Insights from dispatch modelling of the MSEDCL system for 2030

A production cost simulation exercise

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New trends and implications

- **Wind/solar PV and coal generation prices**
  - Rs 2.5-3/kWh for wind/solar & fixed for 25 years vs Rs 4-5/kWh for new coal
- Storage prices falling rapidly
  - Provides many grid services
- Sales migration/ Competitiveness of alternative supply options
  - especially rooftop solar; in future solar + storage
  - Rising open access and captive consumption
  - Short term OA makes planning for power procurement challenging

Consequent transition in the electricity sector

- Cost of marginal capacity addition could be less than the average cost of contracted capacity
- Generation projects no longer require long gestation periods and are modular
- Flexible loads shifting within the day to match generation
- Electricity can be stored with increasing ease and affordability
- Grid services are likely to be as critical as supply
- Focus in system planning needs to switch from baseload to variable renewables, to take advantage of lower prices.
  - Need a more robust approach with higher temporal granularity, which requires more sophisticated tools
- Planners and decision makers need to engage with a modelling based approach to inform decision making

Presentation Structure

- Approach
- Input assumptions
- Scenarios and results
- Coal fleet operation
- Insights

MODEL SETUP AND INPUT ASSUMPTIONS

Model setup

- System : MSEDCL (Maharashtra)
- Base year : 2017-18
- Model year : 2029-30
- Transmission : not modelled (copper plate)
- Load profile : based on 2017-18 data
- Demand assumptions
  - Demand growth: 5% from 2017-18 up to 2029-30
  - Load profile: 4000 MW of non-monsoon night-time agricultural load moved to day time by FY30 in line with Maharashtra's solar feeder policy

Category	Contracted Capacity (MW) in FY18
State Genco Coal	10,162
State Genco Gas	672
State Genco Hydro	2,352
Central Coal	4,471
Central Gas	404
Central Hydro	491
Central Nuclear	748
IPP Coal	5,585
Wind	3,641
Solar	654
Other NCE	923
Total	**30,103**

- Unit-wise disaggregation of generation sources
- Existing solar and wind profiles: based on state generation in base year
- New solar profiles: generated using SAM (fixed and single axis tracking)
- New wind profile scaled up (to ~28% CUF) from base year wind profile
- Bagasse generation based on seasonal availability

Thermal and hydro operational assumptions

- Coal
  - Technical minimum 55% for all units
  - Ramp rates: 1-1.5 %/min
  - Run up/down (0 ↔ tech min) rates for start and shutdown
    - 6-10 hours for cold start and 4-8 hours for warm start
  - Min up/down time: 24 hours
  - Start costs: CEA's 2019 report on 'Flexible Operation of Thermal Power Plants for Integration of Renewables'
  - Availability: 85%
- Hydro
  - Koyna: Yearly energy budget and monthly minimum energy based on generation data from past few years
  - Rest of the hydro: Generation profile provided based on past few years' data
- Open Cycle Gas ramp rate 4%/min

Cost projections (nominal) in 2030

Coal variable and RE levelised costs			
Rs/unit	FY20	FY30 (nominal)	Weighted average in FY30
New Coal Variable	2.76	4.49	4.49
Wind Levelised	2.86	4.23	3.72
Solar Levelised	2.76	3.71	3.35

- New Coal fixed costs based on Rs 8 Cr/MW (capacity added in 2025)
- Open cycle gas generation @ Rs 12/unit
- Day-ahead market purchase
  - Non-peak (23:00-18:00) Rs 6.5/unit, Peak (18:00-23:00) Rs 7.5-10/unit
- Battery costs (weighted average cost of storage added until FY30)
  - Rs 14,450/kWh for 6 hour, Rs 17,425/kWh for 4 hour
- Cost for complying with environmental norms: 0.3 Rs/unit

Model platform and settings

- **Plexos** - https://energyexemplar.com/solutions/plexos
- Commercial software that offers production cost simulation and capacity expansion optimisation
- Used by transmission system operators, market operators, planners, regulators, distribution utilities, generators, researchers, etc.

- Unit commitment and dispatch optimised over a day with 1 day look-ahead
  - Optimised over 2 days in each step, but unit commitment decisions retained only for the first day
- Thermal maintenance and hydro scheduling optimised on an annual basis
  - Thermal unit maintenance scheduled in high reserve periods
  - Storage based hydro generation optimised over the year, within exogenously provided monthly constraints

SCENARIOS AND RESULTS

Parameters considered for analysis

- Reliability: Shortage quantum and profile
- System operation in stress hours/months
- Thermal PLFs, part-load operation, starts
- RE curtailment
- Variable/operational and total costs

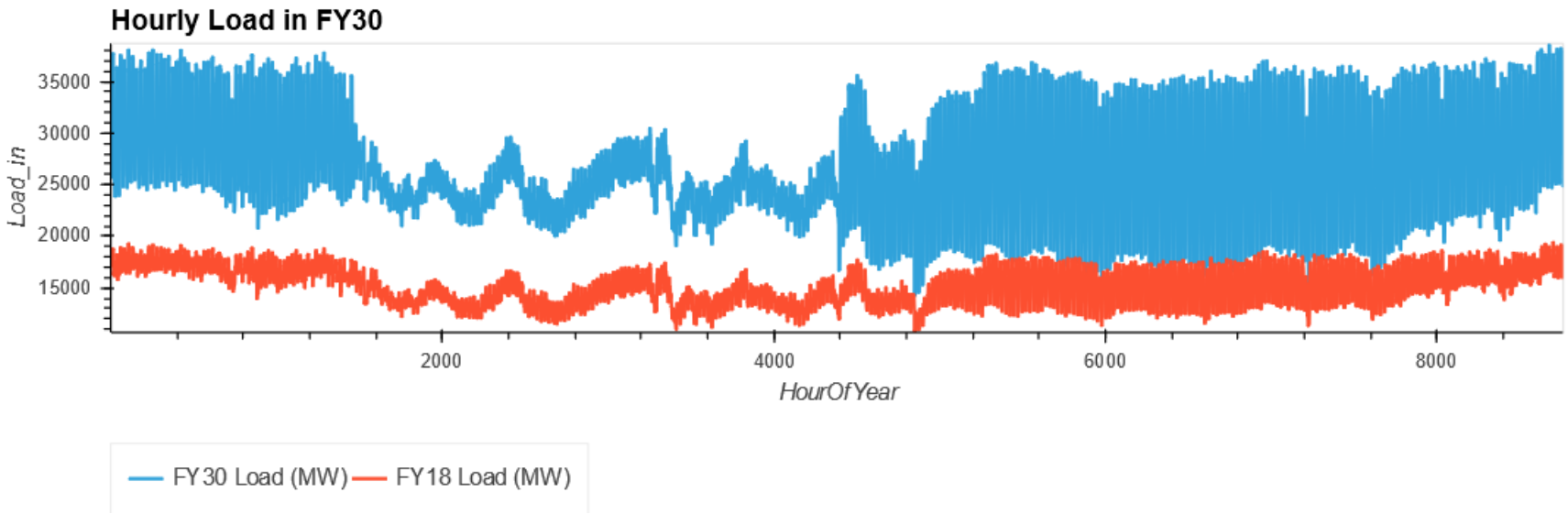
- Focus (of this presentation) on
  - High level numbers/insights
  - Insights about system operation, importance of various inputs & assumptions, and actions required for a high RE scenario
  - Identify policy and regulatory approaches that need to be initiated

Scenarios and sensitivities

	BAU	RE Scenario 1		RE Scenario 2	
	Base	Base	Sensitivity	Base	Sensitivity
Demand (MUs)	2,32,750	2,32,750	2,42,257	2,32,750	2,42,257
Load stress) (5-8 am, 5-12 pm)			10% incr. Demand		10% incr. Demand
Coal Addition (MW)	3,960	no net addition		-1,320	
RE share	30%	50%		50%	
Open Cycle Gas/Mkt (MW)	2000 gas	2000 gas		2000 MW mkt	
Battery Storage	None	3 GW 6-hr and 2.5 GW 4-hr			

Load in FY18 and FY30

Demand	FY18	FY30
Annual (MUs)	129,605	232,750
Average (MW)	14,795	26,750
Peak (MW)	19,077	38,119
Trough (MW)	10,393	14,705

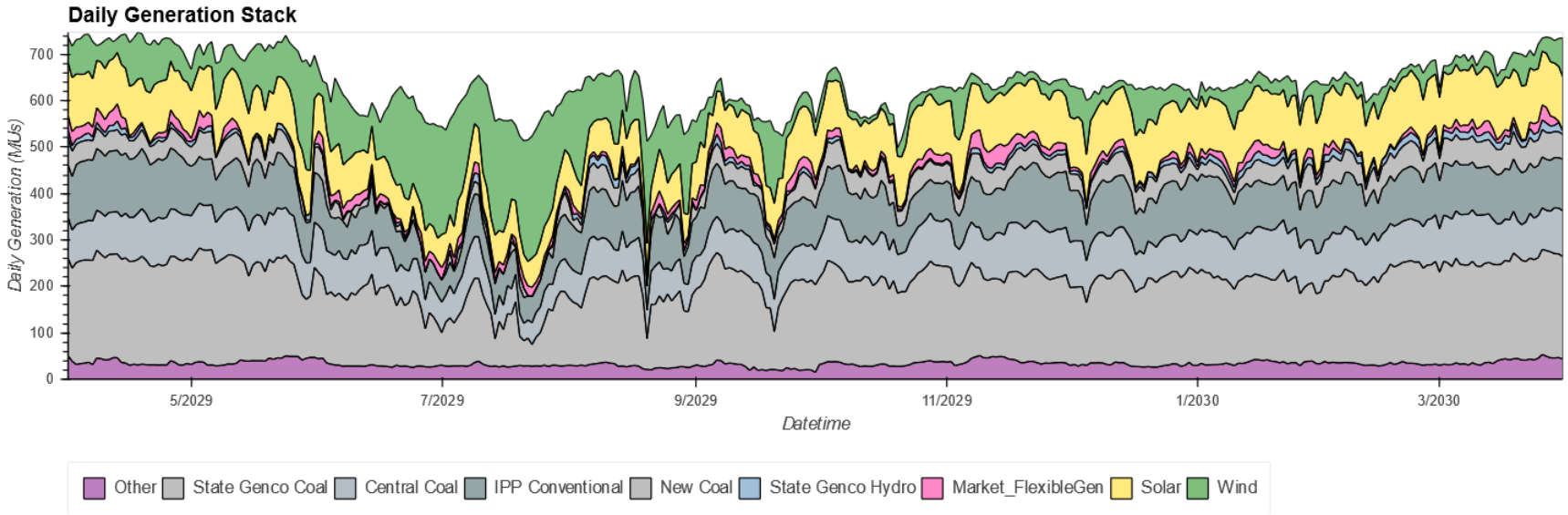


Business as usual case

- Net addition of 6x660 MW
- 30% generation from RE sources
- 2,000 MW Open Cycle Gas

Category	Contracted Capacity (MW) by FY30	Net Generation (MUs) in FY30
State Genco Coal	11,490	66,451
State Genco Hydro	2,352	3,816
Central Coal	5,117	31,729
IPP Coal	5,585	35,921
New Coal	2,640	13,856
Wind	12,940	27,196
Solar	19,675	36,292
Others	3,387	11,849
Total	**63,185**	**227,110**
Open Cycle Gas	2,000	5,193

BAU: Wind dominates in monsoon, coal dominates rest of the year



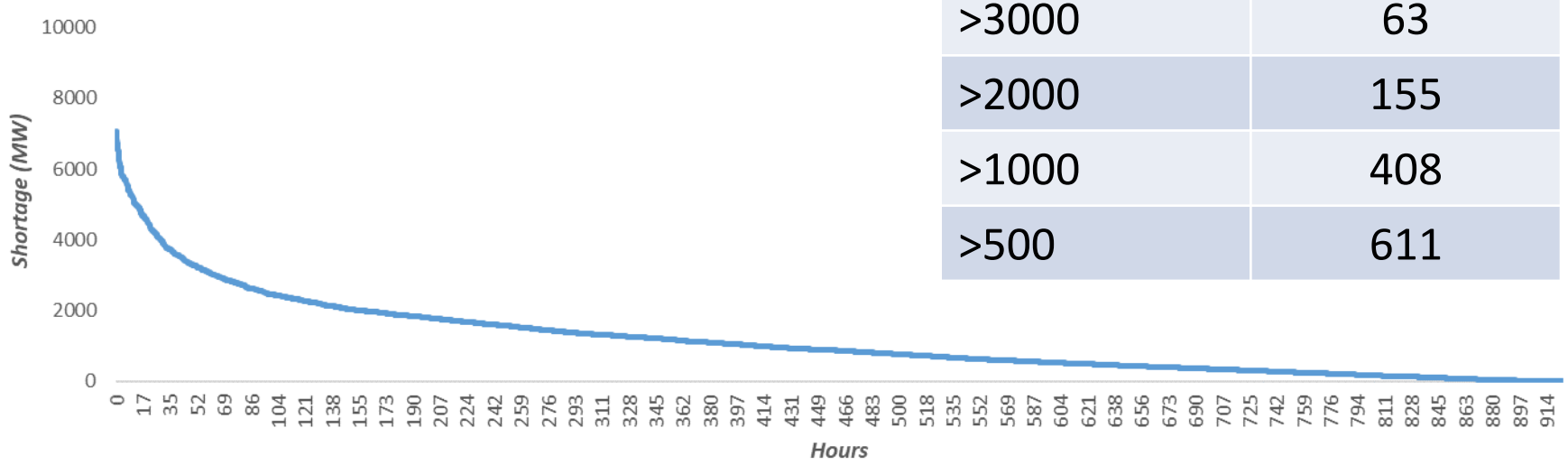
Coal Generation Category	PLF (%)
State Genco Coal	71%
IPP Coal	73%
Central Coal	76%
New Coal	64%

New coal has lower PLF in spite of higher efficiency due to higher variable costs assumed based on recent capacity addition in Maharashtra

BAU: Shortages

Annual Demand: 232,750 MUs
Annual Shortage: 1,072 MUs
RE Curtailment: 1,497 MUs

Shortage (MW)	Number of hours
>5000	13
>3000	63
>2000	155
>1000	408
>500	611



- Shortages are < 0.5% of annual demand, manageable
- A few hours of very high (>5000 MW) shortages exist
- Long term capacity addition cannot address these shortages in an economical manner.

High RE Scenario 1

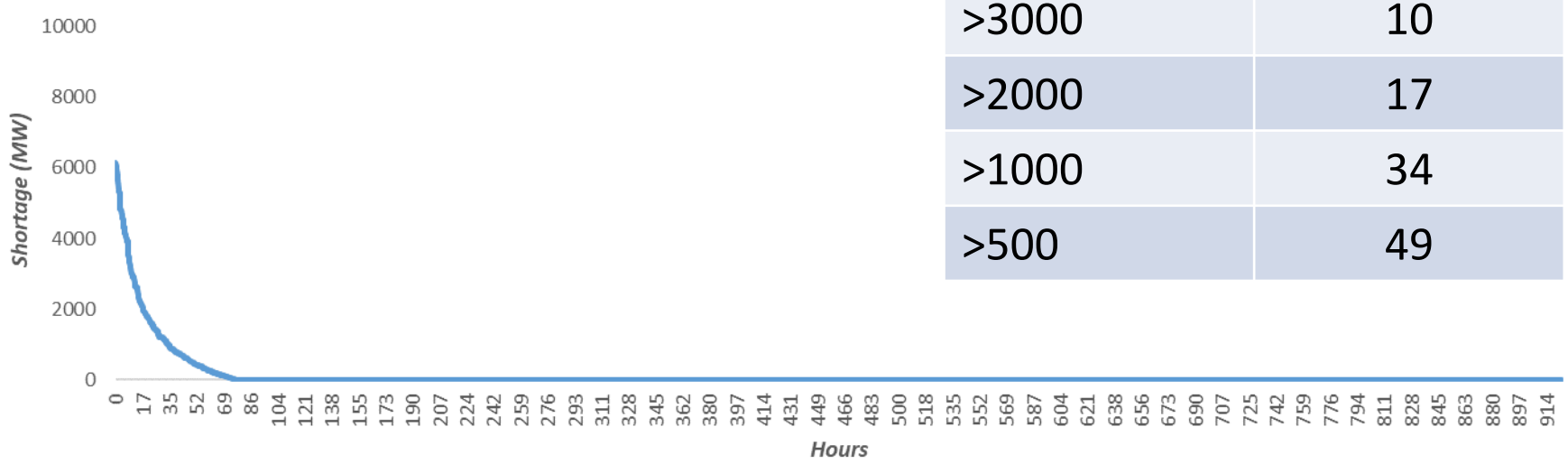
- No net coal capacity addition
- 50% generation from RE sources
- Battery: 3,000 MW/18,000 MWh + 2,500 MW/10,000 MWh
- 2,000 MW Open Cycle Gas

Category	Contracted Capacity (MW) by FY30	Net Generation (MUs) in FY30
State Genco Coal	10,230	48,607
State Genco Hydro	2,352	3,802
Central Coal	5,117	28,804
IPP Coal	5,585	30,916
Wind	21,215	46,557
Solar	28,640	61,485
Others	3,387	10,827
Total	76,526	230,998
Open Cycle Gas	2,000	3,038
Battery Output	5,500	9,308

High RE Scenario 1: Shortages

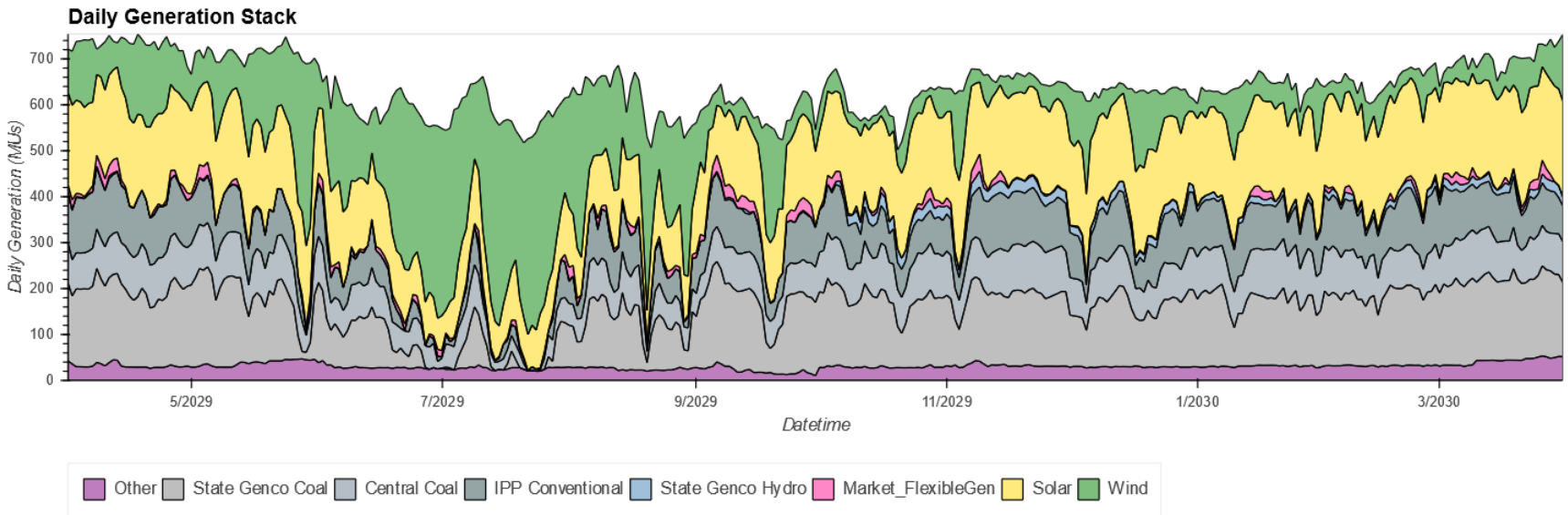
Annual Demand: 232,750 MUs
Annual Shortage: 105 MUs
RE Curtailment: 3,955 MUs

Shortage (MW)	Number of hours
>5000	3
>3000	10
>2000	17
>1000	34
>500	49



- Shortages ~ 0.05% of demand, much lower compared to BAU
- A few hours of very high (>5000 MW) shortages exist
- Long term capacity addition cannot address these shortages in an economical manner.

High RE Scenario 1: Wind dominates in monsoon, Solar significant rest of the year



Coal Generation Category	PLF (%)
State Genco Coal	58%
IPP Coal	63%
Central Coal	69%

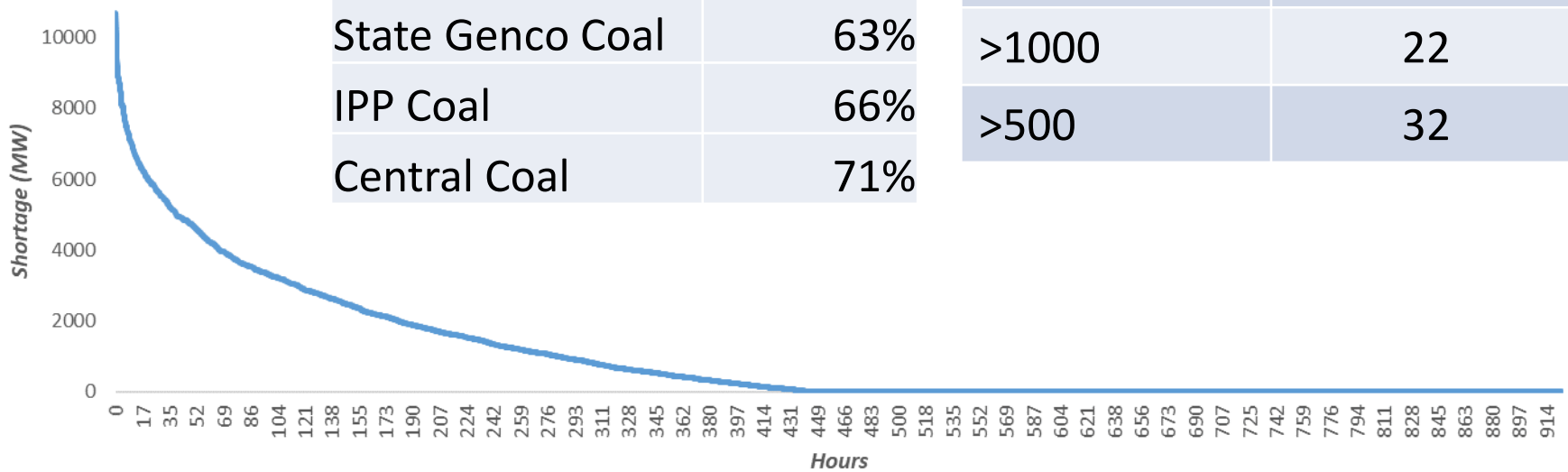
Scenario 1: Higher demand during stress hours

10% higher demand during 5-8am & 5pm - midnight

Annual Demand: 242,257 MUs
Annual Shortage: 928 MUs
RE Curtailment: 4,511 MUs

Shortage (MW)	Number of hours
>5000	3.5
>3000	8
>2000	13
>1000	22
>500	32

Category	PLF (%)
State Genco Coal	63%
IPP Coal	66%
Central Coal	71%



High RE Scenario 2

Scenario 1 +

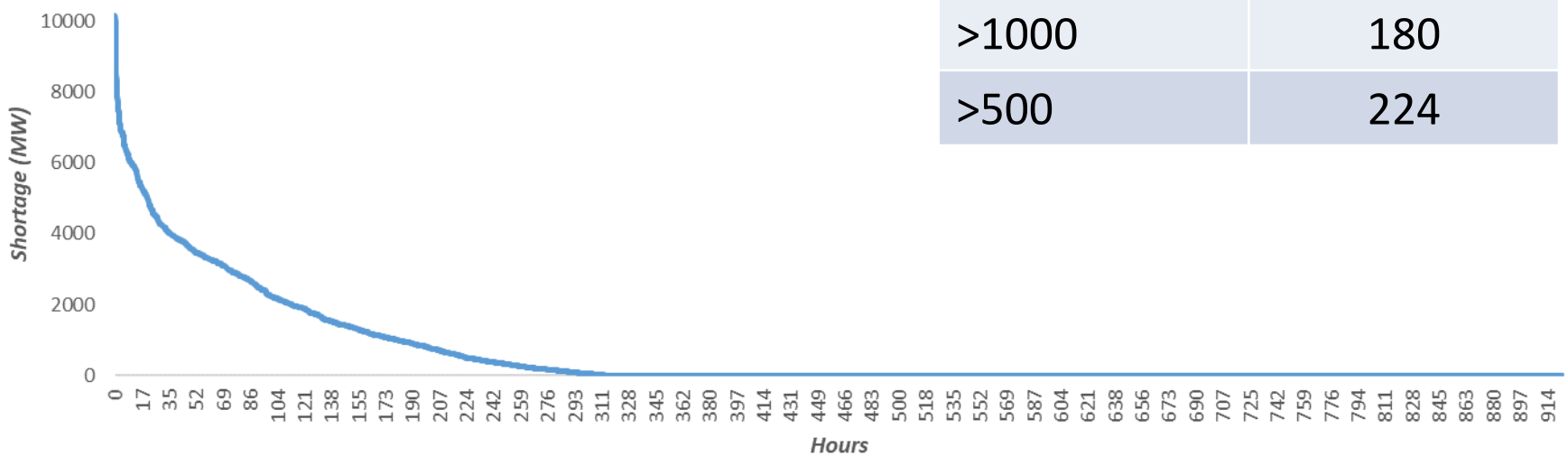
- Retirement of 1,320 MW coal
- 2,000 MW day-ahead market procurement instead of 2,000 MW Open Cycle Gas

Category	Contracted Capacity (MW) by FY30	Net Generation (MUs) in FY30
State Genco Coal	8,910	44,425
State Genco Hydro	2,352	3,801
Central Coal	5,117	29,101
IPP Coal	5,585	31,273
Wind	21,215	46,515
Solar	28,640	61,460
Others	3,387	11,295
Total	75,206	227,870
Market	2,000	5,625
Battery Output	5,500	9,382

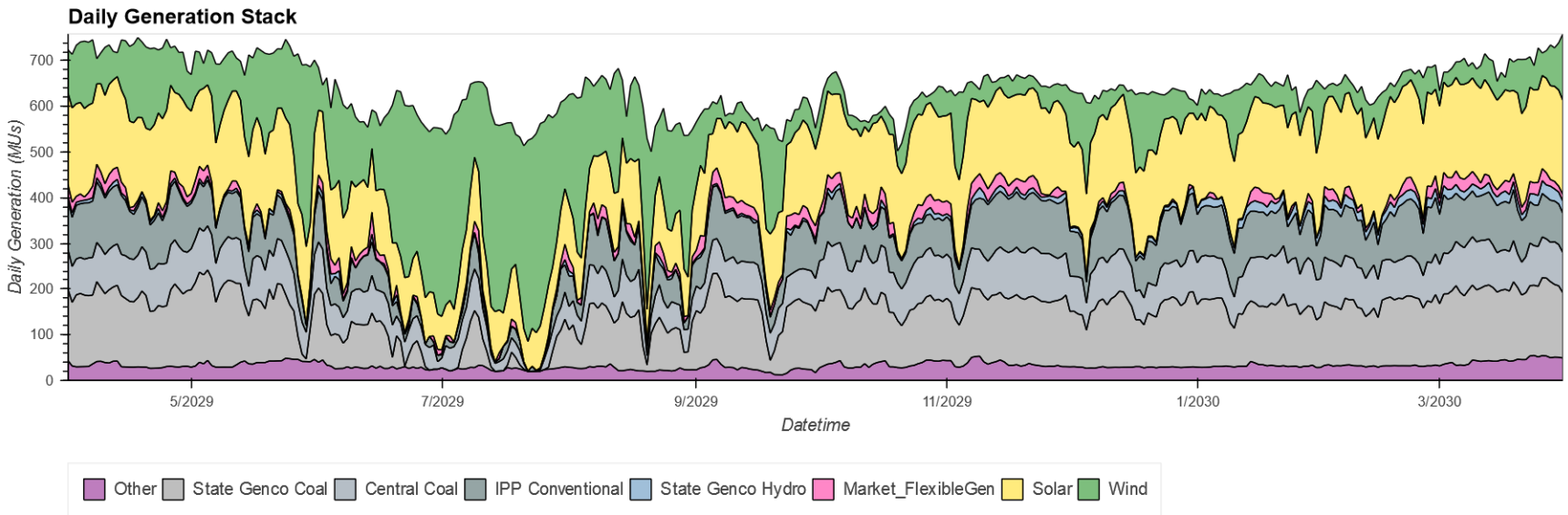
High RE Scenario 2: Shortages

Annual Demand: 232,750 MUs
Annual Shortage: 574 MUs
RE Curtailment: 4,022 MUs

Shortage (MW)	Number of hours
>5000	3.5
>3000	21
>2000	72
>1000	180
>500	224



High RE Scenario 2: Daily generation stack



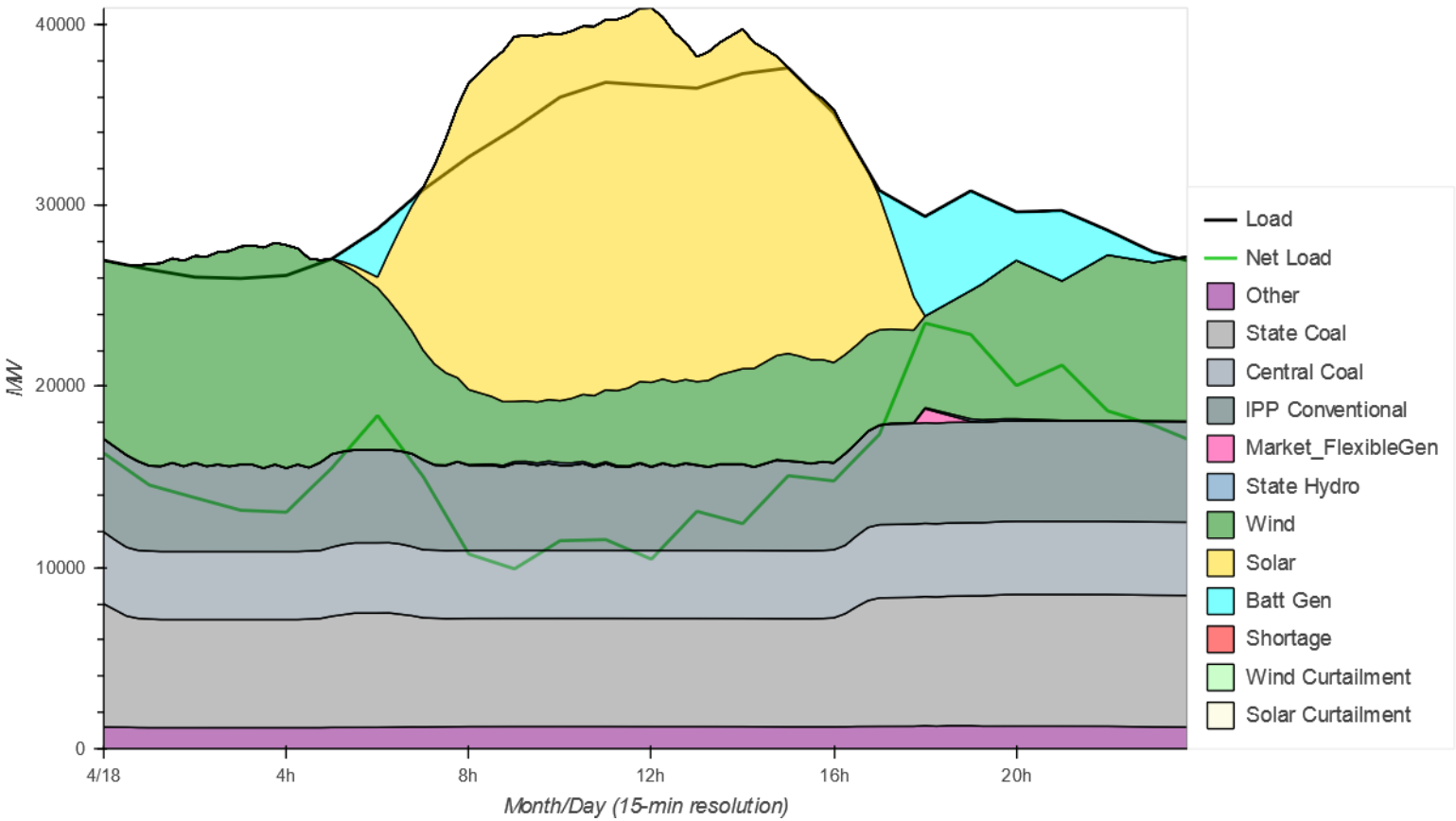
Higher procurement from market in Scenario 2 than from open cycle gas in Scenario 1

Category	PLF (%)
State Genco Coal	61%
IPP Coal	64%
Central Coal	69%

High load, Maximum shortages, Maximum RE curtailment, Flexible Generation

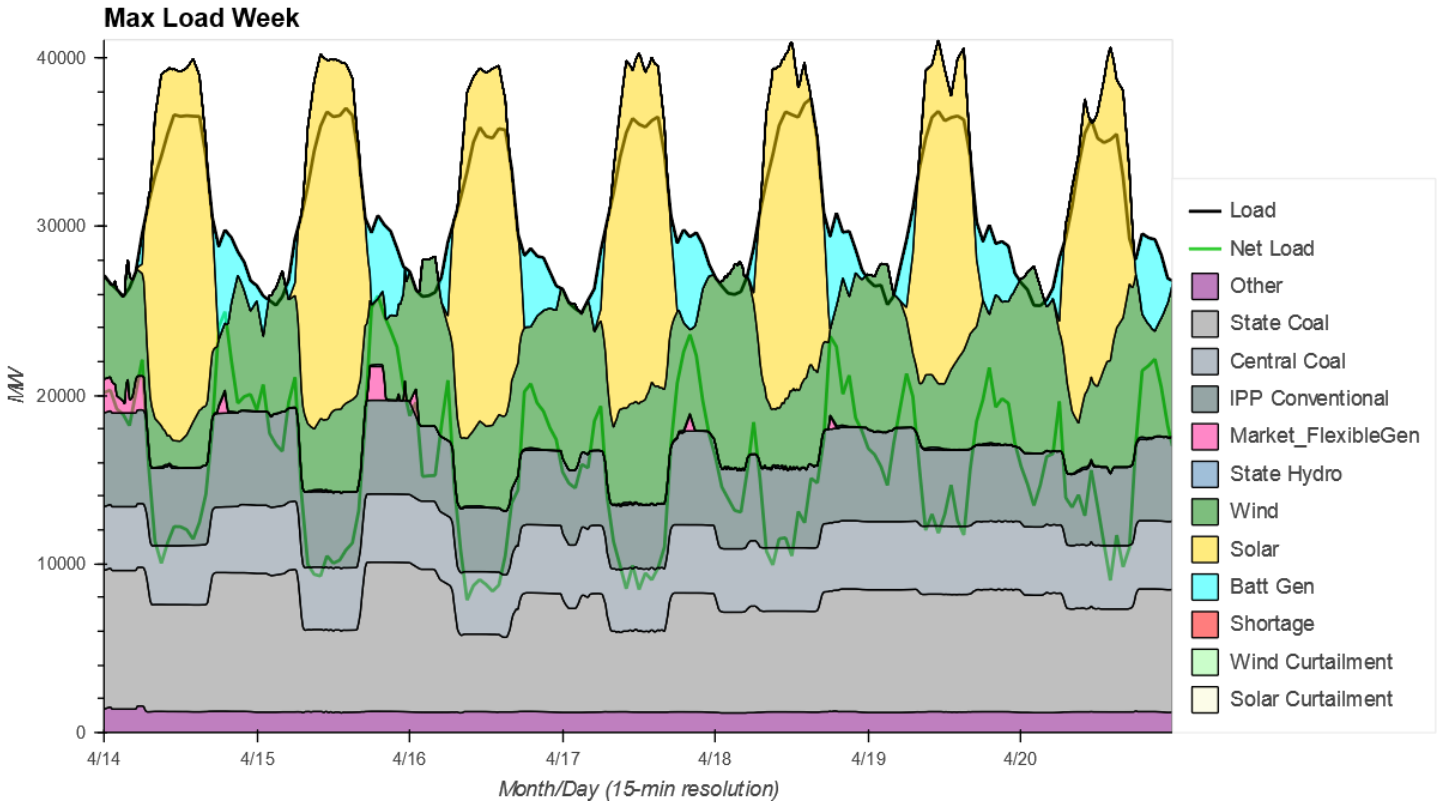
SYSTEM OPERATION ON SPECIFIC DAYS

High RE Scenario 1: High Load Day



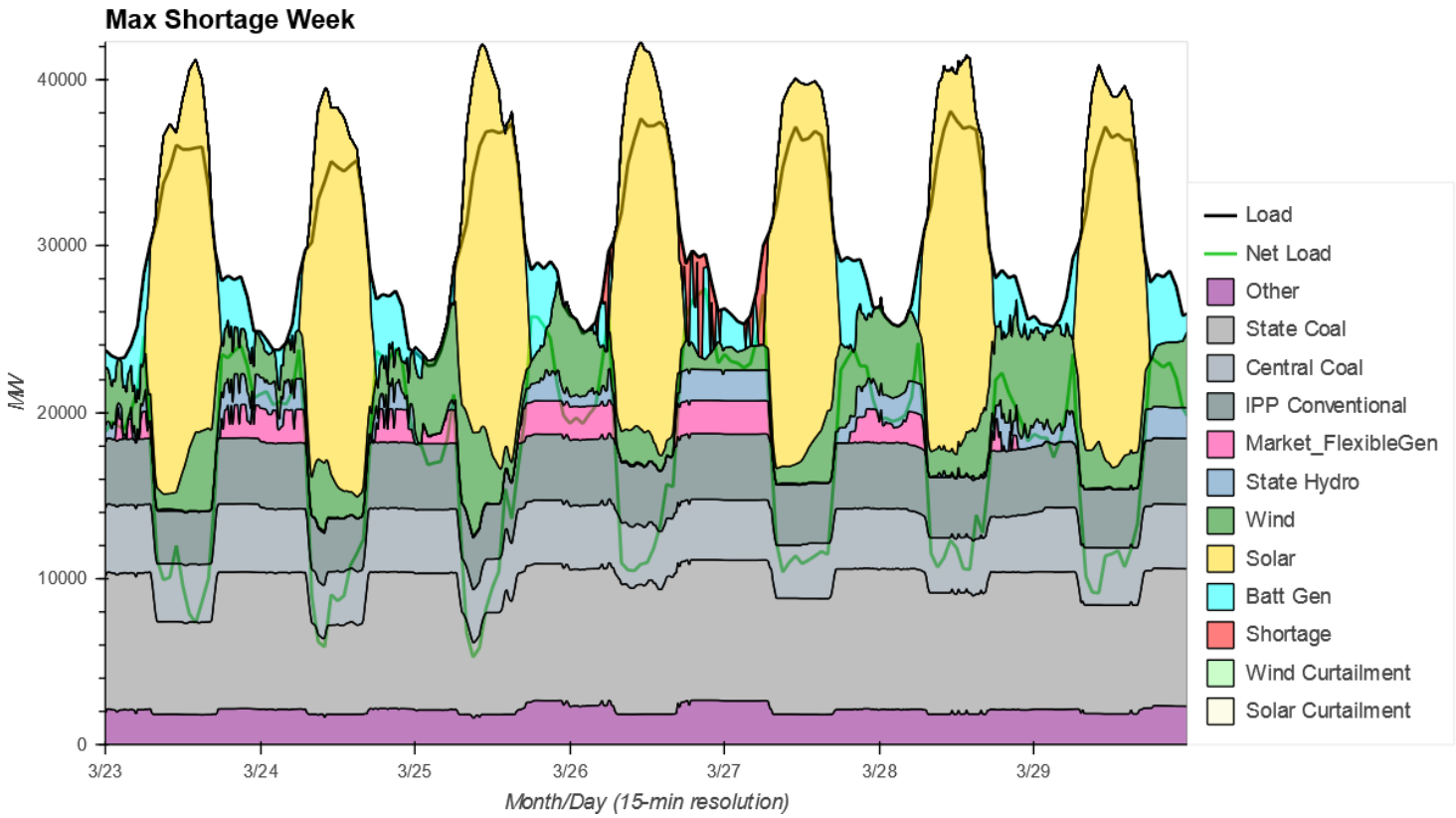
- Battery charged during the day with generation above the load line
- Battery discharged during net load peaks (early morning and late evening)

High RE Scenario 1: High Load Week



- Coal capacity at close to max generation, with a dip during the day
- Open Cycle Gas (labelled 'Market_FlexibleGen') procured opportunistically

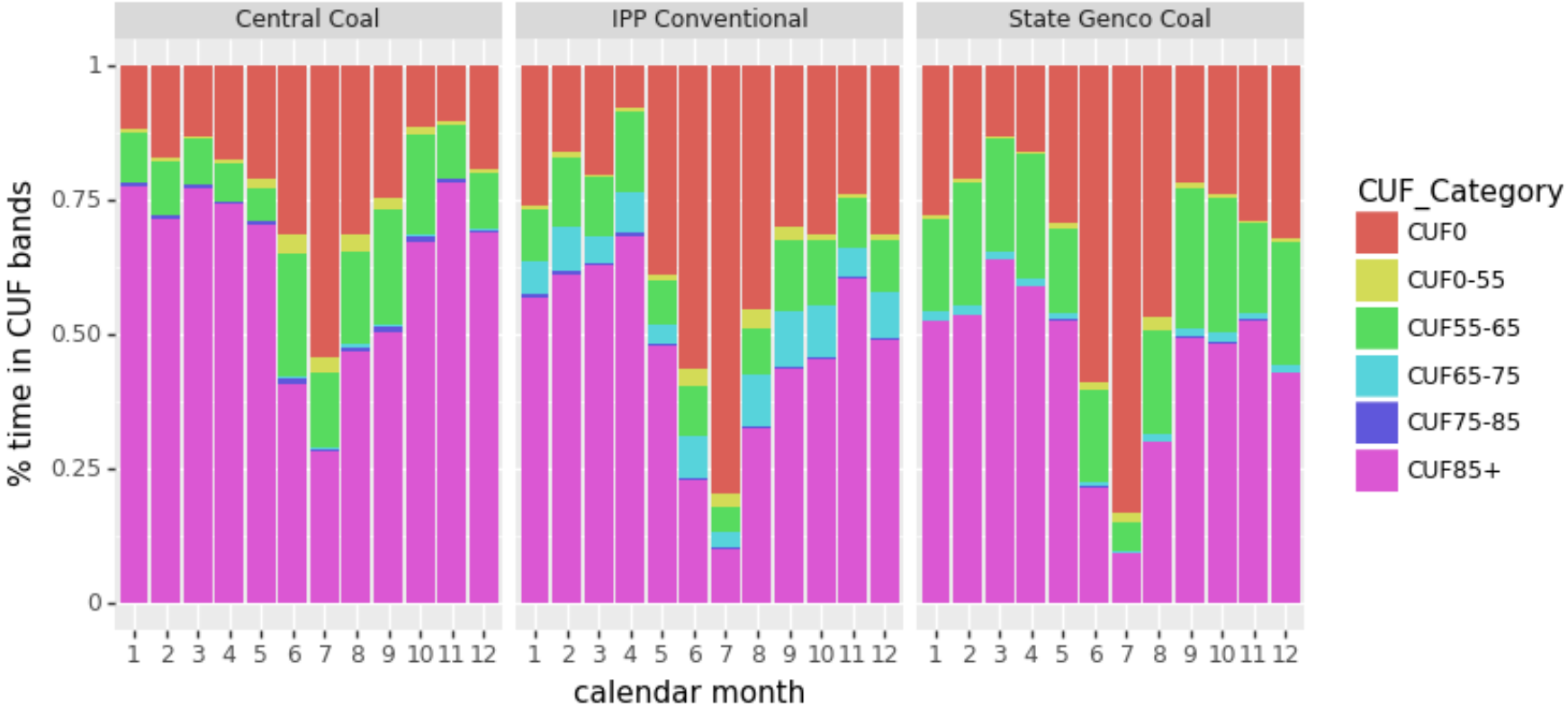
High RE Scenario 1: Max Shortage Week



- Significant variability in wind generation results in shortages since net load ramps are high and coal generation cannot be brought online quickly
- Open cycle gas gen is maxed out during non-solar hours throughout the week
- Perhaps some RE could be curtailed, and coal generation could be brought online instead of or in addition to open cycle gas

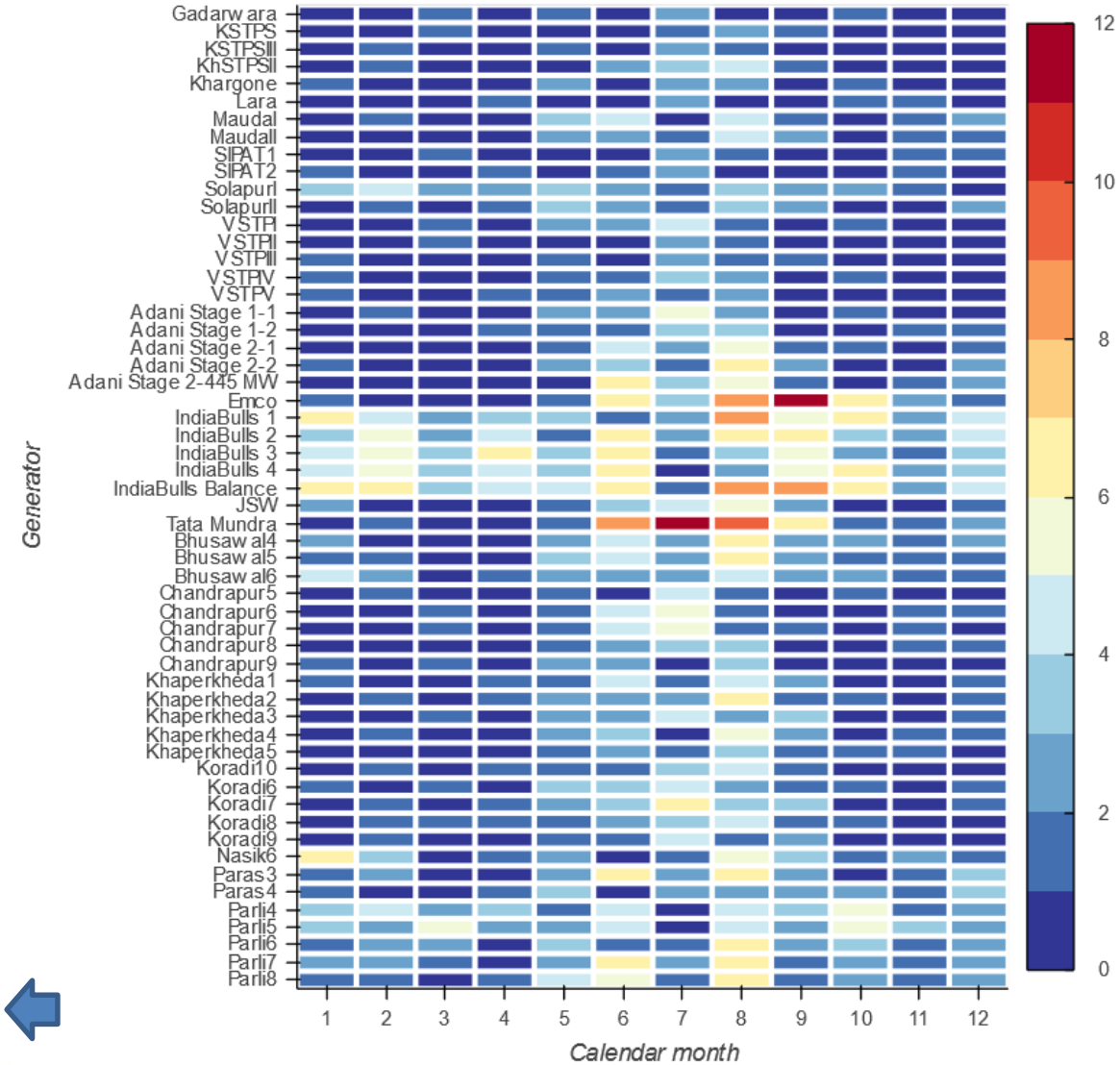
COAL FLEET OPERATION

High RE Scenario 1: Coal unit loading



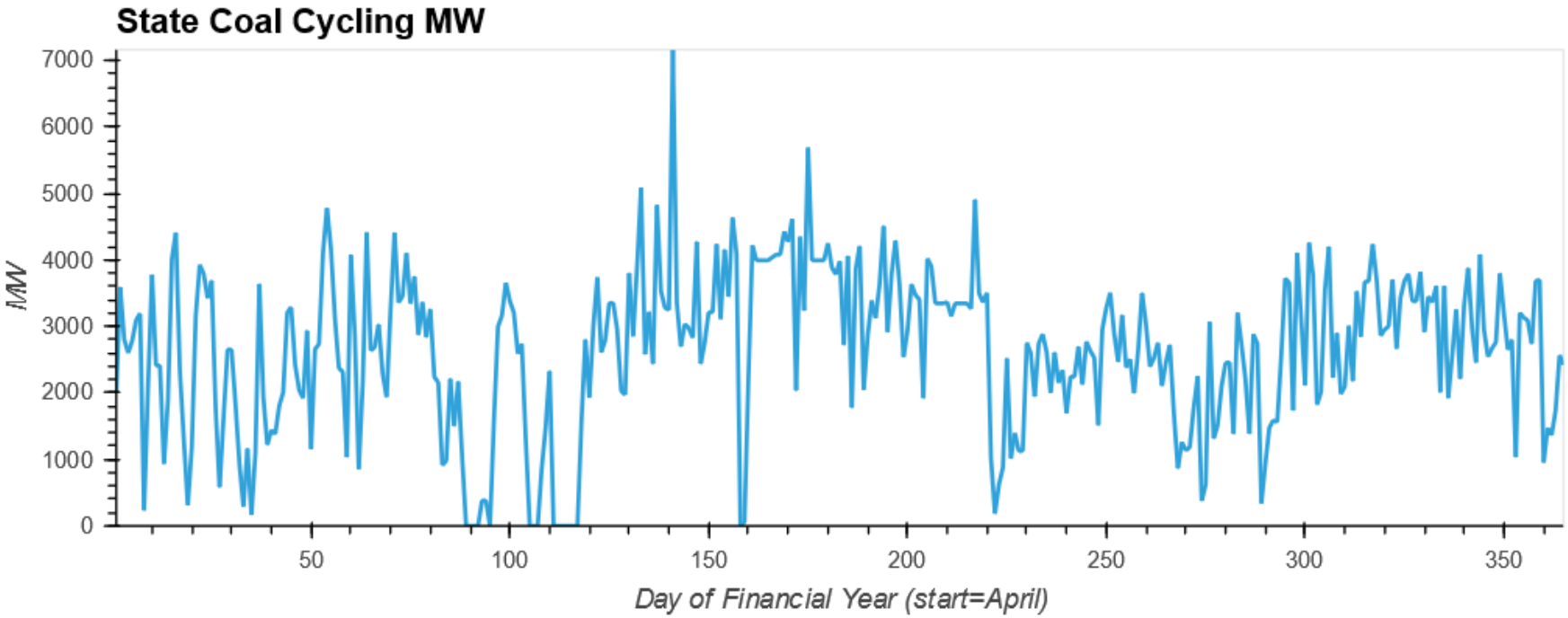
- Coal units operate above 85% load over 50% of the time during non-monsoon months
- During monsoon months
  - Central units operate at partial load for about 25% of the time
  - State and IPP units are offline 60-80% of the time
- State and IPP units operate at part load about 25% of the time throughout the year
- Implications for variable costs and increased O&M

High RE Scenario 1: Coal unit starts/month



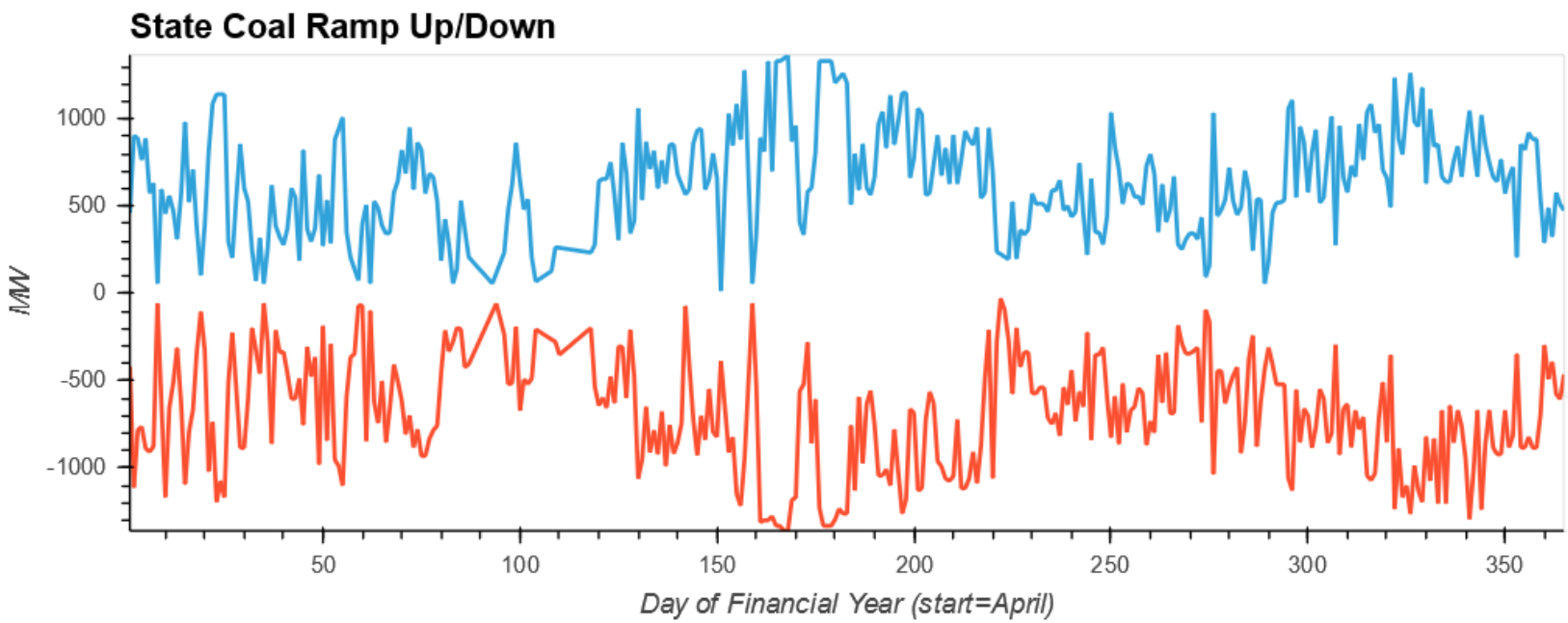
- Higher starts during monsoon months for some high cost units
- Number of starts could be reduced by curtailing RE or by balancing over a larger area without significant cost impact

Scenario 1: Daily min-max generation diff



- Average difference between daily minimum and maximum generation of the Genco coal fleet is ~3000 MW, about 5 times the difference in FY16
- Need to prepare for significant cycling of coal fleet even without significant improvement in ramp rates

Scenario 1: Daily block-wise max ramps



- Daily average max ramp up/down in FY30: ~600 MW for the Genco coal fleet, up from ~300 MW in FY16

KEY INSIGHTS

Summary

- Summary of key parameters across scenarios

	BAU	Scenario 1		Scenario 2	
	Base	Base	Stress	Base	Stress
Demand (MUs)	232,750	232,750	242,257	232,750	242,257
Shortage (MUs)	1072	105	928	148	678
RE curtailment (MUs)	1497	3955	4511	3910	4120
Market/Open Cycle Gas purchase (MUs)	5193	3038	5447	10,297	14,040
Coal PLF (%)	72%	62%	66%	62%	65%
Coal starts/unit	17.3	18.7	15.9	18.2	15.2
Total power purchase cost (Rs/kWh) – not considering transmission costs etc		5-8% lower total power purchase costs across all scenario runs, compared to BAU.			

Key Insights …. 1

- Possible to meet demand in 2030 without any ‘net addition to coal fleet’ and with 50 % energy contribution from RE
  - Similar reliability as a business as usual case
  - Operation of coal plants within acceptable technical limits (technical min, ramp up etc.)
  - MH needs to plan for RE contracted capacity of ~50 GW by FY30 (from 12-13 GW in FY20)

Key Insights …2

- Solar feeder, day time AG load, significantly helps in solar absorption
- For reliability, necessary to procure 'peaking' power ~ 15 - 35% PLF depending on the scenario
  - high cost (either low PLF or market)
- Desirable to have seasonal, short term procurement to meet seasonal high load
- Coal availability, cost and flexible operation ability important considerations in both scenarios
- Demand response measures are essential to avoid sudden shortage for even few hours a year (~ 20 – 30 hrs.)

Key Insights …. 3

- Some immediate actions / policies that could be considered as part of Multi-year Tariff (MYT) framework
  - Seasonal tariffs
  - Expanding ToD regime to 5/10kW+ and adjusting peak tariff slot
  - Seasonal short term procurement
  - Peak / exigency power procurement approval
- Initiating procurement of grid scale battery storage on pilot basis
- Ensure/expand solar feeder
- Transmission planning for 50% RE scenario
- More structured and rigorous RE procurement approach (location, profile etc.). Value to the system rather than just least cost approach needs to be adopted.

Additional considerations

BAU	50% RE
Uncertain availability – needs careful management of coal supply and unit maintenance.	Higher ramp requirements and shutdown of plants – opportunistic contracts with other states/regions
Higher costs for new capacity and uncertainty of coal cost trajectory. Lumpy investments, long gestation and high cost lock in risk.	Additional transmission costs but could also be co-located with load. Highly modular and short gestation giving more optionality; fixed price contracts.
Flexible coal operation is a requirement in this scenario too given RE and demand variability.	Battery helps in addressing diurnal shortages and absorbing economical solar/RE. Hydro becomes a more seasonal resource.
Higher risk of future stricter environmental compliance.	Much lower on water requirements in addition to local air quality and GHG benefits.

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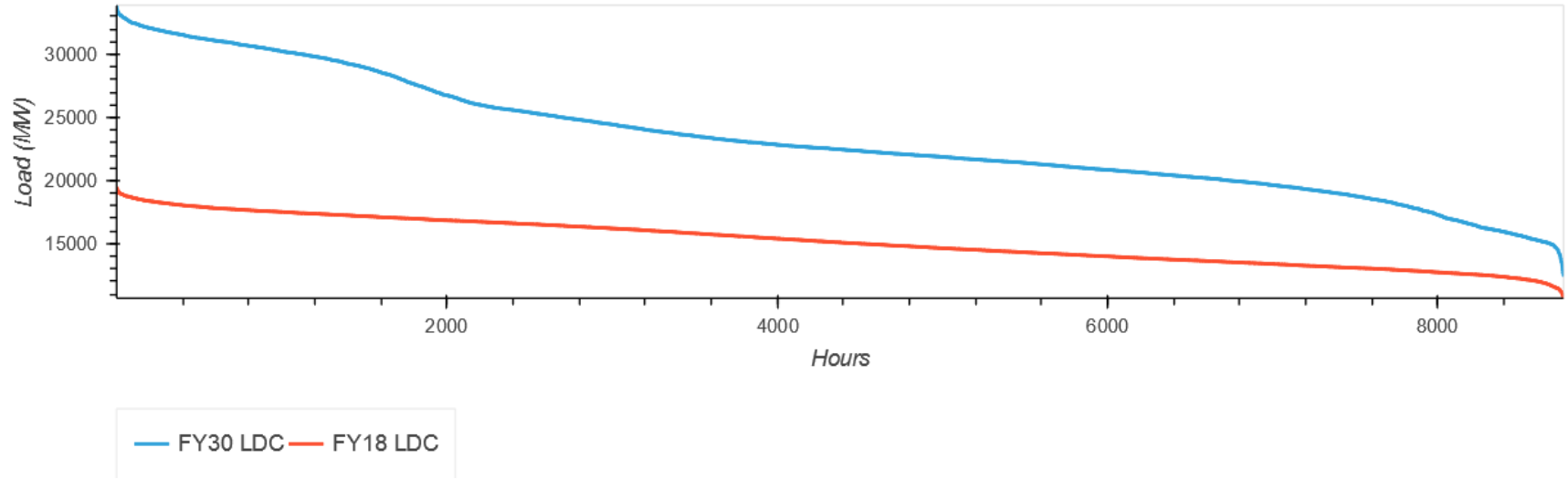
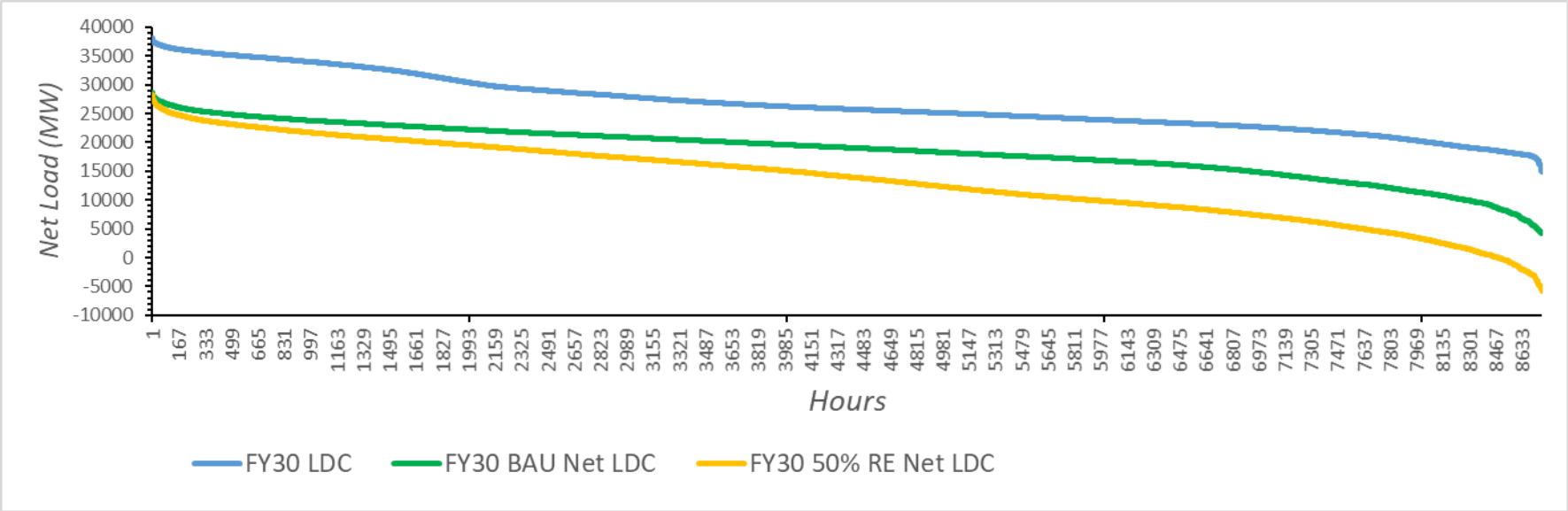
THANKS

Load duration curves for FY18 and FY30





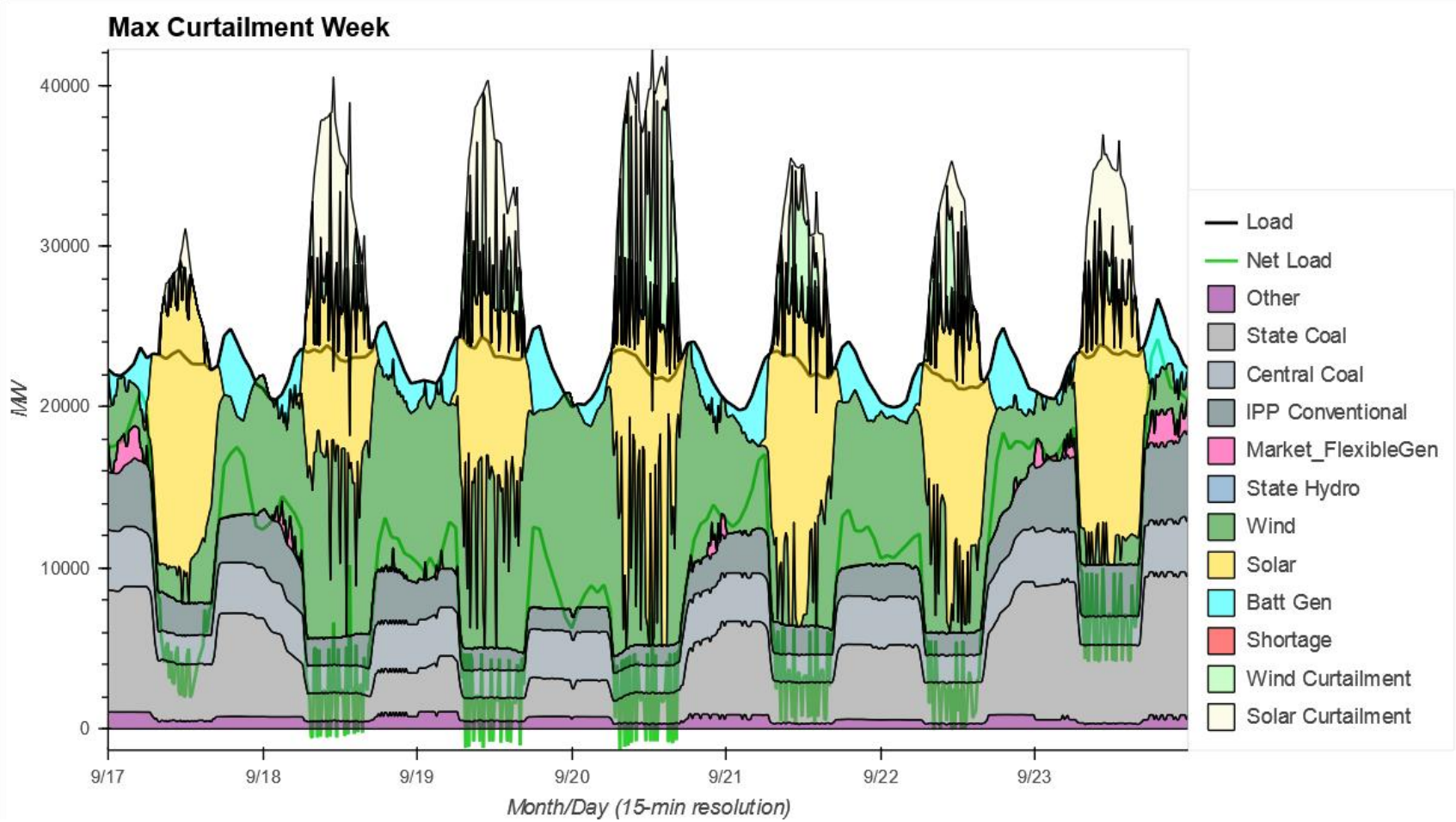
Modelling Approach…1

- Focus on state level analysis
  - Need to demonstrate value and feasibility of large share of RE to state level decision makers
  - Maharashtra state utility (MSEDCL) system is modelled
- Limit the policy/regulatory instruments considered in the model to decisions that can be taken at the state level
  - Less dependence on interstate and central initiatives or regional/national level optimization
  - Paradigm of self sufficiency (investments within state domain)
- Focus on system reliability and adequacy at least system cost, with conservative generation and storage cost trajectories and not considering difficult (but desirable) actions such as
  - Increased flexibility of base load plants
  - Diffused actions such as demand response and vehicle-to-grid
- Assume that necessary transmission system augmentation will happen by 2030

Modelling Approach…2

- Assess appropriateness of ‘high’ RE scenario, rather than ‘maximum’ RE scenario
  - Whether it is technically feasible and cost implications thereof
- Parameters considered for analysis
  - Reliability: Shortage quantum and profile
  - System operation in stress hours/months
  - Thermal PLFs, part-load operation, starts
  - RE curtailment
  - Variable/operational and total costs
- Focus (of this presentation) on
  - High level numbers/insights
  - Insights about system operation, importance of various inputs & assumptions, and actions required for a high RE scenario
  - Identify policy and regulatory approaches that need to be initiated

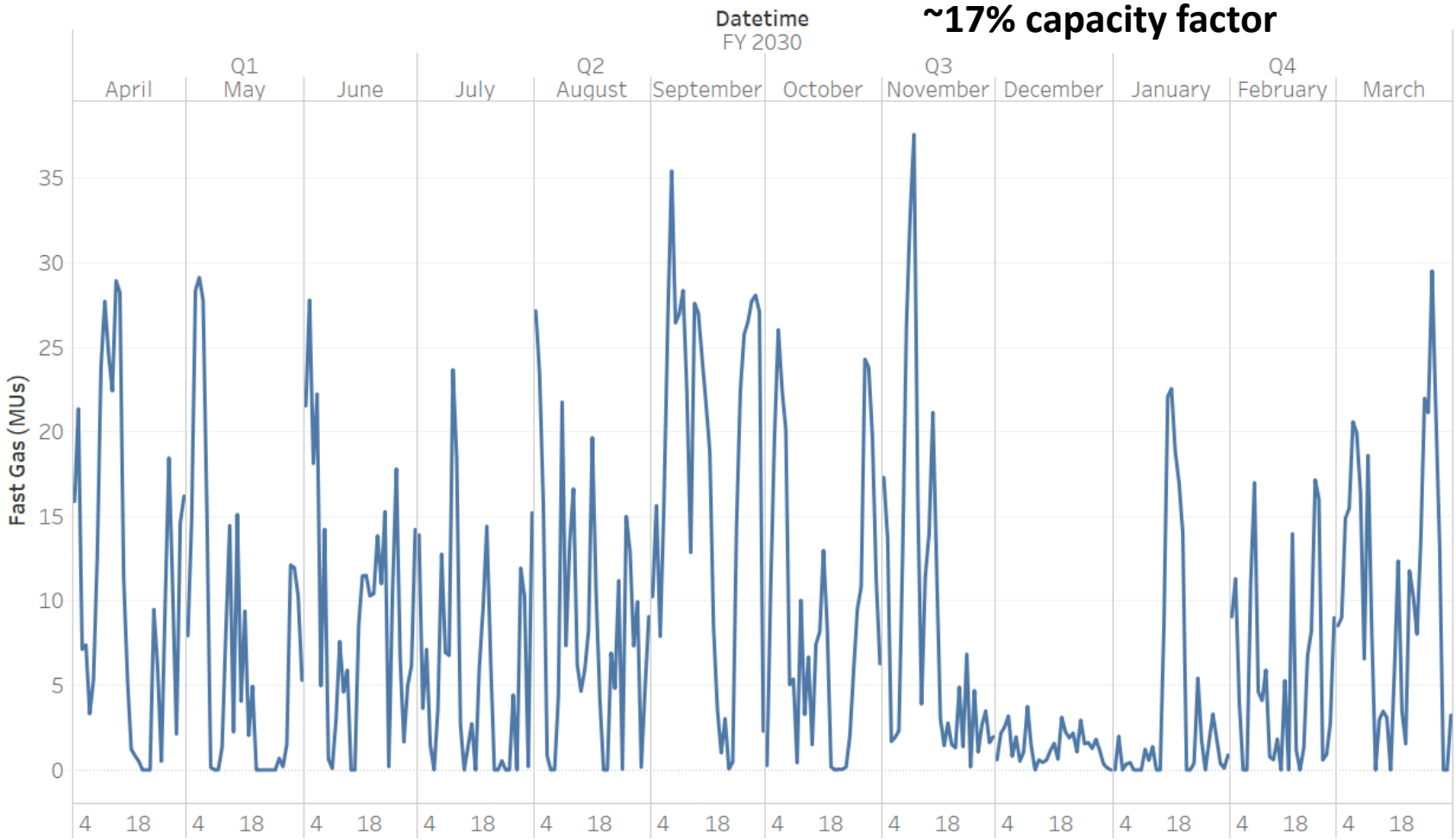
High RE Scenario 1: Max Curtailment week



Negative net load results in significant RE curtailment on some days

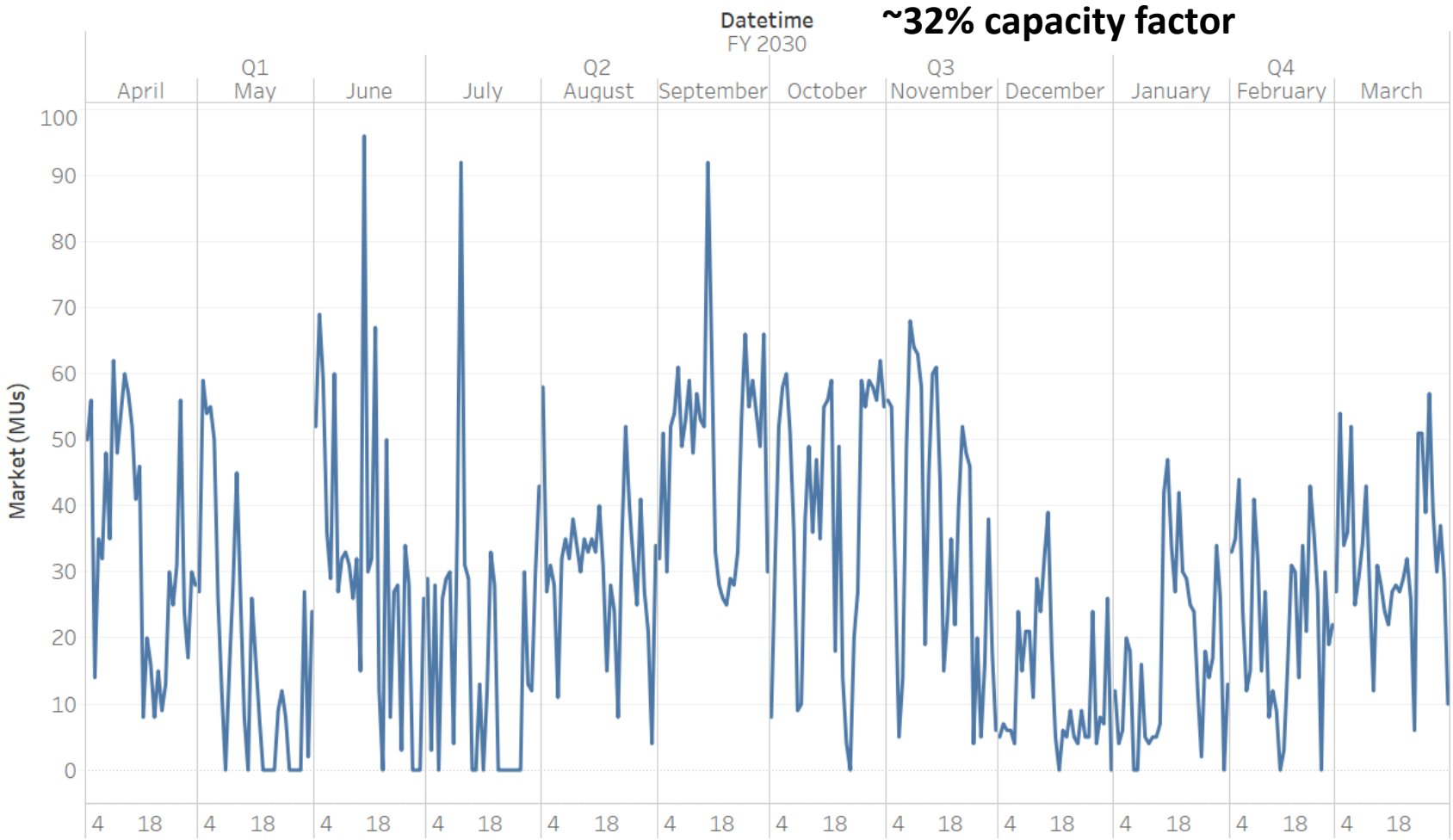
High RE Scenario 1: Open Cycle Gas Generation

3,038 MUs (~1.3% of demand)
Rs 3,646 Crs (~3% of total cost)
~17% capacity factor

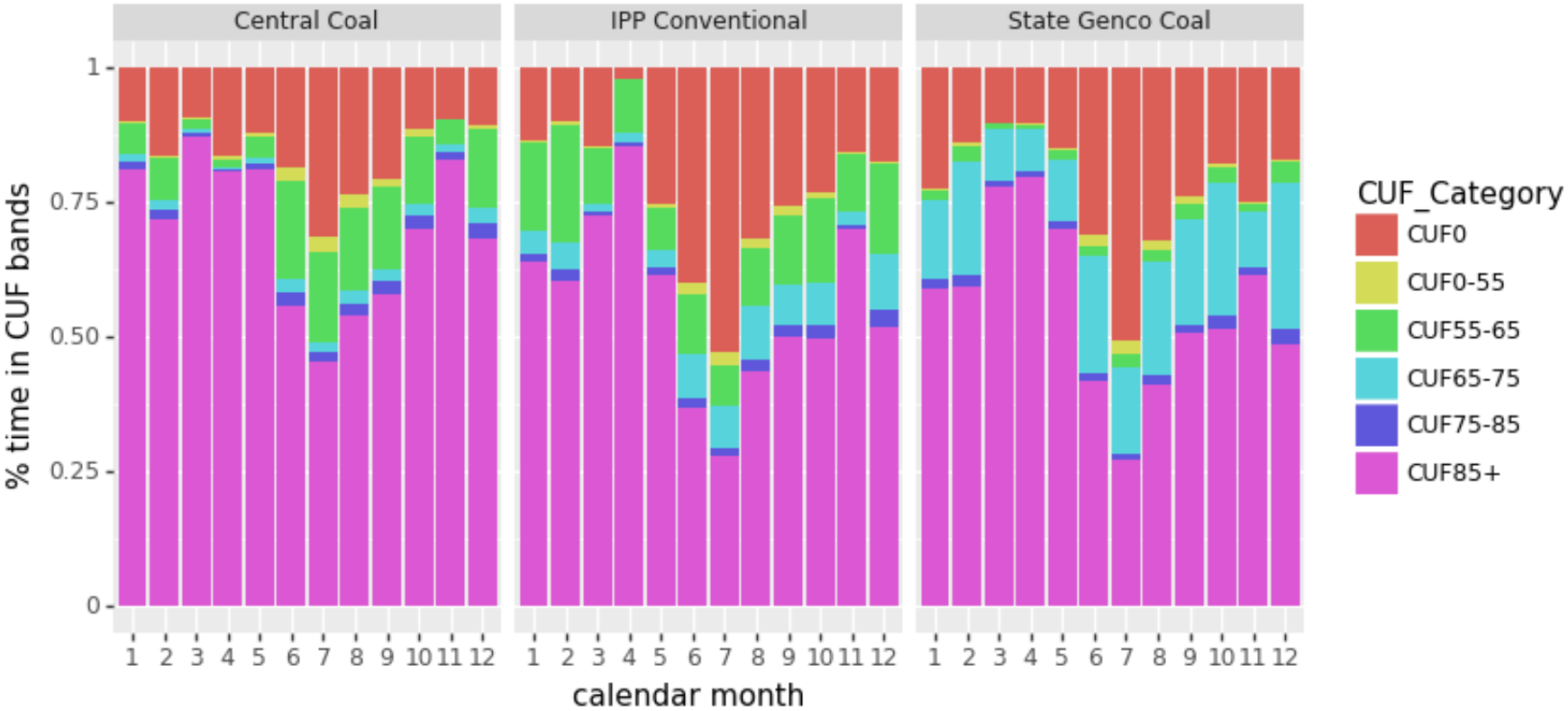


High RE Scenario 2: Daily Market Procurement

5,625 MUs (~2.4% of demand)
Rs 4,048 Crs (~3.5% of total cost)
~32% capacity factor



BAU: Coal unit loading



- Coal units operate above 85% load 50-75% of the time during non-monsoon months
- During monsoon months
  - Central units operate at partial load for about 25% of the time
  - State and IPP units are offline 25-50% of the time
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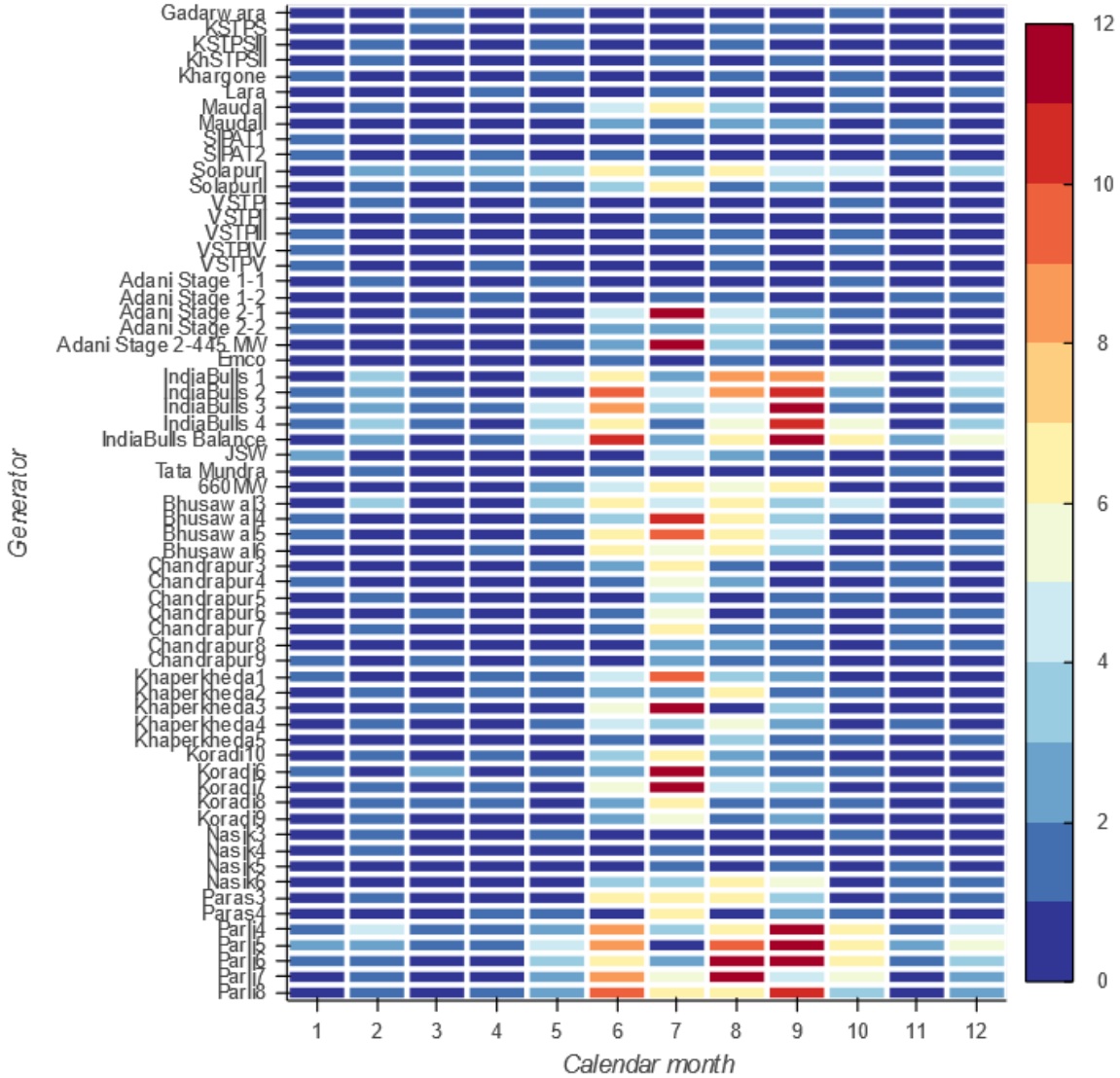
- Implications for variable costs and increased O&M

BAU: Coal unit starts/month



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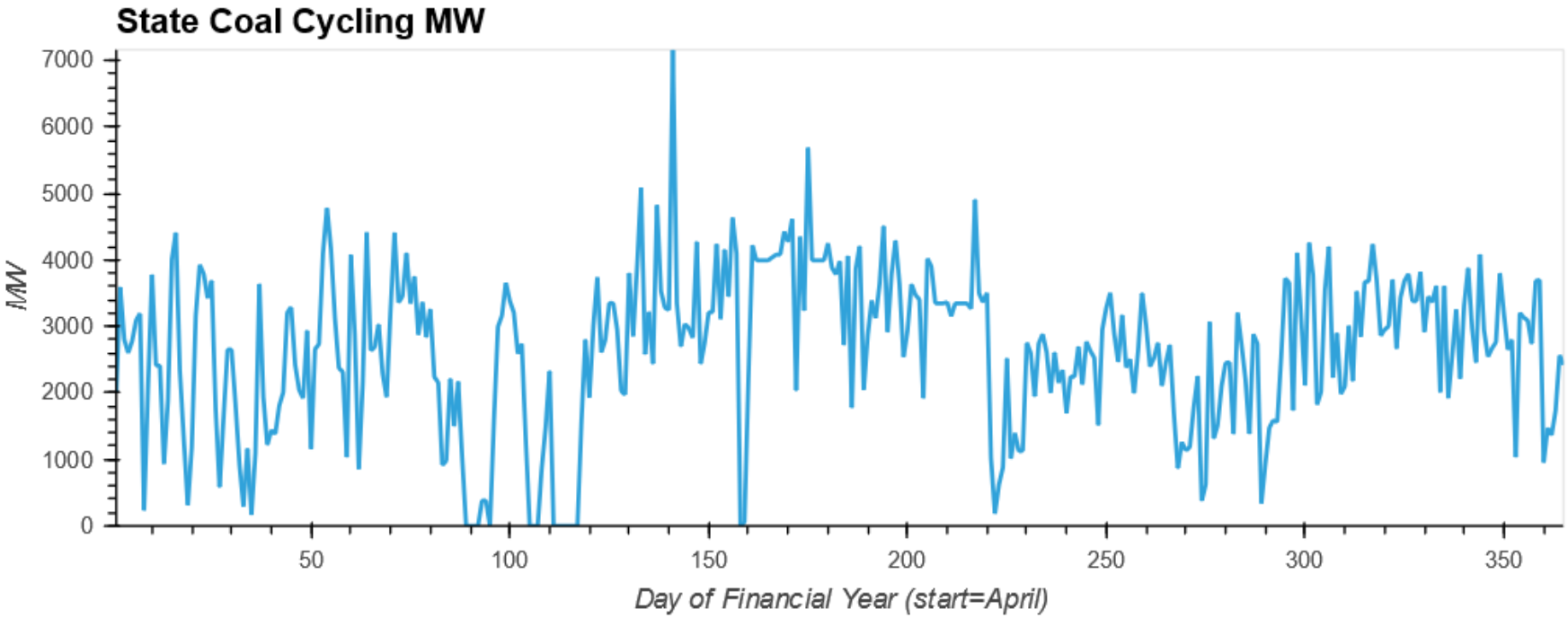
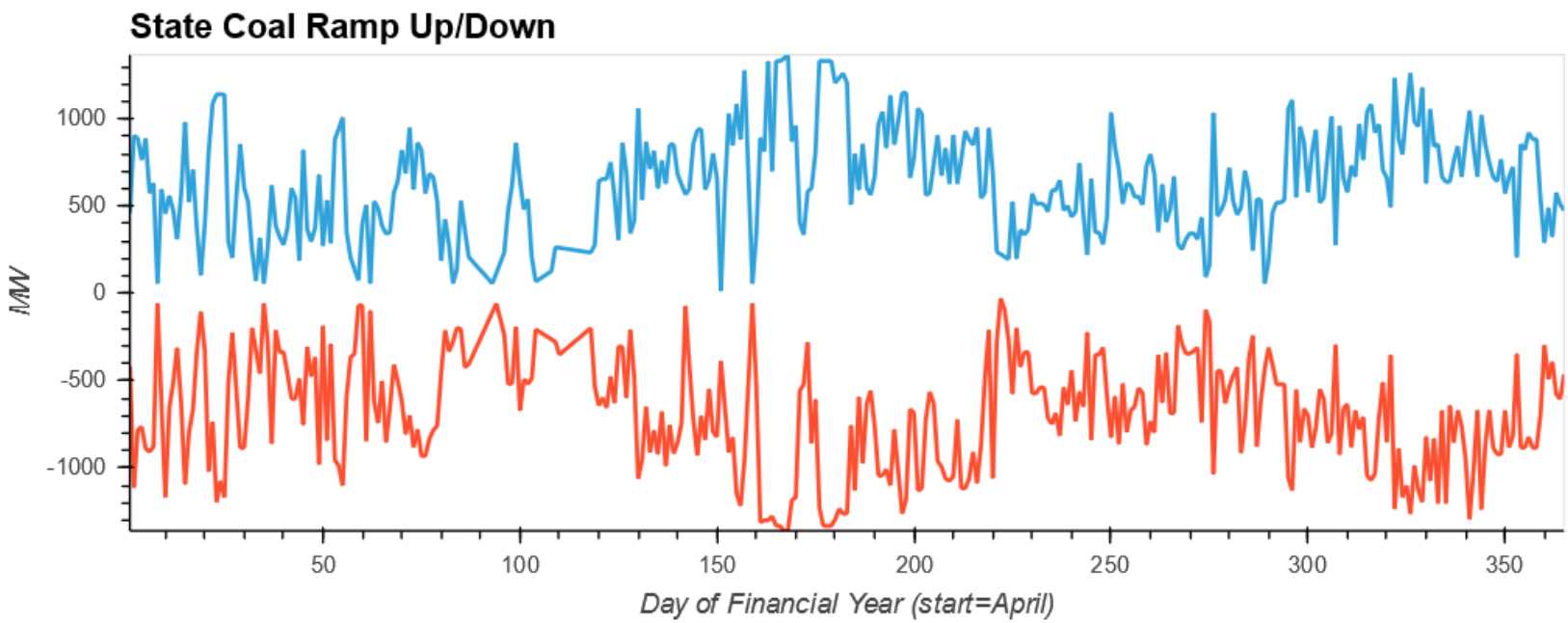


- Average difference between daily minimum and maximum generation of the Genco coal fleet is ~3000 MW, about 5 times the difference in FY16
- Need to prepare for significant cycling of coal fleet even without significant improvement in ramp rates

BAU: Daily block-wise max ramps



- Daily average max ramp up/down in FY30: ~600 MW for the Genco coal fleet, up from ~300 MW in FY16