Techno-Economic Assessment of Integrating 175GW of Renewable Energy into the Indian Grid by 2022

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Summary

- We assess the impact on power system investments, operations, and costs of integrating 175GW of renewable energy in India's electricity grid by 2022
  - We simulate economic power system dispatch using industry standard production cost model, PLEXOS
- We find that 175GW of RE can be reliably integrated into the grid by 2022 at an incremental wholesale electricity supply cost (at region boundary) of ~Rs 32,000 Cr/yr (increase in average wholesale supply cost of 14-22p/kWh or 4-6% over the baseline)
  - However, we have not considered the environmental and energy security benefits of RE generation
- Only moderate levels of additional grid balancing resources are required
  - 2 to 10 GW of additional gas or other flexible capacity by 2022; need to provide cross-seasonal support
  - Mainly due to the complementarity between wind and solar generation and the regional diversity in load and RE generation
- Due to increased RE penetration, significantly less coal capacity is required than planned to minimize the total cost and avoid lowering of capacity factors of coal power plants
  - About 75% coal imports could be avoided as a result of increased RE penetration
- The following strategies will likely limit the cost increase to the levels found in this study
  - Transmission corridors, especially from/to the Southern region are strengthened, and used bi-directionally
  - Cost of wind energy is reduced by developing highest quality wind resource through competitive bidding
  - Power system dispatch is coordinated at the regional level through markets or other mechanisms
  - Several market, policy, and regulatory mechanisms are in place e.g.RE forecasting, more flexible markets etc
- This analysis uses several simplifying assumptions; results are high-level indications only

Introduction

- India has announced a target of increasing the total renewable energy (RE) installed capacity from ~34GW in 2015 to 175GW by 2022
  - 100 GW solar energy (National Solar Mission)
  - 60 GW wind energy (National Wind Mission)
  - 15 GW Other RE such as biomass and small hydro

- Given such aggressive targets, designing appropriate policy, regulatory, and commercial strategies for RE grid integration is crucial
  - 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 India

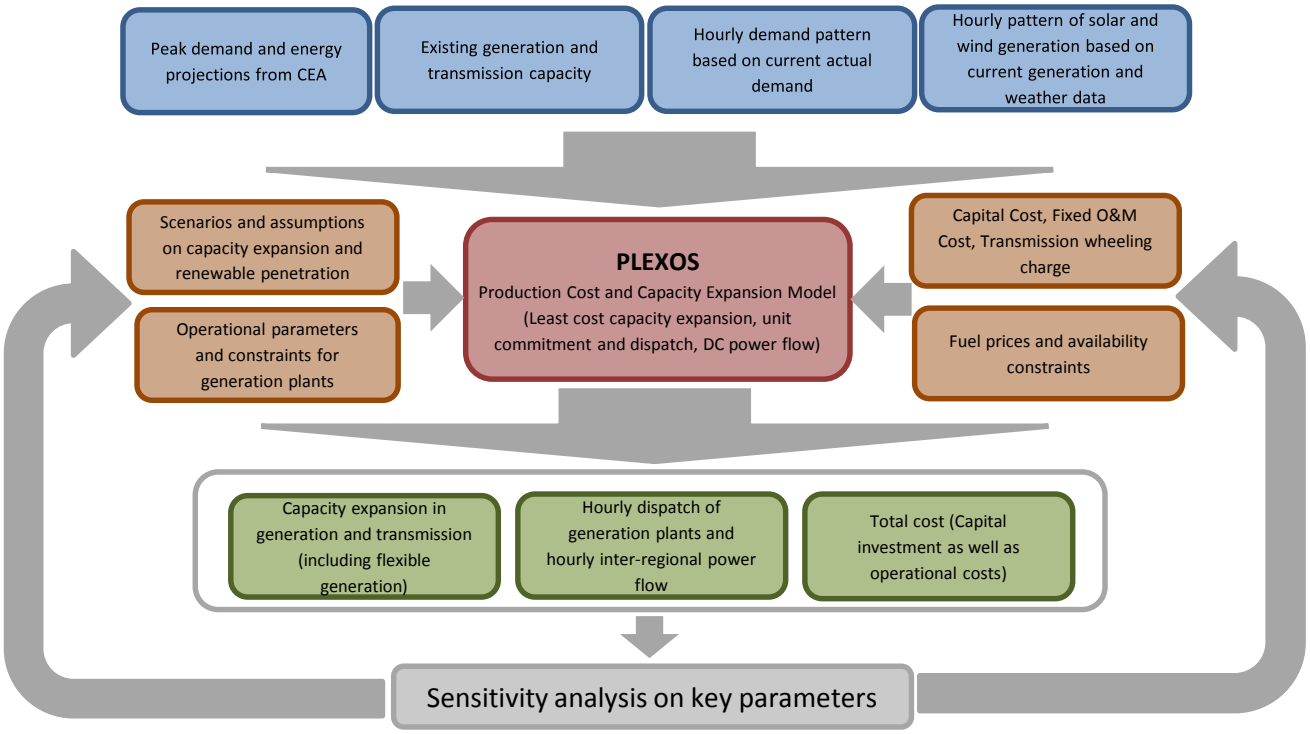
- The objective of our study is to assess the impact on power sector investments, operations, and electricity supply costs of such large-scale RE grid integration. Specifically, we answer the following questions for the financial year (FY) 2022 (April 2021 through March 2022):
  - What is the impact of integrating RE on the capacity addition and capacity factors of conventional generators?
  - Are there any additional ramp requirements and if so how can they be met in a least cost fashion?
  - How do regional transmission flows and investment requirement change?
  - What is the impact on the wholesale electricity supply cost (at region boundary)?

Overview of the Indian Power System

- Overview (2015)
  - National peak load ~148 GW (1069 TWh/yr); ~5% peak shortage and ~3.5% energy shortage
  - Total installed capacity: ~270GW (~60% coal, ~15% hydro, 12% RE, ~9% gas)
- Renewable Energy
  - Significant RE potential exists (~3000 GW of wind and >10,000 GW of solar)
  - Almost all key states have specified Renewable Portfolio Obligation (RPO) of ~5-10% (increasing over years) of annual electricity requirement
  - RE sources are also offered feed-in tariffs in all major states
- Transmission
  - 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.
- Markets
  - India operates a day-ahead electricity market; dispatch schedules have a gate closure time of one hour
  - Deviation Settlement Mechanism (DSM) acts as the de-facto energy imbalance market, where the real-time price is dependent on the system frequency
  - In April 2016, India has created a framework for ancillary services in market, wherein the un-requisitioned capacity of the central government owned generating stations from the day-ahead schedule would be rescheduled to the regional pool
- Growth
  - Peak load is expected to be ~287GW by 2022 and ~500 GW by 2030 (based on 18th Electric Power Survey projections)

Summary of the Method – Modeling Framework

- We conduct our analysis using PLEXOS, an industry-standard production cost model
- For various levels of RE penetration targets, PLEXOS identifies the least cost investment and economic dispatch subject to a range of operational constraints



- We model the Indian electricity grid using 5 nodes – one node for every region which allows us to broadly assess the transfer capacities across regions assuming each region as a balancing area

Summary of the Method – Scenarios for FY 2022

- ***13th Plan*** (41GW Wind, 22GW Solar, 15GW Other RE)
  - This scenario serves as the baseline and uses the generation capacity addition for all technologies as projected in the Government of India's 12th Five-Year Plan document that includes projections up to the 13th Plan period (2022)

- ***RE Missions*** (60GW Wind, 100GW Solar, 15GW Other RE)
  - This scenario models the Government of India's announcement in 2015 to increase the total installed capacity of solar energy to 100GW and wind energy to 60 GW by FY 2022
  - Coal and gas capacity expansion is "optimized" by the model; Hydro, Nuclear, and Other RE capacity assumed same as the 13th Plan

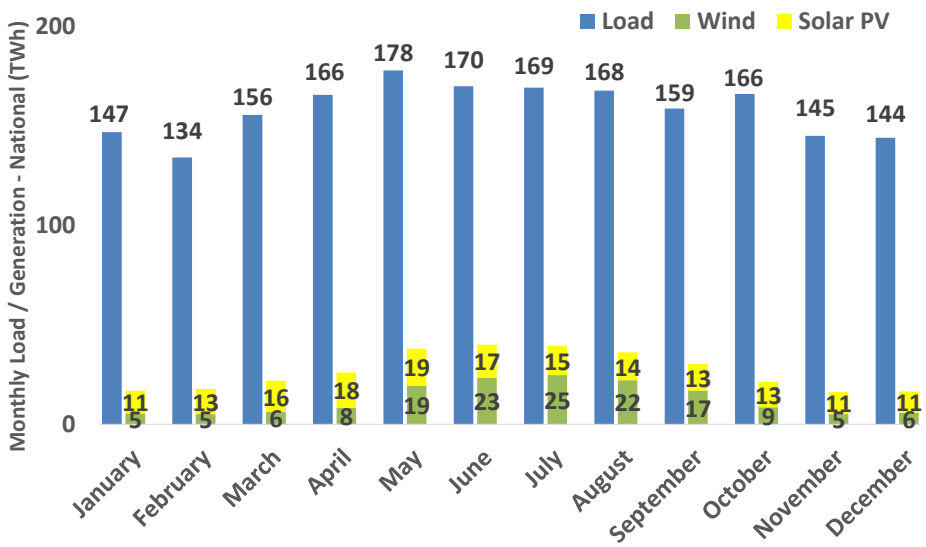
- ***National Action Plan on Climate Change (NAPCC)*** (108GW Wind, 58GW Solar, 15GW Other RE)
  - This scenario models the RE target described in India's NAPCC (2009) - 15% electricity (by energy) by 2020 and ~20% by 2022 (extrapolated)
  - Keeping the other RE capacity same as the 13th Plan, we split the rest of the NAPCC target into wind and solar PV capacity using a 75:25 ratio*
  - Coal and gas capacity expansion is "optimized" by the model; Hydro, Nuclear, and Other RE capacity assumed same as the 13th Plan

Key Assumptions and Data

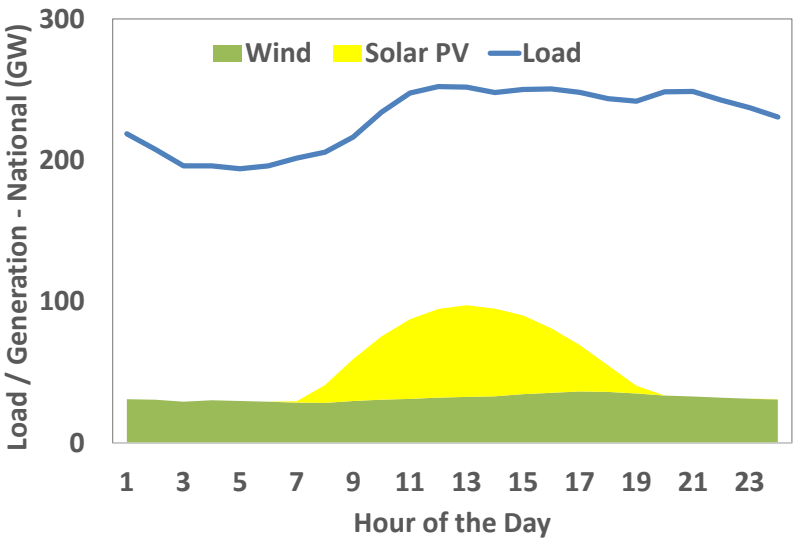
- ***Demand***
  - We project the hourly FY 2022 load based on the historical hourly load pattern between FY 2010 and 2013, projected urbanization, and the projected load growth in the 18th Electric Power Survey (EPS)
- ***RE Generation***
  - Hourly profiles of wind energy generation have been forecasted using the historical generation data for FY 2010 through FY 2013 from the states of Tamil Nadu, Karnataka, Maharashtra, and Gujarat
  - For solar PVs, we choose 100 sites spread over all 5 regions with best quality solar resource (measured in Global Horizontal Irradiance) and assess hourly generation
- ***Generator characteristics***
  - Heat rates, ramp rates, outage, and minimum stable level of the power plants have been estimated using historical dispatch and other performance data, regulatory orders, and other studies
  - Hydro power plants are subject to the historical dispatch restrictions (monthly energy limits for reservoir type hydro and historical capacity limits for run-of-the-river hydro plants)
- ***Generator costs***
  - Capital costs and fixed O&M costs have been taken from CERC's tariff norms for 2014-2015
  - Solar PV prices are assumed to drop from Rs 5.1/kWh (2015) to Rs 3.4/kWh (2022) per historical trends
  - Average wind energy cost is assumed to drop from Rs 4.5/kWh (2015) to Rs 3.3/kWh (2022) due to better sites and turbines
- ***Fuel prices and availability***
  - We take the current year fuel prices and use historical trends to project the fuel prices up to 2022
  - Domestic coal availability is taken from 12th Plan (extrapolated to 2022); domestic gas availability for power sector is assumed to remain the same as 2015
- ***Transmission***
  - We estimate the additional transfer capability needed to achieve a least cost dispatch at the national level
  - We do not include electricity imports from the neighboring countries

Key Results

Solar and Wind Energy Have Complementary Profiles: Seasonally and Diurnally



Monthly Load and RE Generation - National
(RE Missions Scenario – 100GW Solar, 60GW Wind)

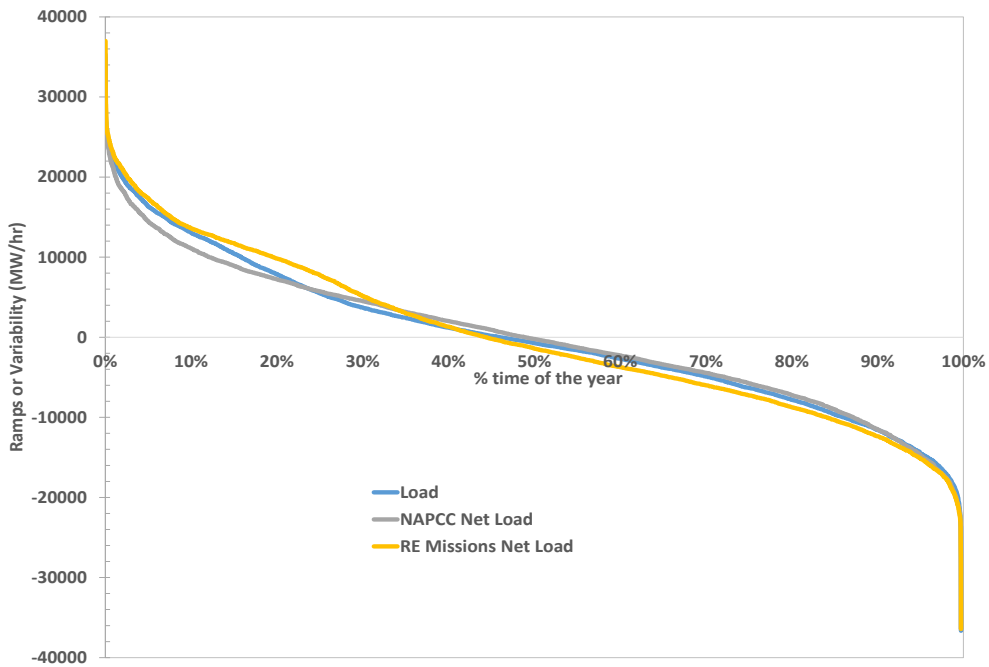


National Average Hourly Load and RE Generation (June-Sep)
(RE Missions Scenario – 100GW Solar, 60GW Wind)

- Wind generation peaks in Monsoon (June-Sep) while solar generation peaks in the Summer (April-May)
- In winter, wind generation drops significantly while the drop in solar generation is modest
- Diurnally, solar generation peaks between 12 and 1 PM; wind generation peaks between 5 and 7 PM (when solar PV generation starts dropping rapidly)
- Regional diversity in wind generation creates a favorable national aggregate hourly profile

Minor increase in net load variability in RE heavy scenarios – limited additional ramping requirements

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



- The maximum net load ramps in the RE Missions as well as the NAPCC scenarios (see table) are almost same as the load ramps in the 13th plan scenario
  - In certain periods (see figure), the net load variability in the RE Missions scenario is slightly higher than the load variability
- This suggests that the additional variability added due to the RE generation is minor
  - This is mainly due to: (a) regional diversity in RE generation and load, and (b) complementarity between wind and solar generation

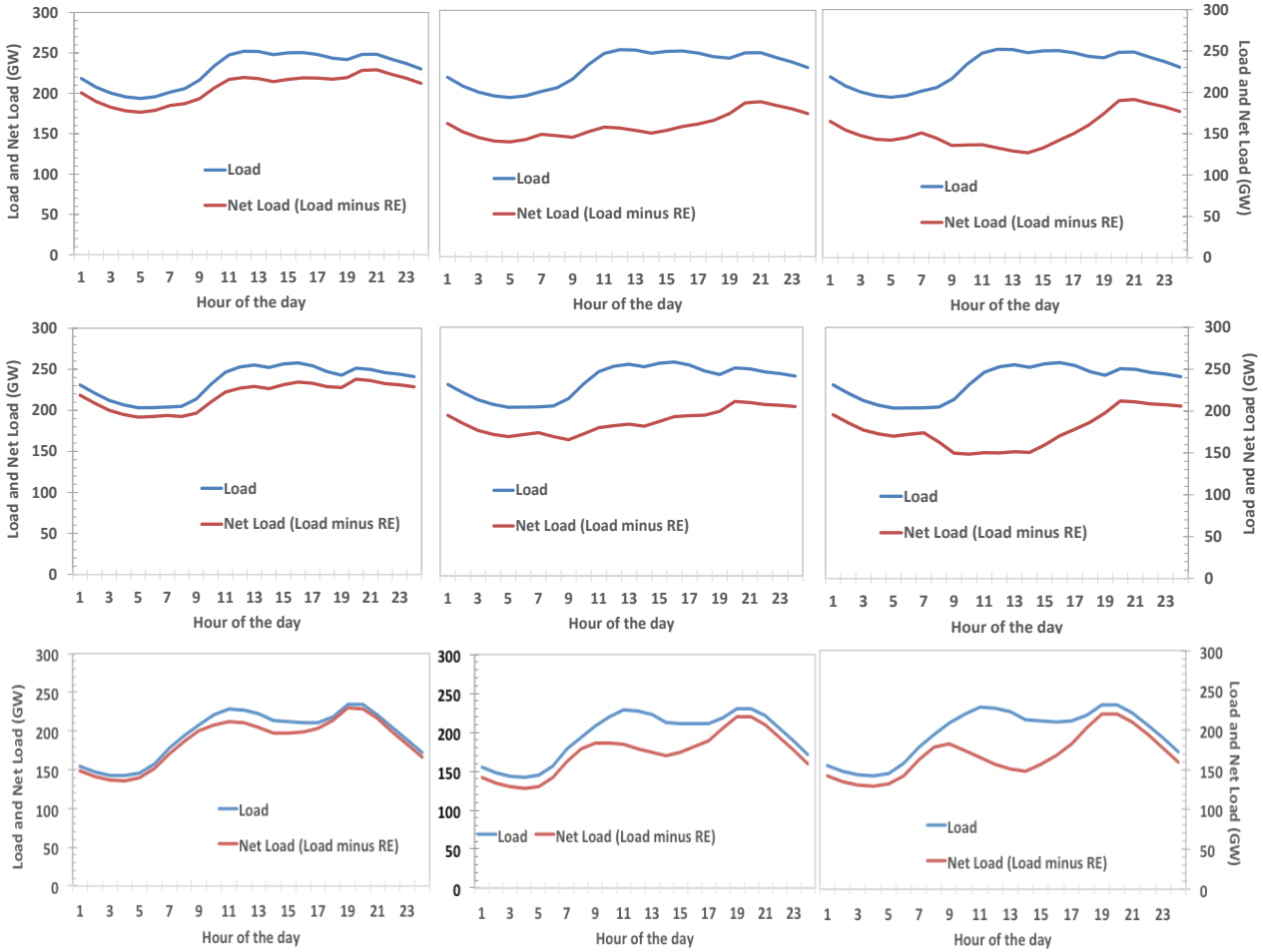
Average Load and Net Load Curves in each Season (FY 2022)

13th Plan (41GW Wind, 22GW Solar) | **NAPCC** (108GW Wind, 58GW Solar) | **RE Missions** (60GW Wind, 100GW Solar)

Summer (April - May)

Monsoon (June - September)

Winter (December - February)



In Summer and Monsoon, RE generation has good correlation with the peak load (afternoon) and can avoid significant conventional generation. However, in Winter (especially evening peak load hours), RE generation drops significantly.

Installed Capacity and Capacity Factors by FY 2022

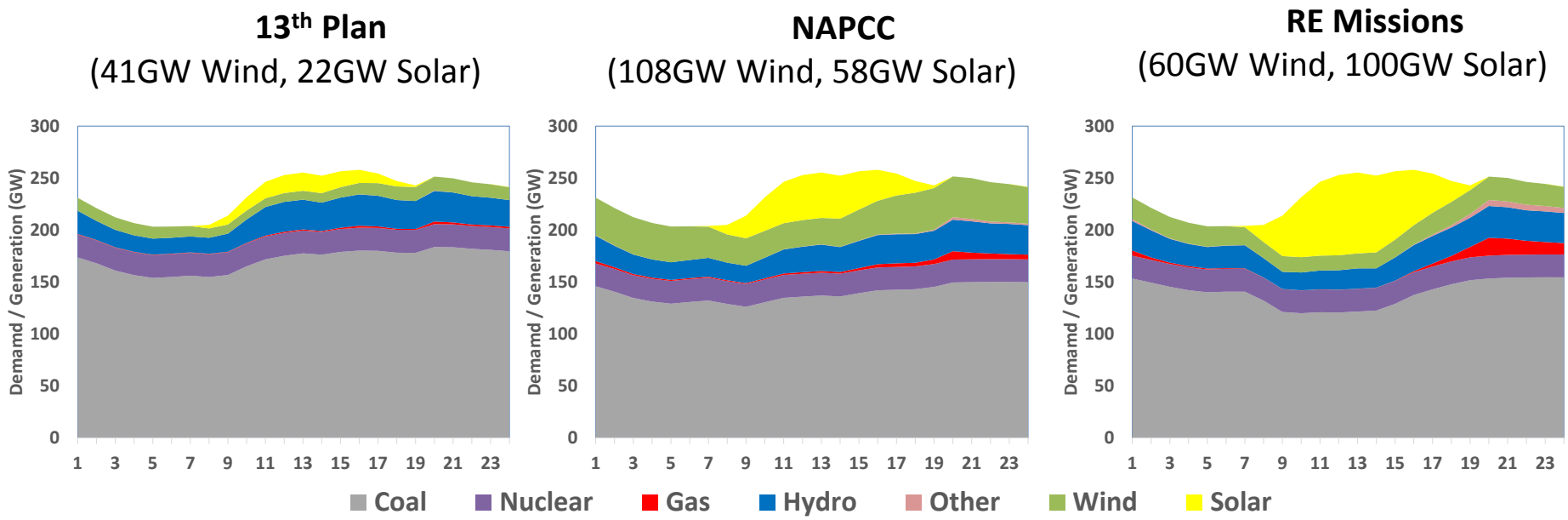
	13th Plan		RE Missions		NAPCC	
	Installed Capacity (GW)	Annual Capacity Factor (%)	Installed Capacity (GW)	Annual Capacity Factor (%)	Installed Capacity (GW)	Annual Capacity Factor (%)
Coal	243	64%	182	71%	182	73%
Gas (CCGT / CT)	23	7%	33	7%	25	9%
Diesel	1	0%	1	0%	1	0%
Nuclear	25	89%	25	89%	25	89%
Hydro (Incl. small hydro)	66	37%	66	37%	66	36%
Biomass + Cogen.	8	1%	8	2%	8	2%
Wind	41	25%	60	29%	108	29%
Solar	22	19%	100	19%	58	19%
Total	**425 GW**		**476 GW**		**472 GW**	

- In both the RE heavy scenarios, significant new coal capacity could be avoided relative to the 13th Plan scenario (the baseline)

- Moderate additions to gas based capacity are needed in both RE heavy scenarios
  - ~10GW in case of RE Missions and ~2GW in case of NAPCC
  - These additions need not be technology specific; if other sources provide such services (e.g. hydro or demand response etc.), the need for gas based capacity addition would reduce

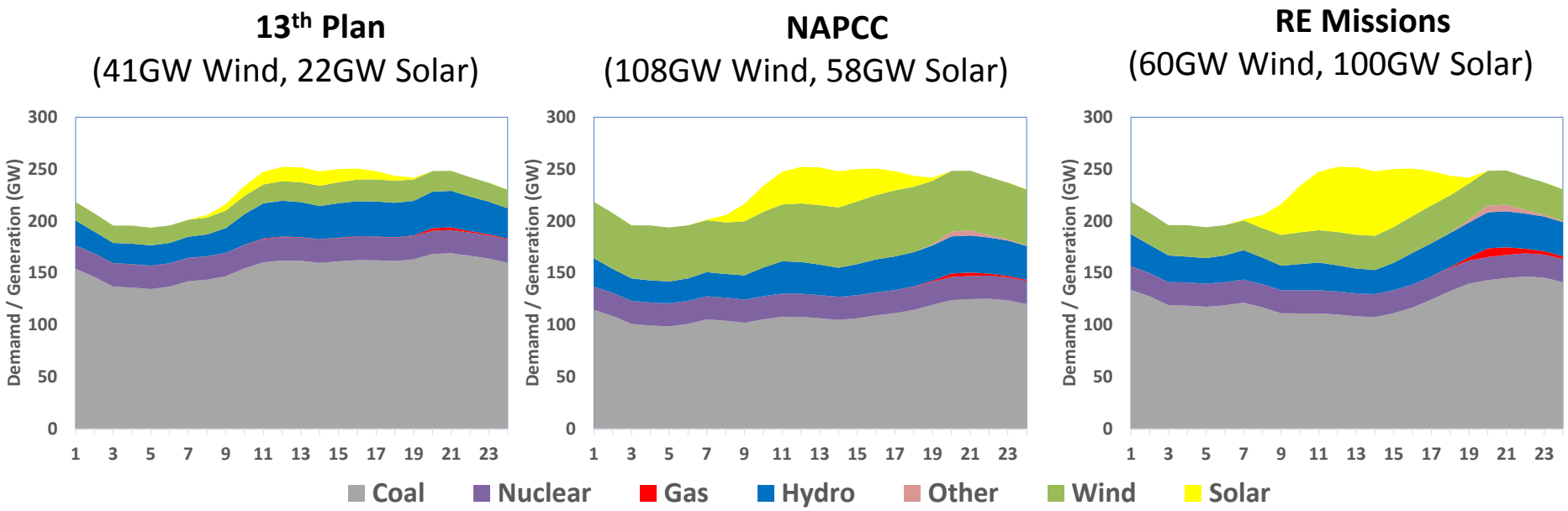
- Gas plants operate with a capacity factor of 7-9% implying that they are primarily used as a peaking resource or for providing additional flexibility to the system

Average Hourly National Dispatch (FY 2022) – Summer (April- May)



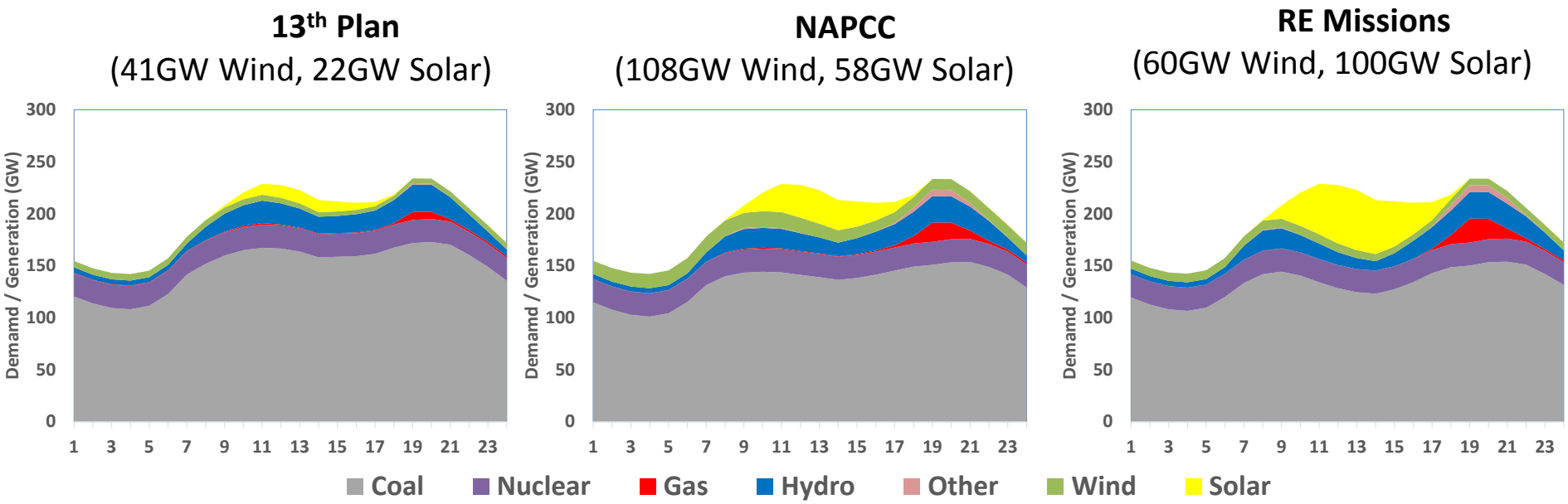
- In all scenarios, most coal units are dispatched as base load units
- In summer, solar output is the highest; however, the generation is limited to afternoon peak load hours
- Gas based capacity (or other flexible capacity) is crucial for the evening ramp-up and energy support, especially in the RE Missions scenario
  - Hydro has limited applicability since ~50% of the installed capacity is run of the river (ROR) and the rest has significant dispatch restrictions
- No RE curtailment is found to be necessary

Average Hourly National Dispatch (FY 2022) – Monsoon (June-Sep)



- In monsoon, wind generations peaks and also has good correlation with the evening peak load
- Increased wind generation also helps with managing the evening ramp-up
  - The need for gas based capacity (or other flexible capacity) is lower
- Despite significant increase in the RE generation (due to wind), no RE curtailment is found to be necessary

Average Hourly National Dispatch (FY 2022) – Winter (Dec-Feb)

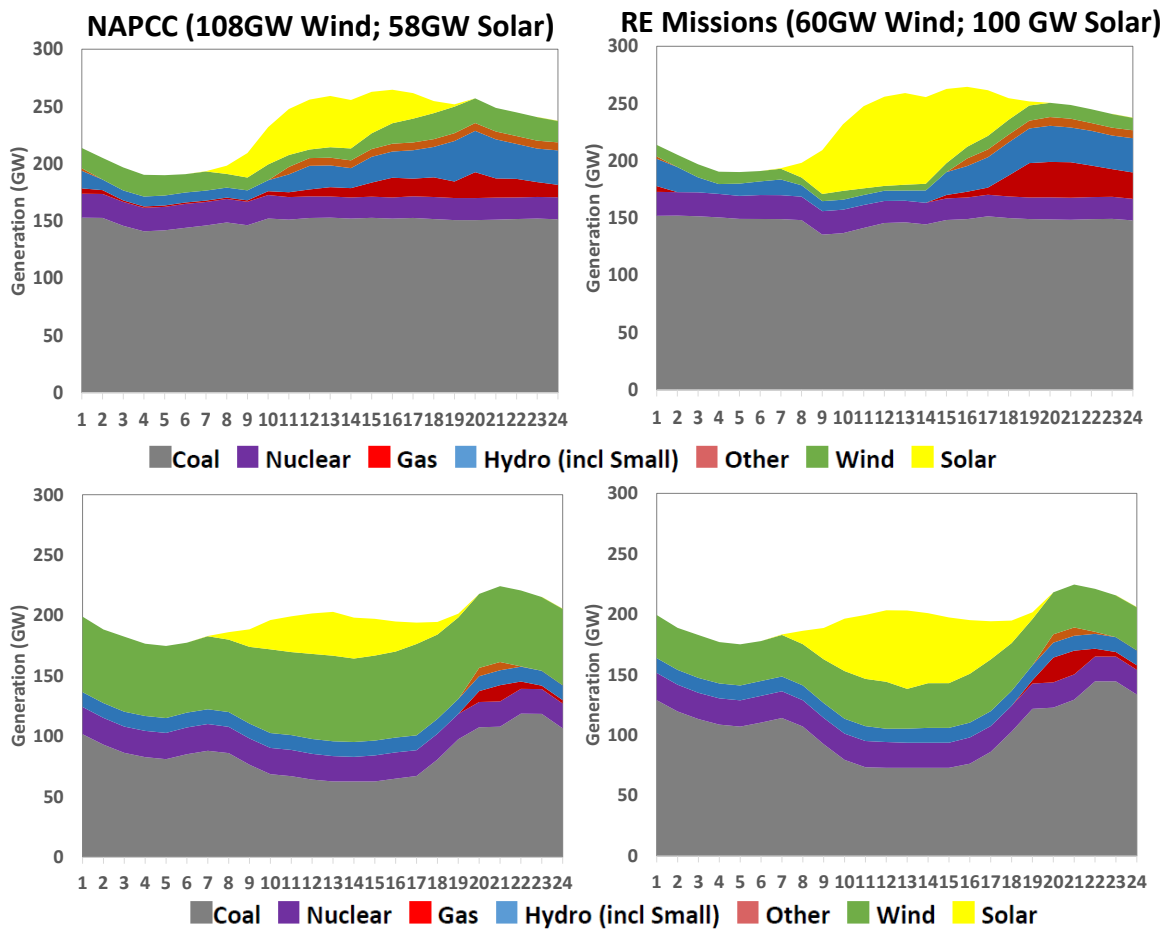


- In winter, wind (as well as solar) output drops significantly relative to other seasons
- However, demand is lower relative to other seasons as well
- Hydro capacity (especially run-of-river) is significantly restricted in winter
- Thus, evening peak support from gas power plants (or other flexible capacity) becomes crucial
    - Building local gas storage and avoiding take-or-pay gas contracts is important

How is the System Operated on Extreme Days ?

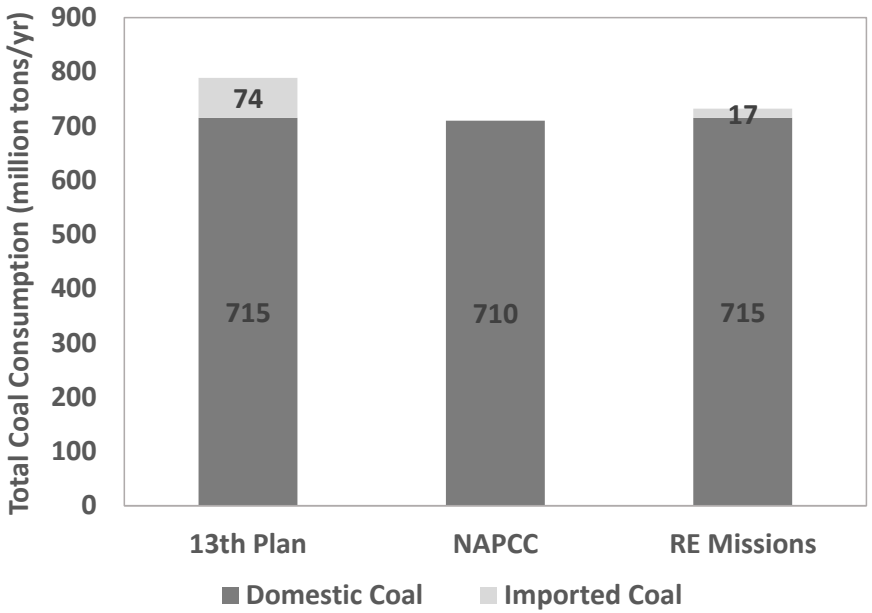
Max RE Variability Day (April 12, 2021)

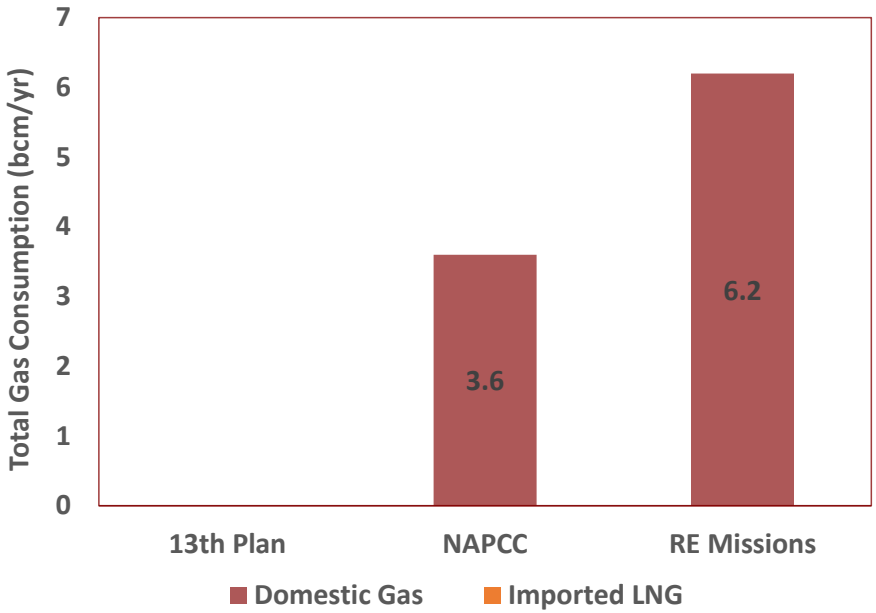
Minimum Demand Day (August 1, 2021)



- **On both occasions, the system could be dispatched reliably**
  - Fast ramping from Gas and Hydro plants was crucial on the maximum RE variability day (at 9AM due to sudden increase in the solar output)
  - On the minimum demand day, most coal units either shut down or operate at minimum load
  - Good RE forecasting practices are crucial to handle such events.

Fuel Consumption in FY 2022: RE dominant scenarios can avoid coal imports





- Both NAPCC and RE Missions scenarios avoid significant fuel imports. In NAPCC and RE Missions scenarios, coal imports by 2022 drop by 100% and 77% respectively relative to the 13th Plan

- Gas consumption increases; but no LNG imports are found necessary, albeit constrained domestic gas availability.

Inter-regional Power Transfer Capacity *

In order to integrate nearly 175GW of 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) interfaces.

	Existing Transmission Capacity (June 2015)	Power Transfer Capacity Requirement in FY 2022		
		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

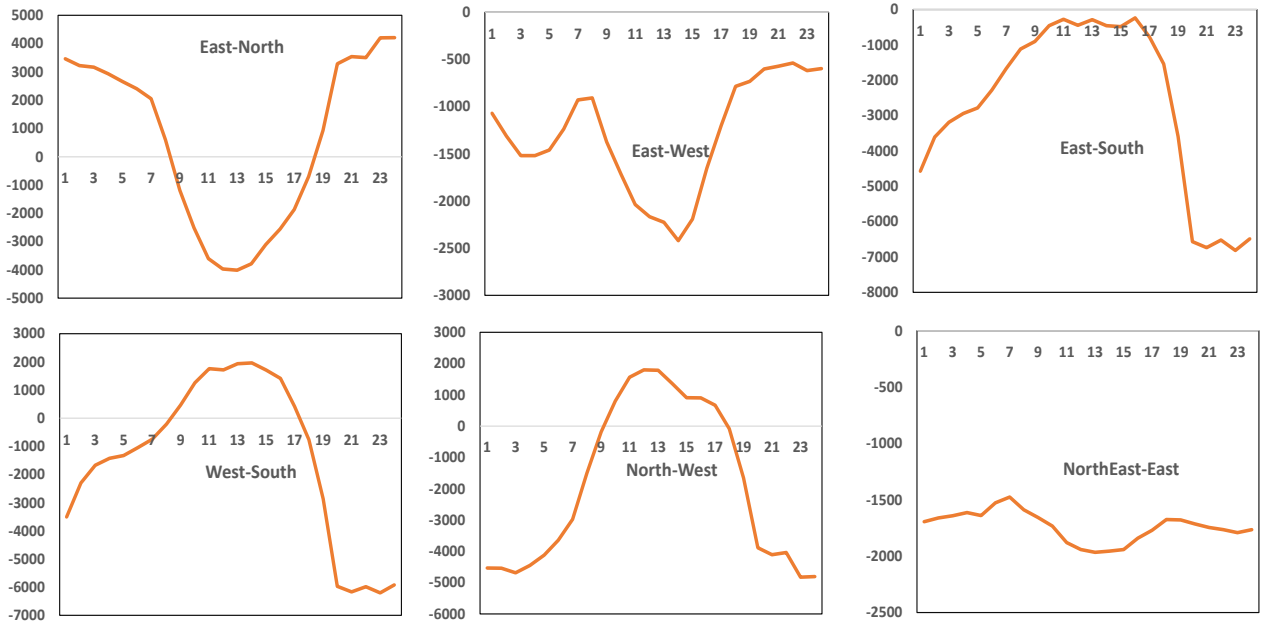
One of the reasons for such relatively moderate increase is that the renewable resources are well distributed among northern (mostly solar and some wind), western (both solar and wind), and southern (mostly wind and some solar) regions.

* Note that 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.

Average Hourly Transmission Flows on Inter-regional Interfaces

- In the RE Missions and NAPCC scenarios, some of the transmission interfaces would have to be used in both directions because of the seasonal and diurnal RE generation patterns.

- Example: Average hourly transmission flows (MW) on major interfaces in the RE Missions scenario (April – May 2021)



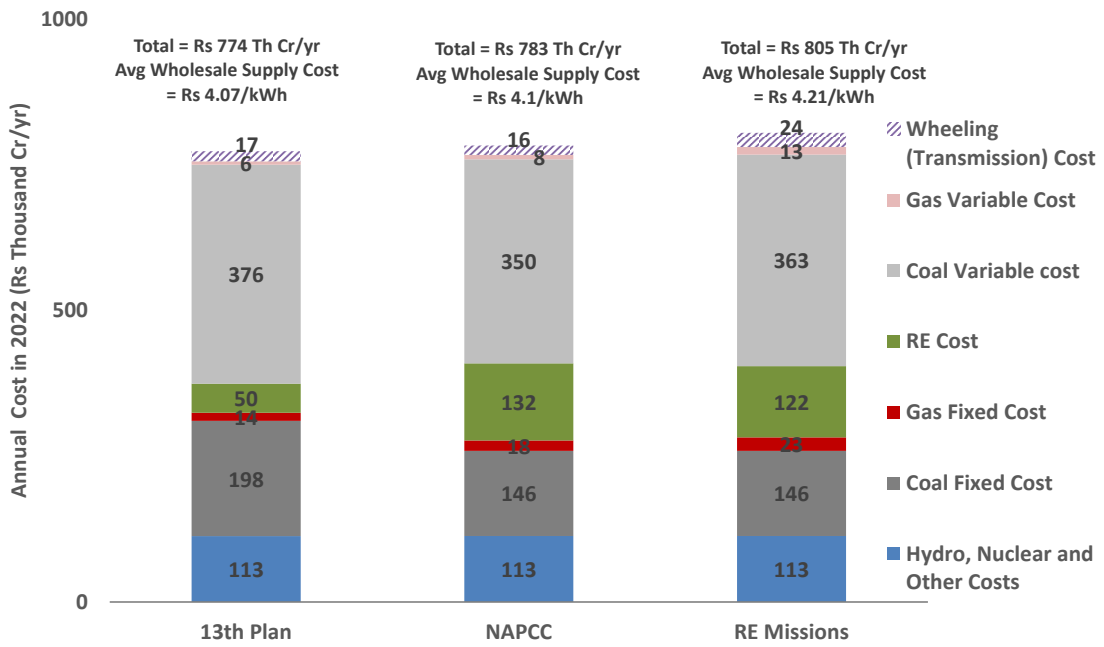
Notes:
1. All numbers are in MW
2. Negative flow means flow in the opposite direction (e.g. negative flow on East-West interface implies flow direction is West to East)

- This implies that for reliable RE grid integration, it is crucial to have an appropriate policy and regulatory framework for moving power across regions more freely.

Incremental Cost of the RE Scenarios is up to Rs 32,000 Cr/yr (4-6% of the baseline)

- The incremental wholesale cost of supply in NAPCC and RE Missions scenarios is found to be ***Rs 10,000 Cr/yr (1%)*** and ***Rs 32,000 Cr/yr (4%)*** respectively relative to the 13th Plan
  - Total cost of the 13th Plan scenario at region boundary is Rs 774,000 Cr/yr by 2022
  - Incremental Increase in the average wholesale supply cost: 3p/kWh (NAPCC) and 14p/kWh (RE Missions)
  - RE generation over 13th Plan: NAPCC = 245 TWh/yr ; RE Missions = 197 TWh/yr

- These costs include majority of the RE integration cost such as additional investments in flexible capacity (such as gas etc.) or operation of expensive gas or diesel plants, and inter-regional transmission cost etc. However, this does not consider the environmental benefits of RE generation.



Does not include procurement of additional ancillary services. Several other studies have found these costs to be minor.

Does not consider new norms for Particulate Matter, SOx, and NOx emissions (2015), which may increase coal fixed costs by over ~10% and reduce the cost-differential between the 13th Plan and RE Dominant scenarios.

Sensitivity Analysis: Impact of Changing Assumptions on Coal Capacity Additions by FY 2022

We create two sensitivity cases:

(a) If the coal capacity is optimally planned in the 13th Plan scenario leading lower total installed coal capacity (would have similar effect to that of "slippages" in capacity addition seen historically)

(b) If the coal capacity in the RE Missions scenario is same as that in the 13th Plan baseline(could be interpreted as the government goes through RE Missions without changing coal targets)

	13th Plan *(Baseline)*	13th Plan *(Optimal coal capacity)*	RE Missions *(Optimal Coal Capacity)*	RE Missions *(Coal capacity same as 13th Plan)*
RE Installed Capacity (GW)	77	77	175	175
Coal Installed Capacity (GW)	243	203	182	243
Coal Capacity Factor (%)	65%	77%	73%	56%
Average Wholesale Energy Cost (at region boundary) (Rs/kWh)	***4.07***	***3.99***	***4.21***	***4.37***

- If the thermal (coal and gas) capacity is optimally planned, the wholesale supply cost in the 13th plan would reduce by ~2% (Rs 3.99/kWh)
  - The incremental cost of RE Missions could increase to about ~6% in such case (increase in avg cost by 22p/kWh)
- If thermal (mainly coal) targets are not revised, cost of the RE Missions scenario could increase by ~4%
  - This is mainly due to significant over-capacity resulting in inefficient operation of the coal fleet (average capacity factor of 56%)
- Smart thermal capacity expansion (and operation) is crucial for cost-effective RE grid integration

Conclusions

- We find that 175GW of RE can be reliably integrated into the grid by 2022 at an incremental wholesale electricity supply cost (at region boundary) of ~Rs 32,000 Cr/yr (increase in average wholesale supply cost of 14-22p/kWh or 4-6% over the baseline)
  - However, we have not considered the environmental and energy security benefits of RE generation
- Only moderate levels of additional grid balancing resources are required
  - Complementarity between wind and solar generation and the regional diversity in load and RE generation helps
  - 2 to 10 GW of additional gas or other flexible capacity by 2022; need to provide cross-seasonal support
- Due to increased RE penetration, significantly less coal capacity is required than planned to minimize the total cost and avoid lowering of capacity factors of coal power plants
  - About 75% coal imports could be avoided as a result of increased RE penetration
- The following strategies will likely limit the cost increase to the levels found in this study
  - Transmission corridors, especially those from/to the Southern region are strengthened
  - Cost of wind energy is reduced by developing highest quality wind resource through competitive bidding
  - Power system dispatch is coordinated at the regional level through markets or other mechanisms
  - Several market, policy, and regulatory mechanisms are in place e.g. RE forecasting, flexible markets etc.
- This analysis uses several simplifying assumptions especially regarding the transmission system; significant refinement is necessary for actual power system planning purposes

Acknowledgements

- LBNL would like to thank Regulatory Assistance Project and the US Department of Energy (21st Century Power Partnership) for providing financial support to this work.

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Full report can be downloaded here:

https://eetd.lbl.gov/sites/all/files/pdf_7.pdf

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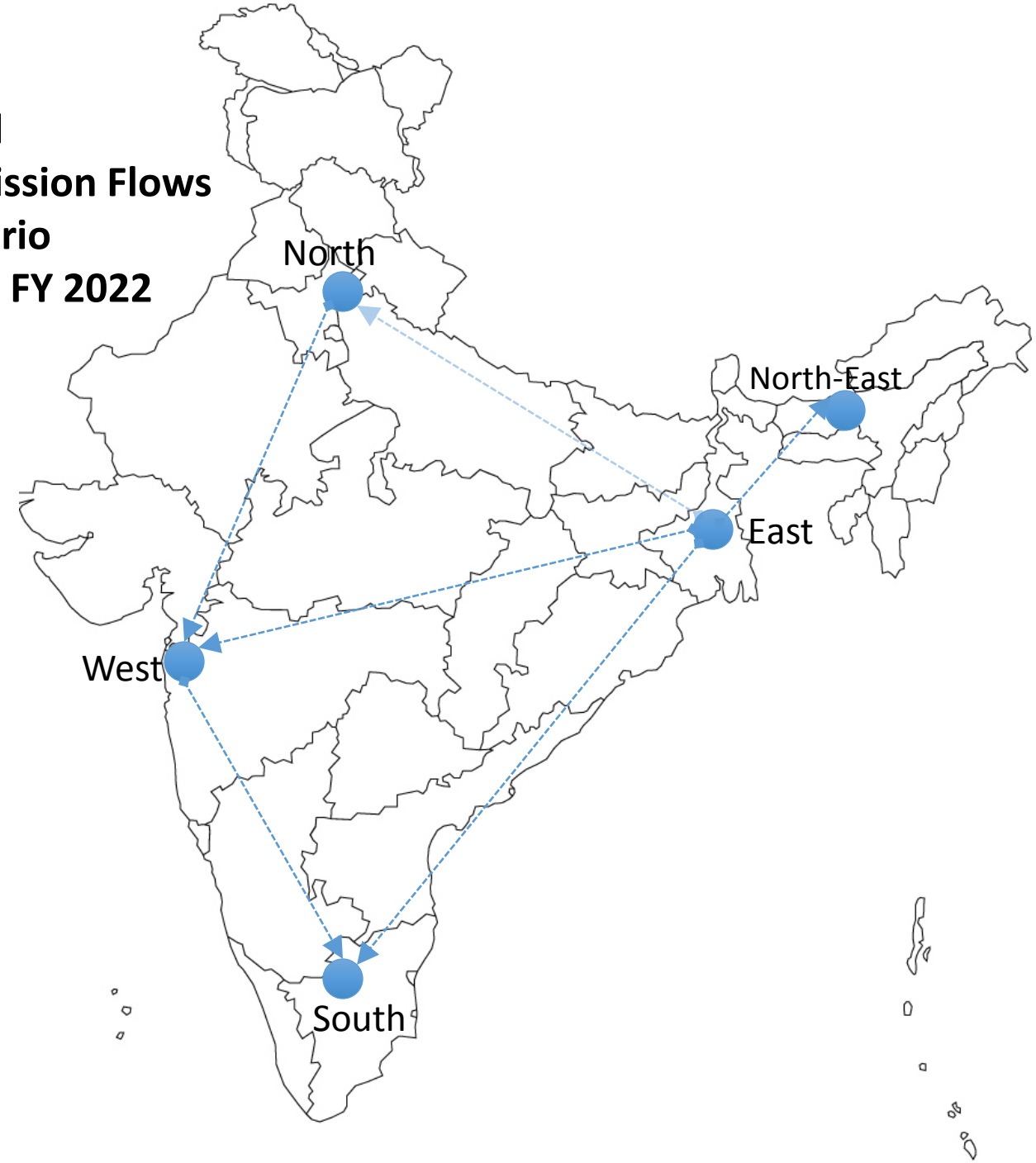
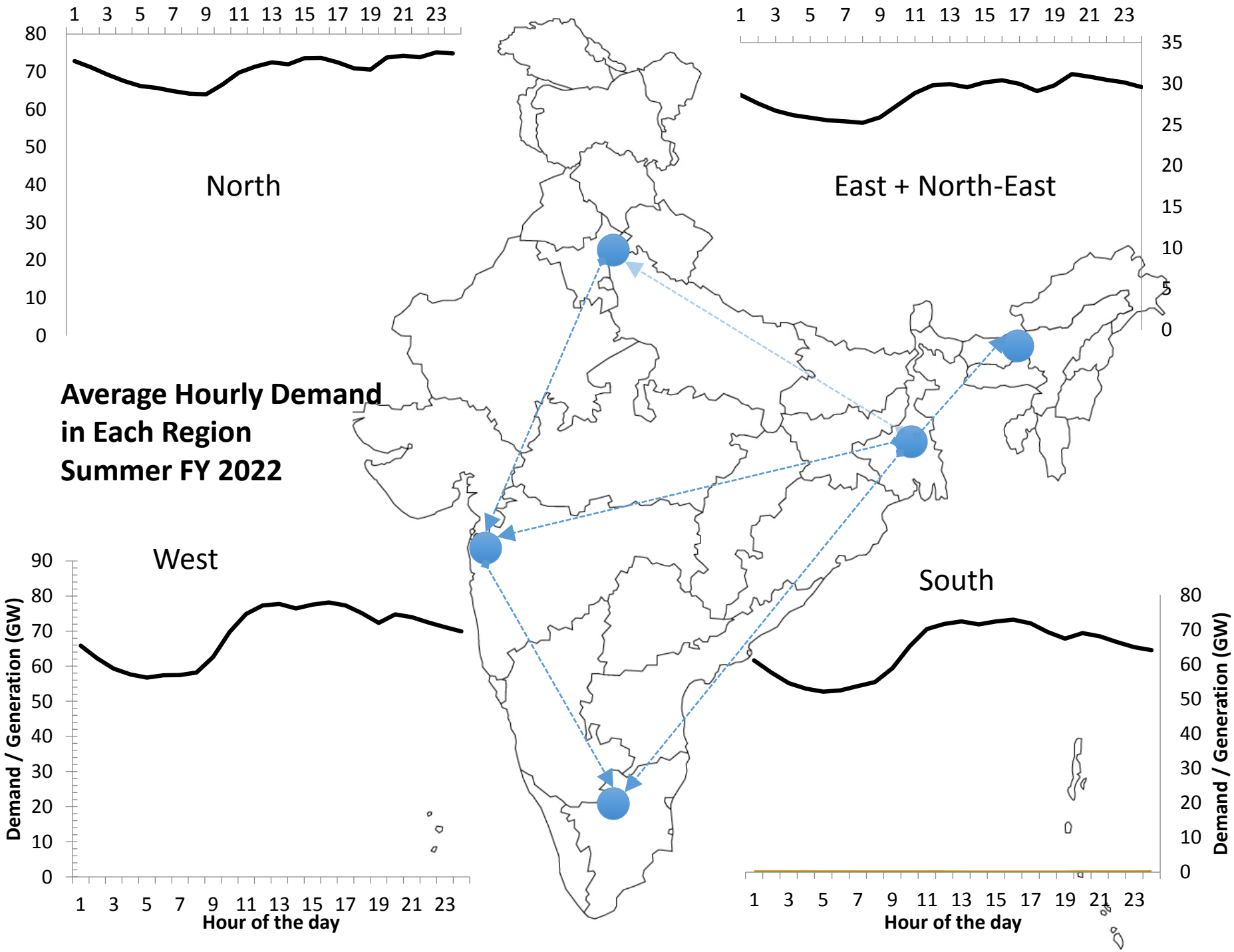
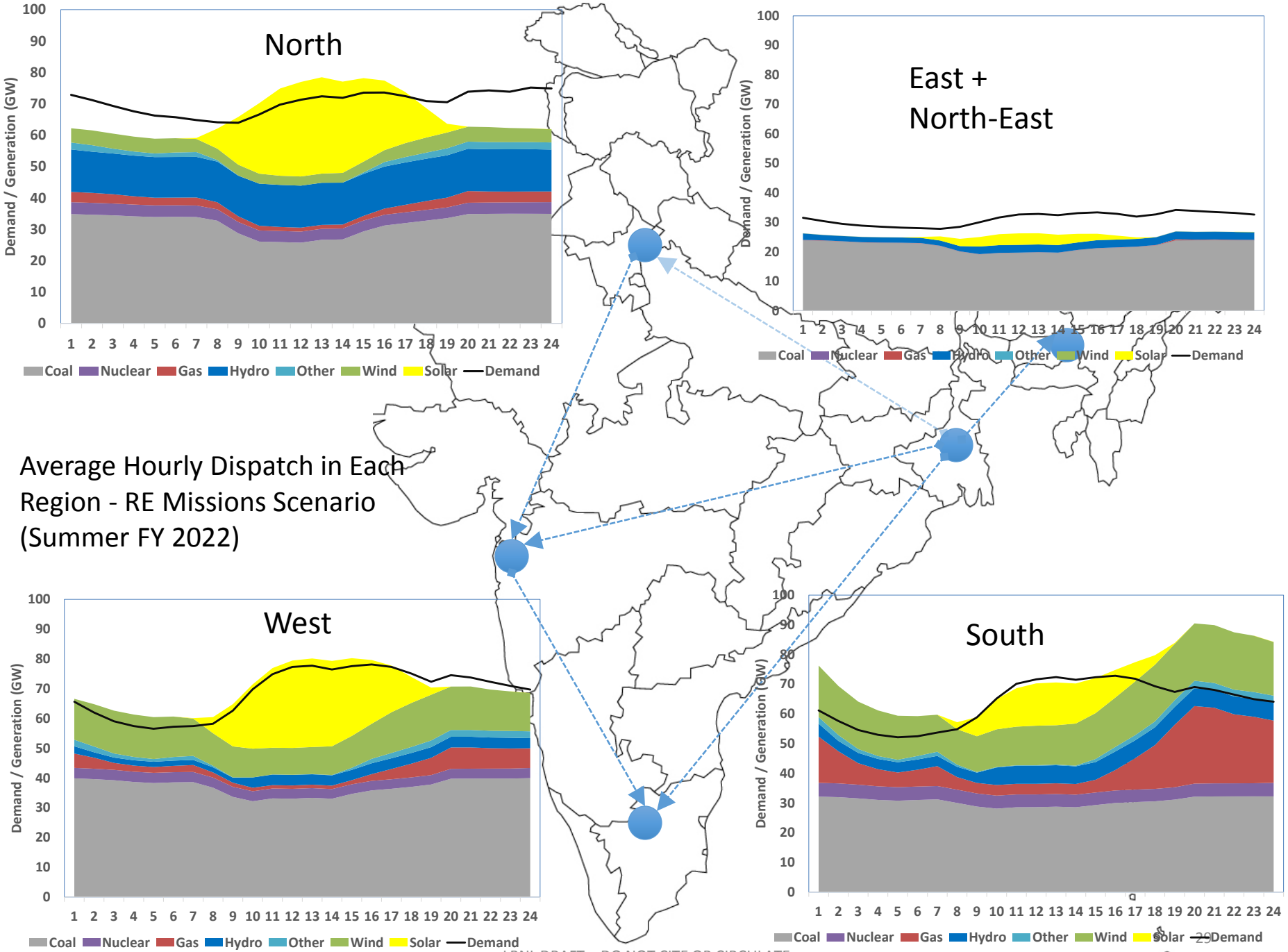
Appendix:
Inter-regional Flows – Example

Average Hourly Regional Dispatch and Inter-regional Transmission Flows For RE Missions Scenario Summer (April – May) FY 2022




Average Hourly Demand
in Each Region
Summer FY 2022
North
East + North-East
West
South
Demand / Generation (GW)
Hour of the day
Demand / Generation (GW)
Hour of the day



Average Hourly Dispatch in Each Region - RE Missions Scenario (Summer FY 2022)

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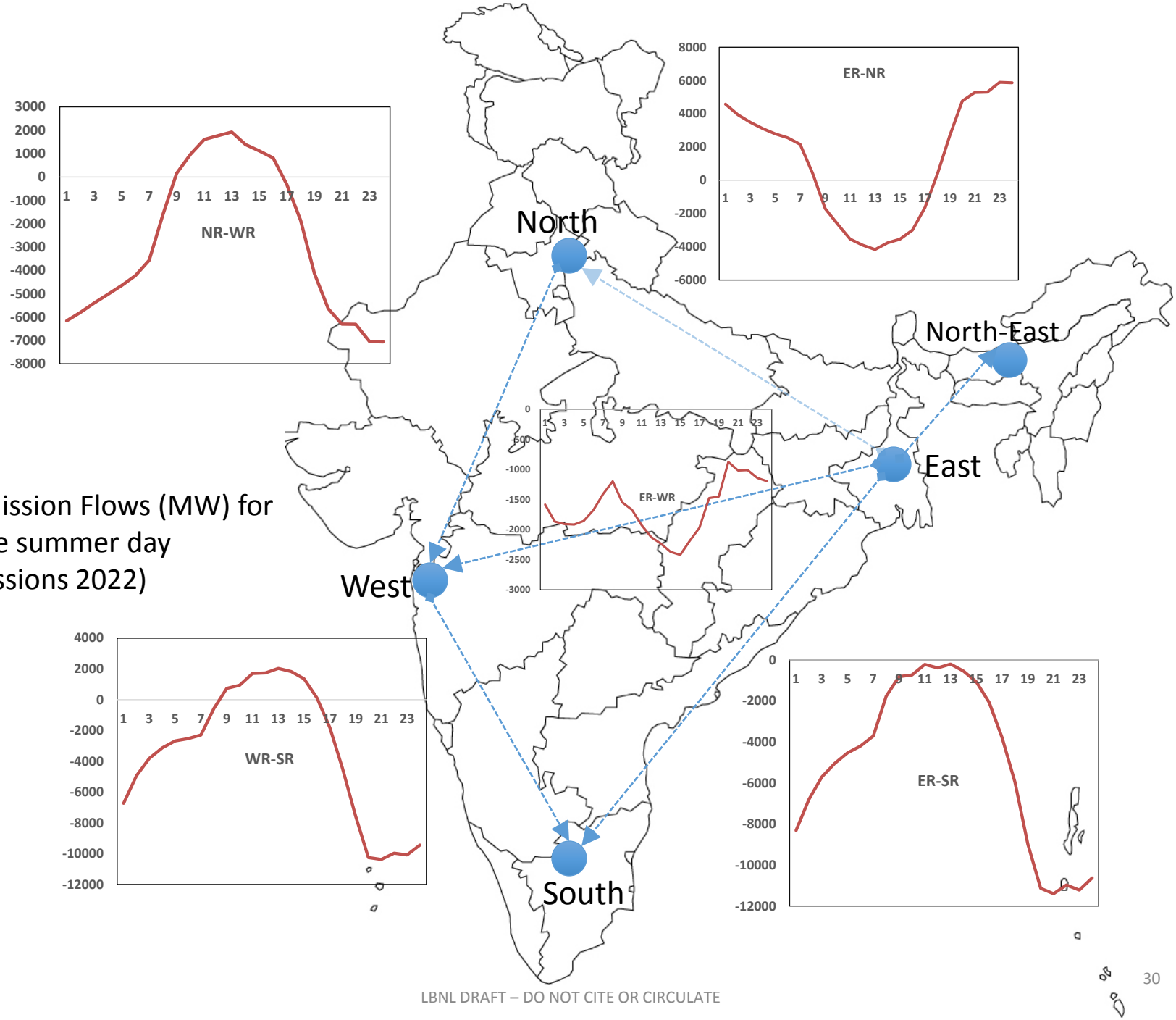
Transmission Flows (MW) for average summer day (RE Missions 2022)



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