th Plan scenario and the High Coal and High RE case.

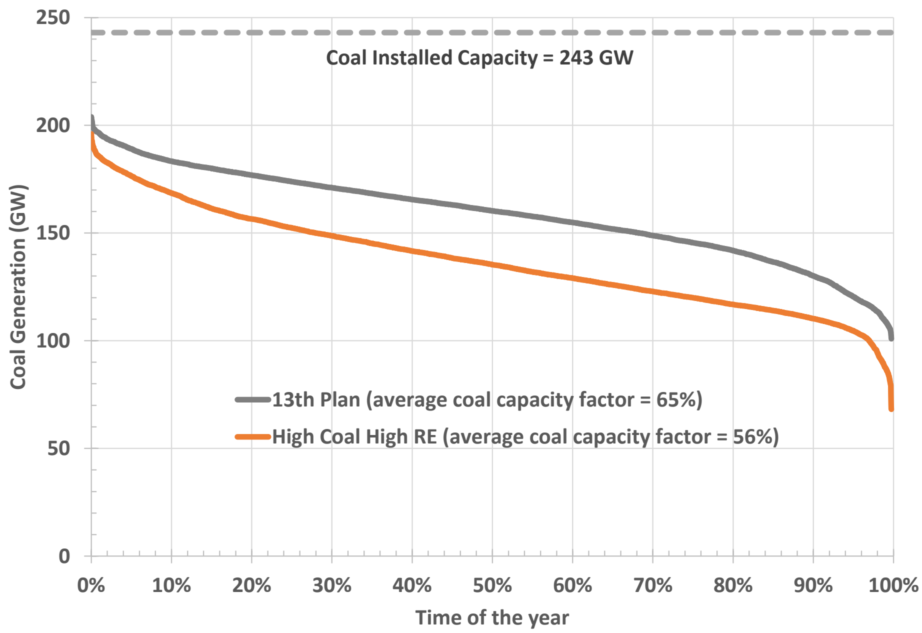


Figure 27: Coal Generation Duration Curves for the 13th Plan Scenario and High Coal High RE Case

Despite high inflexibility in the system, curtailment of the renewable energy is not found to be necessary.

5.1.3 Transmission Constraints

In order to test the importance of transmission in renewable integration, in the NAPCC and RE Missions scenarios, we restrict the inter-regional power transfer capacity to that estimated in the 13th Plan scenario (baseline). The following table shows the restricted inter-regional power transfer capacity:

Table 26: Restricted Inter-regional Power Transfer Capability

	Existing (June 2015)	Required Power Transfer Capacity in 2022		Restricted Capacity in 2022 (Same as 13th Plan Scenario)
		(NAPCC Scenario)	(RE Missions Scenario)	
East-North	15830	11215	12489	15830
East-South	3630	16563	18354	8656
East-West	10690	8717	6772	10690
NorthEast-East	2860	2907	3195	2914
North-West	8720	17315	15654	23173
West-South	5720	14731	20285	10896

It can be seen that West-South and East-South are the only transmission links where the transfer capacity is restricted relative to the NAPCC and RE Missions scenario. Therefore, this sensitivity analysis could also be seen as assessing the value of easing the transmission constraints to the southern region above 13th Plan Scenario.

The following table shows changes in the regional generation investment pattern as a result of the constrained transmission to the southern region.

Table 27: Regional Generation Capacity Built (Coal and Gas) between 2015 and 2022 and Average Cost of the Portfolio including Integration Costs (bus-bar) due to Constrained Transmission

	13th Plan (Original)		NAPCC				RE Missions			
			Original		Transmission Constrained		Original		Transmission Constrained	
	Coal	Gas	Coal	Gas	Coal	Gas	Coal	Gas	Coal	Gas
North	20,860	264	38,000	-	35,500	-	32,500	-	33,500	-
West	62,240	577	-	-	9,500	-	-	-	12,500	2,325
South	24,500	339	30,000	6,970	21,000	6,970	34,500	15,215	22,000	11,645
East	24,500	-	2,500	-	4,500	-	3,500	25	2,500	1,275
North-East	-	42	-	-	-	-	-	-	-	21
Total	**132,100**	**1,222**	**70,500**	**6,970**	**70,500**	**6,970**	**70,500**	**15,240**	**70,500**	**15,266**
Average Cost of Portfolio (incl integration cost) (Rs/kWh)	**4.00**		**4.07**		**4.08**		**4.12**		**4.13**	

The total generation capacity investments do not change as a result of the transmission constraint; but the regional distribution of that capacity changes. For example, in the transmission constrained RE Missions and NAPCC cases, the there is a need of about 12GW of additional coal capacity and 2.3GW of additional gas capacity in the Western region since South to West transmission is constrained. Similarly, in the Northern region, there is a need of additional 1 GW capacity since the South to East (and hence East-to North) transfer capacity is constrained. As a result, the average cost of generation changes – albeit the increase is very small. Average cost due to constrained transmission increases by Rs 0.01/kWh or about 0.3%. In short, the value of enhancing transmission connectivity to the Southern region over and above the 13th Plan scenario is about Rs 0.01/kWh. Intuitive explanation for this is that the excess transfer capacity required in both the RE dominant cases (over and above 13th Plan) is only moderate as explained previously.

5.1.4 Capital Cost of Renewable Technologies

We assess the impact of faster or slower reduction in RE capital costs on the average cost of generation in each scenario. The following table shows the solar PV capital costs in the sensitivity cases.

Table 28: Capital costs of Solar PV (Rs Cr/MW) in the Sensitivity Cases

	2015 Capital Cost (Rs Cr/MW)	Annual Average Rate of Reduction	2022 Capital Cost (Rs Cr/MW)
Baseline Capital Cost	5.87	4.7%	4.18
Slower Reduction in Cost	5.87	2.4%	4.96
Faster Reduction in Cost	5.87	7.1%	3.50

The following table shows the average cost of generation in the baseline as well as sensitivity cases for all scenarios:

Table 29: Average Cost of the Portfolio (including integration cost) at bus-bar (Rs/kWh) for Capital Cost Sensitivity Cases in all Scenarios

	13th Plan (Baseline)	13th Plan (Optimal Thermal Capacity)	NAPCC	RE Missions
Baseline	4.00	3.91	4.07	4.12
Slower Reduction in Cost	4.01	3.92	4.10	4.17
Faster Reduction in Cost	3.99	3.90	4.05	4.08

As expected, the average cost of the portfolio (including the integration cost) in the RE dominant scenarios drops significantly if the solar PV costs drop faster than expected. In fact, the cost differential between the 13th Plan scenario and the NAPCC scenario drops to 1.4% if the solar costs drop faster than expected; the differential for RE Missions scenario would be 2.2% relative to the 13th Plan scenario.

5.1.5 Fuel Prices

In order to assess the impact of volatility in the imported fuel prices due to market dynamics as well as the exchange rate fluctuations, we change the 2022 FOB imported coal, LNG and Diesel prices by +/-25%. The following table shows the fuel prices used in the sensitivity cases.

Table 30: Imported Fuel Prices (FOB) in the Sensitivity Cases

	Baseline	High Fuel Price Case	Low Fuel Price Case
Imported Coal ($/Ton)	82	102	61
LNG ($/MMBTU)	10.5	13.1	7.9
High Speed Diesel (Rs/lit)	50	63	38

The following charts show the total coal consumption and imports in each scenario for the sensitivity cases.

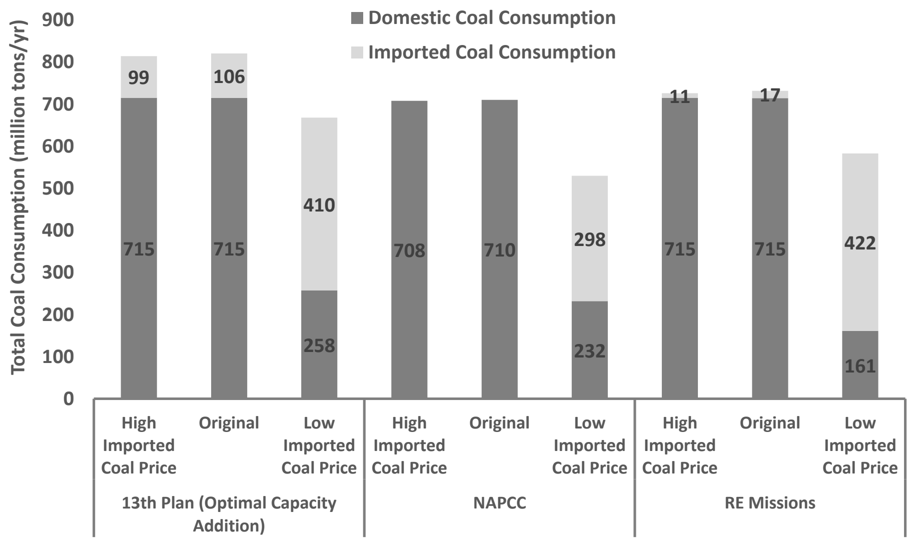


Figure 28: Sensitivity of Total Coal Consumption on Imported Coal Price

As expected, when the imported coal prices increase, its consumption drops and vice versa. Note that the imported coal calorific value is nearly 30% higher than that of the domestic coal; therefore, total coal consumption (in terms of million tons) would be lower in case imported coal consumption increases.

None of the scenarios need to import LNG for operating the gas power plants in the original as well as sensitivity cases. The domestic gas availability for the power sector, although constrained (26 bcm/yr or 72 mmscmd), is enough to operate the gas power plants, which are mainly used as peaking or balancing support. The following chart shows the coal and gas capacity built (between 2015 and 2022) in each of the sensitivity cases.

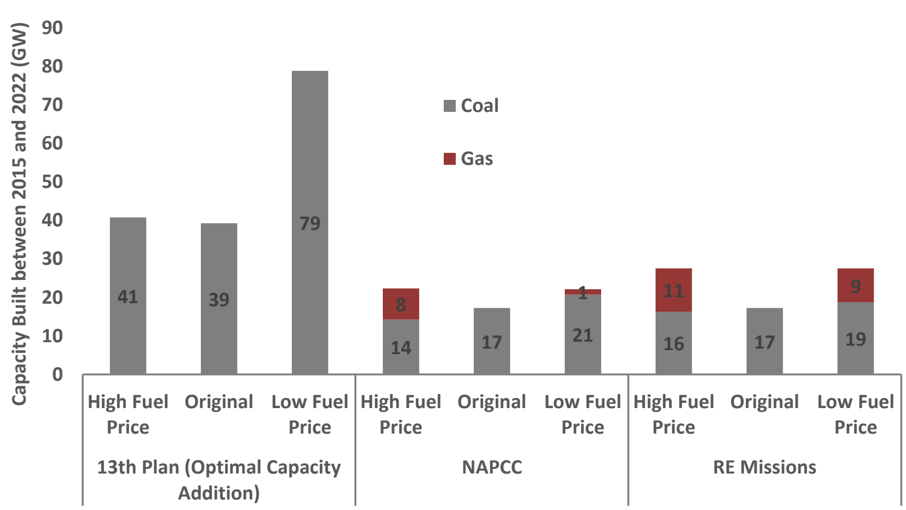


Figure 29: Capacity Built between 2015 and 2022 (GW): Impact of Changes in the Imported Fuel Prices

As expected, when the imported fuel prices increase, the coal capacity addition based on imported fuel reduces significantly in all scenarios and vice versa. In the high fuel price cases, the coal capacity investments are replaced by gas based capacity addition. But note that even when the gas based capacity increases, the total gas consumption is still lower than the constrained domestic gas availability for the power sector. The following chart shows the sensitivity of the average cost of the portfolio in 2022 on imported fuel prices.

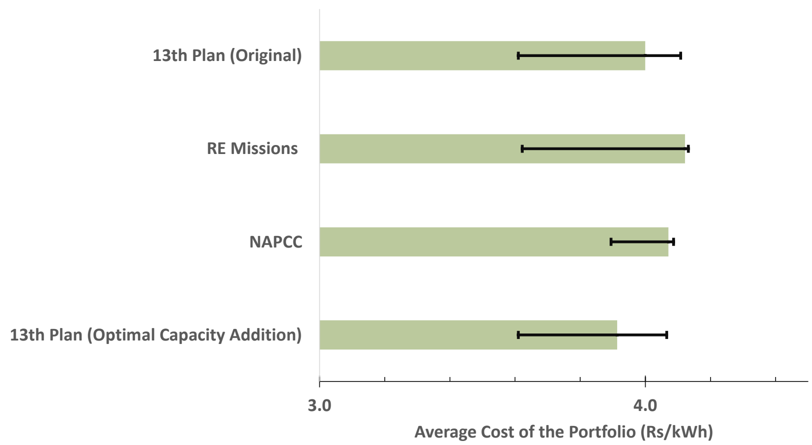


Figure 30: Sensitivity of Average Cost of the Portfolio on Imported Fuel Prices

In summary, both NAPCC and RE Missions scenarios are significantly less sensitive to the imported fuel price and supply risk relative to the 13th Plan scenario.

6 Conclusion

Given aggressive RE capacity targets set by India, there is significant discussion on the policy, regulatory and commercial strategies to integrate RE in the Indian power system. Although large scale RE grid integration has been analyzed widely in the US and European context, there is very limited literature in the Indian context. The objectives of our analysis are to assess the technical feasibility of integrating the large renewables capacity in India that has been planned in the near future, ascertain its impact on power sector investments and operations, and quantify the incremental cost of generation. We conduct the analysis by modeling the least cost generation investments and simulating economic dispatch for the financial year 2022 using PLEXOS for a variety of renewable energy penetration scenarios. We use a five node model of the Indian electric grid (one node each for every region viz. north, east, west, south, and north-east), which allows us to broadly assess the inter-regional power transfer capacities that may be needed for integrating the RE generation reliably. It is important to note that given the regional level resolution of the model, this analysis cannot answer questions on the intra-regional (across states within a region) and intra-state transmission and dispatch issues. Hence the results can be interpreted as what is needed for RE integration once the interstate transmission constraints are resolved and the balancing area for generation dispatch is expanded to the regional level.

In this analysis, we created three scenarios for renewable energy penetration for the financial year 2022 namely, (a) ***13th Plan***, that serves as the baseline and uses the generation capacity addition for all technologies as projected in the Government of India's 12th Plan (which has projections up to the end of the 13th Plan year, 2022), (b) ***National Action Plan on Climate Change (NAPCC)***, that models the renewable energy target described in India's NAPCC (2009); which, based on our projections would be ~20% electricity (by energy) by FY 2022, and (c) ***RE Missions***, that models the Government of India's announcement to increase the total installed capacity of solar projects to 100GW and wind projects to 60 GW by FY 2022.

We project hourly demand by region in 2022 using the Central Electricity Authority's demand projections in their 18th Electric Power Survey and the hourly demand patterns over the financial years 2010 through 2013 adjusting for rapid urbanization. We use actual hourly generation and solar irradiance (DNI and GHI) data to project the hourly wind and solar generation for 2022. We develop assumptions regarding operation and performance of generation technologies based on the historical actual data, capital and fixed cost based on existing regulations, and fuel prices based on long term historical trends. We then conduct sensitivity analysis on key parameters to assess the robustness of our findings.

By 2022, the coal capacity requirement in both NAPCC and RE Missions scenarios is significantly lower relative to the 13th Plan scenario (the baseline). However, significant gas based capacity needs to be added in both scenarios, which serves as the major source of additional flexibility for managing the RE variability. During summer (April-May) and monsoon (June through September) seasons, renewable energy can provide significant support during afternoon peak demand period; solar PVs in summer and wind in monsoon. However, in both seasons, gas based generation (or some form of flexible generation) is necessary to provide the evening ramp-up support and meet the evening peak demand especially after the solar generation drops rapidly. In Winter, when solar and wind generation both drop, gas based generation provides round the clock energy and load following support despite lower demand. This implies that the flexible resource used for grid integration in India should be able to provide cross-seasonal support. Hydro energy projects (reservoir type) would be able to offer such support – however, there are significant barriers to timely completion of large hydro projects. Gas based projects would also be ideal for such cross-seasonal support - however, gas availability in India is a major concern. One solution to that could be building on-site gas storage facility so gas power plants do not have to always have to depend on the pipeline gas for power generation. Other solution is building more gas power plants on the shore based on imported LNG – however, such approach may involve significant price and supply risks.

The regional diversity in renewable energy generation in India and its complementarity with demand as well as other RE resources help reducing the impact of extreme events such as sudden loss of RE generation or over-generation, etc. on the system. In this analysis, we have assumed future capacity addition in the renewable energy resources happens on the same sites as the current installed capacity. This is a highly conservative assumption for diversity and hence will significantly overestimate the variability in RE generation. Despite this, we found that the system can handle extreme events in RE generation – low and high generation and high variability. However, an implicit assumption in this analysis is the ability to perfectly forecast renewable energy generation on a day-ahead basis; RE forecasting is absolutely crucial for reliable grid integration. With newer state-of-the-art forecasting techniques, forecast errors have been reducing rapidly especially with the use of the real-time generation data. With installation of Renewable Energy Management Centers and the new forecasting regulations for the interstate RE generators, India has already started creating a robust framework for RE forecasting.

One of the key enablers of the reliable grid integration is the transmission network. In NAPCC and RE scenarios, there is a need to strengthen the transmission corridor to the Southern region. For example, moderate increases in the power transfer capacities would be required in the West-South corridor (increase by 3000 to 4000 MW relative to the 13th Plan) and East-South corridor (increase of 6000 to 8000 MW relative to the 13th Plan). One of the reasons for such moderate increase in the power transfer capacities is that the renewable resources are well distributed among northern (mostly solar and some wind), western (both solar and wind), and southern (mostly wind and some solar) regions. Note that in the RE dominant scenarios, some of the inter-regional interfaces would have to be used in both directions because of the seasonal and diurnal RE generation patterns. This implies that an appropriate policy and regulatory framework for moving power across regions more freely is crucial for RE integration. This could be achieved by creating robust markets and other measures such as intra-day and ancillary services market, imbalance markets or balancing area coordination etc.

The incremental cost of generation in NAPCC and RE Missions scenarios is found to be 1.8% and 3.1% higher than the 13th Plan respectively. There are three reasons for such moderate increase: (a) reduced investments in coal based capacity, (b) deep reduction in renewable capital cost, especially solar, and (c) avoided coal imports as result of increased RE penetration.

We conducted sensitivity analysis to assess the impact of each of these factors on generation investments and cost. If the generation capacity is optimally planned in the 13th Plan (or slippage in the capacity addition targets), the average cost of generation reduces to Rs 3.9/kWh, which increases the cost differential in the NAPCC and RE Missions scenarios to 4.0% and 5.3% respectively. If the renewable energy costs drop faster than the BAU, then the cost differential would reduce to 1.4% and 2.2% respectively for NAPCC and RE Missions scenarios. Also, average cost of generation in both these RE dominant scenarios is significantly less sensitive to the fuel price and supply risks relative to the 13th Plan; if by 2022, imported fuel prices are 25% more expensive than their projected prices, average cost of generation for the 13th Plan increases by 2.7% while that for the RE Missions and NAPCC scenarios increases by 0.4% and 0.1%.

Given the ambitious targets of renewable energy in the country, such studies that quantify the impact of large scale integration of RE as well as discussions on the potential policy, regulatory, and institutional framework are crucial. This study serves as the first one of our forthcoming series on RE grid integration in India. However, note that this analysis is based on significant simplifications and assumptions especially regarding the transmission system and the deviation settlement mechanism. Therefore, the results and conclusions presented in the paper, especially about the generation and transmission system investments should be viewed only as high-level indications of the impacts of the aggressive penetration of renewable energy on the Indian grid. Significant refinement to this analysis would be necessary for actual power system planning purposes.

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Annexure 1: Assumptions on Operational Characteristics of Generating Plants

Generator Technology	Region	Generator_Name	Average Unit Size (MW)	Min Stable Factor (%)	Heat Rate (GJ/MWh)	Start Cost ($)	Shutdo wn Cost ($)	Min Up Time (hrs)	Min Down Time (hrs)	Max Ramp Up (MW/min.)	Max Ramp Down (MW/min.)	Auxiliary Consump tion (%)	Planned Mainte nance Rate (%)	Forced Outage Rate (%)
Biomass+Cogen	East	ER_Biomass	20	20	16	100	100	1	1	0.5	0.5	10	10	10
Biomass+Cogen	North	NR_Biomass	20	20	16	100	100	1	1	0.5	0.5	10	10	10
Biomass+Cogen	South	SR_Biomass	20	20	16	100	100	1	1	0.5	0.5	10	10	10
Biomass+Cogen	West	WR_Biomass	20	20	16	100	100	1	1	0.5	0.5	10	10	10
Coal	East	ER_Old_<210	87	60	12	8741	8741	48	24	0.87	0.87	10.6	12.3	32.9
Coal	East	ER_Old_210/250	220	60	11.2	22000	22000	48	24	2.2	2.2	9	2.8	11.9
Coal	East	ER_Old_500/600	516	60	10.8	51579	51579	48	24	5.16	5.16	6.5	4.9	11.8
Coal	East	ER_Old_660	660	60	10	66000	66000	48	24	6.6	6.6	8.1	5	11.8
Coal	East	ER_Old_Other	390	60	11	39000	39000	48	24	3.9	3.9	10.5	0.9	18.6
Coal	East	ER_SuperCritical	660	50	9	66000	66000	48	24	6.6	6.6	8	5	5
Coal	North_East	NER_Old	30	0	12	3000	3000	48	24	0.3	0.3	10.6	0	100
Coal	North	NR_Old_<210	114	60	12.2	11378	11378	48	24	1.14	1.14	10.6	13.3	14
Coal	North	NR_Old_210/250	222	60	11.4	22238	22238	48	24	2.22	2.22	9	3.6	8.4
Coal	North	NR_Old_500/600	531	60	10.8	53077	53077	48	24	5.31	5.31	6.5	5.5	5
Coal	North	NR_Old_660	660	60	9.7	66000	66000	48	24	6.6	6.6	8.1	5	5
Coal	North	NR_Old_Other	348	60	10.8	34750	34750	48	24	3.48	3.48	10.5	1.2	19.2
Coal	North	NR_SuperCritical	660	50	9	66000	66000	48	24	6.6	6.6	8	5	5
Coal	South	SR_Old_<210	99	60	12.2	9925	9925	48	24	0.99	0.99	10.6	3.7	10.9
Coal	South	SR_Old_210/250	215	60	11.4	21455	21455	48	24	2.15	2.15	9	5.6	5.7
Coal	South	SR_Old_500/600	512	60	10.8	51176	51176	48	24	5.12	5.12	6.5	3.7	3.5
Coal	South	SR_Old_660	660	60	9.7	66000	66000	48	24	6.6	6.6	8.1	5	3.5
Coal	South	SR_Old_Other	300	60	10.8	30000	30000	48	24	3	3	10.5	8.2	8.6
Coal	South	SR_SuperCritical	660	50	9	66000	66000	48	24	6.6	6.6	8	5	5
Coal	West	WR_Old_<210	106	60	12.2	10603	10603	48	24	1.06	1.06	10.6	6.1	22.9
Coal	West	WR_Old_210/250	220	60	11.4	21968	21968	48	24	2.2	2.2	9	6	7.2
Coal	West	WR_Old_500/600	505	60	10.8	50500	50500	48	24	5.05	5.05	6.5	3.6	4.3
Coal	West	WR_Old_660	774	60	9.7	77429	77429	48	24	7.74	7.74	8.1	0	15.4
Coal	West	WR_Old_Other	312	60	10.8	31200	31200	48	24	3.12	3.12	10.5	1.3	10.8
Coal	West	WR_SuperCritical	660	50	9	66000	66000	48	24	6.6	6.6	8	5	5
Diesel	East	ER_Diesel	17.2	0	13.5	100	100			17.2	17.2	1	5	5
Diesel	North_East	NER_Diesel	60	0	13.5	100	100			17.2	17.2	1	5	5

Generator Technology	Region	Generator_Name	Average Unit Size (MW)	Min Stable Factor (%)	Heat Rate (GJ/MWh)	Start Cost ($)	Shutdown Cost ($)	Min Up Time (hrs)	Min Down Time (hrs)	Max Ramp Up (MW/min.)	Max Ramp Down (MW/min.)	Auxiliary Consumption (%)	Planned Maintenance Rate (%)	Forced Outage Rate (%)
Diesel	North	NR_Diesel	13	0	13.5	100	100			13	13	1	5	5
Diesel	South	SR_Diesel	50	0	13.5	100	100			50	50	1	5	5
Diesel	West	WR_Diesel	17.5	0	13.5	100	100			17.5	17.5	1	5	5
Gas_CCGT	East	ER_CC_GT	25	10	12	250	250	1	1	2.5	2.5	1	5	5
Gas_CCGT	East	ER_CC_ST	11	40	14	1100	1100	6	6	0.04	0.04	5	10	10
Gas_CCGT	North_East	NER_CC_GT	21	10	12	214	214	1	1	2.14	2.14	1	5	5
Gas_CCGT	North_East	NER_CC_ST	11	40	14	1100	1100	6	6	0.04	0.04	5	10	10
Gas_CCGT	North	NR_CC_GT	79	10	12	794	794	1	1	7.94	7.94	1	5	5
Gas_CCGT	North	NR_CC_ST	106	40	14	10589	10589	6	6	0.39	0.39	5	10	10
Gas_CCGT	South	SR_CC_GT	85	10	12	852	852	1	1	8.52	8.52	1	5	5
Gas_CCGT	South	SR_CC_ST	84	40	14	8380	8380	6	6	0.31	0.31	5	10	10
Gas_CCGT	West	WR_CC_GT	155	10	12	1552	1552	1	1	15.52	15.52	1	5	5
Gas_CCGT	West	WR_CC_ST	112	40	14	11250	11250	6	6	0.41	0.41	5	10	10
Gas_CT	East	ER_CT	50	10	12	0	0	1	1	5	5	1	5	5
Gas_CT	North_East	NER_CT	50	10	12	0	0	1	1	5	5	1	5	5
Gas_CT	North	NR_CT	50	10	12	0	0	1	1	5	5	1	5	5
Gas_CT	South	SR_CT	50	10	12	0	0	1	1	5	5	1	5	5
Gas_CT	West	WR_CT	50	10	12	0	0	1	1	5	5	1	5	5
Hydro_Large	East	ER_Hydro_<=100	50	0	0	0	0			5	5	1	5	5
Hydro_Large	East	ER_Hydro_>100	150	0	0	0	0			15	15	1	5	5
Hydro_Large	North_East	NER_Hydro_<=100	29	0	0	0	0			2.9	2.9	1	5	5
Hydro_Large	North_East	NER_Hydro_>100	139	0	0	0	0			13.9	13.9	1	5	5
Hydro_Large	North	NR_Hydro_<=100	60	0	0	0	0			6	6	1	5	5
Hydro_Large	North	NR_Hydro_>100	163	0	0	0	0			16.3	16.3	1	5	5
Hydro_Large	South	SR_Hydro_<=100	29	0	0	0	0			2.9	2.9	1	5	5
Hydro_Large	South	SR_Hydro_>100	118	0	0	0	0			11.8	11.8	1	5	5
Hydro_Large	West	WR_Hydro_<=100	44	0	0	0	0			4.4	4.4	1	5	5
Hydro_Large	West	WR_Hydro_>100	154	0	0	0	0			15.4	15.4	1	5	5
Hydro_Small	East	ER_SmallHydro	20	0	0	0	0			20	20	1	5	5
Hydro_Small	North_East	NER_SmallHydro	20	0	0	0	0			20	20	1	5	5
Hydro_Small	North	NR_SmallHydro	20	0	0	0	0			20	20	1	5	5
Hydro_Small	South	SR_SmallHydro	20	0	0	0	0			20	20	1	5	5
Hydro_Small	West	WR_SmallHydro	20	0	0	0	0			20	20	1	5	5
Pumped Storage	East	ER_Hydro_PS	163	0	10	0	0			16.3	16.3	1	5	5
Pumped Storage	North_East	NER_Hydro_PS	142	0	10	0	0			14.2	14.2	1	5	5
Pumped Storage	North	NR_Hydro_PS	142	0	10	0	0			14.2	14.2	1	5	5

Generator Technology	Region	Generator_Name	Average Unit Size (MW)	Min Stable Factor (%)	Heat Rate (GJ/MWh)	Start Cost ($)	Shutdown Cost ($)	Min Up Time (hrs)	Min Down Time (hrs)	Max Ramp Up (MW/min.)	Max Ramp Down (MW/min.)	Auxiliary Consumption (%)	Planned Maintenance Rate (%)	Forced Outage Rate (%)
Pumped Storage	South	SR_Hydro_PS	130	0	10	0	0			13	13	1	5	5
Pumped Storage	West	WR_Hydro_PS	142	0	10	0	0			14.2	14.2	1	5	5
Run of River	East	ER_Hydro_ROR	48	0	0	0				4.8	4.8	1	5	5
Run of River	North_East	NER_Hydro_ROR	63	0	0	0				6.3	6.3	1	5	5
Run of River	North	NR_Hydro_ROR	68	0	0	0				6.8	6.8	1	5	5
Run of River	South	SR_Hydro_ROR	21	0	0	0				2.1	2.1	1	5	5
Run of River	West	WR_Hydro_ROR	46	0	0	0				4.6	4.6	1	5	5
Nuclear	East	ER_Nuclear	410	70	10	100000	100000	12	12	0.1	0.1	10	10	10
Nuclear	North	NR_Nuclear	410	70	10	100000	100000	12	12	0.1	0.1	10	10	10
Nuclear	South	SR_Nuclear	410	70	10	100000	100000	12	12	0.1	0.1	10	10	10
Nuclear	West	WR_Nuclear	410	70	10	100000	100000	12	12	0.1	0.1	10	10	10

Annexure 2: Monthly Energy and Peak Demand Projections in Each Region

Table 31: Projected Monthly Peak Demands in GW (bus-bar) for the Financial Year 2022

Month	East	North	North_East	South	West	All-India
April, 2021	33.2	77.8	3.1	81.8	87.0	279
May, 2021	34.3	86.7	3.5	81.4	86.6	287
June, 2021	34.1	91.6	3.6	81.7	84.9	287
July, 2021	33.8	90.6	3.5	74.1	77.0	277
August, 2021	34.0	88.6	3.5	74.8	77.2	270
September, 2021	35.6	87.7	3.4	76.0	79.8	271
October, 2021	34.6	80.2	3.2	77.7	82.7	275
November, 2021	33.2	72.3	2.9	72.8	78.2	258
December, 2021	30.6	74.7	2.9	70.7	76.4	247
January, 2022	31.3	84.3	3.2	66.8	72.4	251
February, 2022	31.5	75.4	2.9	70.0	73.8	246
March, 2022	33.6	78.5	3.1	77.9	81.8	265
Annual FY 2022	35.6	91.6	3.6	81.8	87.0	287

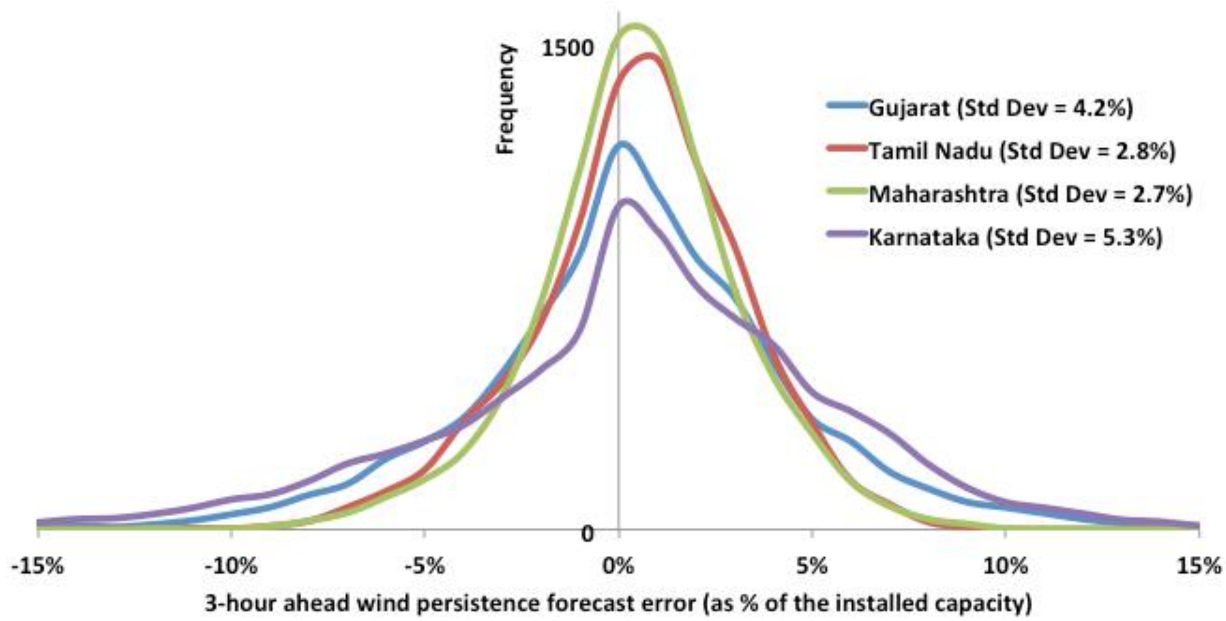
Table 32: Projected Monthly Energy Demand in TWh (bus-bar) for Financial Year 2022

Month	East	North	North_East	South	West	All-India
April, 2021	20	48	1.9	46	50	166
May, 2021	21	56	2.2	47	51	178
June, 2021	21	56	2.2	44	46	170
July, 2021	22	58	2.3	43	44	169
August, 2021	22	57	2.2	43	44	168
September, 2021	20	50	2.0	42	44	159
October, 2021	21	49	1.9	46	48	166
November, 2021	18	41	1.6	41	44	145
December, 2021	18	44	1.7	38	42	144
January, 2022	18	48	1.8	38	41	147
February, 2022	16	41	1.6	37	39	134
March, 2022	20	47	1.8	45	47	161
Annual FY 2022	237	594	23.2	511	540	1,906

Annexure 3: Renewable Energy Forecast

India has implemented a framework mandating the RE generators to provide day-ahead forecasts in early 2016. However, such forecast data is not yet available publicly. Therefore, we have created the day-ahead RE and load forecasts based on simple trend and persistence analysis. The following charts show the 3-hour ahead forecast errors (expressed as a fraction of the annual mean).

Wind Forecast Errors (3-hour ahead):

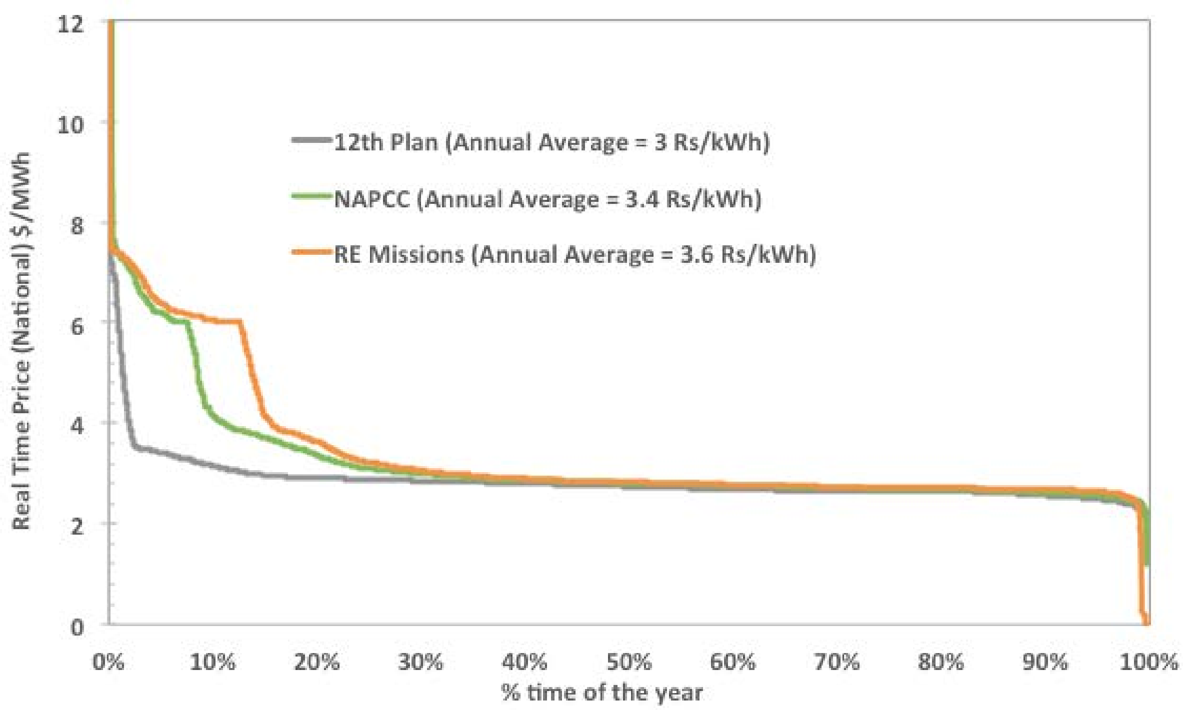


The standard deviation of the forecast errors range from 2.7% to 5.3% of the installed capacity depending on the state. This means that on any given day, there is a 68% chance that the 3-hour-ahead persistence forecast error would be 2.7% of the installed capacity in Maharashtra while there is 95% chance that the 3-hour ahead persistence forecast error would be 5.4% of the installed capacity in Maharashtra (2 standard deviations). Note that these forecasts are developed using simple persistence method; with state of the art weather forecast techniques using real-time weather data, the forecast errors could be reduced significantly. In 2015, using the state of the art forecasting techniques, the 1-hour ahead wind forecast errors in Texas are as low as 4-5%.

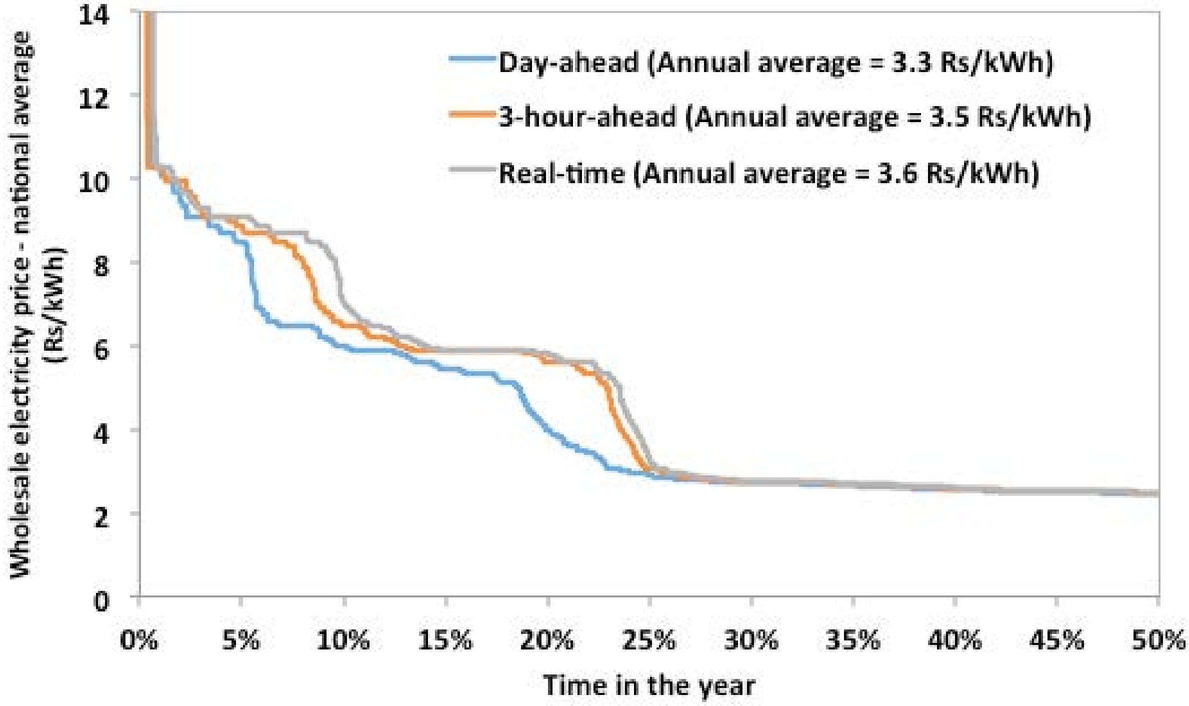
Annexure 4: Day-Ahead and Real-Time Prices

The following charts show the day-ahead price duration curves in each scenario. Note that these prices are based on the schedules updated up to an hour in advance; therefore these could be considered as a the hour-ahead prices as well. Since we do not have all the existing contracts and self-scheduling modeled in the system, these prices are essentially the variable generation cost of the marginal unit on the system in each hour. One can see that in certain instances when the marginal unit on the system is gas CT or diesel CT, the system price is very high. Also, note that we have shown a single electricity price for the entire nation. Indian does not have locational marginal prices, but instead it operates a zonal market. Therefore, in reality, the wholesale electricity prices would be different in each zone if there are transmission constraints. However, since we have not assumed any transmission constraints, prices in all zones are almost identical; they are only different by the transmission wheeling charge between the two zones.

The following chart shows the real time prices in each scenario. As explained previously, these prices should be taken indicatively since what they represent is essentially the variable cost of electricity generation of the marginal unit on the system in that hour.



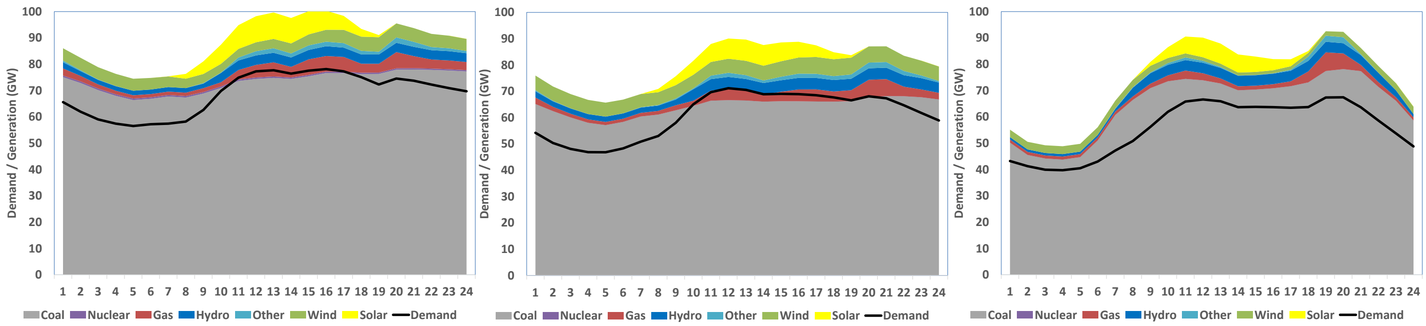
The following chart shows the differences in the day-ahead, intra-day and real time prices in the RE missions scenario:


Day-ahead (Annual average = 3.3 Rs/kWh)
3-hour-ahead (Annual average = 3.5 Rs/kWh)
Real-time (Annual average = 3.6 Rs/kWh)
Wholesale electricity price - national average (Rs/kWh)
Time in the year
0
2
4
6
8
10
12
14
0%
5%
10%
15%
20%
25%
30%
35%
40%
45%
50%

Annexure 5: Generation by Region and Inter-Regional Flows in 2022

6.1 Hourly Regional Dispatch - 13th Plan Scenario

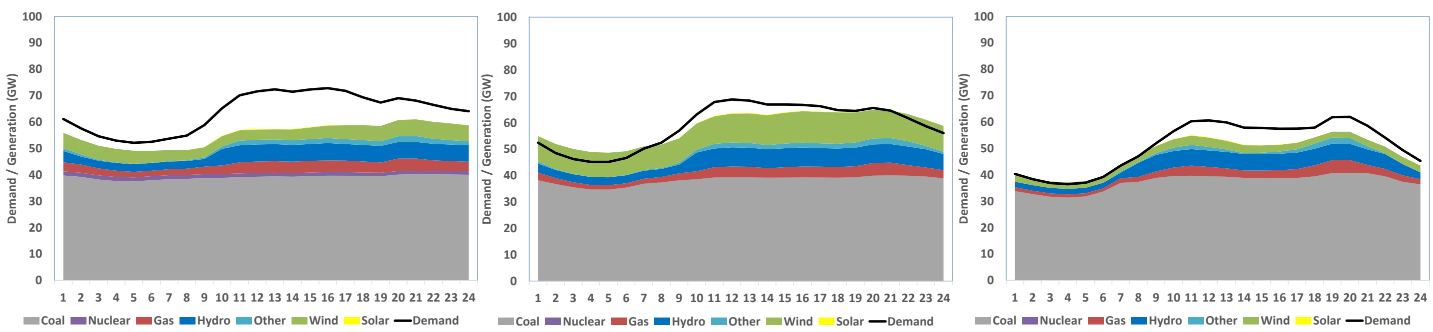
6.1.1 Western Region



(a) Summer **(b) Monsoon** **(c) Winter**

Figure 31: Average Regional Hourly Dispatch in the Western Region by Season in FY 2022 (13th Plan Scenario)

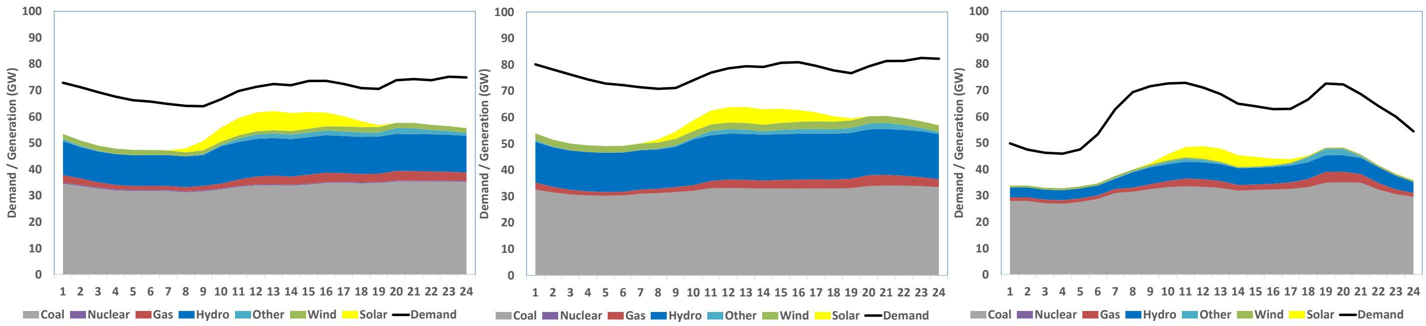
6.1.2 Southern Region



(a) Summer **(b) Monsoon** **(c) Winter**

Figure 32: Average Regional Hourly Dispatch in the Southern Region by Season in FY 2022 (13th Plan Scenario)

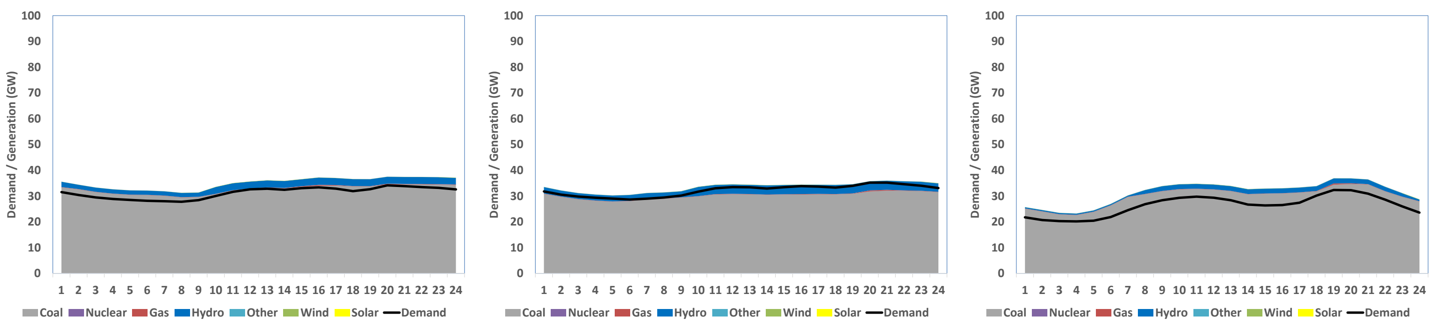
6.1.3 Northern Region



(a) Summer (b) Monsoon (c) Winter

Figure 33: Average Regional Hourly Dispatch in the Northern Region by Season in FY 2022 (13th Plan Scenario)

6.1.4 Eastern + North-Eastern Region



(a) Summer (b) Monsoon (c) Winter

Figure 34: Average Regional Hourly Dispatch in the Eastern and North-Eastern Region by Season in FY 2022 (13th Plan Scenario)

6.1.5 Inter-Regional Transmission Flows

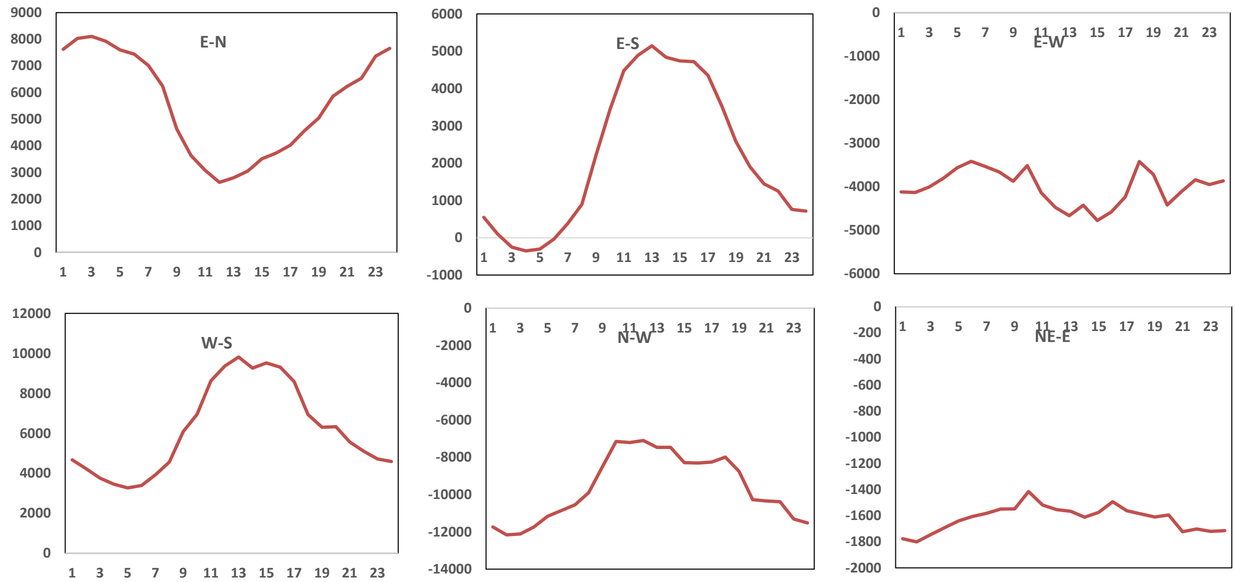


Figure 35: Average Hourly Inter-Regional Transmission Flows during Summer in FY 2022 (13th Plan Scenario)

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

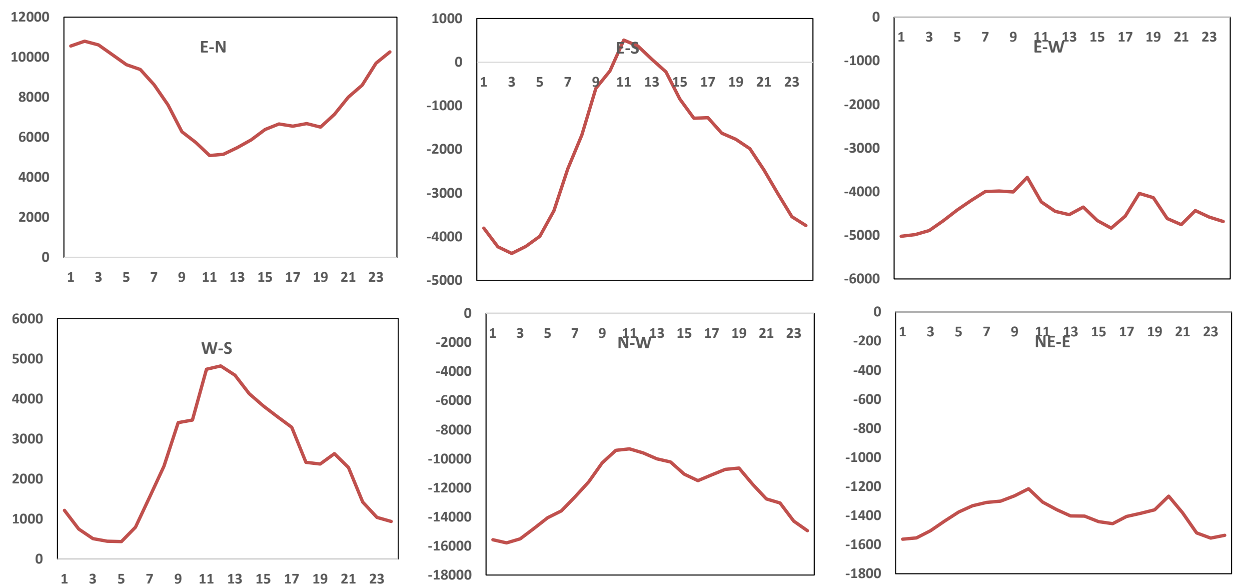


Figure 36: Average Hourly Inter-Regional Transmission Flows during Monsoon in FY 2022 (13th Plan Scenario)

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

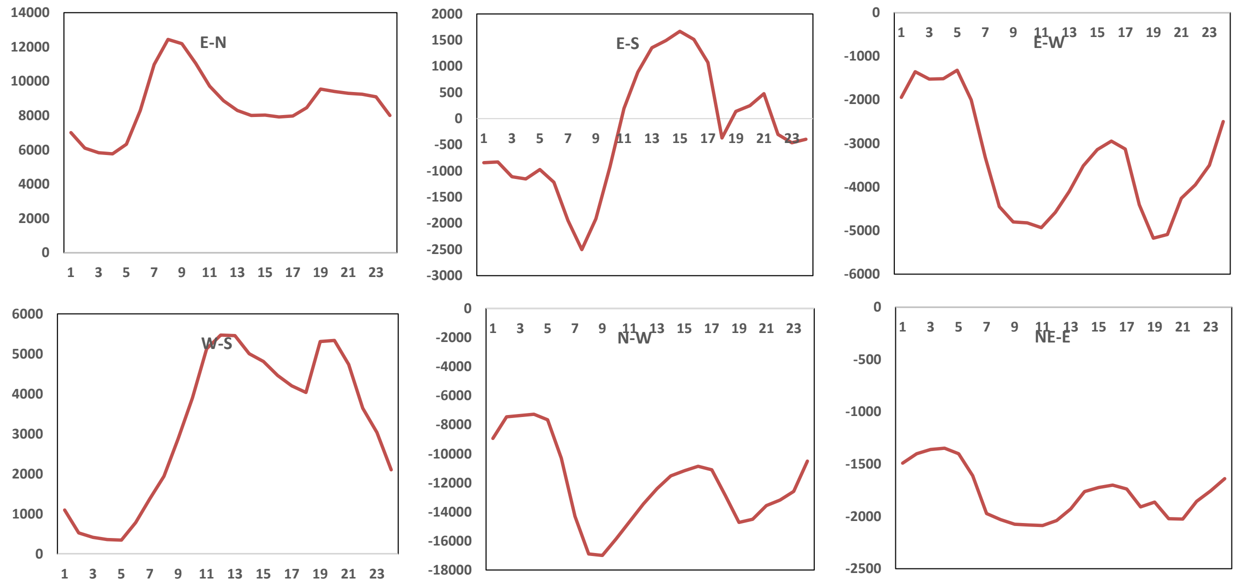
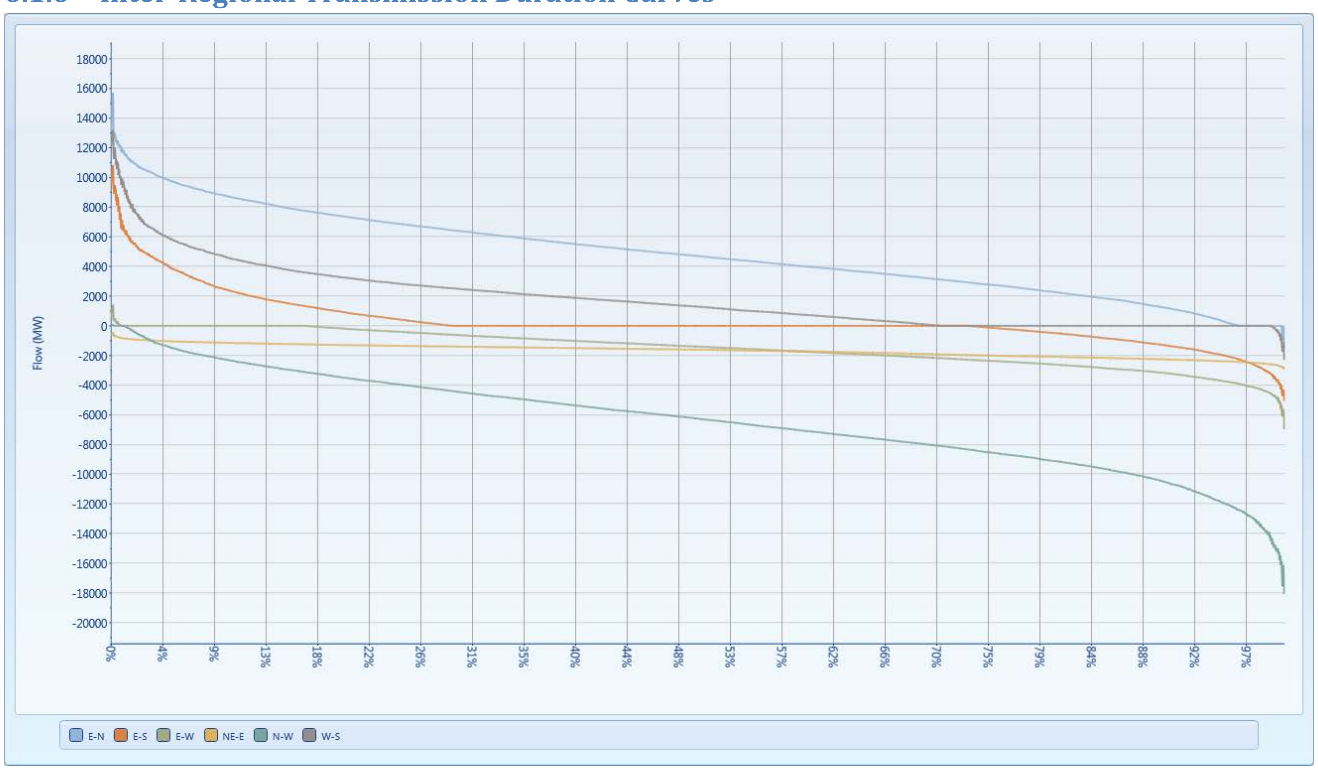


Figure 37: Average Hourly Inter-Regional Transmission Flows during Winter in FY 2022 (13th Plan Scenario)

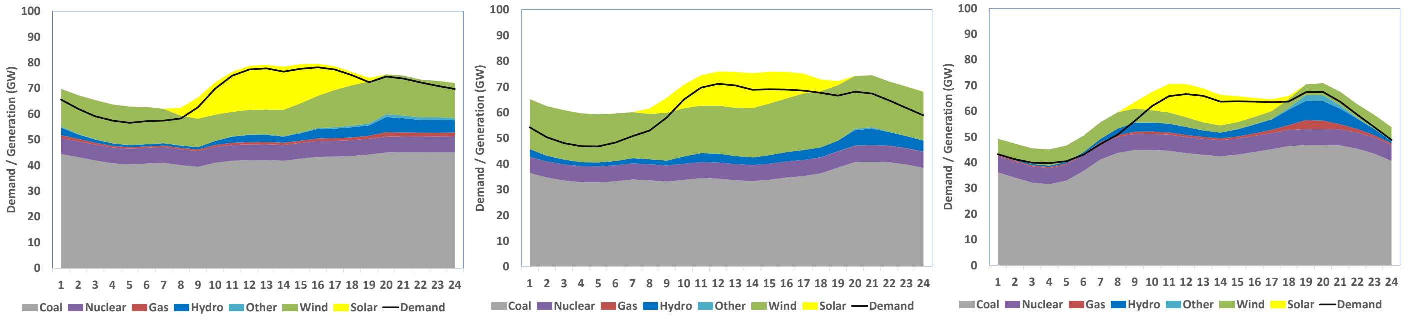
Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

6.1.6 Inter-Regional Transmission Duration Curves



6.2 Hourly Regional Dispatch - NAPCC Scenario

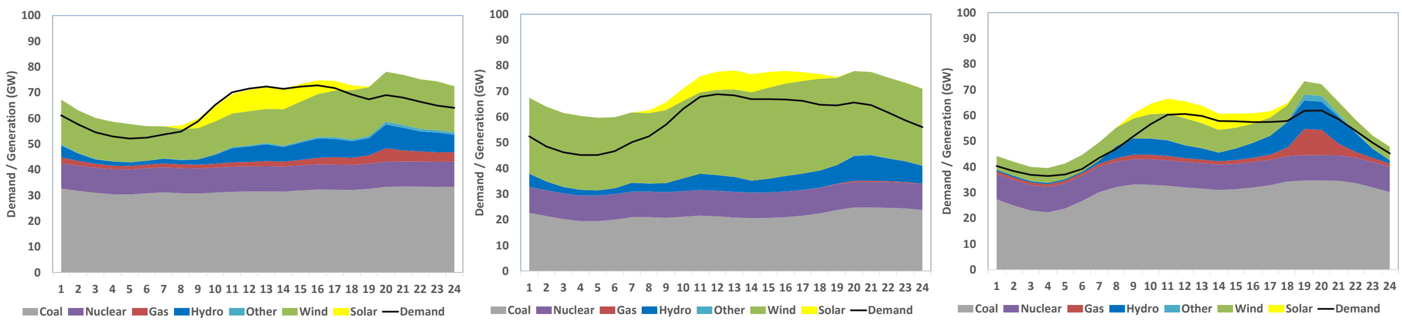
6.2.1 Western Region



(a) Summer (b) Monsoon (c) Winter

Figure 38: Average Regional Hourly Dispatch in the Western Region by Season in FY 2022 (NAPCC Scenario)

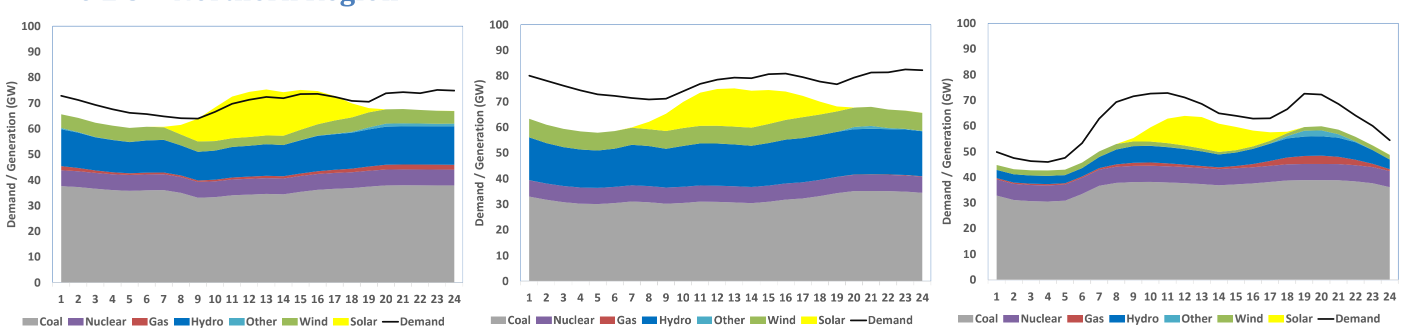
6.2.2 Southern Region



(a) Summer (b) Monsoon (c) Winter

Figure 39: Average Regional Hourly Dispatch in the Southern Region by Season in FY 2022 (NAPCC Scenario)

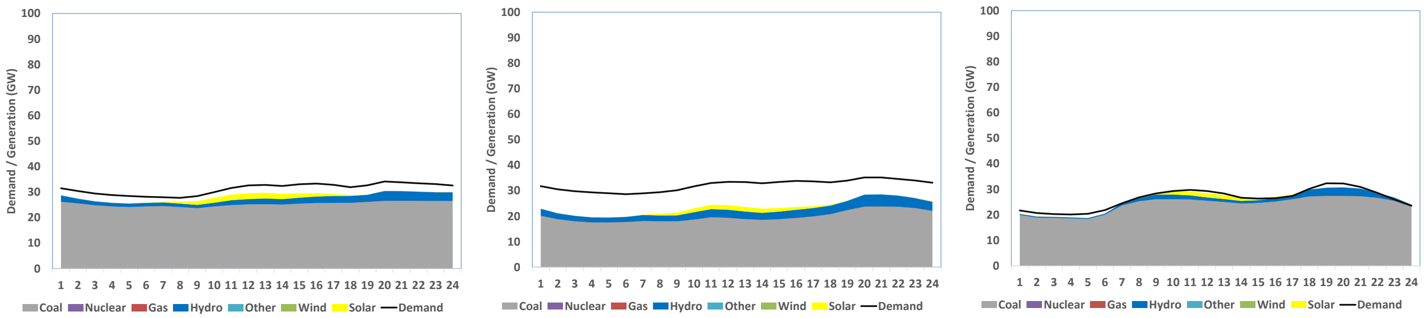
6.2.3 Northern Region



(a) Summer (b) Monsoon (c) Winter

Figure 40: Average Regional Hourly Dispatch in the Northern Region by Season in FY 2022 (NAPCC Scenario)

6.2.4 East + North_Eastern Regions (Combined)



(a) Summer **(b) Monsoon** **(c) Winter**

Figure 41: Average Regional Hourly Dispatch in the Eastern and North-Eastern Region by Season in FY 2022 (NAPCC Scenario)

6.2.5 Inter-Regional Transmission Flows

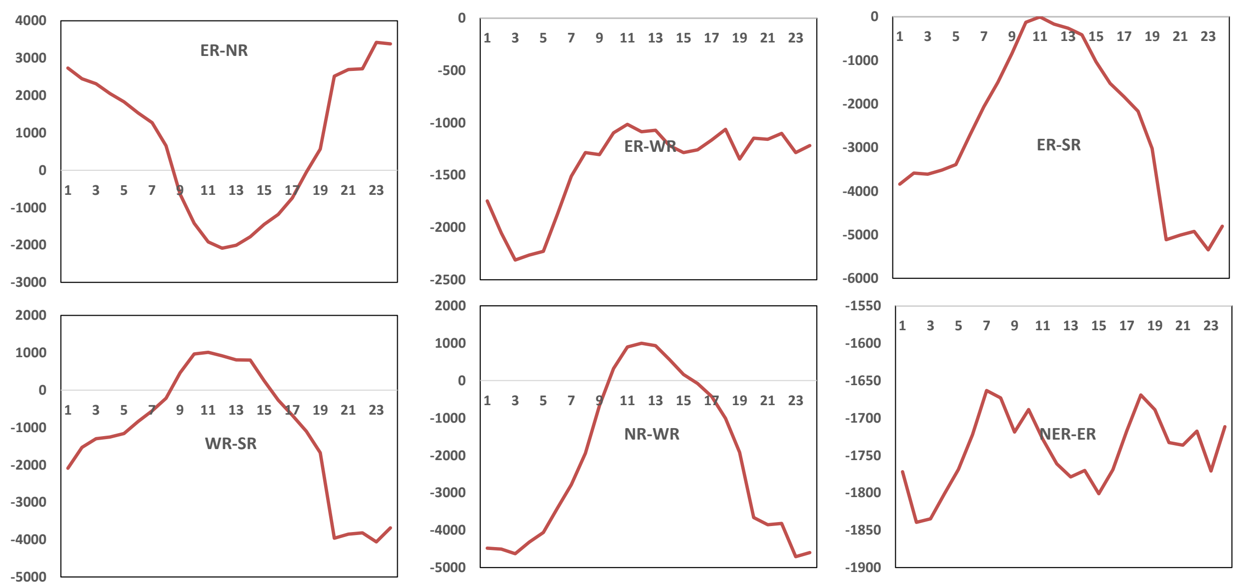


Figure 42: Average Hourly Inter-Regional Transmission Flows during Summer in FY 2022 (NAPCC Scenario)

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

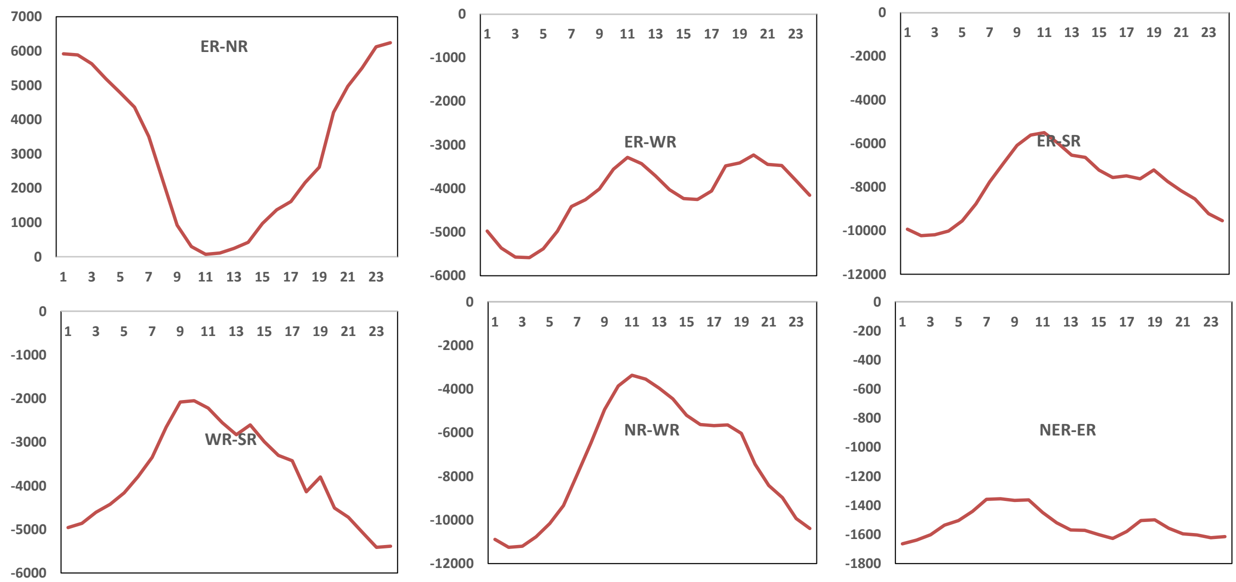


Figure 43: Average Hourly Inter-Regional Transmission Flows during Monsoon in FY 2022 (NAPCC Scenario)

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

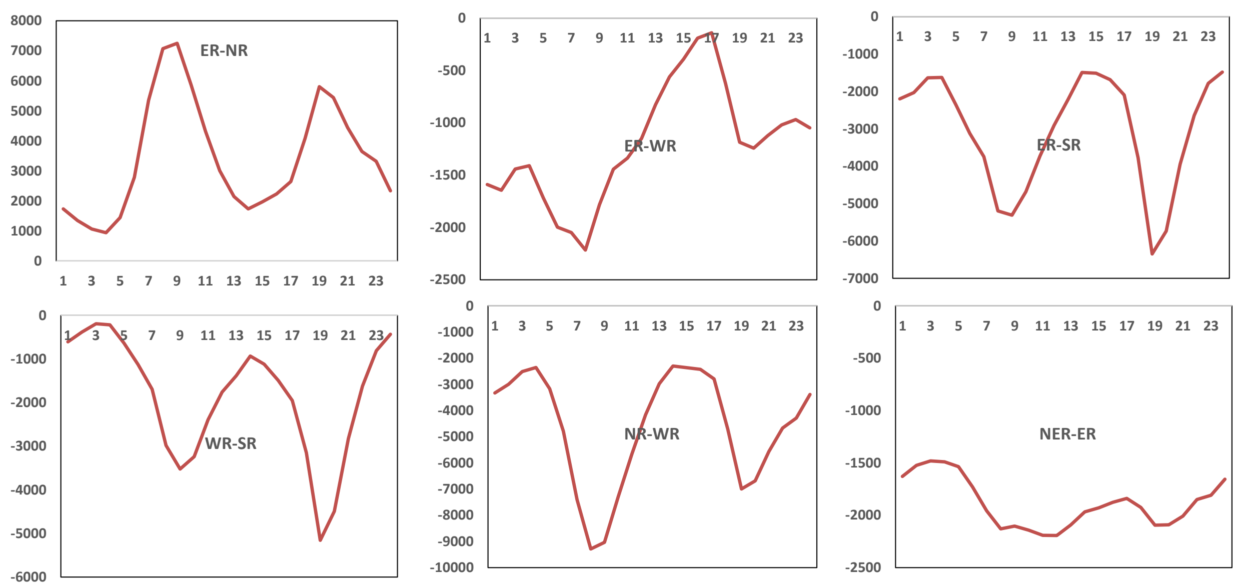
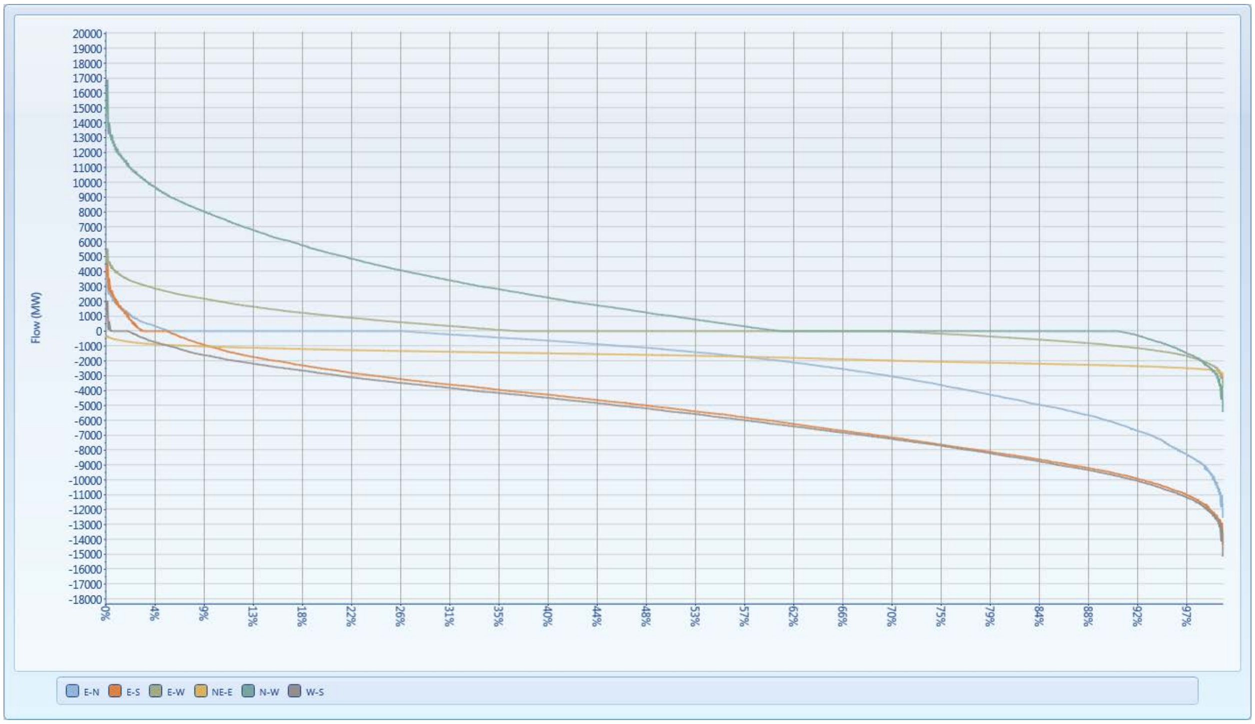


Figure 44: Average Hourly Inter-Regional Transmission Flows during Winter in FY 2022 (NAPCC Scenario)

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

6.2.6 Inter-Regional Transmission Duration Curves



6.3 Hourly Regional Dispatch – RE Missions Scenario

6.3.1 Western Region

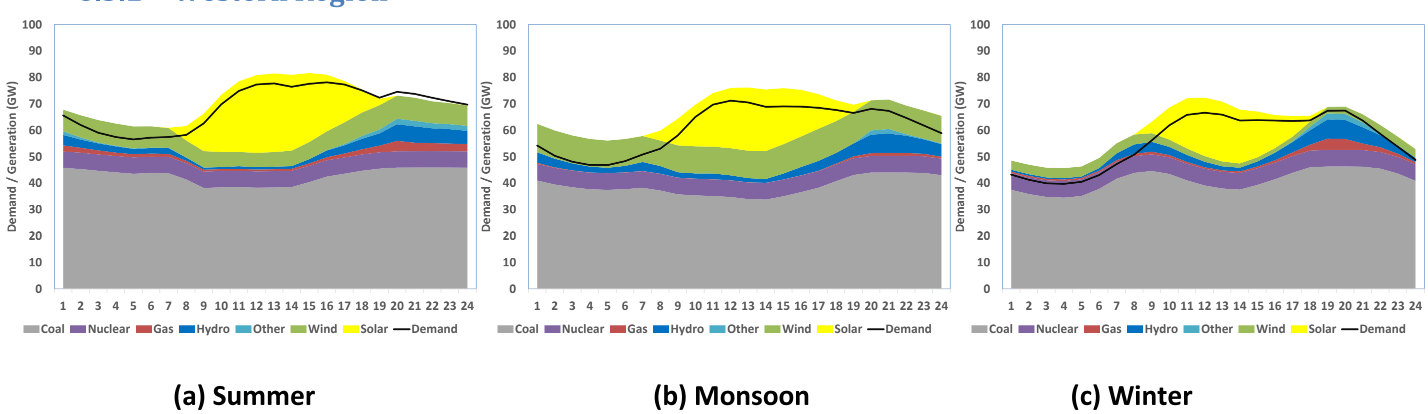
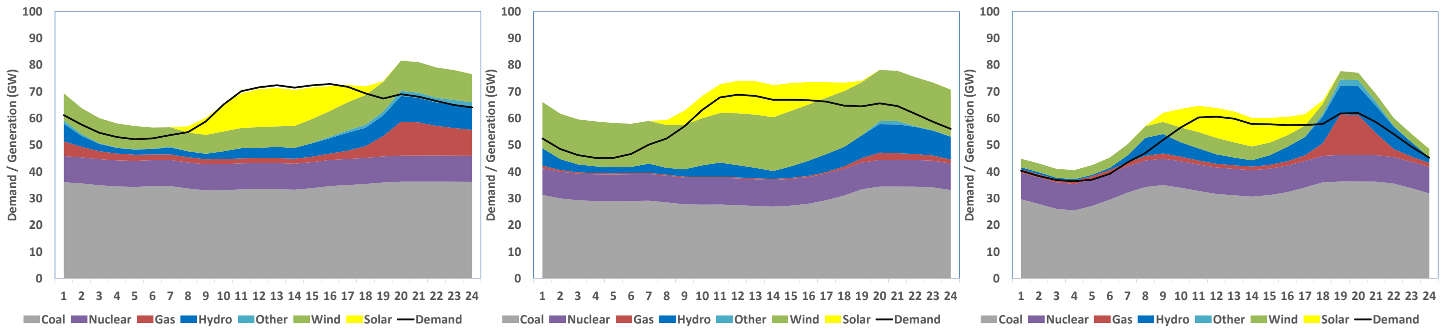


Figure 45: Average Regional Hourly Dispatch in the Western Region by Season in FY 2022 (RE Missions Scenario)

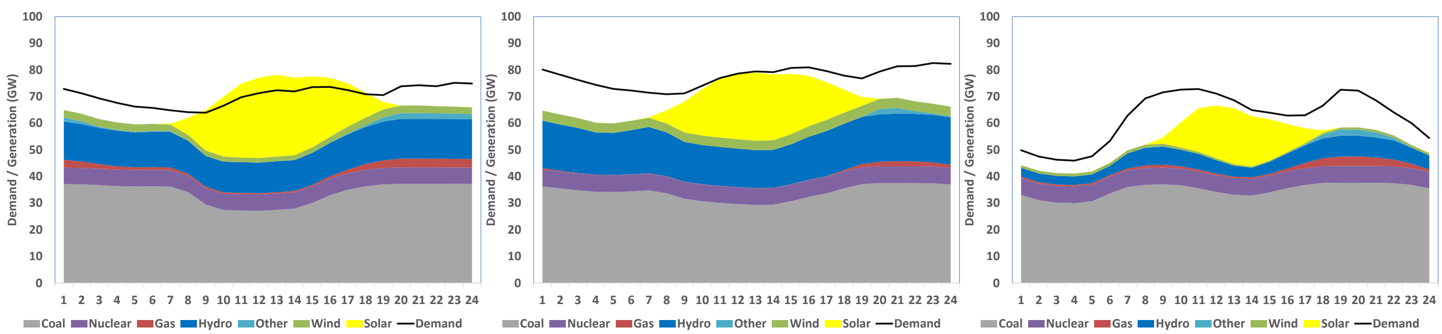
6.3.2 Southern Region



(a) Summer **(b) Monsoon** **(c) Winter**

Figure 46: Average Regional Hourly Dispatch in the Southern Region by Season in FY 2022 (RE Missions Scenario)

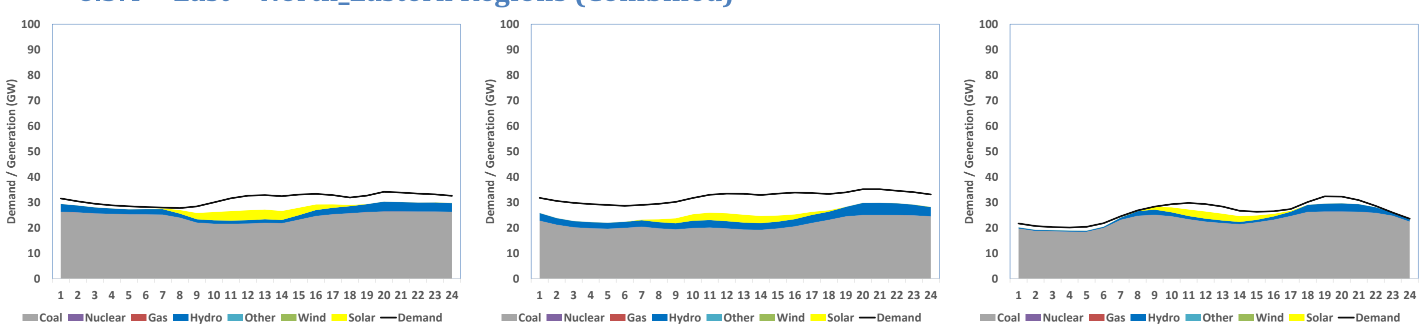
6.3.3 Northern Region



(a) Summer **(b) Monsoon** **(c) Winter**

Figure 47: Average Regional Hourly Dispatch in the Northern Region by Season in FY 2022 (RE Missions Scenario)

6.3.4 East + North_Eastern Regions (Combined)



(a) Summer **(b) Monsoon** **(c) Winter**

Figure 48: Average Regional Hourly Dispatch in the Eastern and North-Eastern Region by Season in FY 2022 (RE Missions Scenario)

6.3.5 Inter-Regional Transmission Flows

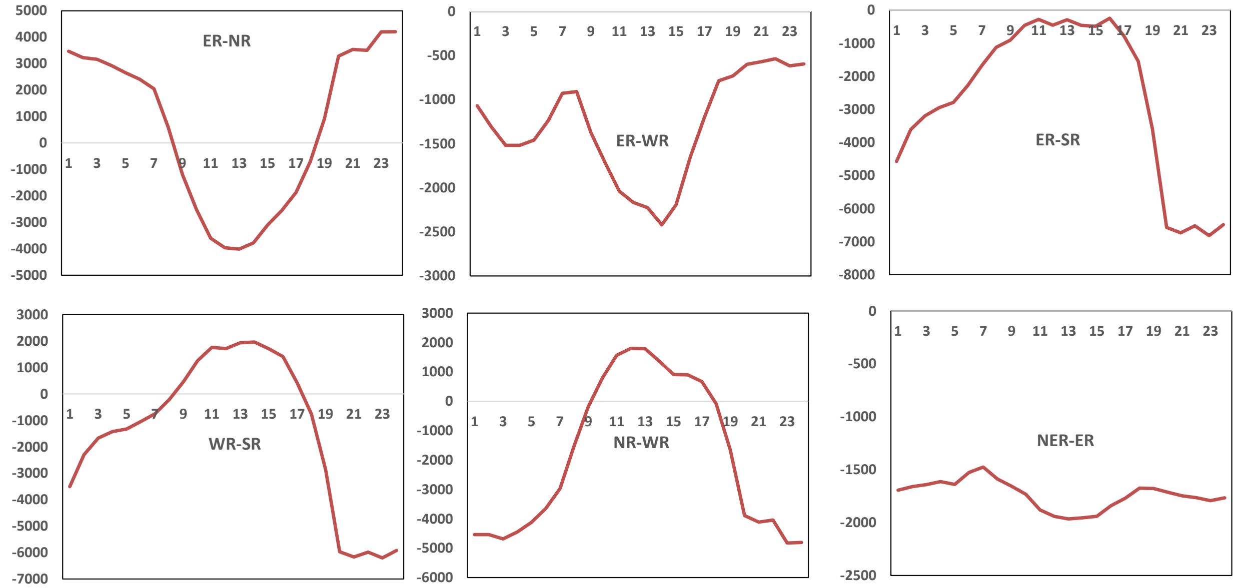


Figure 49: Average Hourly Inter-Regional Transmission Flows during Summer in FY 2022 (RE Missions Scenario)

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

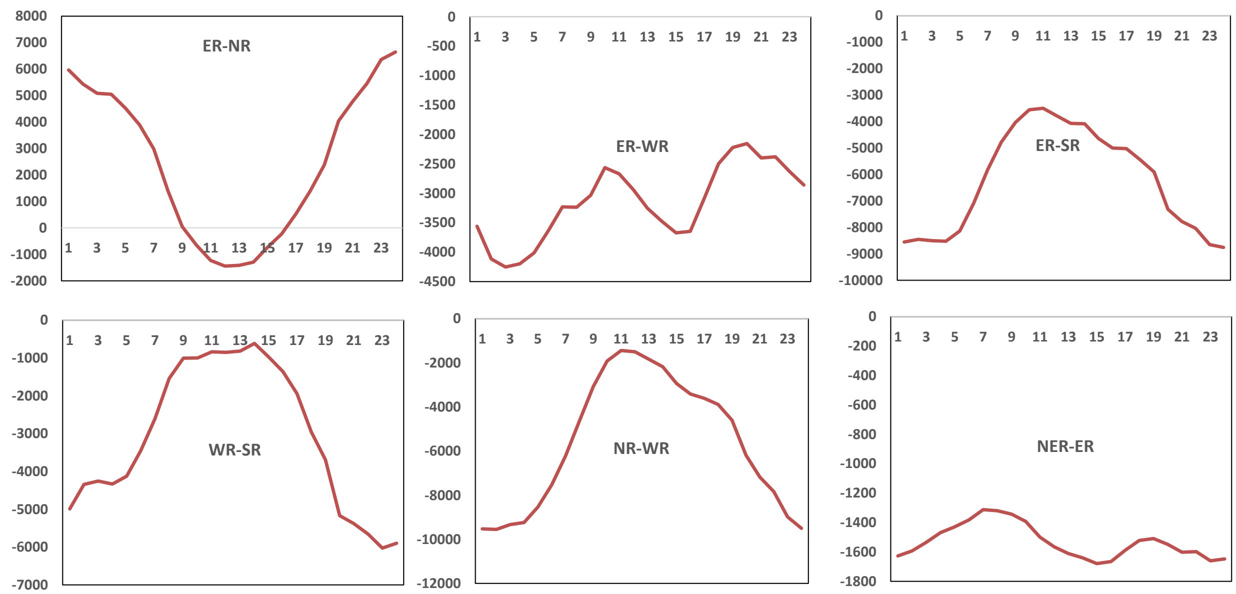


Figure 50: Average Hourly Inter-Regional Transmission Flows during Monsoon in FY 2022 (RE Missions Scenario)

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

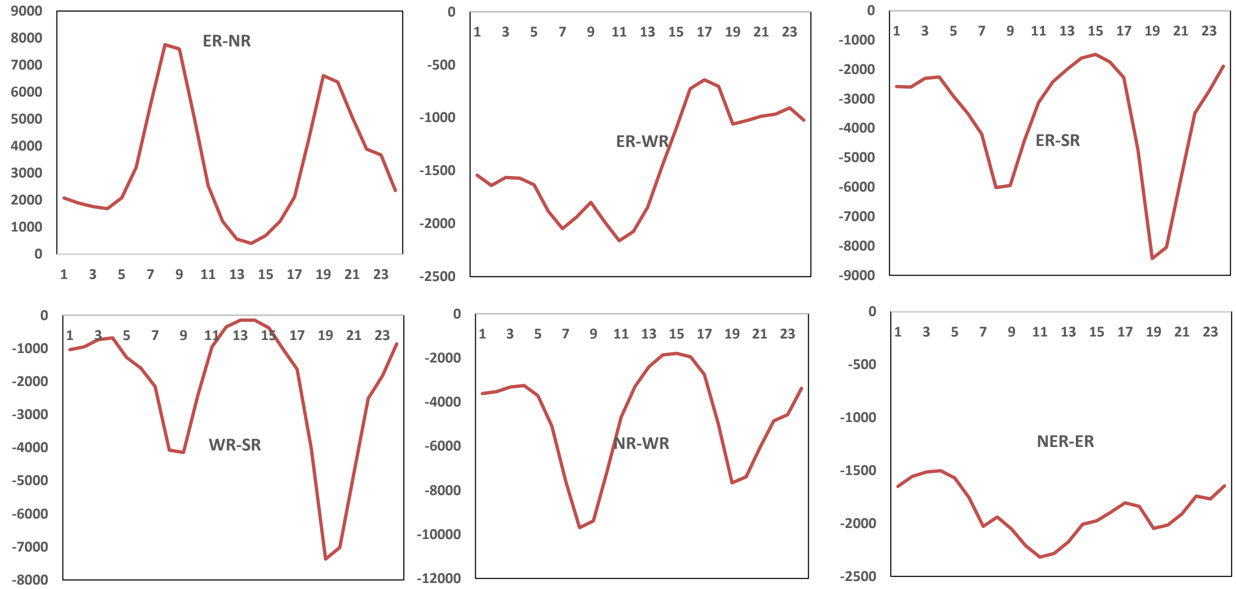
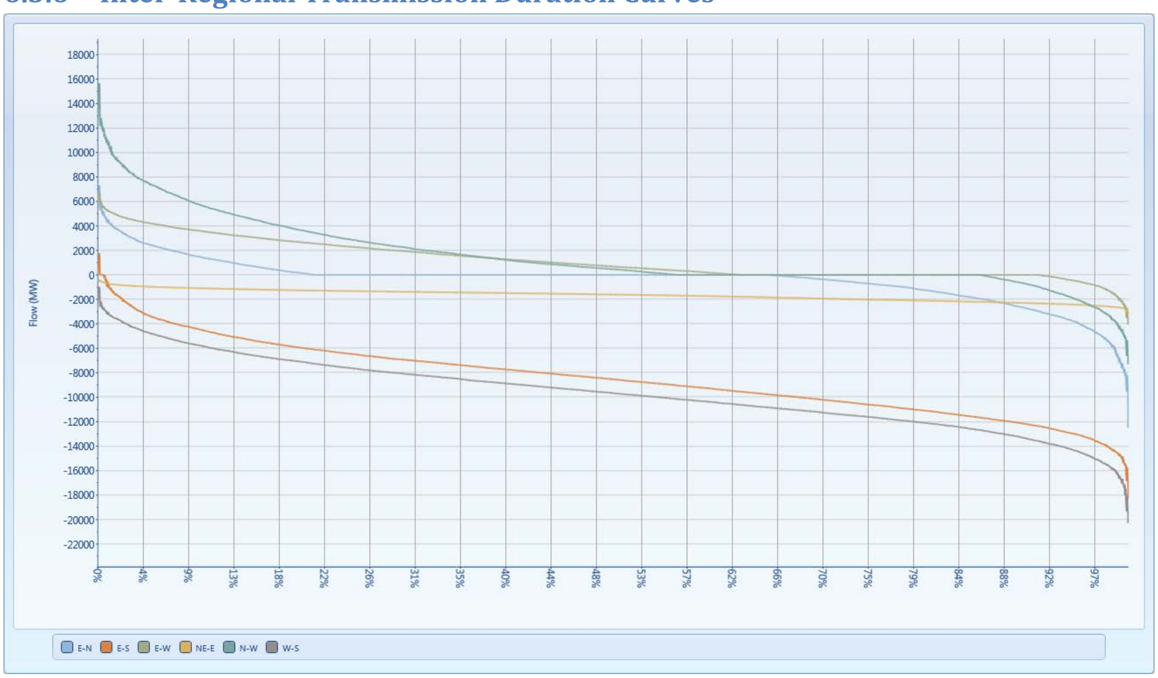


Figure 51: Average Hourly Inter-Regional Transmission Flows during Winter in FY 2022 (RE Missions Scenario)

Note: Sign of the flow indicates the direction. For example, East to North would be counted as positive flow while North to East would count as negative.

6.3.6 Inter-Regional Transmission Duration Curves



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Lawrence Berkeley National Laboratory
One Cyclotron Road
Berkeley, CA 94720
http://www.lbl.gov/

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