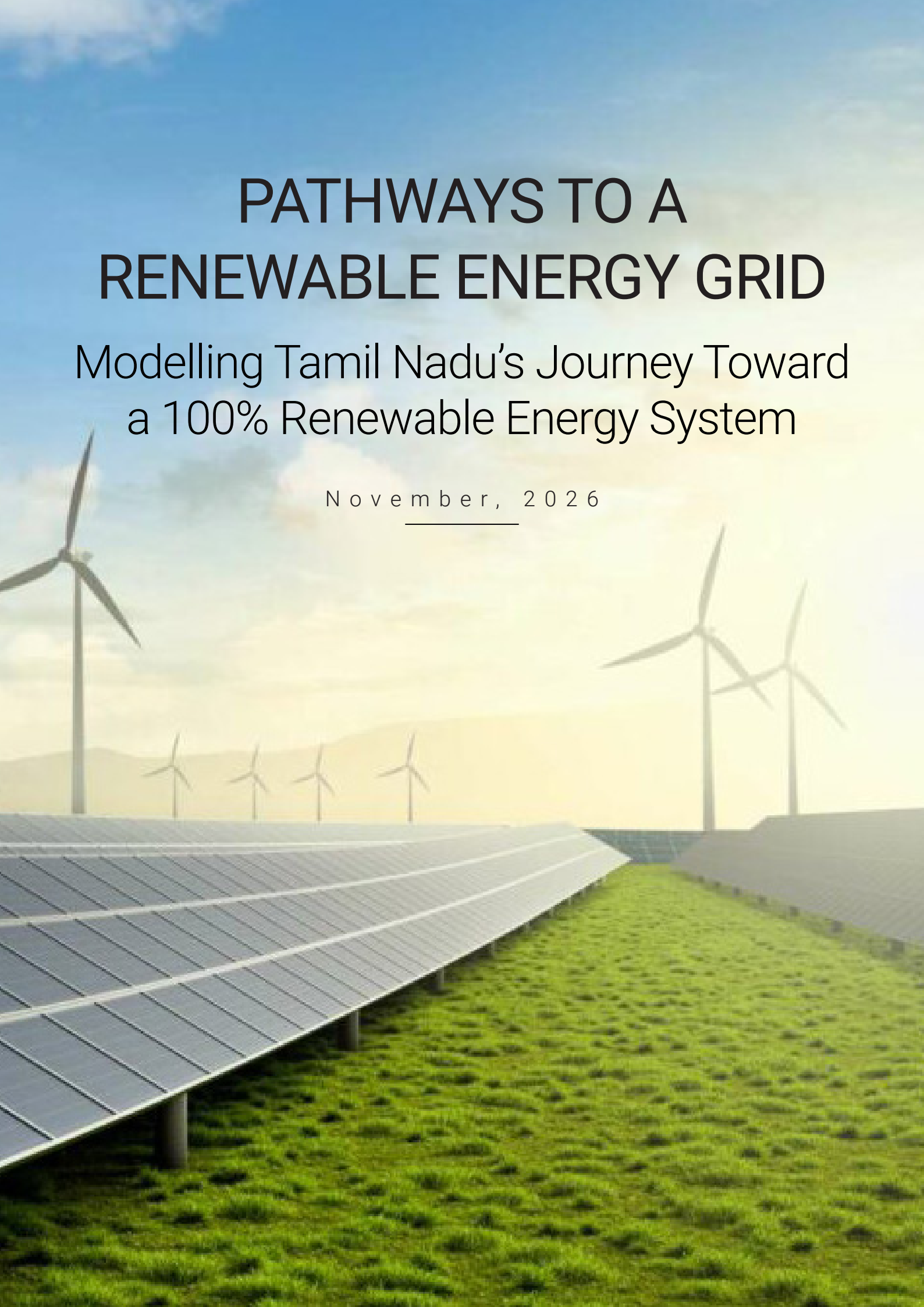
PATHWAYS TO A RENEWABLE ENERGY GRID

Modelling Tamil Nadu's Journey Toward a 100% Renewable Energy System

November, 2026



Acknowledgment

This publication forms a part of the Assessment of Renewable Energy, Tamil Nadu (ARE-TN) series of documents and activities. ARE-TN aims to facilitate higher clean energy deployment in the State by working with all stakeholders to find sustainable and equitable solutions. ARE-TN is a collaborative initiative by Auroville Consulting (AVC) and the World Resources Institute India (WRI).

Authors:
Martin Scherfler, Auroville Consulting
Parvathy, Auroville Consulting
Rohit Reddy Takkala, Auroville Consulting
Sunil Babu, Auroville Consulting
Sai Sarabesh, Auroville Consulting
Designer:
Vimal Bhojraj, Auroville Consulting

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Executive Summary

Tamil Nadu can achieve a fully renewable power system by 2050

Tamil Nadu is already one of India's leading renewable energy states and is well placed to move faster than the national timeline on power-sector decarbonization. With a strong base of wind and solar deployment, a mature clean-energy ecosystem, and a stated net-zero ambition, the state has the foundations needed to build a fully renewable, zero-emission electricity system by 2050. This report shows that such a transition is technically achievable across all modelled scenarios. However, success will depend not only on scaling up renewable generation but also on planning for energy storage, transmission, and flexible demand to maintain reliability and affordability as the system evolves.

Electricity demand will grow rapidly and make flexibility indispensable

Tamil Nadu's electricity demand is expected to rise steeply over the coming decades, driven by economic growth, increasing cooling demand, electric mobility, industrial expansion, and the electrification of end uses. Under the moderate growth scenario used in the core modelling, annual demand rises from 233 TWh in 2035 to 318 TWh in 2040 and 507 TWh in 2050, while peak demand increases from about 39 GW to 54 GW and then to nearly 86 GW. This growth is not only large in scale but also operationally significant. Demand remains concentrated in evening hours and in key load centres such as Chennai and Coimbatore, meaning that future system planning must address both energy supply and the ability to balance power across time and geography. In practice, this makes flexibility just as important as capacity expansion.

Renewable energy becomes the dominant foundation of the future grid

Across all scenarios, installed generation capacity increases substantially from around 100 GW in 2035 to roughly 215–217 GW in 2050. Over the same period, the power system undergoes a clear structural shift, moving away from fossil generation toward a renewables-dominated mix led by solar, wind, and storage. Coal and gas retire along broadly similar pathways in all scenarios, with retirement driven mainly by plant lifetime assumptions and the broader decarbonization objective. By 2050, the remaining fossil generation will be fully phased out. Nuclear capacity remains unchanged across the modelling horizon, indicating that the transition is driven primarily by renewable energy expansion, fossil retirement, and the scale-up of flexibility resources.

The DER pathway offers the most efficient overall outcome

Among the three pathways assessed, the high-DER scenario performs best on several important system indicators. It consistently has the lowest total installed capacity, the lowest cost of supply, the lowest market import dependence, and the lowest transmission requirement, suggesting a comparatively more efficient system configuration.

This finding is important because it shows that distributed energy resources can do more than simply add clean generation. When combined with local storage and flexible demand, DER can improve local self-consumption, reduce long-distance power transfer needs, and ease some pressure on large-scale infrastructure. At the same time, the results do not suggest that DER can replace utility-scale renewables or bulk transmission; rather, the strongest pathway is one in which distributed and centralized resources are planned together.

Energy Storage is a critical pillar of a high-renewables system

Energy storage emerges as one of the most important enablers of the transition. By 2050, storage accounts for around one-fifth of total installed capacity across the scenarios, underscoring its essential role in balancing a system with high shares of variable renewable energy. The energy storage portfolio modelled in this study includes grid-scale battery energy storage systems, distributed BESS, and pumped storage hydropower. These technologies provide complementary forms of flexibility: BESS supports intraday balancing and evening peak management, DER BESS helps manage local variability and improve self-consumption, and PSH offers larger-scale and potentially longer-duration support. Although the DER scenario has the lowest storage requirement in 2050, it still depends heavily on storage and other flexibility measures to manage sharper intraday transitions.

Flexibility becomes as important as generation

A high-renewables system is not only a generation challenge, but also a balancing challenge. As renewable penetration rises, net-load ramping requirements increase significantly across all scenarios, creating a growing need for resources that can respond quickly and shift demand or supply across hours. The modelling shows that demand-side flexibility can play a meaningful role in improving system performance. Modified time-of-use tariffs, active industrial demand response, and flexible operation of electrolysers for green ammonia production can all help absorb surplus renewable generation, reduce curtailment, and lower stress during difficult ramping periods. These findings suggest that Tamil Nadu should treat flexible demand as a core planning resource rather than a secondary efficiency measure.

Transmission remains essential, even in a distributed future

Transmission investment remains a no-regret requirement in every scenario. Even though the DER pathway reduces overall transmission needs compared with the other pathways, it does not eliminate the need for strong inter-zonal connectivity across the state. Renewable-rich zones such as Tirunelveli, Madurai, Coimbatore, and Erode continue to play a strategic role in supporting demand centres, particularly Chennai. This means that key corridors will still need timely strengthening to move renewable power efficiently, reduce congestion, limit curtailment, and maintain reliability. The report therefore reinforces the need for long-term transmission planning that is aligned with both renewable siting and future demand growth.

The transition should be seen as an industrial development strategy

A fully renewable electricity system is not only a climate objective; it is also an economic opportunity. Reliable, low-carbon power can strengthen Tamil Nadu's position as a destination for green manufacturing and help attract investment in sectors such as electric vehicles, batteries, renewable energy equipment, green hydrogen, and associated supply chains. The transition also creates opportunities to strategically site large new loads, including green ammonia production and data centres, in ways that support better system planning. Coordinating industrial policy with power-sector planning can help lower system costs, improve infrastructure utilization, and strengthen Tamil Nadu's long-term competitiveness in a decarbonizing global economy.

The central conclusion is to plan the whole system, not only the generation mix.The main conclusion of this report is that Tamil Nadu can build a reliable and affordable 100% renewable power system by 2050, but only if the transition is approached as a whole-system transformation. Renewable capacity targets alone will not be enough.The most robust pathway combines accelerated renewable deployment with proactive coal and gas retirement, strong investment in energy storage, timely transmission expansion, better use of hydro and pumped storage, and the systematic integration of flexible demand. If these elements are pursued in a coordinated manner, Tamil Nadu can secure a zero-emission electricity system while reinforcing its leadership in clean energy, industrial development, and long-term economic resilience.

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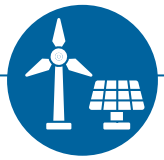
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Abbreviations

Abbreviation	Description
AC	Air Conditioner
ACSR	Aluminium Conductor Steel Reinforced
ARR	Aggregate Revenue Requirement
APR	Annual Performance Review
BESS	Battery Energy Storage System
CAGR	Compound Annual Growth Rate
CC	Capacity Credit
CEA	Central Electricity Authority
CEM	Capacity Expansion Model
CF	Capacity Factor
CMIP	Coupled Model Intercomparison Project
CUF	Capacity Utilization Factor
DAM	Day-Ahead Market
DAP	Diammonium Phosphate
DER	Distributed Energy Resource
DoD	Depth of Discharge
DSF	Demand Side Flexibility
e_initial	Initial state of charge (MWh)
e_max_pu	Maximum state of charge as a percentage of e_nom
e_min_pu	Minimum state of charge as a percentage of e_nom
e_nom	Energy capacity in MWh (nominal energy content of storage)
ESS	Energy Storage Systems
EUE	Expected Unserved Energy
EV	Electric Vehicle
F&V	Fixed and Variable (costs)
GH2	Green Hydrogen
IEA	International Energy Agency
IEX	Indian Energy Exchange
IRENA	International Renewable Energy Agency
LCOE	Levelised Cost of Energy
LCOS	Levelised Cost of Storage
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
MU	Million Units (million kilowatt-hours of electrical energy)
MW	Mega-Watts (unit of power)
NENS	Normalized Energy Not Served
NFHS	National Family Health Survey
NTPC	National Thermal Power Corporation
PAF	Plant Availability Factor
P/E	Power to Energy ratio (MW to MWh ratio for storage sizing)
PCM	Production Cost Modelling
PLF	Plant Load Factor
PSH	Pumped Storage Hydro
p_max_pu	Maximum output for each snapshot per unit of p_nom
p_min_pu	Minimum output for each snapshot per unit of p_nom
p_nom	Power capacity in MW (nominal power rating of an asset in PyPSA)
p_nom_max	Maximum nominal capacity (upper bound on p_nom)
p_nom_min	Minimum nominal capacity (lower bound on p_nom)
p_set	Active power set point (MW)
RA	Resource Adequacy
RM	Reserve Margin
RPO	Renewable Purchase Obligation
RTM	Real-Time Market
RTS	Rooftop Solar
SoC	State of Charge
SLDC	State Load Dispatch Centre
T&D	Transmission and Distribution
TC	Transmission costs
TFC	Transmission fixed costs
VRE	Variable Renewable Energy

01



100%
Renewable electricity system shown achievable by 2050

29 GW
Tamil Nadu's installed renewable capacity, March 2026

~50%
Share of India's CO2 emissions from power generation

Introduction

Tamil Nadu has long been at the forefront of India's clean energy transition, emerging as one of the earliest and most consistent champions of wind and solar power in the country. Recent data indicate that as of March 2026, the state's installed renewable capacity exceeded 29 GW, including around 12.15 GW of wind and more than 13.58 GW of solar, keeping Tamil Nadu among India's top renewable energy states (MNRE 2026). This early leadership has created a mature ecosystem of renewable energy developers, manufacturers, and service providers, and has positioned Tamil Nadu as a reference point for high-renewable operation within the Indian grid. Building on this foundation, the Government of Tamil Nadu has announced its intention to achieve carbon net zero ahead of India's national 2070 target, signalling an ambition to decarbonise faster than the country as a whole and to leverage clean energy as the backbone of future development (Government of Tamil Nadu, 2024).

Globally, the electricity sector is today the single largest source of energy related greenhouse gas emissions, accounting for over 40 per cent of carbon dioxide from fuel combustion and forming the core of the wider energy sector's roughly 77 per cent share of total emissions (UN, 2025). In India, about half of current carbon dioxide emissions are estimated to originate in the power sector, with coal-based generation responsible for the vast majority of these emissions (WRI India, 2023). Yet electricity is also widely recognised as the easiest major sector to decarbonise, because a full suite of low-carbon technologies—solar PV, wind, hydro, nuclear, biomass, and storage—is commercially available and, in many contexts, already cheaper on a levelized cost basis than new fossil-fuel options. For Tamil Nadu, accelerating power-sector decarbonisation therefore offers a double dividend: it directly tackles the state's largest emissions source while enabling deeper decarbonisation in industry, buildings, and transport through electrification with clean power.

A proactive net-zero pathway for its power sector presents a strategic economic opportunity for Tamil Nadu. With its strong industrial base, deep-sea ports, engineering capabilities, and established renewables sector, the state is well placed to emerge as a global hub for green manufacturing—hosting value chains for electric vehicles, green hydrogen and its derivatives, solar PV, wind components, and other low-carbon technologies (KP Energy, 2025; NREL, 2020). International experience suggests that regions which combine abundant renewable resources, reliable low-carbon power, skilled labour, and clear policy signals are best positioned to attract energy-intensive industries seeking to decarbonise their supply chains (IEA, 2021). For Tamil Nadu, aligning power sector planning with a credible net-zero pathway is therefore not only a climate imperative, but also a key element of industrial strategy and job creation.

Realising this opportunity requires timely and coordinated investment across generation, transmission, distribution networks, and system flexibility. As wind and solar deployment expands, electricity generation increasingly

shifts towards resource-rich coastal and inland regions that are often distant from major demand centres such as Chennai. Consequently, long-term transmission planning is essential to ensure reliable and cost-effective integration of renewable energy. Studies have consistently shown that strategic investment in intra-state and inter-state transmission corridors reduces congestion, lowers overall system costs, and avoids expensive network reinforcements in high-renewable power systems (Southern Renewable Energy Association, 2024; Prayas Energy Group, 2020).

Beyond transmission expansion, international experience demonstrates that geographic and technological diversity further enhances system reliability and reduces flexibility requirements. Interconnecting regions with complementary wind and solar resources, alongside a balanced portfolio of onshore and offshore wind, solar PV, hydropower, biomass, distributed energy resources, and flexible demand, can significantly reduce storage requirements, improve renewable energy utilisation, and alleviate transmission congestion (Zeyen et al., 2023; Oxford Energy, 2024; NREL, 2021). For Tamil Nadu, achieving a reliable 100 per cent renewable electricity system will therefore require an integrated planning approach that combines strategic transmission expansion with geographically diversified renewable deployment, demand-side flexibility, and both grid-scale and distributed energy storage.

Addressing these challenges requires robust long-term energy system planning supported by integrated energy system modelling. Integrated planning tools allow policymakers, regulators, and utilities to explore alternative futures, test policy choices, and understand how different technology costs, fuel prices, demand trajectories, and policy constraints affect investment needs and system performance. Previous work in Tamil Nadu has demonstrated how power sector modelling can illuminate the implications of higher renewable targets for generation capacity, retirements, emissions, and system costs out to 2030 and beyond (World Resources Institute, 2022; NREL, 2020). Extending these approaches to a full 100 percent renewable power system allows decision-makers to identify robust pathways, highlight no-regret investments in transmission and storage, and clarify the trade-offs between different resource mixes and institutional choices (Oxford Energy, 2024; Zeyen et al., 2023).

Although several studies have examined renewable energy expansion pathways for India and Tamil Nadu, many primarily focus on generation capacity planning or national-level decarbonisation scenarios. However, relatively few studies adopt an integrated planning framework that simultaneously evaluates generation expansion, transmission development, distributed energy resources, energy storage, demand-side flexibility, and hourly power system operations. Furthermore, limited attention has been given to assessing the spatial distribution of renewable resources, inter-zonal power transfers, and transmission utilisation under a future 100% renewable electricity system. Addressing these gaps is essential for developing cost-effective, reliable, and resilient pathways towards Tamil Nadu's clean energy future.

This study combines long-term capacity expansion planning with hourly operational analysis to evaluate the interactions between renewable energy deployment, transmission expansion, energy storage, distributed energy resources, and demand-side flexibility. It assesses how transmission planning, geographically diversified renewable deployment, demand response, time-of-use tariffs, and green hydrogen electrolysers can enhance renewable energy integration, improve system flexibility, reduce transmission congestion, and maintain reliable power system operation under multiple future scenarios.

This report, Pathways to a Renewable Energy Grid: Modelling Tamil Nadu's Journey Toward a 100% Renewable Energy System, presents long-term scenarios for 2035, 2040, and 2050, representing the medium-term planning horizon, the acceleration of renewable energy deployment, and the long-term transition to a 100% renewable electricity system. By integrating generation expansion, transmission planning, and power system flexibility within a unified modelling framework, the report provides an evidence-based foundation to support strategic decisions on grid development, flexibility resources, and Tamil Nadu's transition to a reliable, affordable, and resilient renewable electricity system.

02

129 GW
Technical DER potential

10%
Reserve/operating margin assumed over peak demand

4%
Shiftable C&I load modelled under Active Demand Response

Methodology

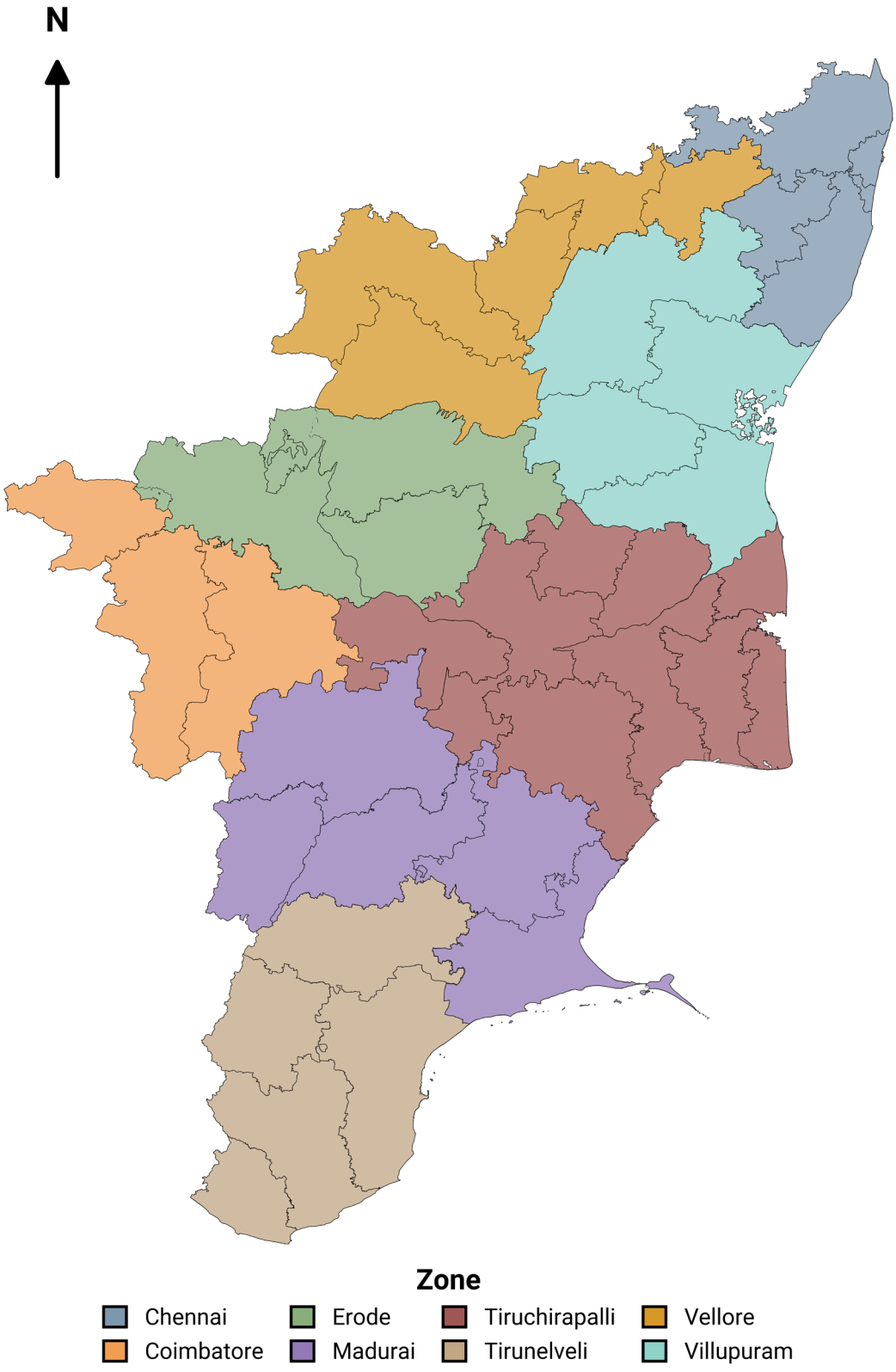
A zonal representation of Tamil Nadu's power system is used to link spatial patterns of demand, renewable resources, and network constraints within a single modelling framework. The state is divided into eight interconnected zones, which form the common spatial basis for demand forecasting, transmission network modelling, and the long-term capacity expansion analysis. This consistent zonal structure allows us to trace how electricity is generated, transported, and consumed across the state and to capture congestion and curtailment effects that would be hidden in a single-node model..

2.1 Zonal Model

Representing Tamil Nadu's power sector at an appropriate spatial resolution is critical to capturing the interactions between generation siting, weather-driven renewable profiles, demand distribution, and transmission constraints. Aggregating the state into a single node can mask intra-state differences in load growth, resource quality, and power flows, leading to an underestimation of congestion, curtailment, and the value of flexibility options. Zonal network representations address these limitations by dividing a state into multiple balancing or operating areas connected by constrained transmission corridors, enabling a more realistic assessment of system operation and investment needs under high shares of variable renewable energy (VRE).

Following this approach, the present study largely adopts the zonal framework used in NREL's Pathways for Tamil Nadu's Electric Power Sector and represents Tamil Nadu as eight interconnected zones: Chennai (North and South), Coimbatore, Erode, Madurai, Tirunelveli, Trichy, Vellore, and Villupuram. This structure aligns with the state's operational and load centres and allows renewable generation, demand, and transmission to be modelled with greater spatial fidelity. Differences in zonal demand profiles and the spatial concentration of wind and solar resources create asymmetric power flows that can stress inter-zonal corridors, making this representation critical for identifying congestion and curtailment risks and for evaluating the roles of transmission expansion, energy storage, and demand-side flexibility in enabling least-cost transition pathways.

Figure 1 Eight Zones of Tamil Nadu



2.2 Demand Forecasting

Electricity consumption patterns are changing rapidly due to factors like rising incomes, urbanization, climate change-driven cooling needs, electrification of cooking, and the growth of electric vehicles. These changes are not necessarily uniform across regions or consumer groups and cannot be captured well by simple top-down trend projections. Therefore, bottom-up demand forecasting, based on appliances, technologies, and user behaviour, is essential to realistically reflect how, where, and when electricity will be consumed in the future.

The state's electricity demand profile of 2019 (NITI Aayog, n.d.) is considered as the baseline demand for forecasting future demand profiles for the years 2035, 2040, and 2050. The forecasting exercise is done by sectors viz., residential, transport, industry, agriculture, and other sectors, with residential and transport sectors modelled using bottom-up methodology and the other sectors by economic growth projections.

To model the demand by sector, the overall or gross demand profile is adjusted against select technologies' demand profiles of households like Air Conditioners (ACs) and Electric Cooking to obtain a net demand profile reflecting the behaviour of the other household demand and other sectors. The normalised demand profile of the Commercial and Industrial Consumers (C&I) is scaled by the annual energy consumed to obtain the demand profile for the year 2019. Subsequently, the net profile is adjusted again to obtain the demand profiles of each remaining sectors scaled by their energy proportions. The sectoral baseline demand profiles obtained are used to compute the demand for future years by both partial end-use and econometric modelling.

Household/Residential Sector

Tamil Nadu's electricity demand projections in the Residential sector are based on both the partial end use method and socioeconomic indicators. Population projections utilize Census population projections data available up to 2036, and for years beyond the year 2036, the projections are approached cautiously - exploring both decrease in population (using regression on historical data) as well as increase in population (using Compound Annual Growth Rate (CAGR) from the last decade i.e., 2027-2036). This growth rate is further disaggregated by historical district-level urbanisation rates, enabling more granular, district-level projections. Urban and rural projections are particularly important for analysing and estimating demand for specific appliances such as Air Conditioners (ACs) and electric cooking devices.

Electricity demand from selects appliances - ACs and electric cooking - at the district level in Tamil Nadu is estimated using the demographic data, weather profiles, and assumptions on consumers' behaviour. District-level adoption rates are projected based on survey data such as the National Family Health Survey (NFHS) 5, Multiple Indicator Survey, etc., and historical and future weather data provided by Coupled Model Intercomparison Project (CMIP).

For cooling appliances, demand is estimated based on temperature projections from Coupled Model Intercomparison Project (CMIP) 6, with adjustments for humidity and urban-rural differences in adoption rates. Electric cooking demand is assumed to occur approximately over two hours each in the morning, afternoon, and evening, with the afternoon occupying a bigger share (40%) as compared to the morning/evening (30% each) of total energy consumed in a day. Other household electricity demand is computed by projecting forward using regression on macroeconomic indicators like Net District Domestic Product (NDDP). Scenarios are designed by varying the adoption rates, growth rates of population, NDDP, etc.

Transport Sector (Electric Vehicles)

There is a significant rise in the adoption of Electric Vehicles (EV) since 2020. The overall number of vehicles per 1000 population is expected to increase from around 415 to 790 in Tamil Nadu (Author's analysis based on the projections made by CEEW at the national level). Of this, the number of EVs in the years 2035, 2040, and 2050 is exogenously determined by the EV adoption rates to be modelled in various scenarios. The average distance travelled per vehicle type, the energy required per kilometre per vehicle type, the charging profile by vehicle type, etc., are obtained from AVC 2024. Based on these assumptions and the normative goals of the share occupied by EVs in total vehicles, the EV demand profiles are obtained at the district level, which is subsequently aggregated to the zonal or state levels.

Industrial and Other Sectors

For the Industrial, Commercial, Agriculture, and Miscellaneous Sectors, electricity demand elasticity is computed based on historical growth rates at the sectoral level (state/district) and is used to project the demand based on the sectoral macroeconomic growth rates.

The demand forecast is adjusted for rooftop solar generation to obtain the true baseline demand profile. The rooftop solar generation is estimated using the tool provided by Pfenninger et al. 2023 (Renewables Ninja) at the district levels and the rooftop solar generation installed (approximately disaggregated by the rooftop solar potential proportions at the district level (CSTEP)).

Table 1 Sectoral Projections – Demand Elasticity and Measure of Fit (R2)

Sector	Demand Elasticity	Measure of Fit (R2)
Agriculture	1.181	0.992
Commercial / Service	0.636	0.977
Industrial	0.688	0.890
Residential & Others	0.804	0.989

Source: Authors' Analysis

2.3. Transmission network modelling

Tamil Nadu's transmission network is represented through a simplified model in which the existing infrastructure is clustered into eight balancing areas. This approach is designed to capture network constraints that may emerge due to the addition of new generation capacities, such as offshore wind in the southern region and spatially varying demand. Publicly available data on generators and loads is used to cluster the system based on spatial and technical characteristics, resulting in an eight-node transmission network with the flexibility to expand as future capacities are installed. To connect these nodes, Delaunay triangulation, a standard technique for creating synthetic transmission networks, is applied using spatially weighted averages of generators and loads within each zone, aggregated from the sub-district level. Power transfer between zones is then estimated heuristically, based on the surplus and deficit at each node.

A base case transmission network for the year 2020 is constructed using open-source data. Network data, voltage levels, and line lengths are collected from sources such as OpenStreetMap, generator locations and capacities from Global Energy Monitor, and demographic data from the Census to estimate spatially distributed demand. Loads and generators are first aggregated at the sub-district level, after which the distribution network is no longer explicitly modelled. Using assumed technical parameters of standard transmission lines such as Aluminium Conductor Steel Reinforced (ACSR) conductors, line characteristics are assigned and transfer capacities are estimated. Each deficit node is assumed to meet its demand from surplus nodes in proportion to their surplus and inversely to their distance. Building on this base case, green energy corridor projects, particularly 765 kV lines in the pipeline, are added for the 2035 scenario, with their transfer capacities set using typical thermal limits.

Figure 2 Simplified Transmission Network of Tamil Nadu

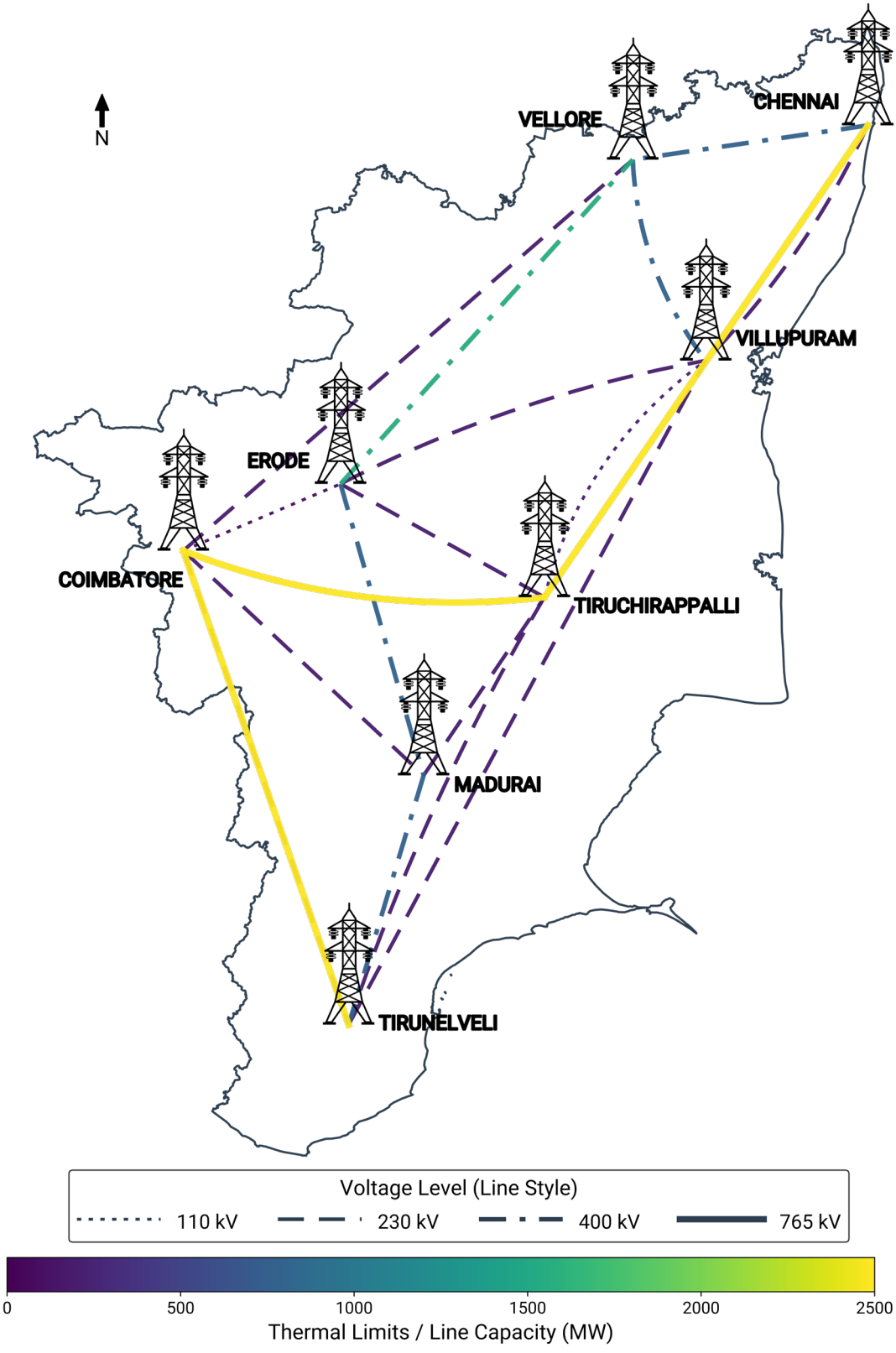


Table 2 Thermal limits of Tamil Nadu's simplified transmission network model

From Zone	To Zone	Voltage (kV)	Thermal limits (MW)	Length (km)
Z1-Chennai	Vellore	400	780	183.14
Z1-Chennai	Villupuram	230	192	185.16
Z7-Coimbatore	Erode	110	78	119.47
Z7-Coimbatore	Madurai	230	192	161.36
Z7-Coimbatore	Tirunelveli	230	192	267.04
Z7-Coimbatore	Vellore	230	192	253.97
Z4-Erode	Madurai	400	780	185.45
Z4-Erode	Tiruchirappalli	230	192	145.41
Z4-Erode	Vellore	400	1560	137.86
Z4-Erode	Villupuram	230	192	171.64
Z5-Madurai	Tiruchirappalli	230	192	141.51
Z5-Madurai	Tirunelveli	400	780	138.25
Z8-Tiruchirapalli	Tirunelveli	230	192	265.97
Z8-Tiruchirapalli	Villupuram	110	192	105.35
Z6-Tirunelveli	Villupuram	230	192	371.21
Z2-Vellore	Villupuram	400	780	140.83
Z6-Tirunelveli	Coimbatore	765	2,500	251.74
Z7-Coimbatore	Tiruchirappalli	765	2,500	240.00
Z8-Tiruchirapalli	Chennai	765	2,500	446.09

2.4. Capacity expansion model

The long-term capacity expansion model is developed using the Python for Power System Analysis (PyPSA) framework to identify the least-cost electricity generation portfolio for Tamil Nadu under different renewable energy pathways. The optimization simultaneously determines generation capacity additions and hourly dispatch while minimizing the total annualized system cost, including investment, fixed operation and maintenance, and variable operating costs. The model is solved at an hourly (8,760-hour) resolution for the planning years 2035, 2040, and 2050, subject to electricity demand, renewable resource availability, transmission constraints, storage operation, and technology-specific capacity limits. The optimization is performed using the HiGHS linear programming solver integrated within PyPSA.

The model incorporates existing generating stations, committed pipeline projects, and the technical and commercial potential of renewable energy technologies, including utility-scale solar, onshore wind, offshore wind, rooftop solar, battery energy storage systems (BESS), and pumped hydro storage (PHS). Three generation expansion scenarios are developed to evaluate alternative renewable energy pathways under different assumptions for wind and solar deployment, as summarized in Table 3. The installed capacities, committed projects, and renewable energy potentials used in the model are provided in Appendix 2.

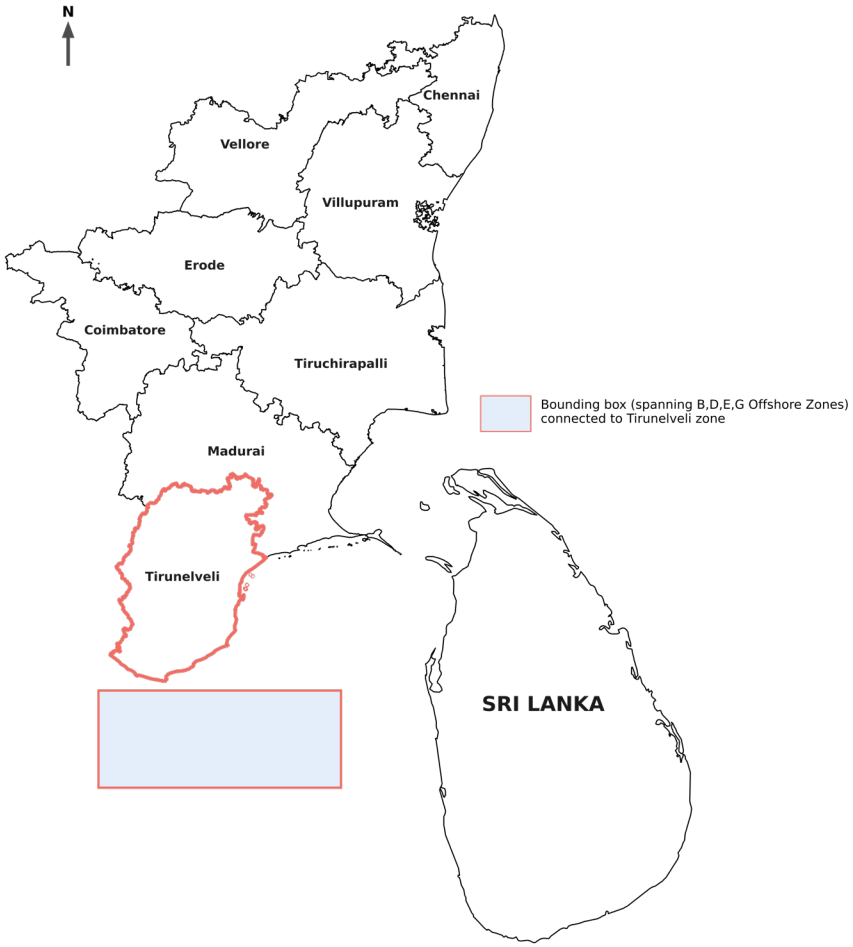
Table 3 Generation Scenarios

Scenario	Wind	Solar	DER
Unconstrained Scenario (Unconst)	Optimized with upper bound limit (technical/ commercial potential)		Optimized with tighter upper bound limit (RPO targets & projections)
Constrained Wind Scenario (Const_wd)	Optimized, with tighter upper limits (as per RPO Obligations) Same as unconstrained scenario		Same as unconstrained scenario
Distributed Energy Resources Scenario (DER)	Optimized with tighter upper limits (as per RPO Obligations)		Optimized with max commercial/ technical potential

Hourly solar, onshore wind, and hydro generation profiles are developed using historical dispatch data from the Tamil Nadu State Load Dispatch Centre (SLDC) for the period 2020–2022. Solar and onshore wind generation profiles are normalized using the corresponding installed capacities, while hydro inflow profiles are derived from historical hydro dispatch data and incorporated into the model.

As offshore wind projects are not yet operational in Tamil Nadu, representative offshore wind generation profiles are developed using historical offshore wind reanalysis data for 2020–2022. Wind speeds from the high-resource offshore regions identified by the National Institute of Wind Energy (NIWE) (Sub-zones B, D, E, and G) are converted into hourly power output using the NREL 5 MW reference offshore wind turbine through the PyPSA-Atlite framework. These normalised profiles are incorporated into the capacity expansion model to evaluate the contribution of offshore wind under future renewable energy scenarios while ensuring consistency with the modelling framework used for other renewable technologies

Figure 3 Offshore Wind Zone



2.5 Sensitivity Analysis

For each of the three generation expansion scenarios, a separate sensitivity analysis is conducted to evaluate the role of demand-side flexibility in enabling a high-renewable electricity system. Four flexibility cases are assessed: green ammonia production, modified Time-of-Use (ToU) tariffs, active demand response (ADR) for Commercial and Industrial (C&I) consumers, and an integrated flexibility scenario combining all three measures. These sensitivity cases evaluate the potential of flexible electricity demand to improve renewable energy utilisation, reduce renewable curtailment, relieve transmission constraints, enhance system flexibility, and maintain reliable and cost-effective power system operation.

2.5.1 Demand flexibility through Green Ammonia

Green ammonia production is modelled as a flexible industrial demand representing the fertiliser sector in Tamil Nadu. Future green ammonia demand is estimated based on published projections for major fertiliser clusters, including Thoothukudi, Chennai, Ennore, Neyveli, and Coimbatore, as summarised in Table 4. The corresponding

electricity demand is determined from the electrolyser capacity required to meet the projected ammonia demand, assuming an annual plant load factor (PLF) of 30% (Table 5). The projected demand growth is based on published policy and market studies and reflects the expected transition of Tamil Nadu's fertiliser sector towards green ammonia production.In the PyPSA capacity expansion model, electrolyser clusters are assigned to their respective transmission zones to represent the spatial distribution of fertiliser facilities.

Table 4 Green Ammonia Demand Estimate for Tamil Nadu

Cluster	2025 (t/year)	2030 (t/year)	2040 (t/year)	2050 (t/year)
Thoothukudi	5,000	5,70,000	7,50,000	9,50,000
Manali/Chennai	-	1,65,000	2,15,000	2,40,000
Ennore	-	50,000	67,500	80,000
Neyveli	-	15,000	20,000	25,000
Coimbatore	-	4,500	7,500	10,000
Total	**5,000**	**8,04,500**	**10,60,000**	**13,05,000**

Source: Bhagurkar et al. 2024, Deloitte 2023

Electrolysers are modelled as flexible loads that operate only during periods of surplus renewable generation after local battery and pumped hydro storage systems are fully charged. Operation is constrained to an annual plant load factor of 30%, allowing electrolysers to utilise electricity that would otherwise be curtailed. The electricity supplied to electrolysers is assumed to be priced at 50% of the avoided renewable curtailment cost, reflecting the system value of absorbing surplus renewable generation. This modelling approach reduces renewable curtailment, improves renewable energy utilisation, enhances system flexibility, and supports cost-effective integration of large-scale renewable energy.

Table 5 Electrolyser capacity required (MW), assuming a 30% plant load factor

Locations	Zone	2030 (MW)	2035 (MW)	2040 (MW)	2050 (MW)
Thoothukudi	Tirunelveli	1,499	1736	1,972	2,498
Manali/Chennai	Chennai	434	500	566	631
Ennore		132	155	178	210
Neyveli	Villupuram	40	47	53	66
Coimbatore	Coimbatore	12	16	20	26
Total		**2,117**	**2,453**	**2,789**	**3,431**

2.5.2 Demand flexibility through Time of Use Tariffs

A modified Time-of-Use (ToU) tariff is evaluated as a demand-side flexibility measure to encourage electricity consumption during periods of high renewable energy generation. The alternative tariff design is based on previous work by Auroville Consulting (2023), which assessed multiple ToU structures for Tamil Nadu. The objective is to shift electricity demand from morning and evening peak periods to solar-rich midday hours through revised price signals. The alternative ToU design retains the existing tariff framework while introducing a daytime "solar sponge" tariff to encourage daytime electricity consumption. Compared with the existing tariff, the alternative design increases the peak tariff from 20% to 25%, increases the off-peak rebate from 10% to 20%, introduces a morning peak period (06:00–08:00), extends the evening peak period (17:00–23:00), and designates 10:00–16:00 as an additional off-peak period to promote greater utilisation of surplus solar generation. The detailed tariff assumptions are summarised in Table 6.

Table 6 ToU tariff design

Scenario	Peak Tariff Increase	Off-peak Tariff rebate	Peak hours	Off-peak hours	Applicability
BAU	20%	10%	18:00 to 22:00	22:00 to 06:00	All HT consumers and LT C&I consumers
Alternative	25%	20%	6:00 to 8:00 17:00 to 23:00	0:00 to 5:00 10:00 to 16:00	All consumers

2.5.3 Demand flexibility through an Active Demand Response

An Active Demand Response (ADR) is modelled for Commercial and Industrial (C&I) consumers using an interruptible/curtailable demand response framework. It is assumed that up to 4% of the hourly C&I electricity demand is shiftable, with demand response events activated during the 20 highest peak demand hours each year. During each demand response event, the curtailed demand is recovered by redistributing it equally across the nearest non-peak hours, specifically the two hours immediately preceding and the two hours immediately following the peak demand event. This approach preserves total electricity consumption while reducing peak demand, alleviating grid stress, and improving overall system flexibility.

2.5.4 Integrated Flexibility Scenario

An Integrated Flexibility (INT) scenario is developed by simultaneously implementing green ammonia production, the modified Time-of-Use (ToU) tariff, and Active Demand Response (ADR) within each generation expansion scenario. Unlike the individual sensitivity analyses, this scenario evaluates the combined impact of multiple demand-side flexibility measures and their interactions with renewable energy generation, transmission infrastructure, and energy storage. By coordinating flexible industrial loads, consumer load shifting through dynamic price signals, and active demand response, the integrated scenario assesses their collective ability to improve renewable energy utilization, reduce renewable curtailment, alleviate transmission congestion, lower peak demand, enhance system flexibility, and support a reliable and cost-effective transition towards a 100% renewable electricity system in Tamil Nadu.

03

507 TWh
Estimated annual electricity demand by 2050

86 GW
Estimated peak electricity demand by 2050

~50%
Chennai & Coimbatore's combined share of 2050 TN's peak demand

Demand & Generation Projections

This chapter summarises the long-term demand outlook for Tamil Nadu and shows how rapidly rising annual demand and higher evening peaks increase the challenge of relying mainly on wind and solar. Because renewable output is intermittent, varies by season, and does not fully align with peak demand, the system will require substantial flexibility from storage, demand response, backup capacity, and grid upgrades to reliably meet future loads.

3.1 Demand Projections

Across all three demand project scenarios, Tamil Nadu's electricity demand rises steadily from 152 TWh in 2025 to about 210–240 TWh in 2035, 276–332 TWh in 2040 and then surges to roughly 413–537 TWh by 2050. This widening range indicates that while near-term planning can centre on the moderate case, long-term generation, network, and storage planning must explicitly accommodate the broad uncertainty band between the low- and high-growth futures.

4 Demand projection scenarios

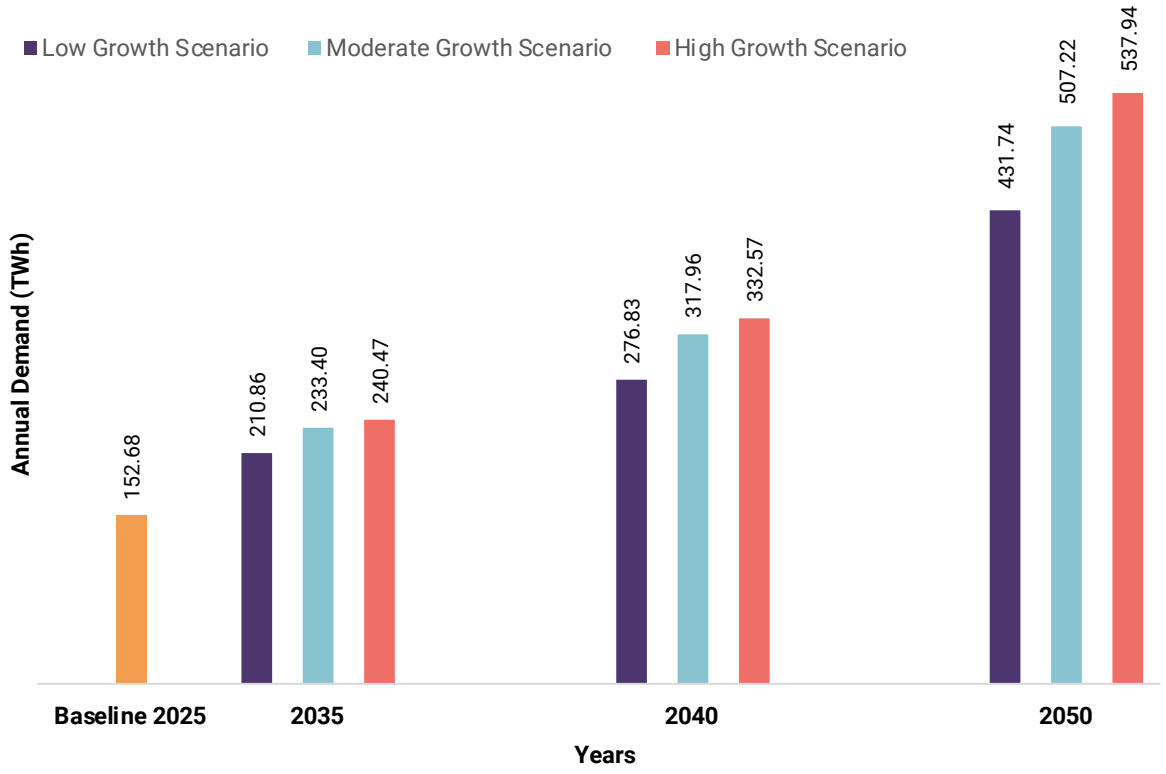


Table 7 compares the demand projections from this study with those of the Tamil Nadu Resource Adequacy Report by the Tamil Nadu Green Energy Corporation Limited (TNGECL) and the Central Electricity Authority (CEA). TNGECL and CEA projections are only available up to 2035, so 2040 and 2050 demand values for TNGECL and CEA are extrapolated using their average annual growth rate observed between 2025 and 2035. Under the moderate growth scenario of this study, demand in 2035 is only about 6% lower than TNGECL's forecast, widening to around 9% in 2040 and 17% in 2050. The high growth scenario remains broadly aligned with, or slightly below, the TNGECL projections, while the CEA projections are consistently lower than both TNGECL and our results. The moderate growth scenario is adopted for the capacity expansion model in this report, as it closely aligns with TNGECL's planning outlook while remaining conservative relative to the high-growth pathway.

Table 7 Comparisons with other demand projections

Year	TN Resource Adequacy (TWh)	CEA's Projections (TWh)	Low Growth Scenario (TWh)	Moderate Growth Scenario (TWh)	High Growth Scenario (TWh)
2035	249.58	195.77	210.86	233.40	240.47
2040	349.42	236.55	276.83	317.96	332.57
2050	612.25	352.43	413.74	507.22	537.94

Sources: CEA (2025), TNGECL, CEA (2022)

Here, the load factor is the ratio of average demand to peak demand over a given period, indicating how steadily the system is utilized across hours. Under the Moderate Growth Scenario, annual peak demand increases from 39 GW in 2035 to nearly 86 GW in 2050, and average demand more than doubles over the same period, from 26.6 GW to 57.9 GW. The load factor stays in a narrow band of 0.67–0.68, implying that demand growth is broad-based across the day, with no major structural change in load shape (refer to Table 8).

Table 8 Key load parameters for Moderate Growth Scenario

Characteristics	2035	2040	2050
Annual Peak Demand (GW)	39.13	53.82	85.70
Average Demand (GW)	26.64	36.27	57.90
Load Factor	0.68	0.67	0.68

The load frequency distribution for the Moderate Growth Scenario shows how many hours the system spends in different demand bands in each year. In 2035, the system operates in the high-load band (25–35 GW) for most of the year, with only about 322 hours above 35 GW and very few hours below 15 GW. By 2050, the system spends far more time at high and peak loads, with more than 6,500 hours between 50–80 GW and 134 hours above 80 GW, while low-load hours remain rare. This indicates a strong shift towards a "high load" system throughout the year, reinforcing the need for adequate capacity, flexibility, and transmission to handle a much heavier and more sustained demand profile.

Table 9 Load frequency distribution 2035, 2040, 2050 for Moderate Growth Scenario

Load Segment	2035		2040		2050	
	Load Range	Number of Hours	Load Range	Number of Hours	Load Range	Number of Hours
Peak	>35 GW	322	>50 GW	250	> 80 GW	134
High	25-35 GW	5,131	35–50 GW	4,321	50–80 GW	6,561
Moderate	15-25 GW	3293	20–35 GW	4,171	35–50 GW	2,017
Low	<15 GW	13	<20 GW	18	< 35 GW	48

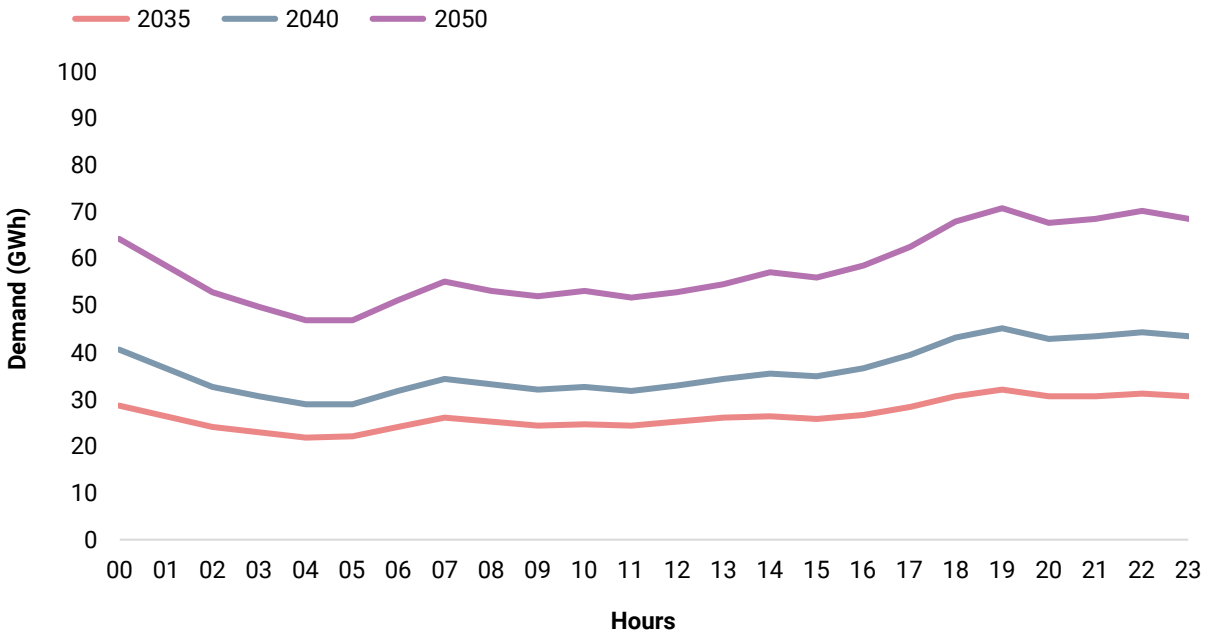
Under the Moderate Growth Scenario, demand rises strongly in every zone, with Chennai and Coimbatore emerging as the largest load centres by both peak demand and annual energy use. By 2050, Chennai's peak demand will reach about 26 GW and Coimbatore's about 16 GW, together accounting for nearly half of the state's total peak load and electricity demand. Annual energy consumption more than doubles between 2035 and 2050 in most zones, with total state demand increasing from roughly 233 TWh to over 507 TWh. This pronounced spatial concentration of demand highlights the importance of reinforcing transmission and integrating new generation capacity around Chennai and Coimbatore, while still planning adequately for growing loads in other zones.

Table 10 Zone-wise demand forecast for Moderate Growth Scenario

Zone	2035		2040		2050	
	Peak demand (GW)	Annual Energy (TWh)	Peak demand (GW)	Annual Energy (TWh)	Peak demand (GW)	Annual Energy (TWh)
Chennai	11.54	70.56	16.07	95.37	25.64	157.62
Coimbatore	6.15	38.65	8.98	54.74	16.03	101.24
Erode	4.61	27.72	6.96	38.05	10.52	62.42
Tiruchirappalli	4.16	22.66	6.21	29.97	8.18	40.43
Madurai	3.63	20.27	5.41	27.84	7.61	39.81
Vellore	3.32	19.05	4.85	25.95	7.27	40.82
Tirunelveli	3.18	17.89	4.42	23.56	6.13	31.74
Villupuram	2.92	16.6	4.09	22.26	6.08	33.15
Total	**39.50**	**233.40**	**56.99**	**317.76**	**87.46**	**507.22**

Across 2035, 2040, and 2050, the shape of the average daily demand curve stays similar. Demand is lower in the late night and early morning, rises through the day, and peaks in the evening, then remains high until midnight. The overall level of demand increases each year. By 2050, hourly demand is roughly twice that of 2035, with a stronger evening peak around 18:00–21:00. This means long-term growth mainly scales up existing load patterns and puts more pressure on the evening peak, rather than changing the intraday profile.

Figure 5 Average hourly demand profiles 2035, 2040, 2050



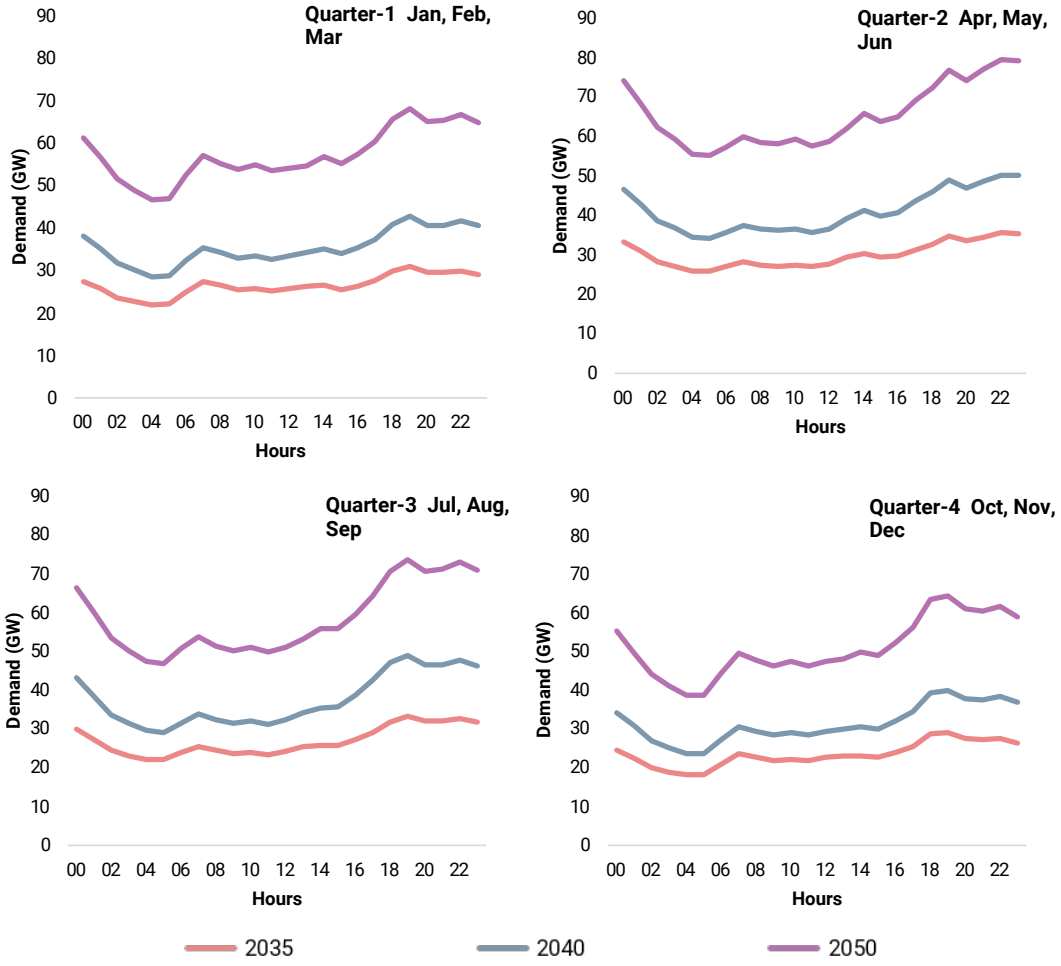
The quarterly statistics highlight both the seasonality and the rapid growth of Tamil Nadu's electricity demand under the Moderate Growth Scenario. In all three analysis years, Q2 (April–June) records the highest peaks and averages, reflecting strong cooling and agricultural loads in the summer months. By 2050, Q2 peak demand rises to nearly 86 GW, with average demand above 65 GW, indicating that the system operates at elevated load levels for much of the quarter. Q4 consistently shows lower peaks and averages and a slightly lower load factor, but even in this "lighter" season, both peak and average demand almost double between 2035 and 2050, underscoring the need for year-round resource adequacy and flexibility. The load factors for Q1, Q2, and Q4 are decreasing from 2035 to 2050, indicating that the demand is becoming more 'peaky' and the system is being used less evenly and less efficiently over time.

Table 11 Key characteristics by quarter 2035, 2040, 2050

Quarter		Q1 (Jan - Mar)	Q2 (Apr -Jun)	Q3 (Jul - Sept)	Q4 (Oct - Dec)
2035	Peak (GW)	35.85	39.13	37.99	34.04
	Valley (GW)	14.71	22.16	18.12	12.79
	Average Demand (GW)	26.48	29.94	26.72	23.36
	Load Factor	74%	77%	70%	69%
2040	Peak (GW)	50.07	53.82	52.93	51.09
	Valley (GW)	19.44	29.75	23.79	17.06
	Average Demand (GW)	35.41	40.92	37.32	31.32
	Load Factor	71%	76%	71%	61%
2050	Peak (GW)	80.76	85.70	82.63	78.31
	Valley (GW)	32.23	47.91	39.20	27.00
	Average Demand (GW)	57.16	65.28	58.18	50.82
	Load Factor	71%	76%	70%	65%

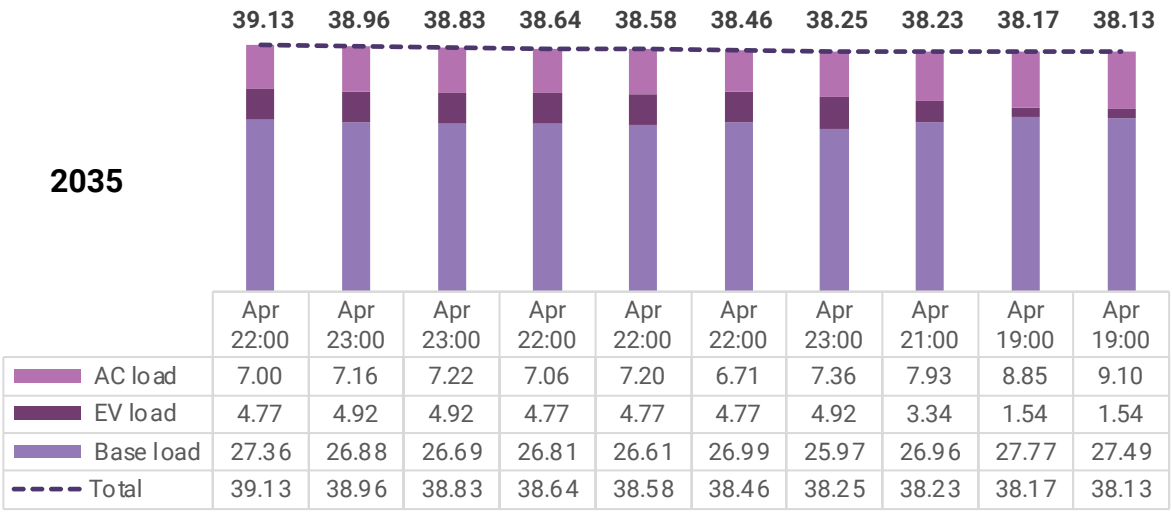
Figure 6 shows average daily demand curves for each quarter. The level and timing of demand change with the seasons. The curves are higher in the hotter quarters, Q2 and Q3, due to increased cooling loads. The milder seasons have flatter and lower curves. This means Tamil Nadu will increasingly face stronger evening peaks and tighter capacity margins during the summer months.

Figure 6 Diurnal variation of quarterly average demands 2035, 2040, 2050

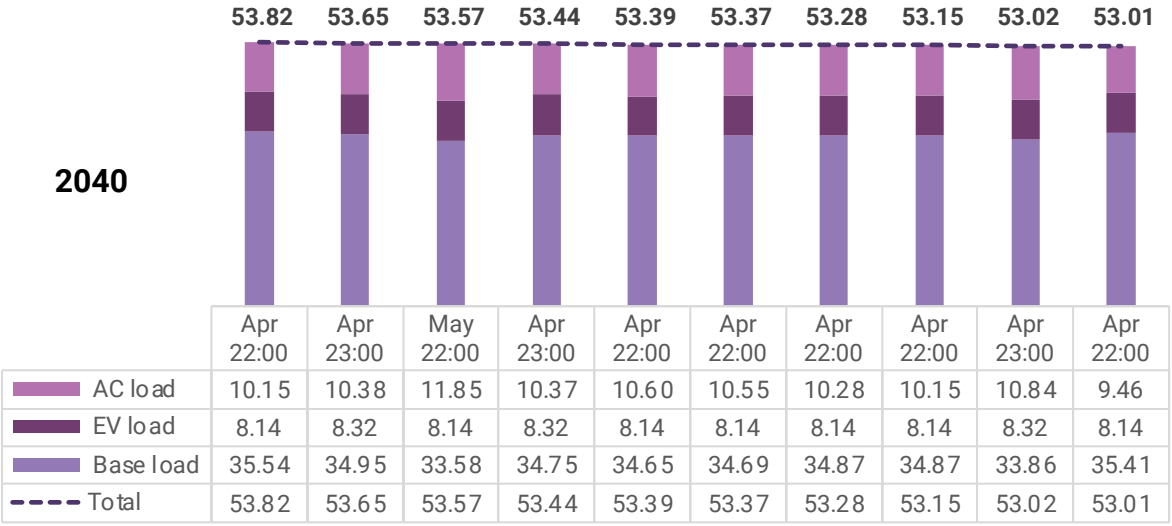


Across all years shown, electric vehicles and air conditioners together account for at least 30% of demand during the top 10 gross load peak instances, and their combined share shows a clear increasing trend over time. This underscores that EVs and ACs are not only already major contributors to system peaks, but are becoming progressively more important drivers of peak demand, reinforcing the need to target these end uses with focused demand side measures and smart charging/cooling strategies (Figure 7).

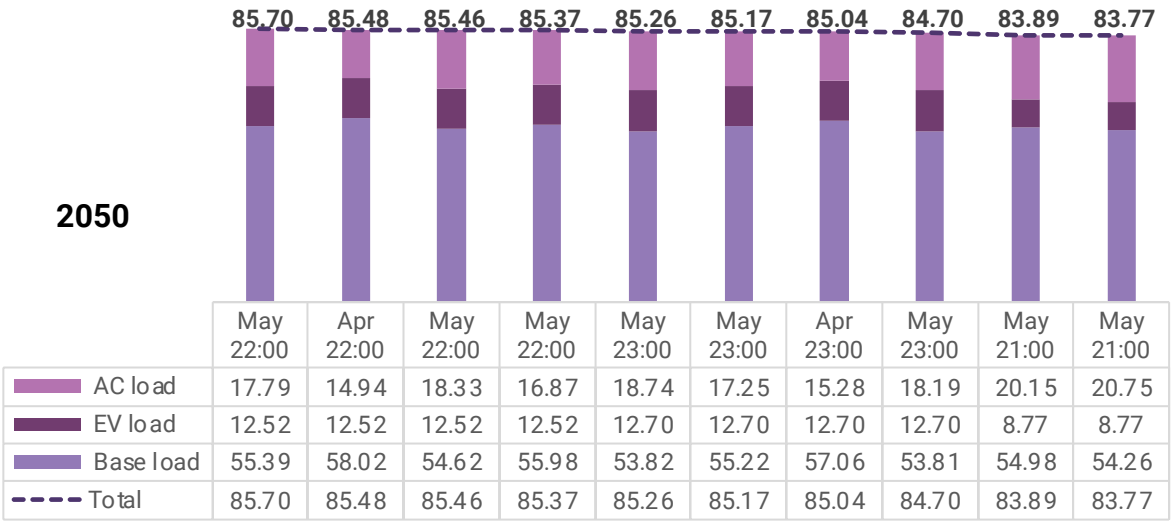
Figure 7 Top 10 gross load peak instances



	Apr 22:00	Apr 23:00	Apr 23:00	Apr 22:00	Apr 22:00	Apr 22:00	Apr 23:00	Apr 21:00	Apr 19:00	Apr 19:00
AC load	7.00	7.16	7.22	7.06	7.20	6.71	7.36	7.93	8.85	9.10
EV load	4.77	4.92	4.92	4.77	4.77	4.77	4.92	3.34	1.54	1.54
Base load	27.36	26.88	26.69	26.81	26.61	26.99	25.97	26.96	27.77	27.49
Total	39.13	38.96	38.83	38.64	38.58	38.46	38.25	38.23	38.17	38.13



	Apr 22:00	Apr 23:00	May 22:00	Apr 23:00	Apr 22:00	Apr 22:00	Apr 22:00	Apr 22:00	Apr 23:00	Apr 22:00
AC load	10.15	10.38	11.85	10.37	10.60	10.55	10.28	10.15	10.84	9.46
EV load	8.14	8.32	8.14	8.32	8.14	8.14	8.14	8.14	8.32	8.14
Base load	35.54	34.95	33.58	34.75	34.65	34.69	34.87	34.87	33.86	35.41
Total	53.82	53.65	53.57	53.44	53.39	53.37	53.28	53.15	53.02	53.01



	May 22:00	Apr 22:00	May 22:00	May 22:00	May 23:00	May 23:00	Apr 23:00	May 23:00	May 21:00	May 21:00
AC load	17.79	14.94	18.33	16.87	18.74	17.25	15.28	18.19	20.15	20.75
EV load	12.52	12.52	12.52	12.52	12.70	12.70	12.70	12.70	8.77	8.77
Base load	55.39	58.02	54.62	55.98	53.82	55.22	57.06	53.81	54.98	54.26
Total	85.70	85.48	85.46	85.37	85.26	85.17	85.04	84.70	83.89	83.77

While understanding the magnitude and timing of future electricity demand is essential for planning new generation capacity, equally important is understanding when renewable energy will be available. The temporal mismatch between electricity demand and renewable generation determines the need for transmission expansion, energy storage, demand-side flexibility, and other balancing resources. The following section therefore examines the projected generation characteristics of solar and wind resources that underpin the capacity expansion modelling.

3.2 Solar and Wind Generation Forecast

Solar and wind energy are expected to play an increasingly dominant role in the power sector. Figure 8 shows the typical hourly output of wind and solar over an average day in 2035, 2040, and 2050, so you can compare when these resources generate relative to demand. It highlights the strong midday solar peak that grows over time and the relatively steady but lower wind output, underlining both the intermittency of solar (only daytime, with a sharp ramp up and ramp down) and the different, more continuous but variable nature of wind. The gradual increase in solar and wind generation across the years in this figure is a modelling assumption, reflecting higher future plant load factors driven by improvements in technology and resource utilisation. The projected renewable generation profiles presented below are based on the assumptions and resource assessment methodology described in Chapter 2 and represent the typical hourly availability of solar and wind resources used in the optimisation model.

Figure 8 Average daily generation profile of wind and solar

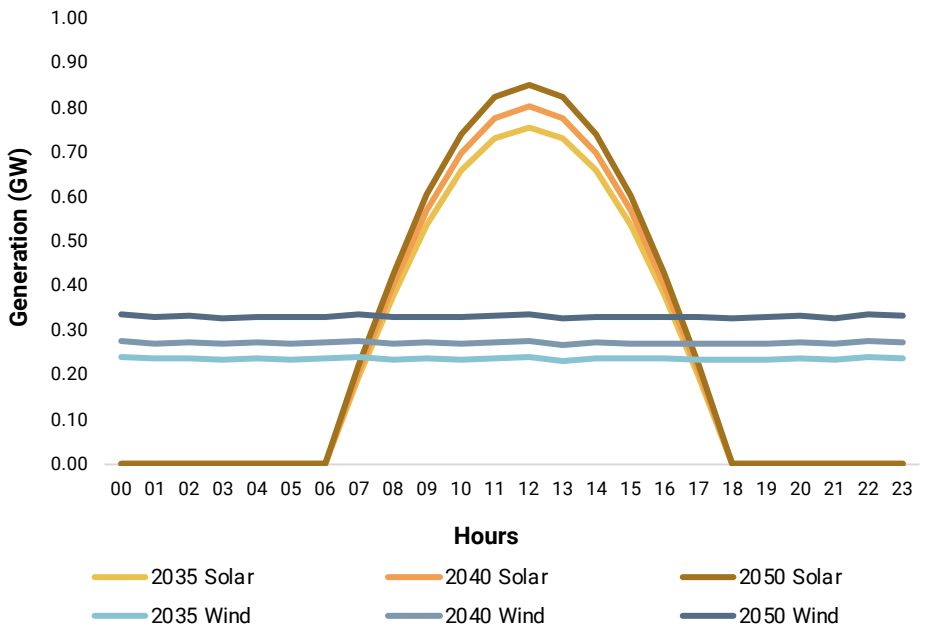


Figure 9 highlights how the daily generation profiles of solar and wind vary significantly by quarter, even as their overall contribution grows over time. Solar output shows the strongest and widest midday peaks in Quarter 1 (Jan–Mar) and Quarter 3 (Jul-Sep), indicating particularly favourable solar conditions in the cooler, clearer months, while wind generation is highest and most sustained in Quarter 3 (Jul-Sep), and Quarter 4 (Oct- Dec), reflecting the seasonal strength of wind resources in that period. The visible increase in solar and wind generation across the three analysis years is driven by an in-built modelling assumption that the efficiency and plant load factors of both technologies improve in the future, as technology performance, siting, and resource utilisation continue to advance.

Figure 9 Average daily generation profile of wind and solar by quarter

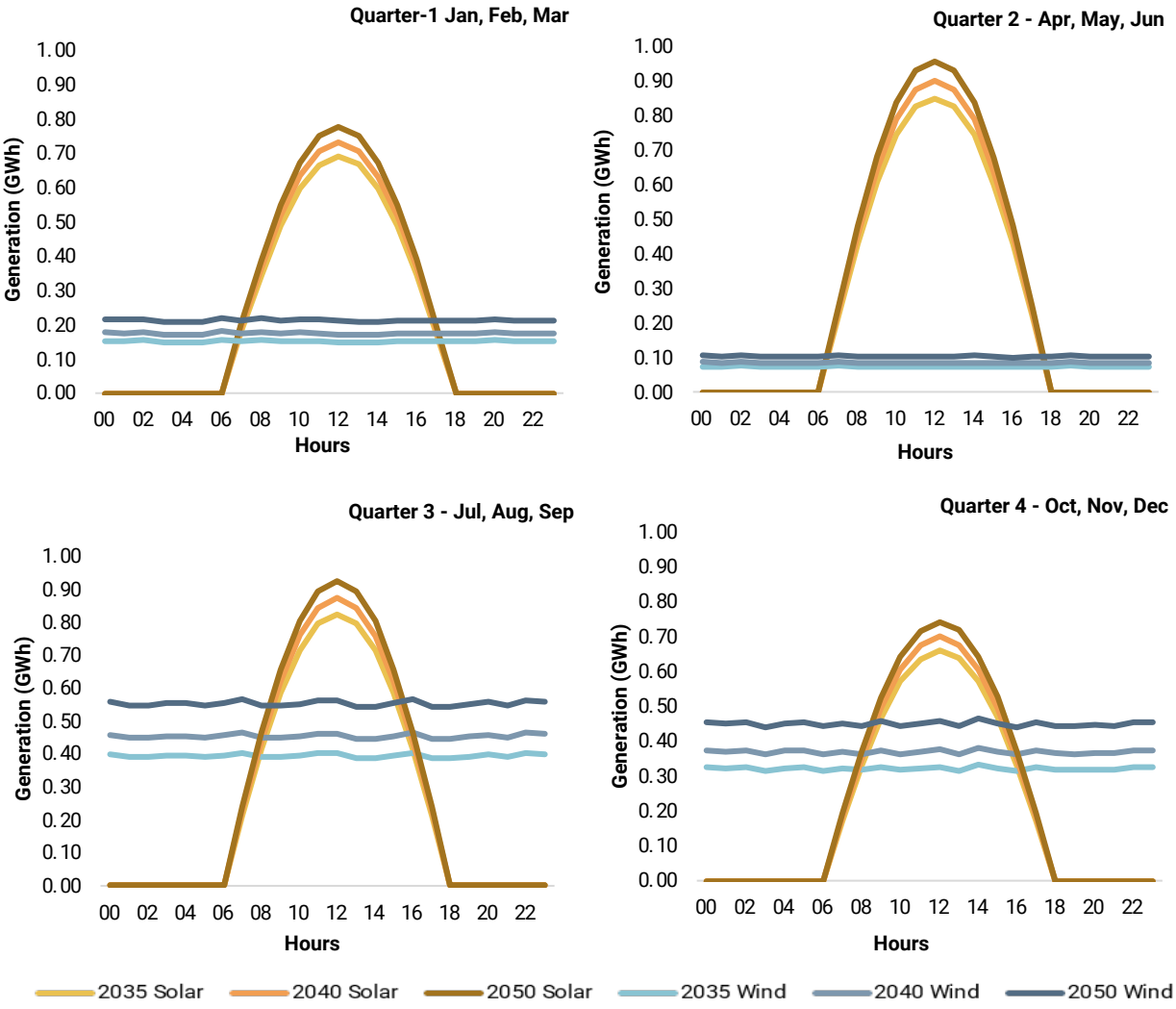
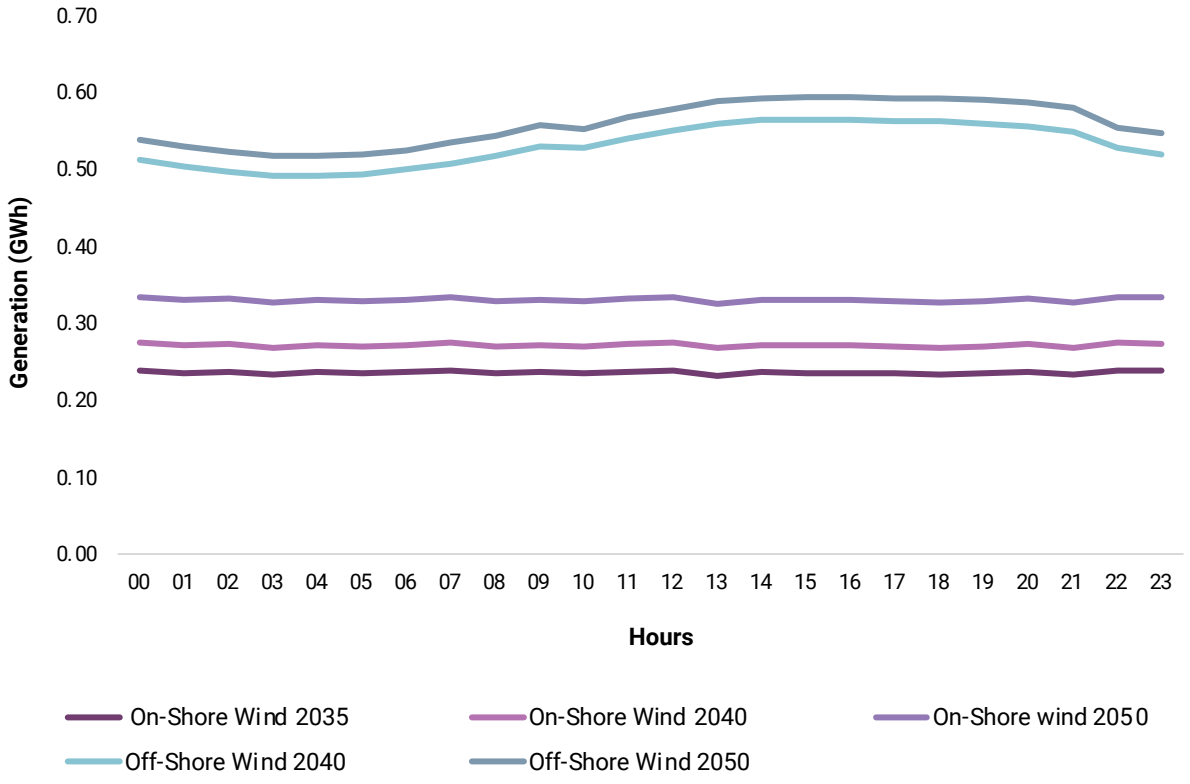


Figure 10 compares the average daily generation profiles of onshore and offshore wind for 2035, 2040, and 2050. Offshore wind is expected to have higher and more consistent output across the day than onshore wind in all years, with both resources increasing over time, indicating that offshore wind can provide a stronger and more stable contribution to meeting demand as Tamil Nadu's wind fleet expands.

Figure 10 Wind generation profiles for onshore and offshore wind



04

0 tCO_2/MWh
Emission intensity reached in all scenarios by 2050

16.57 ₹/kWh
Lowest cost of supply under DER scenario

215-217 GW
Installed capacity across scenarios by 2050

Capacity Expansion And Energy Shares

This chapter presents how different 2035, 2040, and 2050 pathways perform as Tamil Nadu's power system transitions from coal-dominated to renewable-led. It compares an unconstrained renewables pathway (Unconst), a constrained-wind case (Const_wd), and a high distributed energy resources (DER) scenario, highlighting their impacts on peak demand, storage needs, net load, curtailment, and CO_2 intensity on the road to a zero-emissions system.

4.1 High-level results for 2035, 2040, 2050

Across all three analysis years, the three scenarios show different mixes of wind, solar, and battery storage, impacting net peak demand, ramping needs, and overall system costs. DER scenarios achieve the lowest net peaks and system costs in each of the three analysis years, while the constrained wind scenario generally has higher net peaks and the highest system costs. By 2050, total peak demand more than doubles compared to 2035, and ramping requirements become much larger, with the DER case exhibiting the highest maximum ramping event, followed by the Constrained wind case.

Table 12 High-level power system results by scenario

Scenario	Wind share (%)	Solar share (%)	BESS share (%)	Gross peak (GW)	Net peak (GW)	Max ramping event (GW/h)	Total
Unconst _2035	22%	30%	4%	39.13	31.81	8.61	**3.80**
Const_ wd_2035	14%	36%	5%	39.13	33.11	12.52	**3.99**
DER_2035	14%	38%	7%	39.13	28.53	16.38	**3.68**
Unconst _2040	31%	39%	5%	53.82	48.56	19.23	**5.64**
Const_ wd_2040	23%	44%	6%	53.82	50.34	21.23	**5.81**
DER_2040	24%	43%	9%	53.82	41.03	24.01	**5.19**
Unconst _2050	39%	45%	7%	85.70	70.22	16.05	**8.73**
Const_ wd_2050	33%	51%	8%	85.70	71.73	19.23	**9.15**
DER_2050	33%	52%	7%	85.70	68.12	21.23	**8.40**

4.2 System cost comparison

Across all planning years, the DER scenario consistently achieves the lowest total system cost and cost of supply, demonstrating the economic advantages of distributed energy resources, renewable energy, and energy storage. In contrast, the Constrained Wind scenario records the highest system cost and Cost of Supply, reflecting the increased reliance on higher-cost generation and flexibility resources when wind potential is constrained.

The breakdown of the Cost of Supply into energy cost and network cost provides a clearer understanding of the key drivers of electricity supply costs. The DER scenario consistently achieves the lowest energy cost and the lowest network costs. As the power system transitions towards a net-zero electricity system by 2050, we find the energy cost declines when low-cost RE is available. Meanwhile, the network cost, comprising transmission and distribution, increases over the planning horizon. The network cost is becoming an increasingly defining element of the overall cost of supply.

Table 13 System cost and cost of supply comparison

Parameters	Total System Cost (₹ Lakh Crore)	Energy Cost (₹/kWh)	Network Cost (₹/kWh)	Cost of Supply (₹/kWh)
Unconst_2035	3.80	10.08	6.21	16.29
Const_wd_2035	3.99	10.87	6.21	17.08
DER_2035	3.68	9.55	6.21	15.76
Unconst_2040	5.64	10.31	7.46	17.77
Const_wd_2040	5.81	10.73	7.56	18.29
DER_2040	5.19	9.03	7.30	16.33
Unconst_2050	8.73	8.18	9.04	17.22
Const_wd_2050	9.15	8.83	9.21	18.04
DER_2050	8.40	7.79	8.78	16.57

4.3 Projected power generation capacities

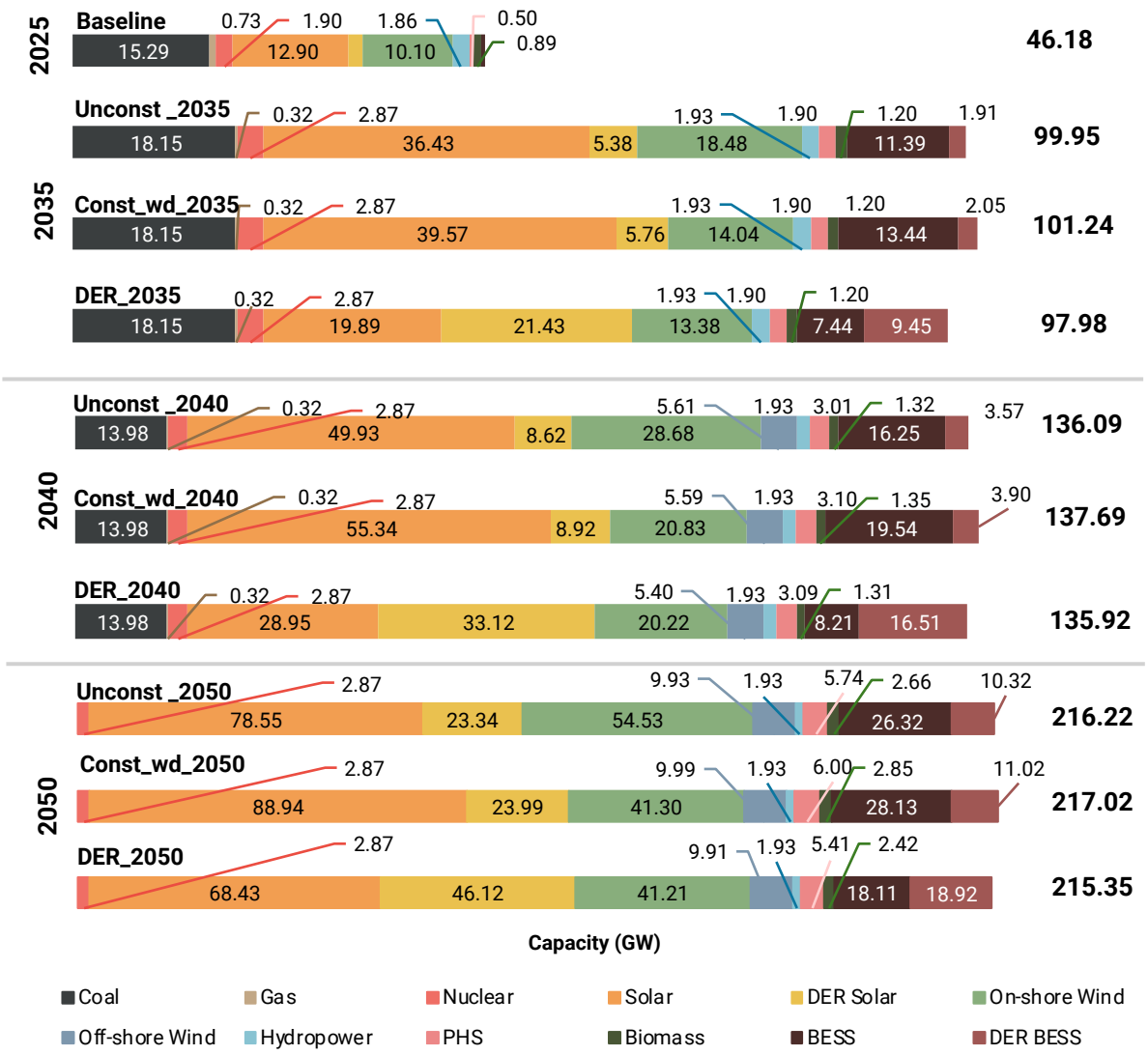
From 2025 to 2050, capacity expands by about a factor of four, while the system shifts from coal dominated to renewable-led generation with a broader technology mix. Coal follows a common phase-down path in every scenario, driven solely by end-of-life retirements and a gradual reduction in utilisation of the remaining units by 2050. Across all years, the DER scenarios deliver the lowest total installed capacity while maintaining reliability, because DER solar and battery energy storage are used to reduce peak needs and improve utilisation of existing assets.

2035: In 2035, the DER scenario has the lowest total installed capacity among the three scenarios for that year, reflecting more efficient use of distributed solar and storage. Coal capacity is identical across scenarios, as coal plants are retired strictly at the end of their technical life, and no additional coal units are added beyond this closure schedule. Battery energy storage systems (BESS) and DER-connected BESS already play a visible role in reducing net peak demand and helping to limit the need for additional central thermal capacity in the DER 2035 scenario compared to the other cases.

2040: In 2040, the DER 2040 scenario again shows the lowest total installed capacity, while still meeting the same demand as the other scenarios. The modelling exercise assumes that offshore wind becomes available by 2040, so overall wind capacity increases across all scenarios. Coal capacity remains the same in all scenarios because any units reaching the end of life are shut down, and the remaining fleet is operated without life extension. Grid scale BESS and DER BESS grow further in all scenarios by 2040, with the fastest growth in the DER 2040 case, where they provide more flexibility and reduce reliance on coal and gas to manage variability.

2050: By 2050, the DER 2050 scenario continues to have slightly lower total installed capacity than the Unconstrained 2050 and Constrained Wind 2050 scenarios, due to higher contributions from distributed solar and storage. Coal capacity has been phased down in all scenarios. By this time, both grid-scale BESS and DER-connected BESS have expanded substantially, providing a major share of flexibility needs and enabling deeper reductions in coal use and smoother integration of high shares of variable renewables.

Figure 11 Power generation capacity by scenario and year



Overall, total energy storage requirements rise sharply as wind and solar shares grow, and the mix shifts from mainly 2-hour assets today toward a more balanced portfolio with 4-hour, 6-hour, and 8-hour technologies by mid-century. Across all years, distributed storage is assumed to have 2 hours of discharge duration, so all DER-connected storage in the scenarios is 2-hour storage.

In 2035, 2-hour storage dominates the mix: for example, in the DER_2035 scenario, almost the entire storage requirement is provided by 2-hour systems, while 4-hour, 6-hour, and 8-hour pumped hydro remain very small in comparison. By 2040, the picture begins to change, with visible growth in 4-hour and 6-hour storage blocks and an emerging contribution from 8-hour pumped hydro; the DER_2040 scenario shows several gigawatts in these longer durations on top of a still-large 2-hour segment.

By 2050, the demand for longer-duration storage has increased even more: in the 2050 scenarios, 4-hour and 6-hour storage together reach values comparable to or higher than the 2-hour segment, and 8-hour pumped hydro represents a notable share of total storage. This progression from mainly 2-hour storage in 2035 to a richer mix including substantial 4-hour, 6-hour, and 8-hour capacity by 2050 illustrates how rising wind and solar penetration create a growing need not only for fast, short-duration balancing but also for medium and long-duration storage to manage multi-hour variability and reduce dependence on thermal plants.

Figure 12 Storage power capacity requirement by scenario (GW)

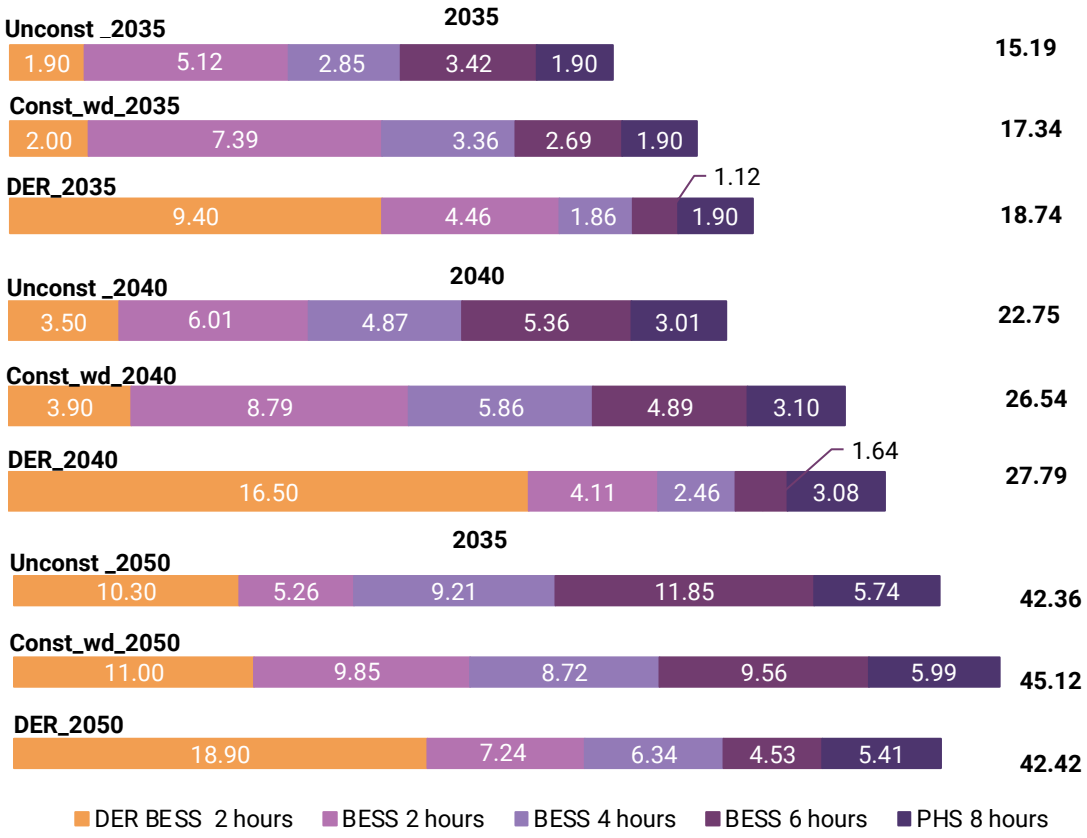
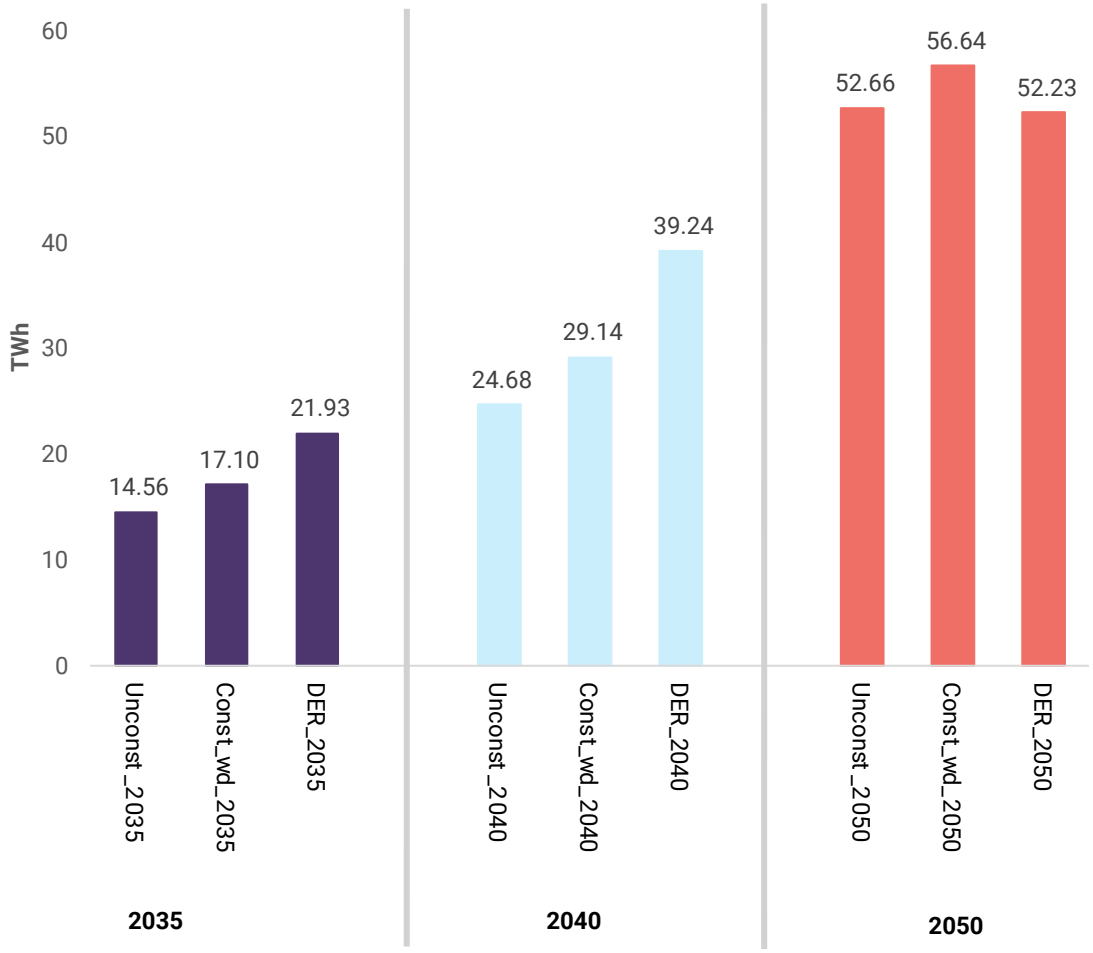


Figure 13 shows the energy dispatched from storage systems across the three scenarios in 2035, 2040 and 2050. In 2035, storage dispatch remains moderate because system flexibility is still partly provided by residual thermal generation, grid reinforcement and lower levels of variable renewable energy. By 2040, energy dispatched from storage increases substantially across all scenarios, reflecting deeper renewable integration, greater evening peak-shifting requirements and more frequent multi-hour balancing needs.

The strongest increase occurs between 2040 and 2050, when the power system becomes increasingly dependent on variable solar and wind generation and thermal ramping becomes more limited. Storage systems are therefore used more intensively to balance supply and demand over longer periods. The DER scenario records the highest storage dispatch requirements in 2035 and 2040. By 2050, however, its requirement is broadly comparable to the Unconstrained scenario and marginally lower than the Constrained Wind scenario. This convergence is partly explained by the stronger growth of wind generation between 2040 and 2050. Combined onshore and offshore wind capacity increases from 356 GW, or 23% of total installed capacity, in 2040 to 567 GW, or 32%, in 2050. The higher wind share provides a more diversified renewable generation profile and reduces the extent of system-level storage cycling required.

Figure 13 Dispatch from energy storage systems (TWh)



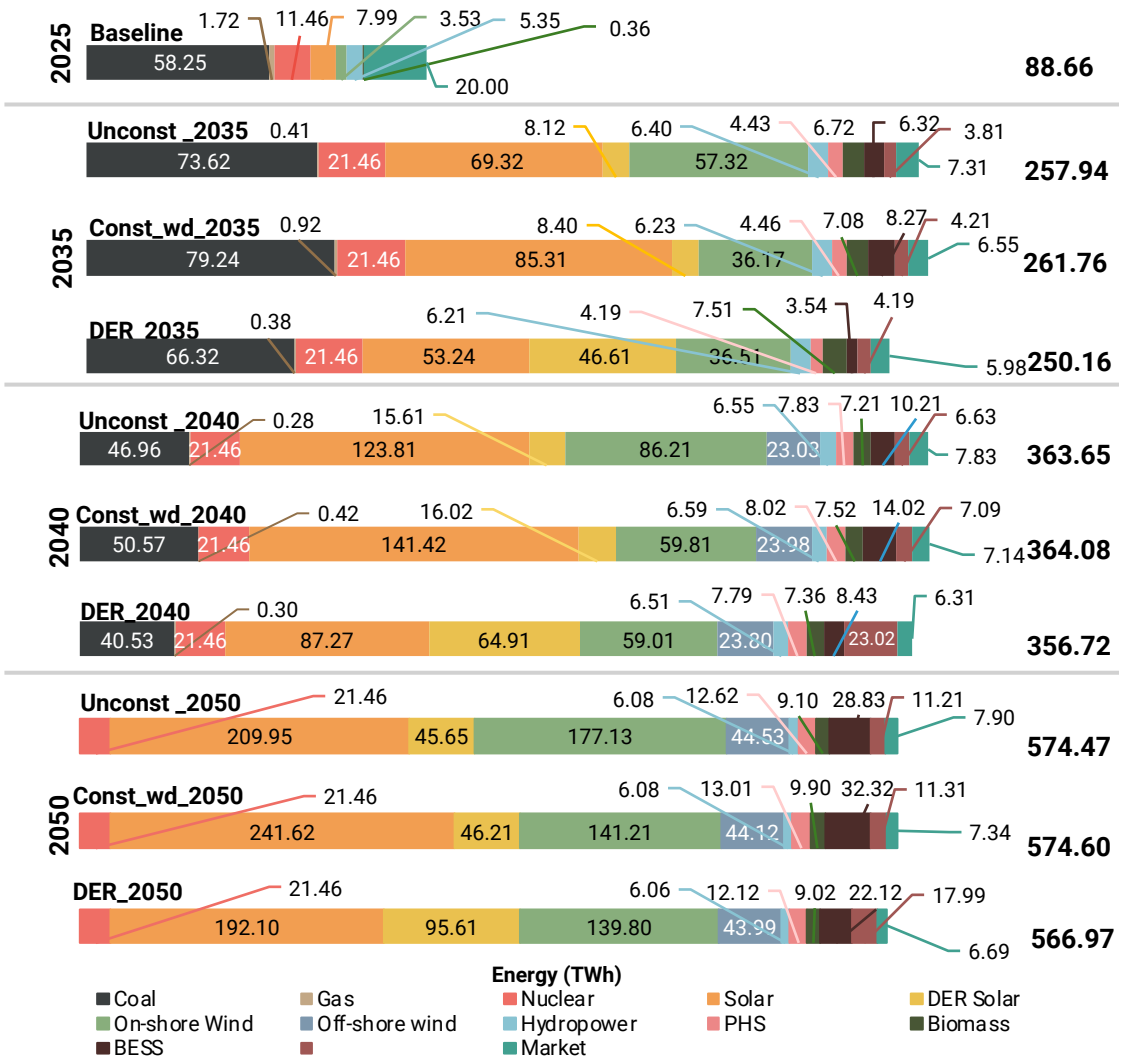
4.4 Energy share and CO2 emissions by scenarios

2035: In 2035, all three scenarios already show substantial contributions from solar and wind, but coal and gas still supply a large share of total energy. The unconstrained and constrained scenarios retain a higher coal output, while the DER 2035 scenario has a noticeably larger combined energy share of distributed and utility-scale renewables and energy storage, resulting in a lower coal share. The DER 2035 scenario has a noticeably lower total energy generation of 250.16 TWh, which is on account of reduced technical losses.

2040: By 2040, total energy supplied increases and renewables expand further in every scenario, but their composition diverges more clearly. In the unconstrained and constrained scenarios, the coal energy share remains sizeable. In contrast, the DER 2040 scenario shows a much larger share of solar, wind, and other low-carbon resources, with coal pushed back in comparison. Offshore wind is starting to make a marked contribution to the overall energy share in all scenarios

2050: In 2050, the differences between pathways are most visible in the mix of wind, solar, and storage. In the unconstrained and constrained scenarios, total solar and wind generation is high, but the system leans more on large-scale BESS, with more modest contributions from DER-connected storage. In contrast, the DER 2050 scenario shifts a larger share of energy to distributed solar and shows a higher DER BESS output, alongside strong contributions from utility-scale solar and onshore and offshore wind. This results in a system where distributed storage plays a much bigger role in meeting demand and managing variability than in the other 2050 pathways.

Figure 14 Energy share by scenario

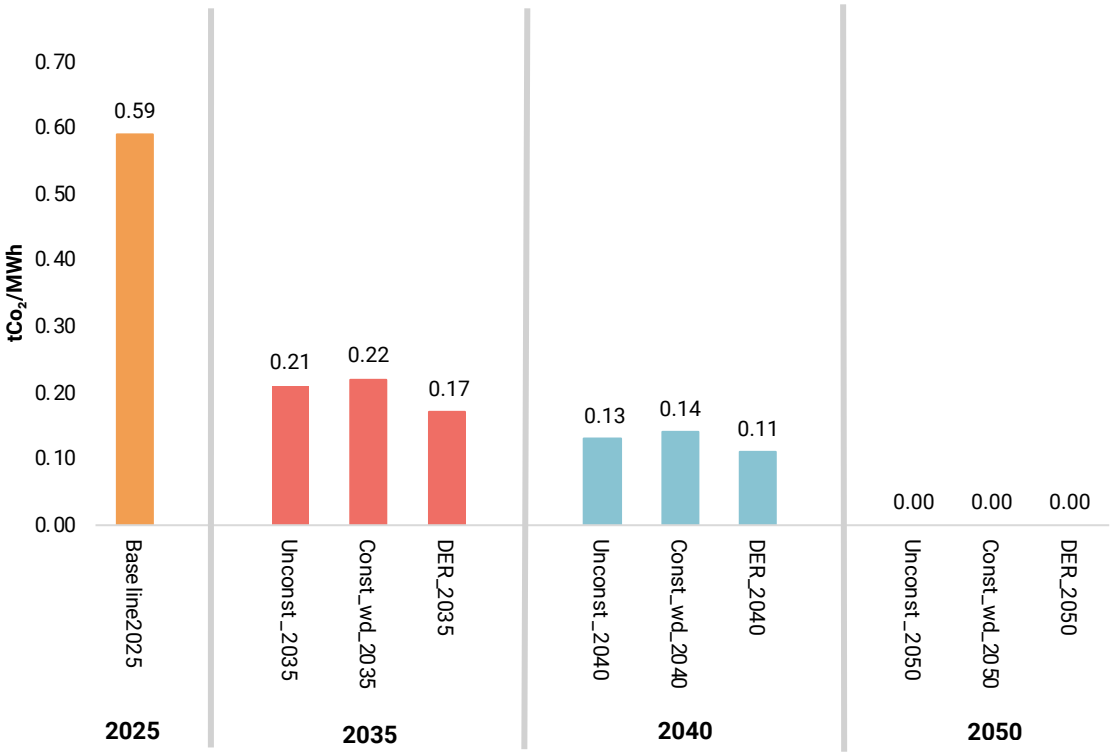


Overall, the CO2 emission intensity improves strongly over time, falling from about 0.59 tCO2/MWh in the 2025 baseline to zero in all scenarios by 2050. This indicates that the combination of higher renewable capacity, growing energy storage, and coal phase-down can deliver a fully reliable system in the long term across all scenarios.

In 2035, the indicator drops to around 0.21 and 0.22 tCO2/MWh in the Unconstrained 2035 and Constrained Wind 2035 scenarios and to about 0.17 tCO2/MWh in the DER scenario, showing an early emission benefit from higher distributed solar and storage.

By 2040, values fall further to roughly 0.13 and 0.14 tCO2/MWh in the Unconstrained 2040 and Constrained Wind 2040 scenarios and around 0.11 tCO2/MWh in the DER scenario, reflecting continued improvements from additional renewables and storage deployment.
By 2050, the indicator reaches zero in all three scenarios.

Figure 15 CO_2 emissions by analysis year and scenario



4.5 Plant load factors

Plant load factors remain high for baseload coal plants in 2035 but begin to decline across scenarios as more solar and wind are added and coal plants are used more flexibly rather than running at full output. By 2040, PLFs for many coal units fall further, with the largest reductions in the Distributed Energy Resources scenarios, indicating less annual operation of coal and greater utilisation of renewables and storage. Gas plants show moderate PLFs in all years, reflecting their role as mid merit and peaking resources that back up variable renewables rather than running continuously. Renewable plants (solar and wind) operate at relatively stable technology-specific PLFs over time. Still, their growing installed capacity means they provide a much larger share of total generation even as coal unit PLFs fall. By 2050, all coal and gas power plants will be phased out.

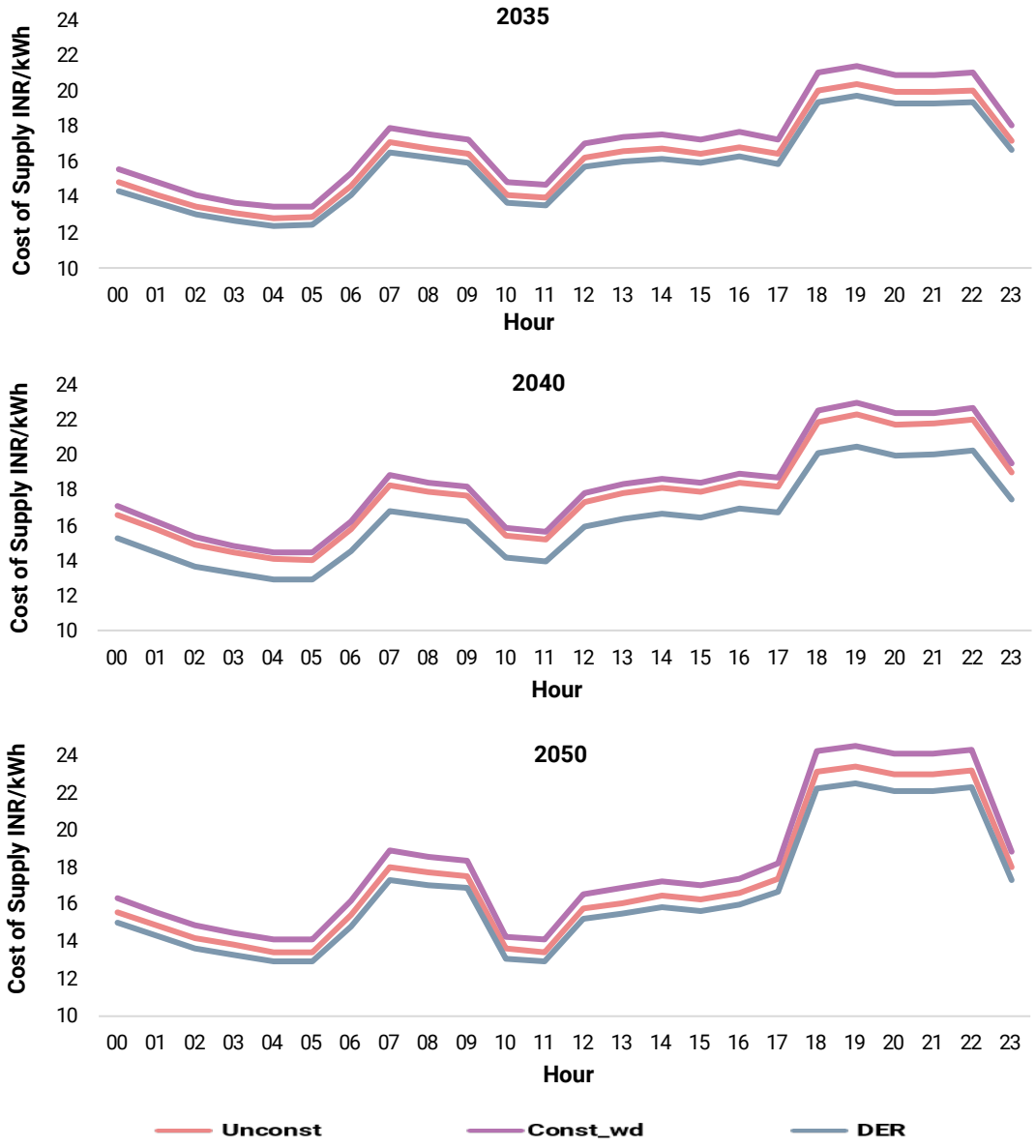
Table 14 PLF by coal and gas power plant

Plant	Unconstrained 2035	Constrained Wind 2035	DER 2035	Unconstrained 2040	Constrained Wind 2040	DER 2040
NCTPS I	46%	49%	40%	Retired	Retired	Retired
NTPCS II	52%	55%	45%	49%	52%	41%
Ennore STTP	43%	46%	38%	40%	43%	40%
Mettur TPS I	58%	58%	50%	Retired	Retired	Retired
Mettur TPS II	50%	53%	43%	47%	50%	40%
Tuticorin TPS	45%	48%	40%	Retired	Retired	Retired
NLC TPS II	55%	57%	48%	Retired	Retired	Retired
North Chennai TPS	52%	55%	45%	49%	52%	41%
Vallur TPS	45%	48%	40%	42%	45%	40%
Neyveli Zero Power	43%	46%	40%	42%	45%	40%
Talabira I	57%	58%	50%	54%	56%	46%
Basin Bridge GTPS	10%	16%	7%	Retired	Retired	Retired
Vallur GTPS Phase I	22%	27%	17%	18%	24%	12%
Kuttalam GTPS	16%	21%	9%	12%	18%	8%

4.6 Cost of supply analysis

Figure 16 illustrates the variation in the average hourly cost of supply over a typical day for the three planning horizons (2035, 2040, and 2050). Across all years, the cost of supply is lowest during the midday period, when abundant solar generation reduces the reliance on higher-cost generation resources and enables energy storage charging. Costs increase during the morning and evening peak periods as solar generation declines, and the system increasingly depends on storage discharge and dispatchable generation to meet demand. The hourly cost profiles also show that pathways with higher levels of flexibility exhibit lower supply costs throughout the day, particularly during the evening peak, compared to pathways with more limited flexibility.

Figure 16 Annual average hourly cost of supply



4.7 Net load analysis

As renewable energy penetration increases, the net load profile becomes an important indicator of system flexibility. Negative net load values occur when renewable generation exceeds demand, creating surplus energy that must be stored, exported, or curtailed, while high positive net load values indicate periods when additional firm and flexible generation is required to reliably meet demand.

2035: In 2035, the net load distribution across all three scenarios is concentrated within moderate positive ranges, indicating that the system continues to rely primarily on dispatchable resources to meet demand. Negative net load events are relatively limited, suggesting that renewable generation only occasionally exceeds demand. Compared with the Unconstrained and Constrained scenarios, the DER scenario records slightly fewer hours in the highest net

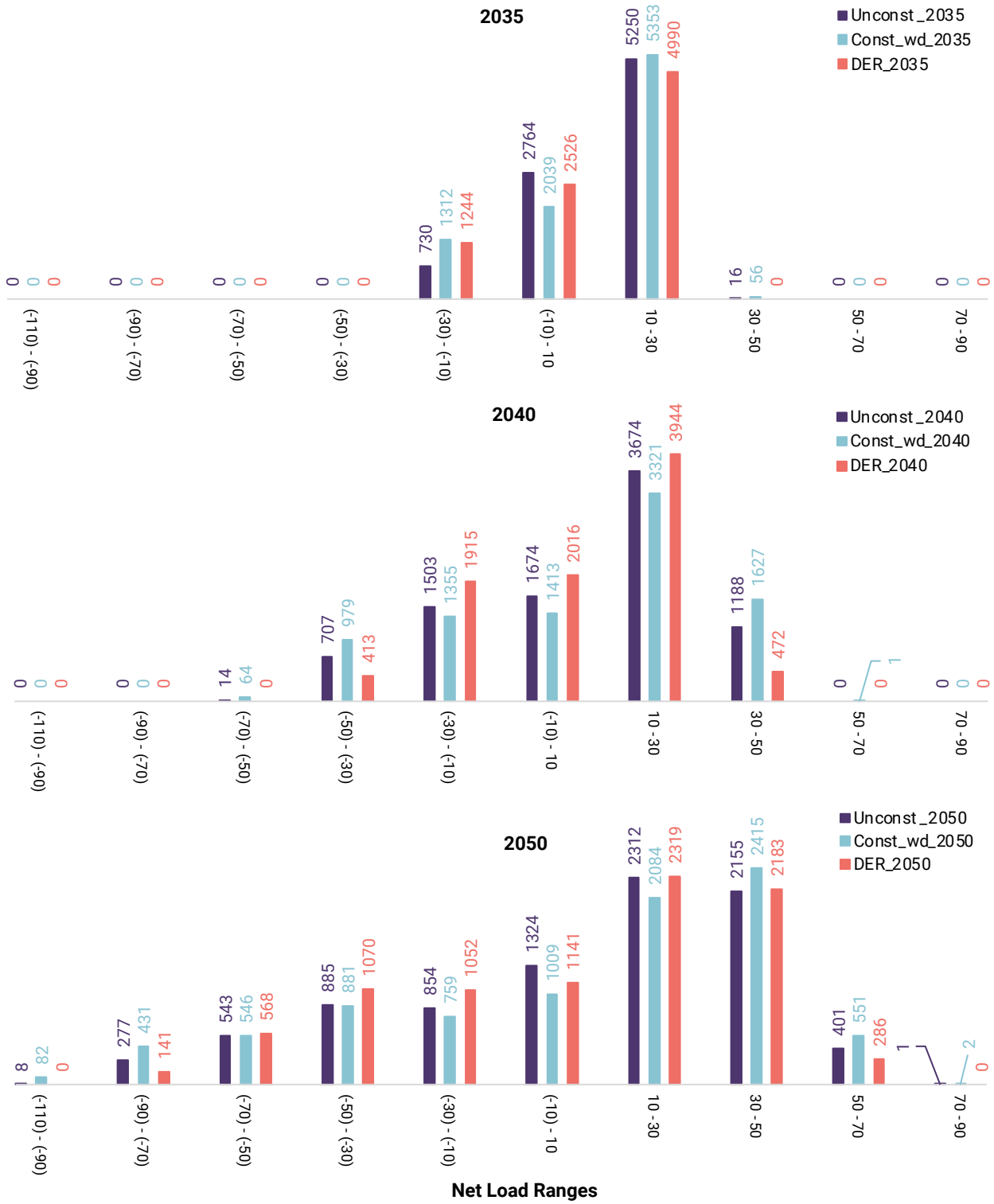
load range, indicating that distributed energy resources help reduce peak net load and improve the balance between electricity demand and renewable generation.

2040: By 2040, the net load distribution becomes more dispersed as renewable generation increases. Both negative net load events and high positive net load hours become more frequent, reflecting greater variability in the demand that must be supplied by dispatchable resources. The Constrained scenario experiences the largest number of hours at high net load levels, indicating a greater dependence on conventional generation during periods of low renewable output. In comparison, the DER scenario records fewer hours at both the negative and high positive ends of the distribution, demonstrating its ability to smooth net load variations and improve overall system flexibility.

2050: By 2050, the influence of high renewable penetration is clear. Negative net load occurs much more frequently across all scenarios, indicating recurring periods when renewable generation exceeds demand and highlighting the increasing need for energy storage, demand response, electricity exports, or renewable curtailment. At the same time, periods of high positive net load persist, confirming that firm generation capacity remains essential during times of low renewable availability. Among the three scenarios, the DER pathway exhibits the most balanced net load distribution, with fewer hours in both the strongly negative and high positive net load ranges and a greater concentration of hours within intermediate ranges. This indicates that distributed energy resources are effective in reducing renewable surplus while simultaneously lowering peak net load, resulting in a more stable and operationally flexible power system.

This analysis shows that increasing renewable energy penetration expands the range of net load conditions, increasing the need for system flexibility. While all scenarios experience greater net load variability over time, the DER scenario consistently delivers the most balanced net load profile, reducing both surplus renewable generation and peak net load. This improves the utilization of renewable energy, reduces reliance on dispatchable generation during peak periods, and lowers the overall requirement for flexibility resources, supporting a more reliable and resilient power system.

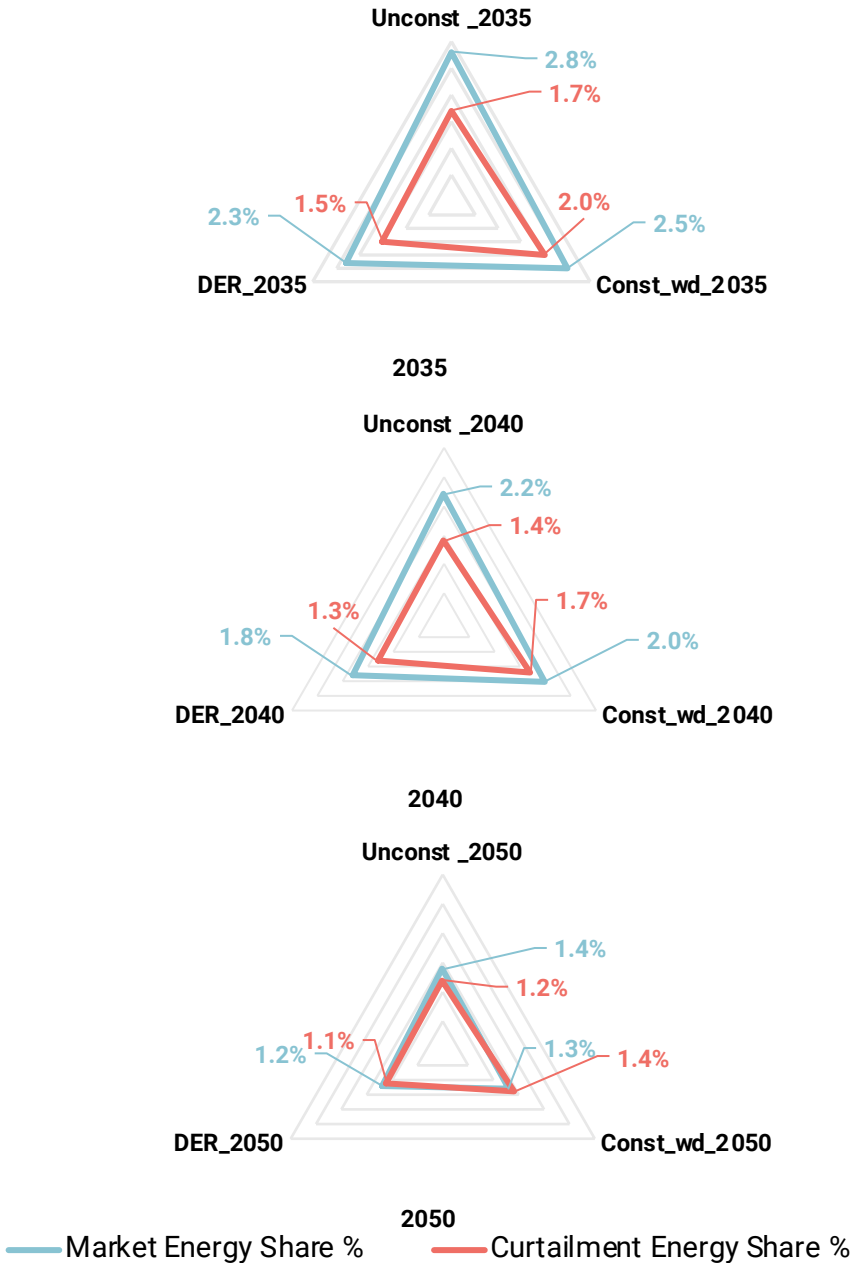
Figure 17 Load distribution on net load by scenario



4.8 RE curtailment and market purchase

Figure 18 compares, for each year, how much renewable generation is curtailed and how much electricity is bought from the market under the three scenarios. In 2035, both curtailment and market purchases are in the low single-digit range as a share of annual energy, with the DER_2035 scenario at the lower end of market purchases among the three. Overall, curtailment and market purchase percentages are highest in 2035 and gradually decline toward 2050, indicating that as storage, distributed resources, and grid reinforcements are added, the system can absorb more local renewables and rely less on external markets even as demand continues to grow.

Figure 18 Curtailment and market purchases by scenario



05

16:00-19:00
Window of the steepest evening net-load ramps

37 GW
Highest single-day peak demand in 2035

Jun-Sep
Season of peak renewable curtailment

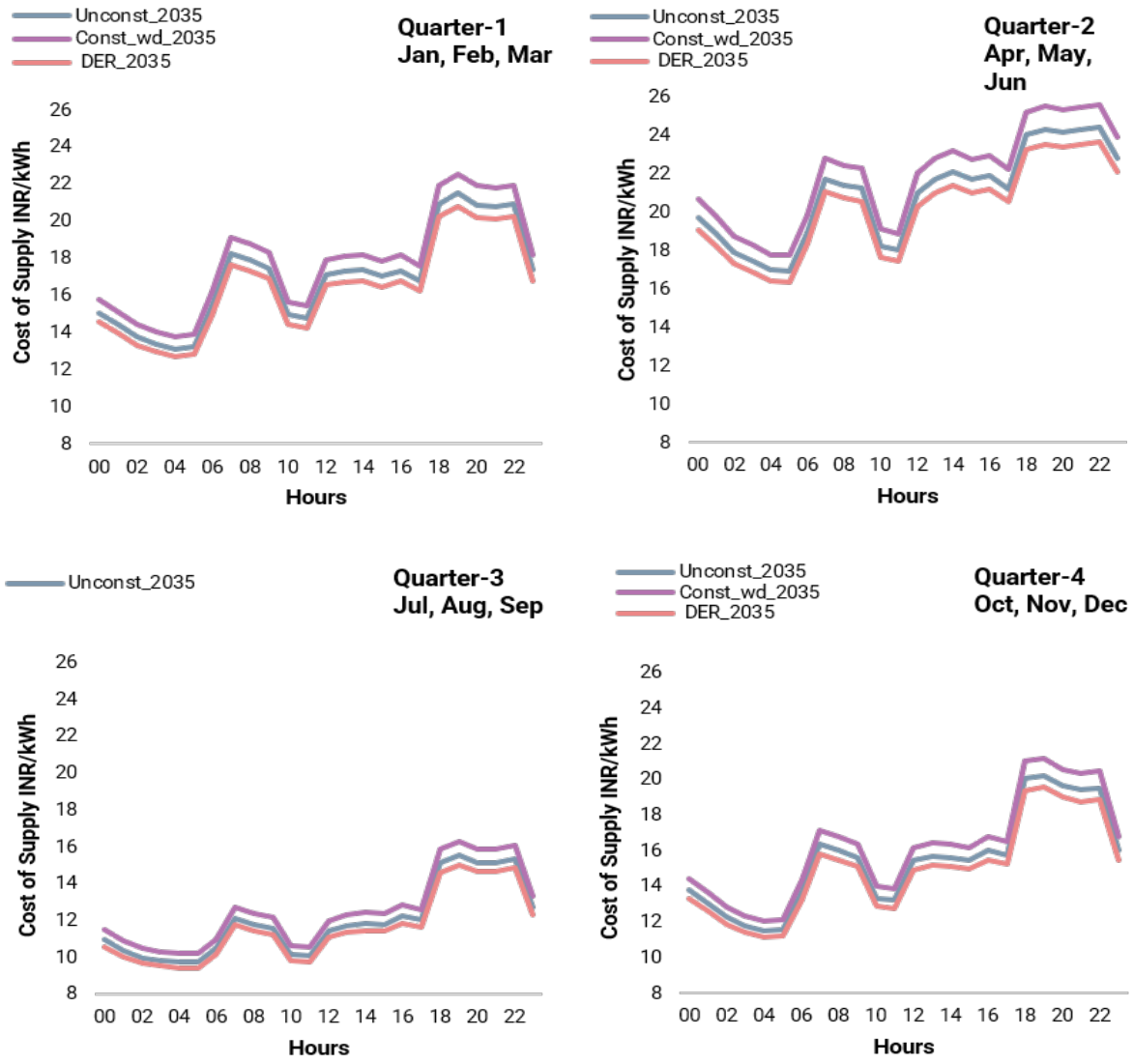
Deep Dive 2035

This chapter zooms in on the analysis year 2035 and examines how the system operates under the three RE-scenarios across seasons, hours of the day, and different resource portfolios. In 2035, the power system is already strongly shaped by seasonal renewables and pronounced duck-curve effects. Costs of supply vary markedly by quarter and time of day, with monsoon wind and midday solar lowering costs while evening peaks remain the most expensive hours. Net-load profiles and ramping patterns highlight growing flexibility needs, as surplus renewable output in some periods coexists with steep ramps and high reliance on coal, gas and imports in others

5.1. Quarterly cost of supply analysis

Figure 19 shows that the daily shape of the cost of supply is broadly similar in all four quarters, but the costs vary by season. Across all three scenarios, Q3 has the lowest cost of supply throughout all hours of the day, particularly in the evening peak, which is likely driven by stronger wind availability during the monsoon months that displaces more expensive generation and reduces balancing costs. By contrast, Q2 shows the highest cost of supply across all hours, and the costs are particularly steep in the evening hours, in every scenario, reflecting a combination of higher cooling loads and periods with limited low cost renewable generation—especially weaker wind conditions—which require more costly thermal or market purchases to meet demand. These insights on seasonal and diurnal cost variation can be used to inform tariff determination, for example, by introducing seasonal tariffs and time of day tariffs that better reflect underlying system costs and encourage demand to shift toward lower cost periods.

Figure 19 Average hourly cost of supply by quarter

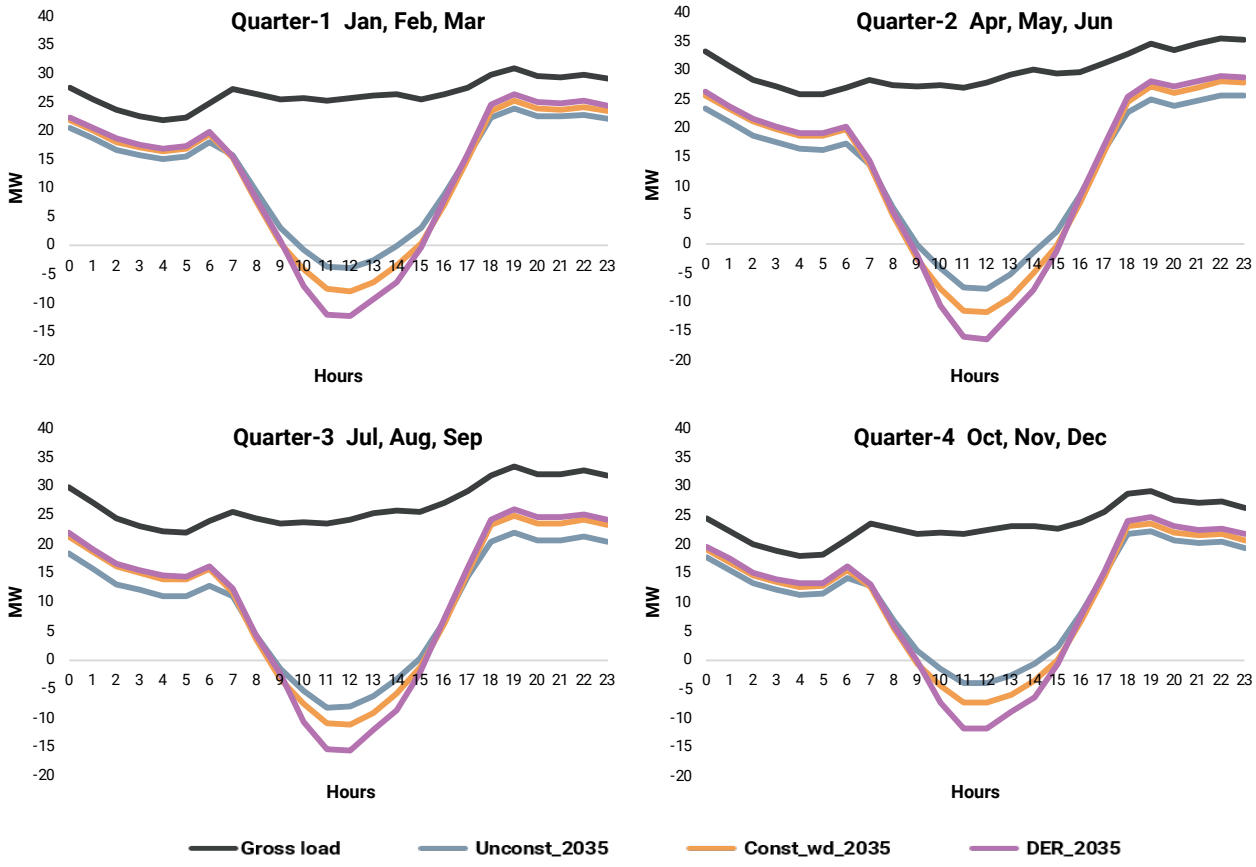


5.2. Quarterly Net Load Analysis

The quarterly net-load profiles show distinct differences between the three scenarios: The DER scenario exhibits the highest negative net-load values overall, resulting in the most pronounced “duck curve” shape. This indicates frequent periods of large surplus generation during solar hours, followed by steep evening ramps that strongly increase flexibility and storage requirements. By contrast, the Unconstrained scenario with higher and more geographically diverse wind penetration shows the least pronounced duck curve. Midday net load does not drop as deeply, and the transition to evening peaks is smoother, suggesting that additional wind generation helps to fill in the midday trough and moderates the severity of ramping needs across quarters.

Q1 and Q4 show less pronounced duck curves due to shorter daylight hours and lower solar irradiance, resulting in moderate net load swings and reduced ramping requirements. Summer quarters (Q2 and Q3) exhibit deeper midday troughs and steeper evening ramps, particularly in the DER scenario where concentrated rooftop solar creates the most severe operational challenges.

Figure 20 Quarterly net loads by scenario



5.3 Deep dive – net load ramping

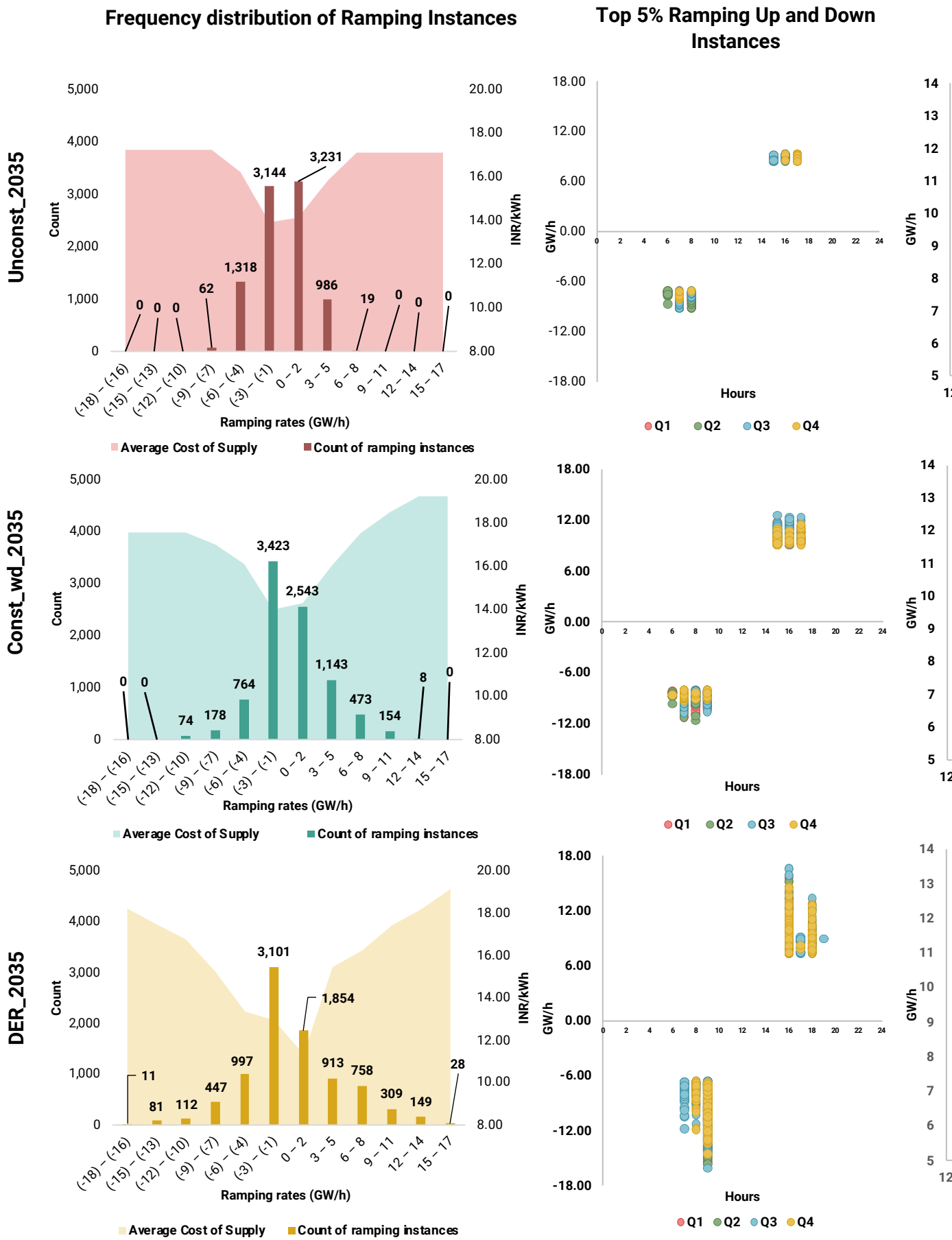
Net load ramping emerges as one of the key operational challenges in a high-renewable electricity system, as increasing shares of variable renewable energy require the system to respond more rapidly to changes in net demand. Figure 21 compares the magnitude, timing, duration, and seasonal occurrence of ramping events across the three 2035 scenarios.

The Unconstrained scenario exhibits the fewest high-magnitude and long-duration ramping events, demonstrating that higher and more geographically diversified wind deployment smooths net load variations and reduces overall flexibility requirements. In contrast, the Constrained Wind scenario experiences a greater frequency of medium- and high-magnitude ramps due to its increased reliance on solar generation, resulting in a more pronounced evening transition as solar output declines.

The DER scenario concentrates ramping events within shorter evening periods as rooftop solar significantly reduces midday net load before rapidly declining towards sunset. However, these operational challenges are largely mitigated through increased deployment of battery energy storage, enabling surplus daytime renewable generation to be shifted into the evening peak and reducing dependence on thermal generation and market purchases.

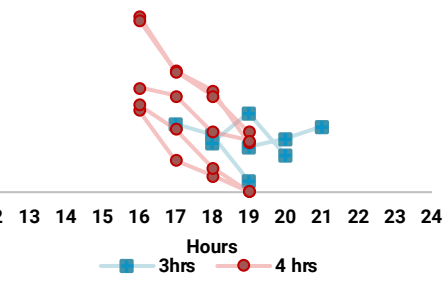
Across all scenarios, the largest upward ramping events occur predominantly between 16:00 and 19:00, coinciding with the decline in solar generation and the onset of the evening demand peak. Seasonally, higher-magnitude ramping events are concentrated during Q2 and Q3, when renewable generation is highest. Overall, the analysis highlights that renewable resource diversity, supported by energy storage and demand-side flexibility, plays a critical role in reducing ramping requirements and maintaining reliable operation of a high-renewable power system.

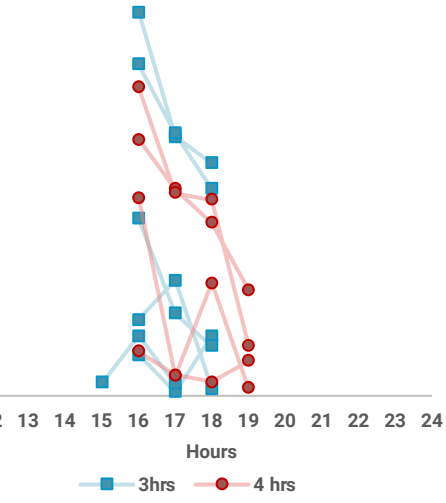
Figure 21 Ramping instances by scenario



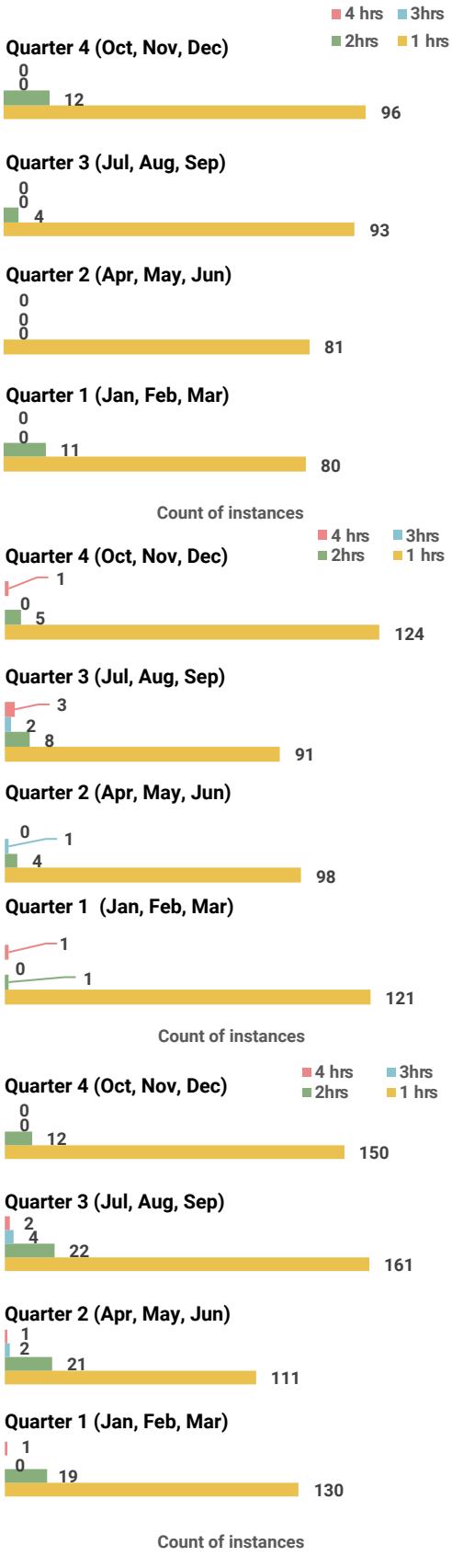
Ramping Instances > 5 GW/h by Duration







Ramping Instances by > 5 GW/h counts by Duration



Top 15 Ramping Instances

No	GW/h	Month	Time
1	8.61	Jan	07:00
2	8.14	Dec	07:00
3	7.90	Jun	07:00
4	7.68	Mar	07:00
5	7.61	Jan	07:00
6	7.58	Aug	07:00
7	7.49	Sep	07:00
8	7.48	Dec	07:00
9	7.45	Dec	07:00
10	7.31	Mar	07:00
11	7.27	Aug	07:00
12	7.25	Sep	18:00
13	7.16	Jan	07:00
14	7.09	Feb	07:00
15	7.03	Dec	07:00

No	GW/h	Month	Time
1	12.52	Feb	16:00
2	12.41	Nov	16:00
3	12.96	Mar	16:00
4	12.81	May	16:00
5	12.73	Sep	16:00
6	12.64	May	16:00
7	12.60	Oct	16:00
8	12.51	Mar	16:00
9	11.36	Sep	16:00
10	11.32	Aug	16:00
11	11.30	Apr	16:00
12	11.16	Apr	16:00
13	10.75	Sep	18:00
14	10.23	Feb	16:00
15	10.16	Nov	16:00

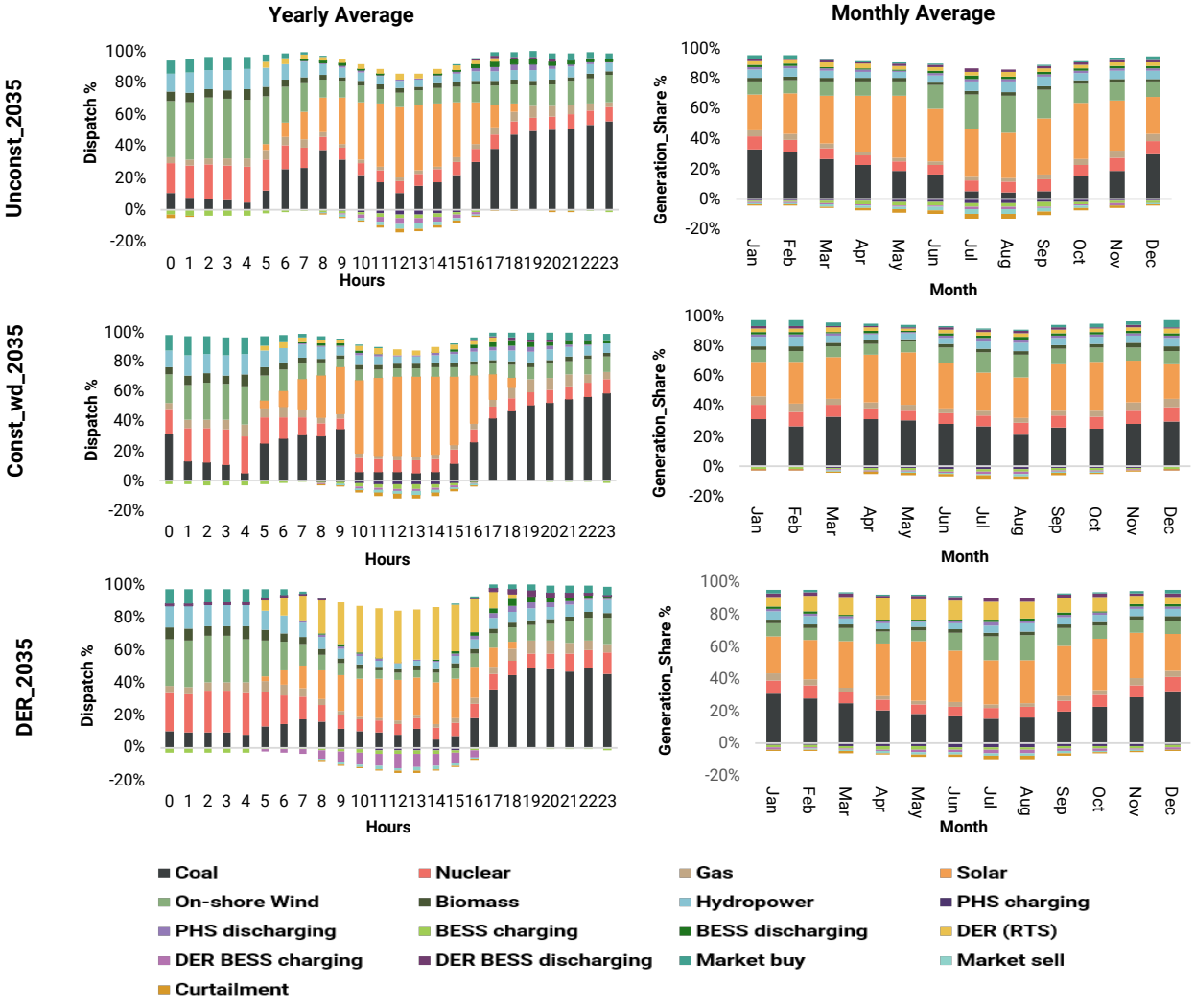
No	GW/h	Month	Time
1	16.38	Aug	16:00
2	16.12	Dec	16:00
3	16.09	Jun	16:00
4	16.01	May	16:00
5	15.99	Dec	16:00
6	15.91	Jul	16:00
7	15.88	May	16:00
8	15.77	Jul	16:00
9	15.71	Nov	16:00
10	15.64	Apr	16:00
11	15.51	Jul	16:00
12	15.44	Apr	16:00
13	15.38	Sep	16:00
14	15.21	Apr	16:00
15	15.04	Mar	16:00

5.4 Energy Dispatch Analysis

In 2035, the hourly dispatch profiles show that all three scenarios transition from a coal-dominated mix during morning and evening hours to substantially higher shares of utility-scale solar, distributed energy resources (DER), and wind during midday hours. In the DER scenario, the combination of strong rooftop PV and utility-scale PV pushes midday net load very low, causing coal plants to back off sharply while battery storage discharges steeply during the evening peak to meet ramping requirements. The Constrained scenario exhibits similar pronounced midday renewable dominance due to limited wind and high solar penetration, with heavy reliance on storage, market purchases, and fast-ramping gas to cover the rapid evening ramp as solar output falls. By contrast, the Unconstrained scenario with higher and more geographically diverse wind capacity spreads renewable generation more evenly throughout the day, reducing the depth of the midday trough and enabling a smoother thermal dispatch profile with less extreme ramping from coal, gas, and batteries.

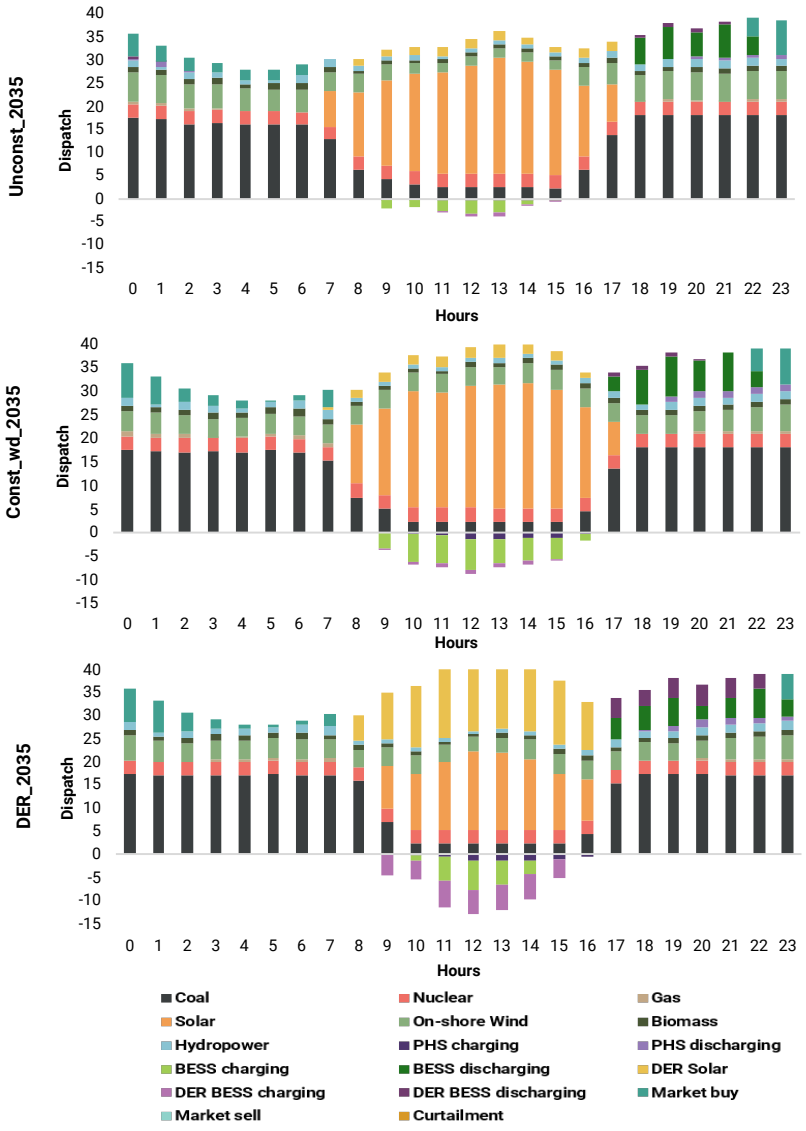
The monthly dispatch profiles aggregate these patterns and reveal how each technology's contribution varies seasonally. In the DER and Constrained scenarios, high-solar months show a large share of energy from both utility and rooftop solar, with batteries frequently charging during midday surplus and discharging in the evening, while coal, market energy, nuclear, and gas provide residual capacity and firm energy when renewable output is low. During lower-solar or higher-demand months, coal, gas, and wind carry larger shares of the energy mix, with hydro and storage helping to manage variability. In the
Unconstrained scenario, stronger wind penetration maintains substantial renewable contribution in almost every month, reducing the need for extreme fossil generation peaks and resulting in more balanced monthly dispatch between wind, solar, hydro, storage, and thermal units

Figure 22 Hourly and monthly dispatch profiles across scenarios (2035)



On 17 April 2035, the day with the highest expected peak demand of 37GW, all three scenarios significantly reduce coal generation during daytime hours, with the mid day peak being met largely by solar, wind, and other renewables. In the DER_2035 case, higher utilisation of both grid-scale BESS and DER BESS allows more of this renewable output to be shifted into the evening, which in turn limits the need for market imports on the peak day. Compared with the unconstrained and constrained-wind scenarios, the DER pathway therefore relies more on storage based flexibility and less on external purchases, while still achieving a low coal, renewables-dominated profile over most of the day.

Figure 23 Energy share on the day with the single highest gross peak

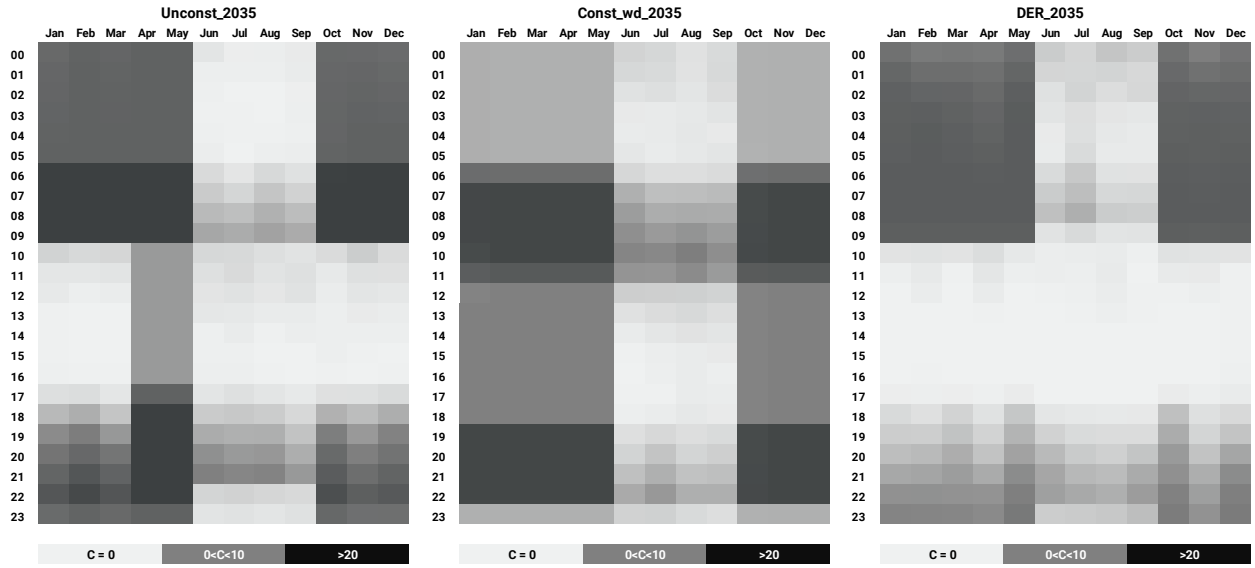


5.5 Coal Dispatch Patterns: Monthly Trends and Peak-Day Dynamics

In the Unconstrained and especially the Distributed Energy Resources (DER) scenarios, coal dispatch between roughly 10:00 and 16:00 is minimal or close to zero in most months, indicating that daytime demand is largely met by solar and other renewables. For the Unconstrained and Constrained Wind scenarios, coal remains significant in the evening, night, and early morning hours, reflecting its role in covering residual demand when renewables are low. In the DER scenario, higher battery storage capacity reduces this evening's dependence on coal, so coal utilisation between about 18:00 and 23:00 is visibly lower than in the other two scenarios.

All three scenarios show the lowest coal utilisation during the main wind season of June, July, August, and September. This confirms that strong monsoon season wind significantly reduces the need for coal across the system, regardless of the scenario.

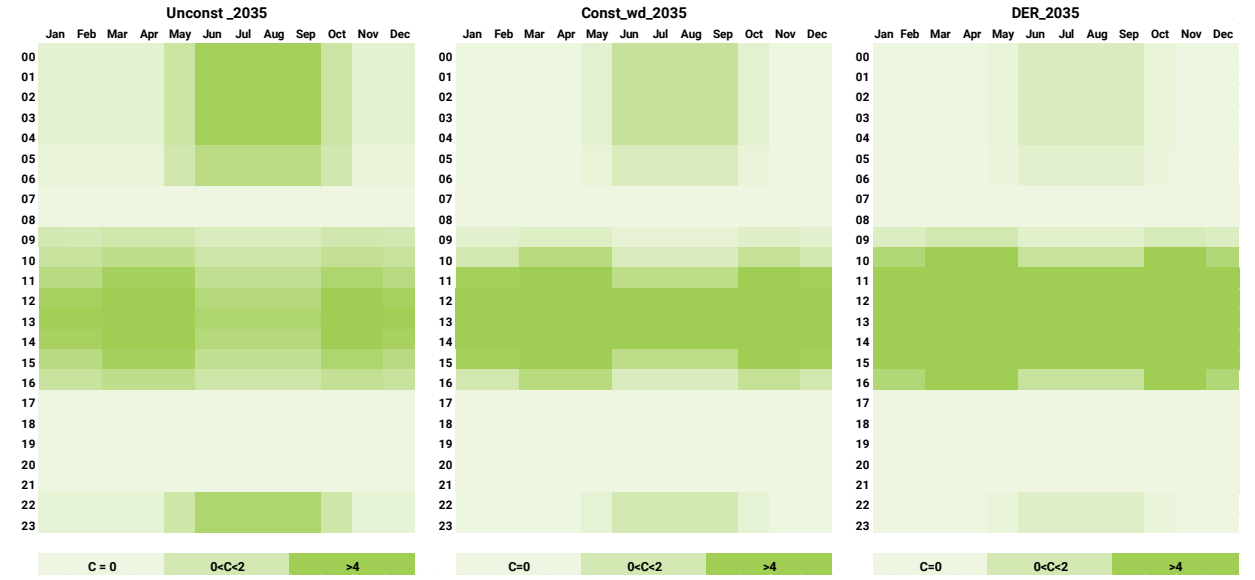
Figure 24 Average hourly coal dispatch for each month



F5.6 Energy Storage Behaviour Across Scenarios

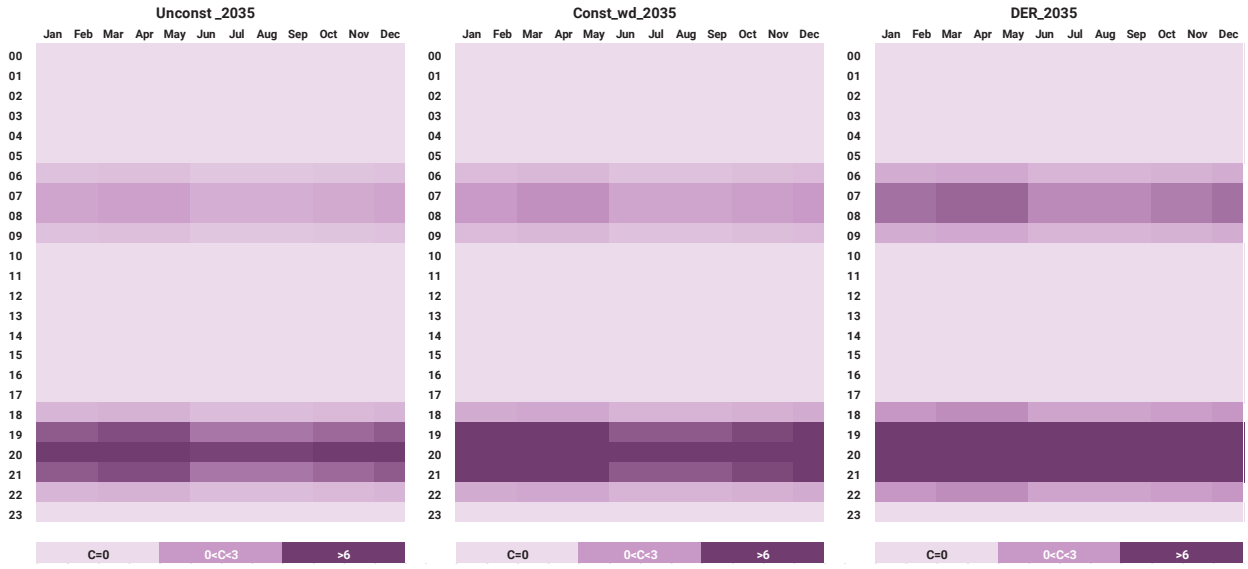
Across all three scenarios, batteries charge mainly during low-cost, high-renewable hours and discharge during peak demand periods. Charging shows a clear seasonal pattern: from June to September, there is more intensive charging during the night and early morning hours (around 22:00 to 6:00), when demand is low, but wind turbines are producing strongly. In most other months, charging is concentrated between late morning and mid-afternoon, when solar output is highest, and surplus renewable energy is available. The DER scenario shows the most intense charging blocks overall, reflecting the larger battery fleet and greater use of storage to soak up both midday solar and off peak wind.

Figure 25 Average hourly BESS charging pattern across months for each scenario



Discharging is focused on the evening hours, roughly from 18:00 to 23:00, when demand is high and solar is no longer available. The DER scenario again stands out, with stronger evening discharge across more months, indicating that the additional BESS capacity is being used to replace coal in meeting the evening peak and to provide cleaner, flexible capacity. In the Unconstrained scenario, evening battery discharge is relatively modest, so storage plays a smaller role in covering the 18:00–23:00 peak compared with the other cases. By contrast, the DER scenario shows not only stronger evening discharge but also a clear block of morning discharge between about 6:00 and 9:00, indicating that the larger BESS fleet is used to support both the morning and evening peaks and to reduce reliance on conventional generation at those times.

Figure 26 Average hourly BESS discharging pattern across months for each scenario

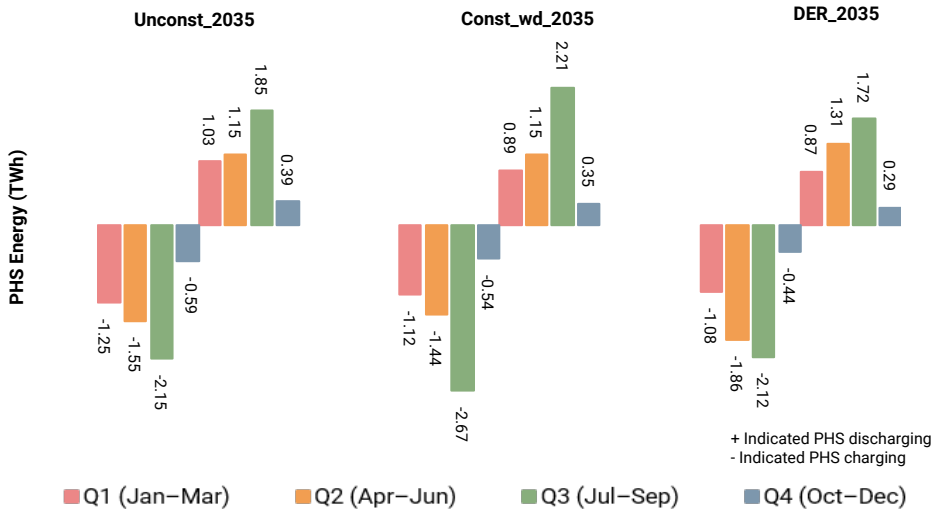


Pumped hydro storage operation exhibits distinct quarterly patterns that vary significantly across the three scenarios, reflecting differences in renewable energy surplus availability and evening ramping requirements (Figure 27).

In Q1 (Jan-Mar), all scenarios show moderate PSH charging volumes, with the DER scenario demonstrating slightly higher charging due to winter rooftop solar surplus. Q2 (Apr-Jun) marks the period of highest PSH activity, with both charging and discharging volumes peaking as strong solar irradiance creates substantial midday surplus for pumping and steep evening ramps requiring storage dispatch. The DER scenario shows the most intensive Q2 operation, with charging volumes exceeding both other scenarios, indicating that concentrated rooftop PV generation creates larger midday energy surpluses that must be absorbed through pumping.

Q3 (Jul-Sep) operation patterns diverge notably: the Unconstrained scenario maintains relatively high charging levels due to sustained wind generation, while the DER and Constrained scenarios show reduced charging as monsoon cloud cover limits solar surplus. Q4 (Oct-Dec) exhibits the lowest PSH utilisation across all scenarios, with minimal activity reflecting reduced solar output during shorter daylight hours. The DER scenario consistently shows higher round-trip efficiency losses due to greater daily cycling depths throughout the year.

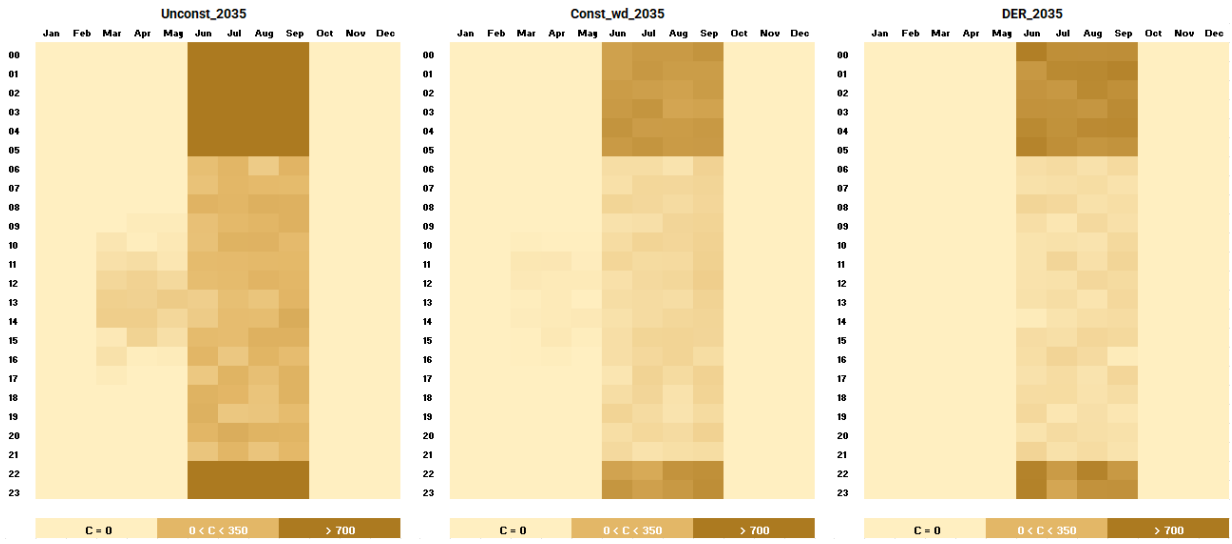
Figure 27 Seasonal Pumped Hydro Storage Operation Across Scenarios



5.7 Curtailment trends across the different RE scenarios

Curtailment increases visibly during the main wind season of June to September in all three scenarios, reflecting frequent surplus renewable generation in these months. Curtailment is also concentrated in the low demand night and early morning hours, roughly between 22:00 and 5:00, indicating that significant amounts of wind and other RE are being curtailed when demand is weakest. Together, these patterns underline a clear opportunity for demand shifting—through time of day and seasonal tariffs, flexible industrial loads, and new uses such as green hydrogen—to move consumption into periods of high curtailment and reduce both waste and market purchase costs.

Figure 28 Average curtailment patterns observed across different scenarios



5.8. Market interactions

Across all three scenarios, market purchases are strongest in the evening peak hours, roughly between 18:00 and 21:00, when demand is high, and solar is no longer available. In the Constrained and DER scenarios, there is also noticeable market activity in the morning ramp period, around 6:00 to 9:00, indicating a need to import power to cover the early morning rise in demand before solar and other resources are fully online.

Seasonal variation is actually quite pronounced, and it lines up with your coal and wind patterns. Market purchases are highest in the “low wind, high coal” season: roughly October to March, when wind output is weakest, and the system leans most on coal and imports to meet demand. In these months, you see both elevated coal dispatch and darker bands of market purchases, indicating a tighter supply–demand balance and less surplus RE available to cover peaks. By contrast, during the main wind season (June–September), market purchases are noticeably lower because strong wind generation and storage can cover more of the load, reducing the need to buy from the market.

Figure 29 Average hourly market purchases for each month

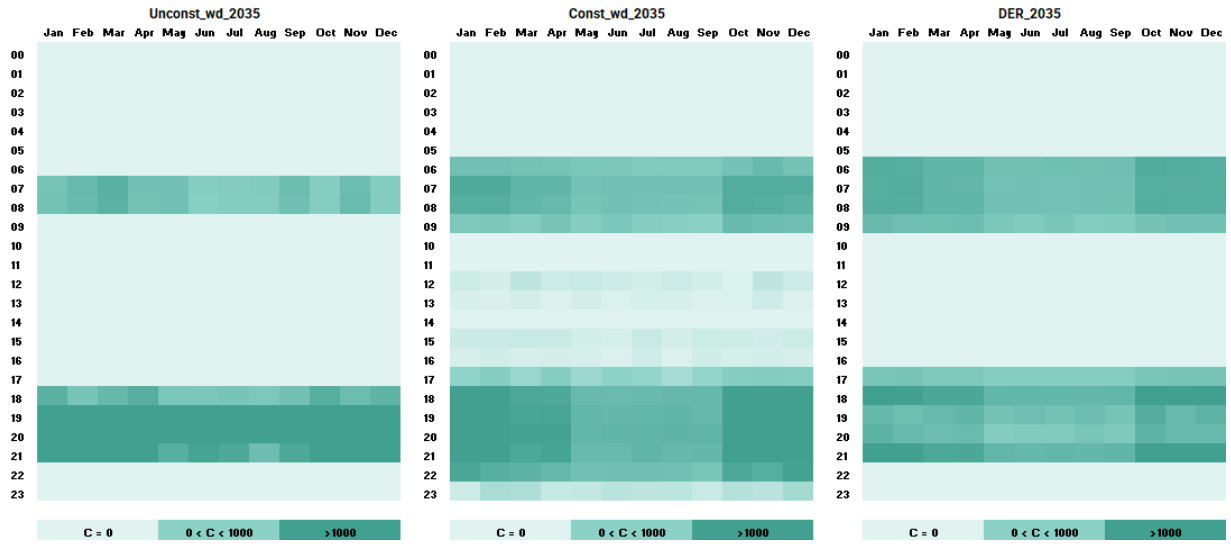
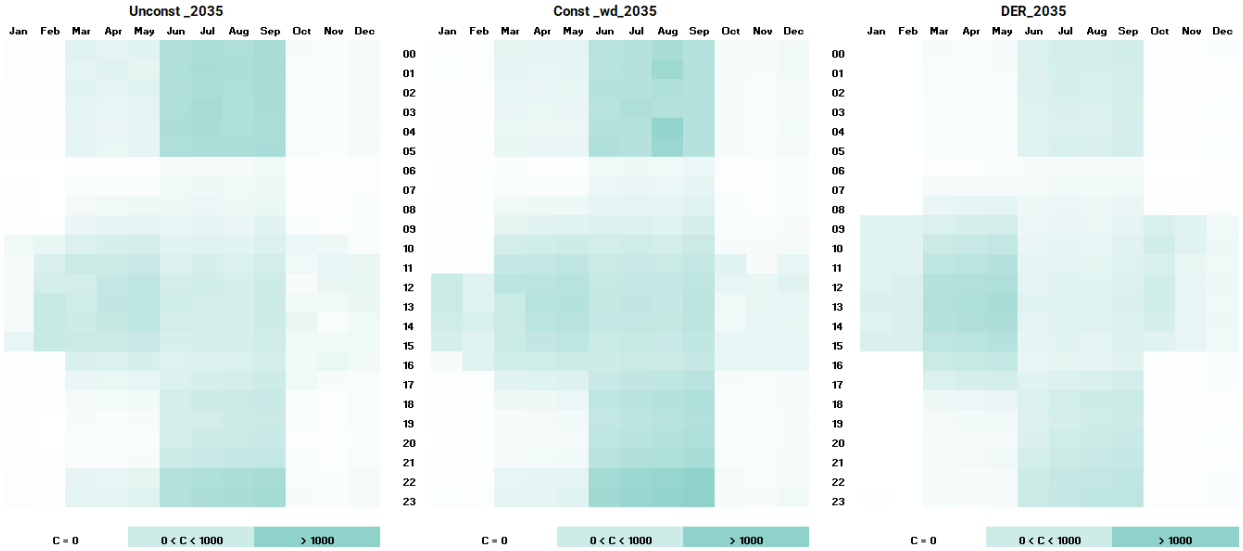


Figure 30 Average hourly market sales for each month



Overall, the operational assessment demonstrates that higher renewable penetration fundamentally changes system operation by increasing the importance of flexibility rather than energy adequacy. The results show that geographically diversified renewable resources, supported by battery energy storage, pumped hydro storage, demand-side flexibility, and strategic market interactions, enable reliable operation while reducing dependence on conventional generation. These operational insights reinforce the importance of integrated planning approaches that combine renewable energy expansion with complementary flexibility resources to support Tamil Nadu's transition towards a secure and cost-effective renewable electricity system.

06

Rs 15.21/kWh
Lowest cost of supply, DER Integrated scenario

8.21 GW/h
Lowest ramping event, DER Integrated case

0.68%
Lowest annual curtailment, DER scenario with Time-of-Use tariffs

Simulating Demand Flexibility Options 2035

This chapter assesses how demand-side flexibility can improve the performance of the 2035 power system across the Unconstrained, Constrained Wind, and DER scenarios. It compares Time-of-Use tariffs, Automated Demand Response, Green Ammonia, and an integrated flexibility package to understand their effects on system cost, peak demand, storage requirements, ramping, renewable integration, emissions, curtailment, and market purchases.

6.1 High-level results for 2035

The 2035 demand-side sensitivity analysis compares how different flexibility options—Time-of-Use (ToU) tariffs, Automated Demand Response (ADR), Green Ammonia (GA) and an integrated package (INT) that combines ToU, ADR and GA—affect system performance across the three RE scenarios. The results reveal clear patterns in how these measures change total system cost, storage needs, peak demand and ramping requirements. The key insights by parameter are summarised below.

Most cost-effective configuration: DER_2035 ADR achieves the lowest total system cost at ₹3.53 lakh crore, followed closely by DER_2035 INT (₹3.57 lakh crore) and DER_2035 ToU (₹3.61 lakh crore). Green Ammonia alone is the costliest flexibility option, with Const_wd_2035 GA reaching ₹4.14 lakh crore—indicating that GA should be combined with other measures rather than deployed in isolation.

Peak demand management: The integrated package (INT) consistently delivers the strongest peak reduction across all scenarios. In the DER scenario, INT reduces net peak demand from 29.7 GW (GA-only) to 26.4 GW, while ADR achieves 27.5 GW. ToU tariffs provide moderate peak relief (reducing Unconstrained scenario peaks from 33.5 GW to 31.8 GW) but are less effective than ADR or INT.

Storage requirements diverge by scenario: All DER_2035 variants with GA, ADR, or INT show the highest battery storage shares at 7-8%, reflecting the need for substantial storage in solar-heavy systems. By contrast, Unconstrained and Constrained scenarios maintain much lower BESS shares at 4-5%, relying instead on diverse wind generation and demand-side flexibility.

Ramping stress reduction: Green Ammonia alone does little to smooth ramping requirements, with DER_2035 GA showing the steepest maximum ramp event at 17.93 GW/h. The most effective ramp-smoothing configuration is DER_2035 INT, which reduces the maximum ramp to just 8.21 GW/h, followed by DER_2035 ADR at 9.11 GW/h. This demonstrates that integrated flexibility measures in DER-rich systems can create a smoother operational profile.

Renewable energy penetration: The highest wind-plus-solar shares (56%) occur in Unconstrained_2035 GA, DER_2035 GA, and DER_2035 INT cases, representing the most RE-intensive portfolios. Scenarios relying primarily on ToU or ADR without GA achieve slightly lower but still substantial RE shares of 51-55%.

Table 15 High-level results by scenario

Scenario	Wind & Solar share (%)	BESS share (%)	Gross peak (GW)	Net peak (GW)	Max ramping event (GW/h)	Total system cost (₹ Lakh Crore)
Unconst_2035	52%	4%	39.13	31.81	8.61	3.80
Unconst_2035 GA	56%	4%	39.12	33.55	10.46	3.94
Unconst_2035 ToU	54%	4%	38.15	31.85	9.79	3.73
Unconst_2035 ADR	52%	4%	37.76	30.73	9.75	3.61
Unconst_2035 INT	55%	4%	37.4	29.62	9.53	3.69
Const_wd_2035	50%	5%	39.13	33.11	12.52	3.99
Const_wd_2035 GA	54%	5%	39.12	32.31	12.72	4.14
Const_wd_2035 ToU	51%	4%	38.15	30.52	10.42	3.91
Const_wd_2035 ADR	51%	4%	36.92	29.71	10.24	3.79
Const_wd_2035 INT	54%	5%	37.41	28.73	10.61	3.87
DER_2035	52%	7%	39.13	28.53	16.38	3.68
DER_2035 GA	56%	8%	39.12	29.74	17.93	3.86
DER_2035 ToU	54%	7%	38.15	28.40	10.17	3.61
DER_2035 ADR	51%	8%	36.93	27.59	9.11	3.53
DER_2035 INT	56%	8%	37.46	26.41	8.21	3.57

6.2 System cost comparison

Table 16 compares the total system cost, annual electricity demand, energy cost, network cost, and Cost of Supply for the different flexibility pathways in 2035. Across all three base scenarios, the implementation of flexibility measures generally reduces both the total system cost and the Cost of Supply compared to the corresponding base case. Among the individual flexibility options, ADR consistently achieves the largest reduction in total system cost, while the ToU pathway also lowers the Cost of Supply by shifting electricity demand towards periods of higher renewable energy availability and improving the utilisation of renewable generation and energy storage.

The Green Ammonia (GA) pathway results in slightly higher system costs and Cost of Supply because of the additional electricity required for green ammonia production, increasing annual demand from 233.39 TWh to 239.51 TWh. Among all pathways, DER_2035 INT achieves both the lowest total system cost, at ₹3.53 lakh crore, and the lowest Cost of Supply, at ₹15.21/kWh. In comparison, Const_wd_2035 GA has the highest total system cost (₹4.14 lakh crore) and the highest Cost of Supply (₹17.28/kWh), around 14% higher than DER_2035 INT. The network cost is held constant at ₹6.21/kWh across the 2035 sensitivity cases because the transmission and distribution infrastructure assumptions remain unchanged. Therefore, the differences in Cost of Supply are primarily driven by changes in energy cost, with DER_2035 INT achieving the lowest energy cost of ₹8.99/kWh.

Table 16 System cost and cost of supply comparison

Parameters	Total Demand (TWh)	Total System Cost (₹ Lakh Crore)	Energy Cost (₹/kWh)	Network Cost (₹/kWh)	Cost of Supply (₹/kWh)
Unconst_2035	233.39	3.80	10.08	6.21	16.29
Unconst_2035 GA	239.51	3.94	10.24	6.21	16.45
Unconst_2035 ToU	232.53	3.73	9.83	6.21	16.04
Unconst_2035 ADR	233.39	3.61	9.63	6.21	15.84
Unconst_2035 INT	234.86	3.69	9.51	6.21	15.72
Const_wd_2035	233.39	3.99	10.87	6.21	17.08
Const_wd_2035 GA	239.51	4.14	11.07	6.21	17.28
Const_wd_2035 ToU	232.53	3.91	10.61	6.21	16.82
Const_wd_2035 ADR	233.39	3.79	10.42	6.21	16.63
Const_wd_2035 INT	234.86	3.87	10.27	6.21	16.48
DER_2035	233.39	3.68	9.55	6.21	15.76
DER_2035 GA	239.51	3.86	9.90	6.21	16.11
DER_2035 ToU	232.53	3.61	9.32	6.21	15.53
DER_2035 ADR	233.39	3.57	9.28	6.21	15.49
DER_2035 INT	234.86	3.53	8.99	6.21	15.21

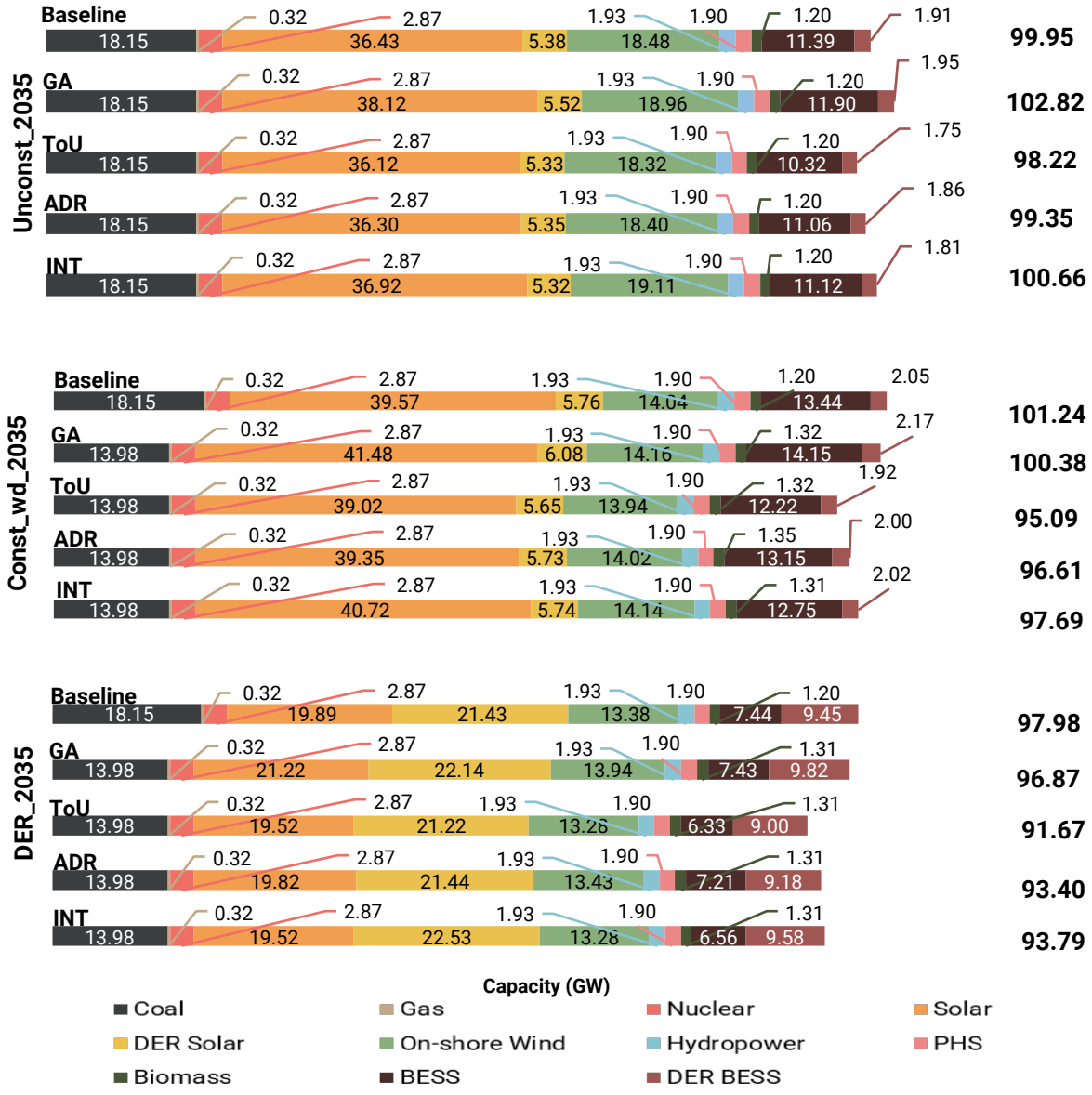
6.3 Projected power generation capacities

Since coal (18.15 GW), nuclear (~0.32 GW), gas (~2.87 GW), hydropower (~1.93 GW), and pumped hydro storage (1.90-1.93 GW) capacities are held constant, the key differences lie in solar, wind, and battery storage deployment.

Unconstrained scenarios require 98-103 GW total capacity, with 36-39 GW solar dominated by utility-scale installations. Constrained wind scenarios need 95-101 GW, deploying higher solar at 39-42 GW to compensate for limited wind (13-14 GW vs. 18-19 GW in Unconstrained). DER scenarios are most efficient at 91.67-97.98 GW total, with a dramatic shift: utility solar drops to 19-21 GW while distributed rooftop solar surges to 21-23 GW. Green Ammonia scenarios consistently add 2-3 GW across all families due to increased electricity demand from electrolyser operations, raising total system demand from ~233 TWh to ~240 TWh.

BESS capacity diverges sharply: Unconstrained variants need minimal BESS (DER and utility scale) 12.07 to 13.85 GW as diverse wind provides natural smoothing. Constrained scenarios require slightly more at 14.18 to 16.32 GW. DER scenarios demand the highest at 15.33 to 16.89 GW.

Figure 31 Power generation capacity by scenario and year

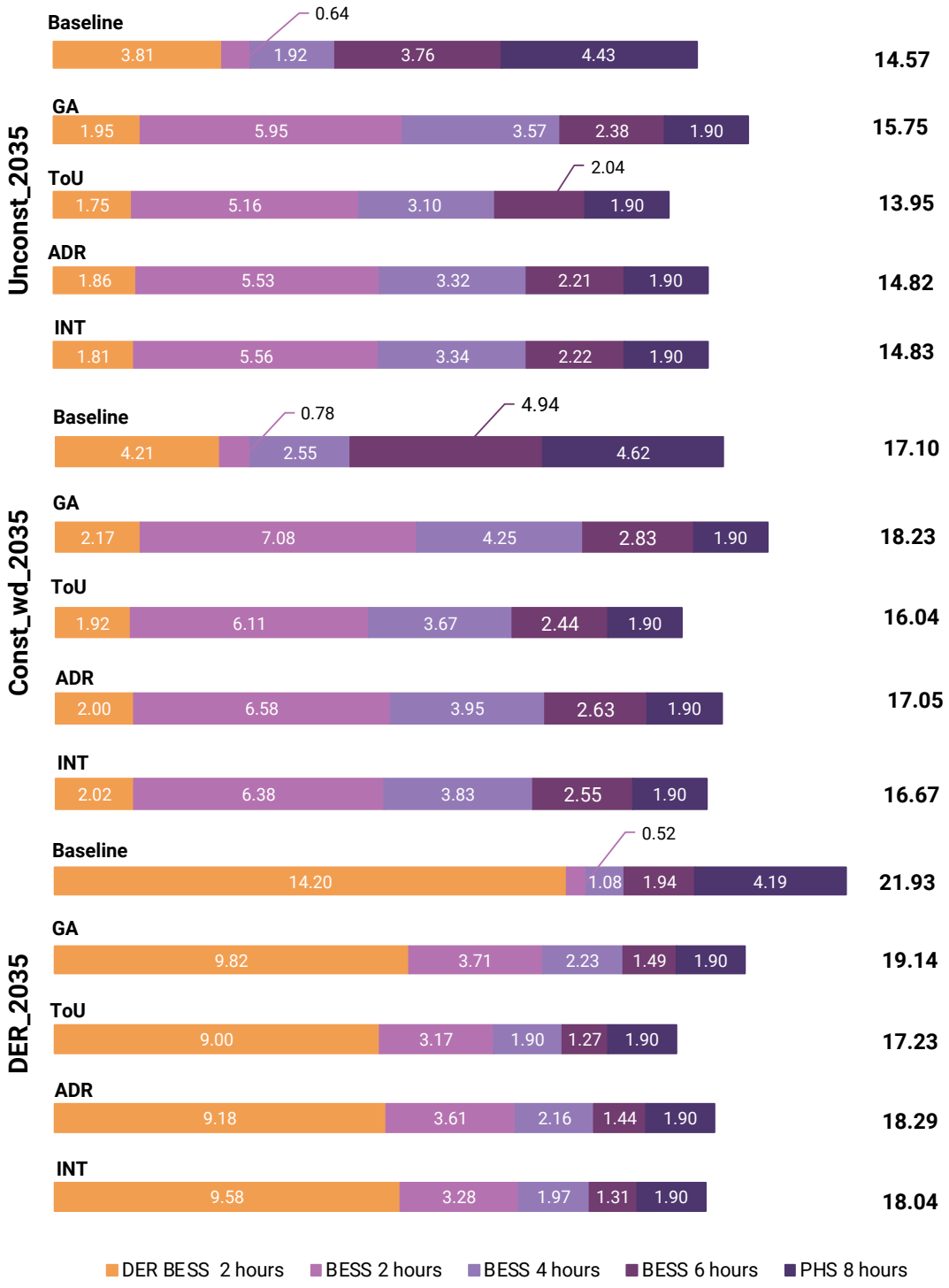


The storage analysis reveals a fundamental divergence between scenarios, with DER configurations requiring significantly higher battery deployment than wind-based portfolios across both power capacity (GW) and energy capacity (TWh) dimensions.

DER scenarios demand the highest power capacity for battery storage, ranging from 6.33 GW (ToU) to 9.82 GW (GA), reflecting the need to manage steep evening ramps when distributed solar output drops sharply. Within the DER family, Green Ammonia drives the highest requirement at 9.82 GW, while ToU achieves the lowest at 6.33 GW through effective load-shifting.

Unconstrained scenarios require minimal storage power, ranging from just 1.75 GW (baseline) to 1.95 GW (GA and INT), as geographically diverse wind generation naturally smooths output variability and reduces reliance on batteries. All Unconstrained flexibility variants cluster tightly around 1.8-1.9 GW, indicating that demand-side measures have limited impact on storage needs when wind diversity is high. Constrained wind scenarios fall in between at 1.92-2.17 GW, with GA showing the highest power requirement (2.17 GW) due to increased electrolyzer demand and limited wind availability. The constrained portfolio requires roughly 15% more storage power than Unconstrained but only one-quarter of DER requirements.

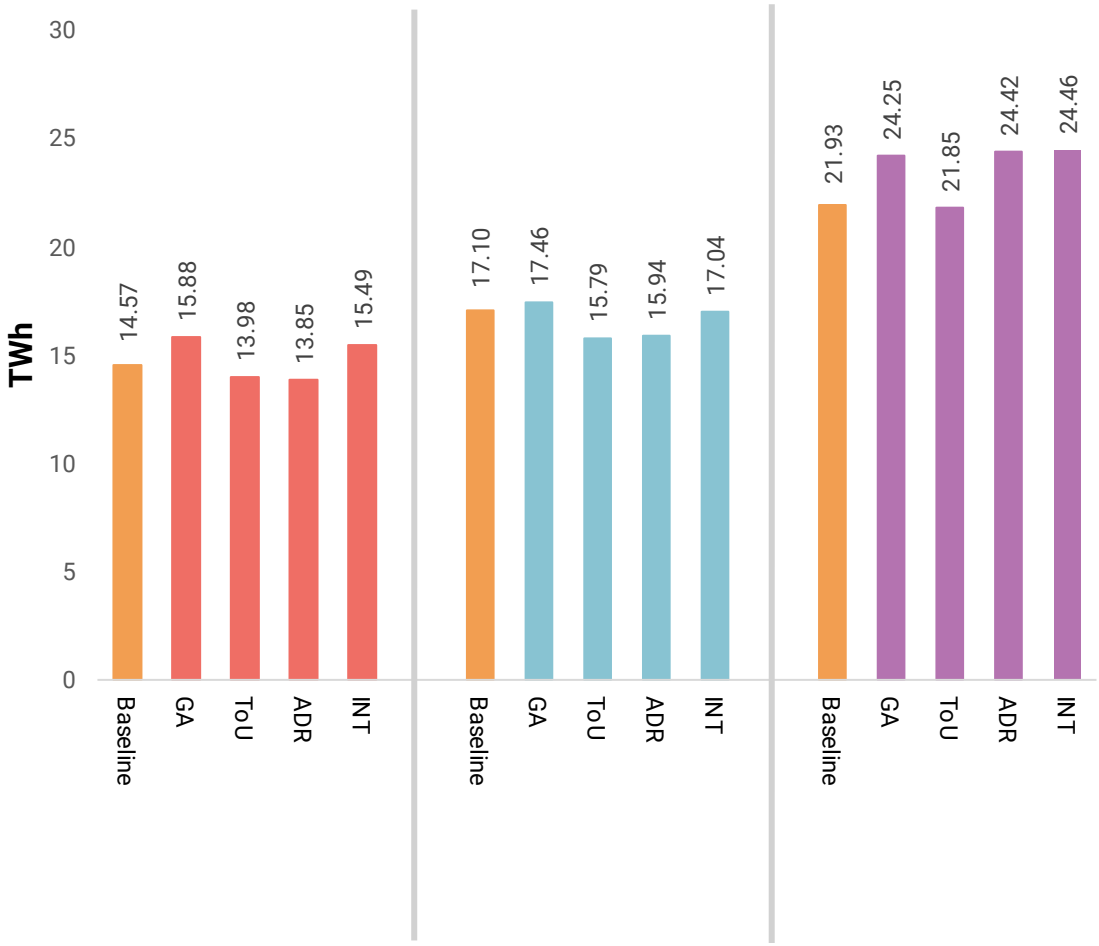
Figure 32 Storage power capacity requirement by scenario (GW)



Energy dispatch from storage follows a similar pattern, but with a wider spread across the flexibility options. In the Unconstrained scenarios, dispatched energy ranges from 13.85 to 15.88 TWh, with the baseline at 14.57 TWh and the Green Ammonia scenario at the upper end. The Constrained Wind scenarios require 15.79 to 17.46 TWh of storage dispatch, approximately 10% more than the Unconstrained variants, largely because the lower wind share provides less smoothing of variable renewable generation. The DER scenarios show the highest levels of storage dispatch, ranging from 21.85 to 24.46 TWh, around 50% higher than in the Unconstrained scenarios.

The flexibility measures have different effects. Time-of-Use tariffs achieve the greatest reduction in energy dispatched from storage across all scenarios, indicating that shifting electricity demand away from peak periods can materially reduce battery use. Green Ammonia consistently increases both storage power requirements and energy dispatch across all scenarios. This may reflect the higher shares of wind and solar generation and the lower dependence on electricity market imports in these pathways.

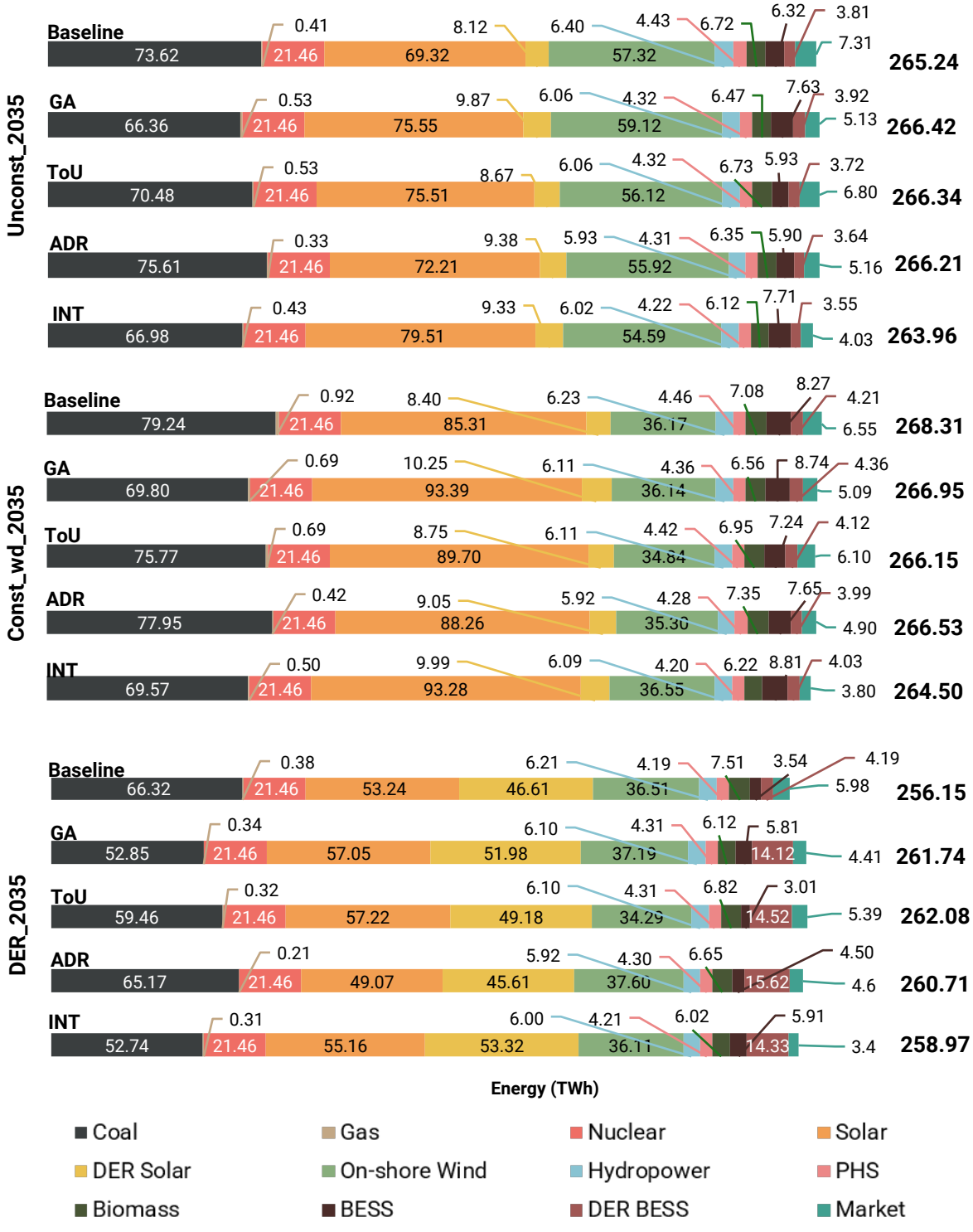
Figure 33 Energy dispatched from storage by scenario (TWh



6.4 Energy share and CO_2 emissions by scenarios

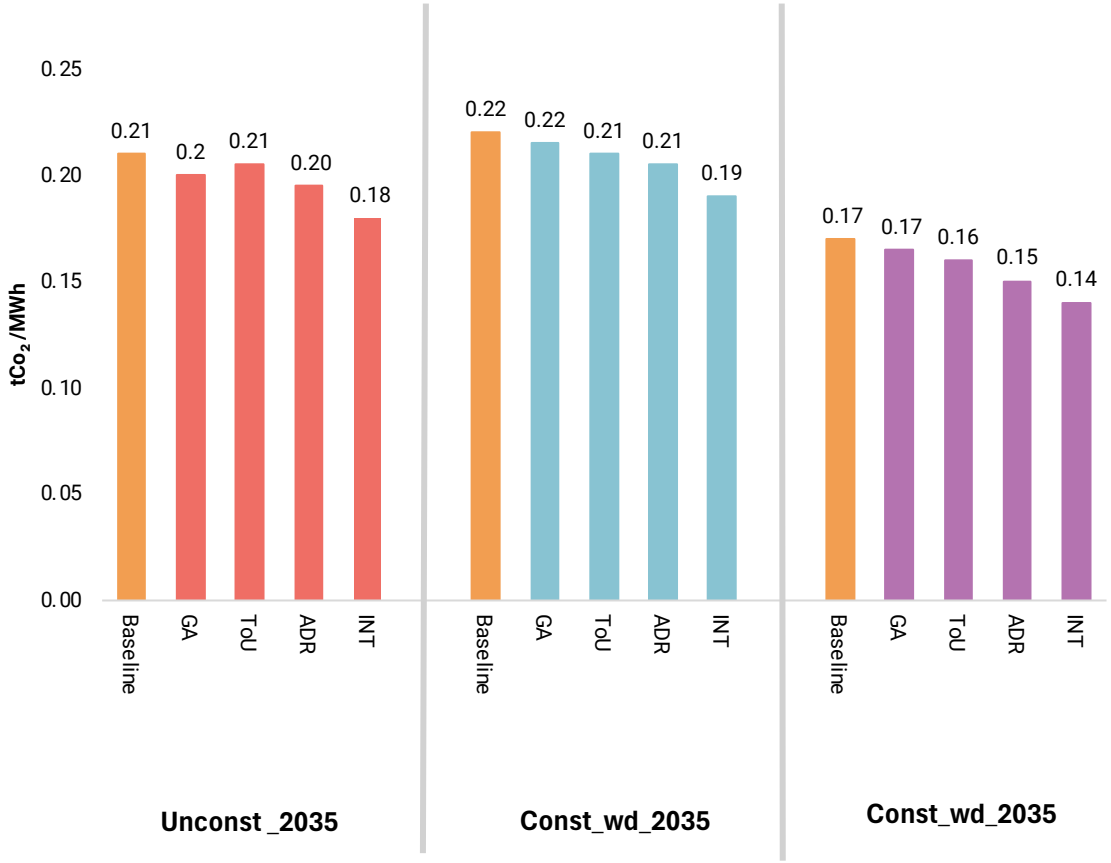
Coal's energy contribution in 2035 varies dramatically from 52.72 TWh (DER INT) to 77.95 TWh (Constrained ADR), depending on renewable pathway and flexibility strategy, revealing which configurations most effectively displace fossil generation. The Constraint scenarios maintain the highest coal dependency. Total system energy demand ranges from 256 to 268 TWh. GA delivers dramatic coal reduction in all scenarios, but particularly so in the DER scenario, where the coal share is reduced from 66.32 TWh in the DER baseline to 52.72 TWh in the DER GA, this represents a 21% reduction.

Figure 34 Energy share by scenario



The emissions range from 0.14 to 0.22 tCO_2/MWh, representing a difference of more than 50% between the lowest emission intensity (DER INT) and the scenario with the highest emission intensity (Const_wd baseline) configurations. All DER scenarios offer the clearest decarbonization pathway, achieving emissions intensities below 0.17 tCO_2/MWh, highlighting the fundamental emissions advantage of distributed solar-heavy systems.

Figure 35 CO_2 emissions by analysis year and scenario

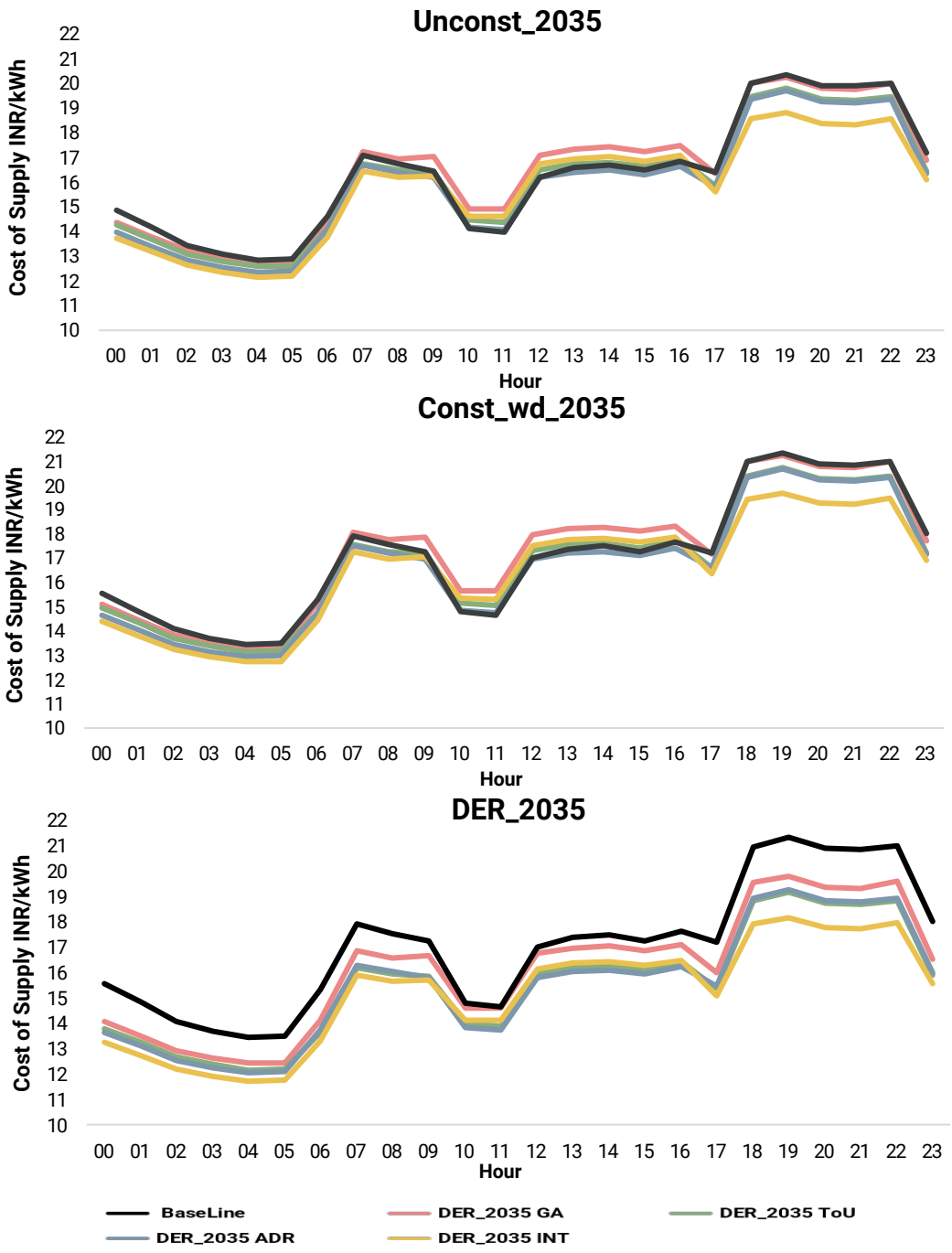


6.5 Cost of supply analysis

Figure 36 compares the average hourly Cost of Supply for the different flexibility pathways across the three base scenarios in 2035. All scenarios exhibit a similar daily pattern, with the lowest costs occurring during the midday period (approximately 10:00–15:00) when solar generation is at its highest. Costs increase during the morning and evening hours as electricity demand rises and solar generation declines, requiring greater reliance on storage and other dispatchable resources.

Across all three scenario families, the implementation of flexibility measures reduces the hourly Cost of Supply compared to the corresponding base case. The ADR and ToU pathways lower costs throughout the day by improving demand flexibility and increasing the utilization of renewable energy, while the GA pathway records slightly higher hourly costs due to the additional electricity demand associated with green ammonia production. The Integrated (INT) pathway consistently achieves the lowest hourly costs and the smoothest daily cost profile by combining multiple flexibility measures. This reduction in hourly cost variation indicates more efficient utilization of renewable resources and storage, while reducing system stress during peak demand periods and improving the overall economic performance of the power system.

Figure 36 Annual average hourly Cost of Supply across flexibility scenarios – 2035



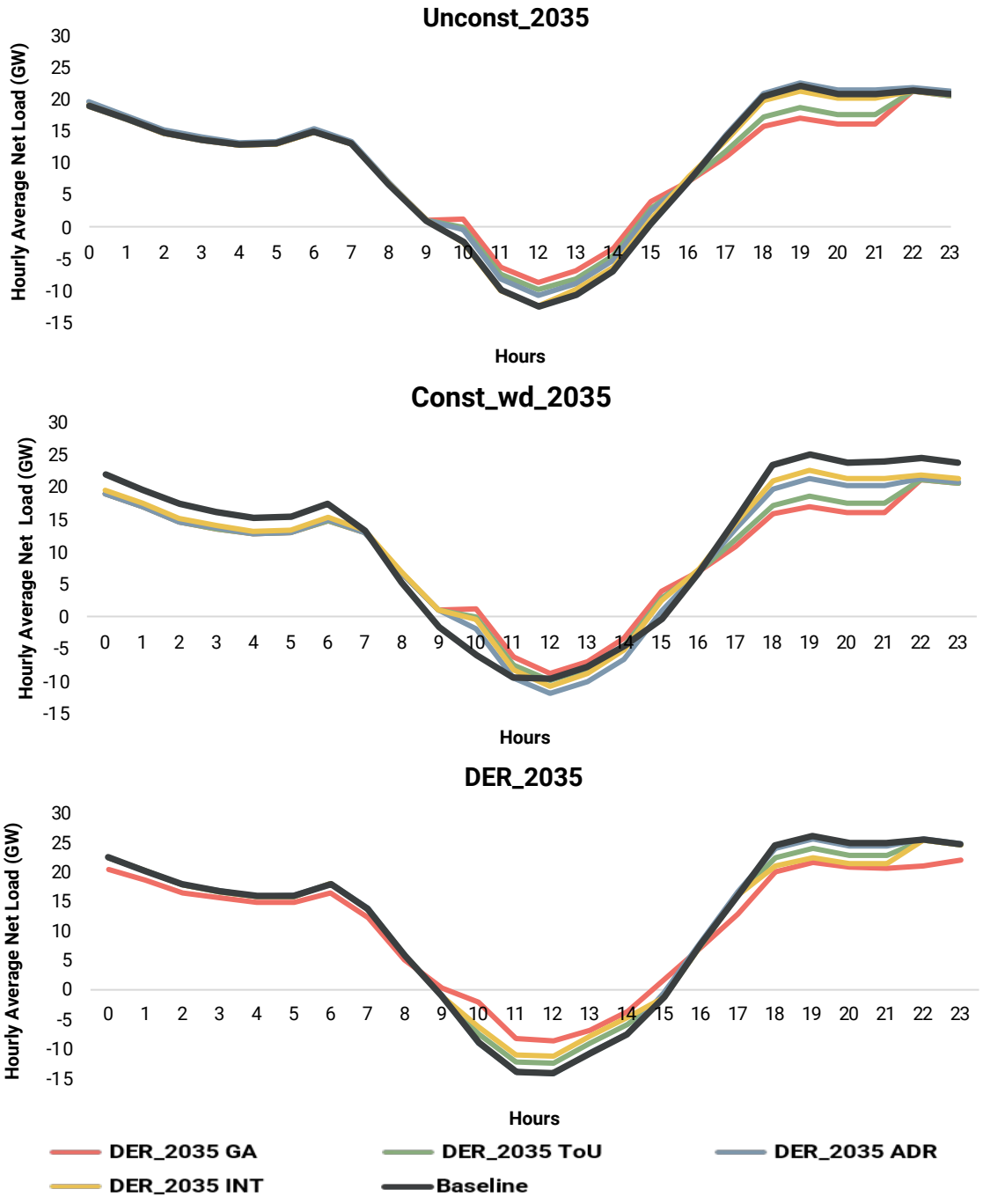
6.6 Net load analysis

Figure 37 compares the annual average hourly net load profiles for the different flexibility pathways under the Unconstrained, Constrained Wind, and DER scenarios. Across all three scenarios, the characteristic duck curve remains evident, with net load decreasing during midday due to high solar generation before increasing rapidly during the late afternoon and evening as solar output declines and demand rises.

The implementation of demand-side flexibility moderates these net load variations by shifting electricity demand towards periods of high renewable generation. Time-of-Use (ToU) tariffs reduce the depth of the midday trough while lowering the evening peak through load shifting. Automated Demand Response (ADR) further smooths the evening ramp by reducing peak-hour demand, resulting in a flatter net load profile. The Green Ammonia (GA) pathway increases daytime electricity consumption through flexible electrolyser operation, helping absorb surplus renewable generation and reducing midday net load curtailment, although its impact on the evening peak is comparatively smaller.

Among the flexibility pathways, the Integrated (INT) approach consistently produces the smoothest net load profile across all three renewable energy scenarios. By combining load shifting, automated demand response, and flexible industrial demand, it effectively reduces both the midday surplus and the steep evening ramp. Overall, these results demonstrate that integrating multiple flexibility measures improves renewable energy utilization, reduces net load variability, and enhances the operational flexibility and reliability of a high-renewable electricity system.

Figure 37 Annual Average Hourly Net Load Profiles under Different Flexibility Scenarios

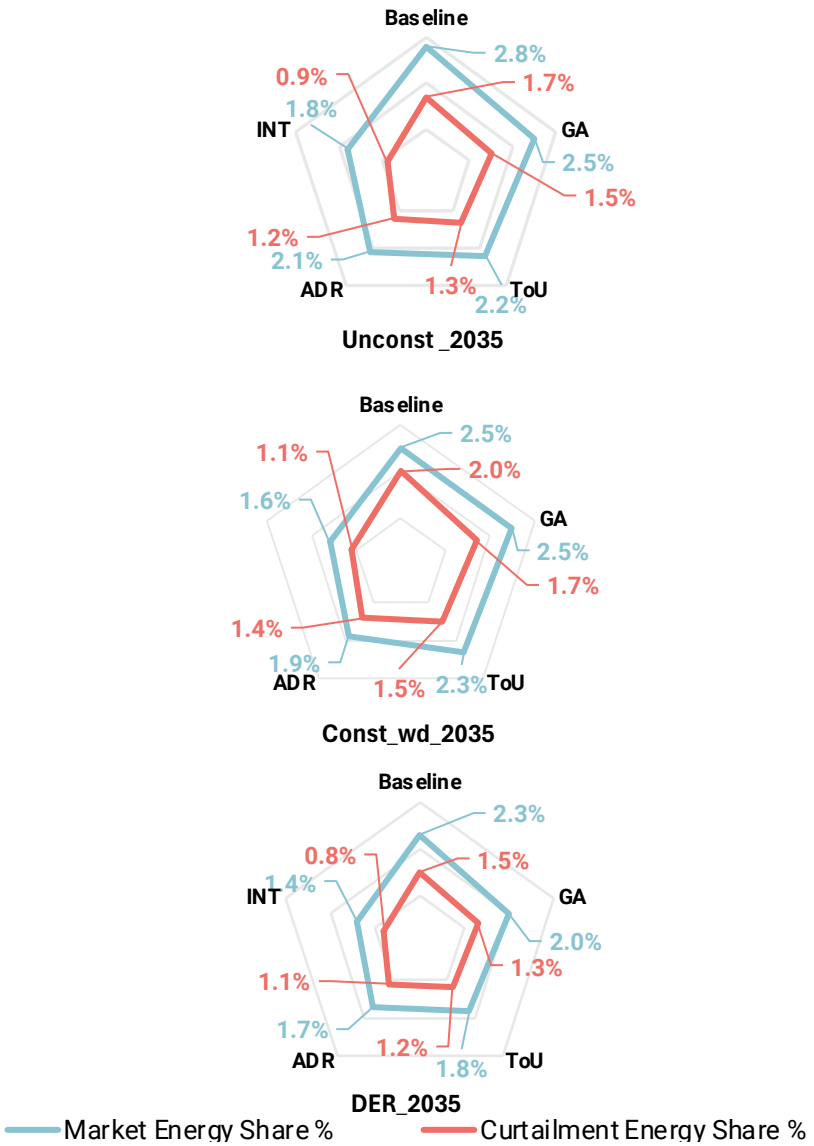


6.7 RE curtailment and market purchase

The radar charts reveal trade-offs between renewable integration efficiency and external grid dependence, measured as percentage shares of total energy. Constrained scenarios curtail up to 3.26% of energy (baseline) while requiring moderate market imports of 1.06-1.41%, reflecting the dual inefficiency of wasting renewable energy while importing external power.

DER scenarios minimize curtailment at 0.68-1.35%, with ToU achieving just 0.68%—the lowest across all configurations. However, market dependence is highest at 1.49-2.30%, with baseline at 2.30%. ToU cuts market purchases by 35% to 1.49%, demonstrating that load-shifting significantly improves DER self-sufficiency. Unconstrained scenarios achieve optimal balance with 1.29-2.29% curtailment and minimal market dependence at 0.61-0.76%. Unconstrained ToU delivers the best overall performance: 1.36% curtailment and 0.61% market purchases, representing near-complete self-sufficiency with minimal renewable waste.

Figure 38 Curtailment and market purchases by scenario



Overall, the demand-side flexibility assessment demonstrates that combining multiple flexibility measures delivers substantially greater system benefits than implementing individual measures in isolation. While Time-of-Use tariffs primarily improve renewable energy utilisation, Automated Demand Response effectively reduces peak demand and ramping requirements. The integrated flexibility package consistently provides the best overall system performance by lowering costs, reducing net load variability, improving renewable integration, and limiting curtailment. These findings highlight the importance of coordinated demand-side flexibility strategies in enabling a reliable and cost-effective transition to a high-renewable electricity system.

07

71.64 GW
Lowest transmission requirement by 2050 under the high DER pathway

3 Nos
Critical transmission corridors identified for 2050 renewable evacuation

82.79 GW
Highest transmission requirement, Unconstrained pathway

TRANSMISSION MODELLING INSIGHTS

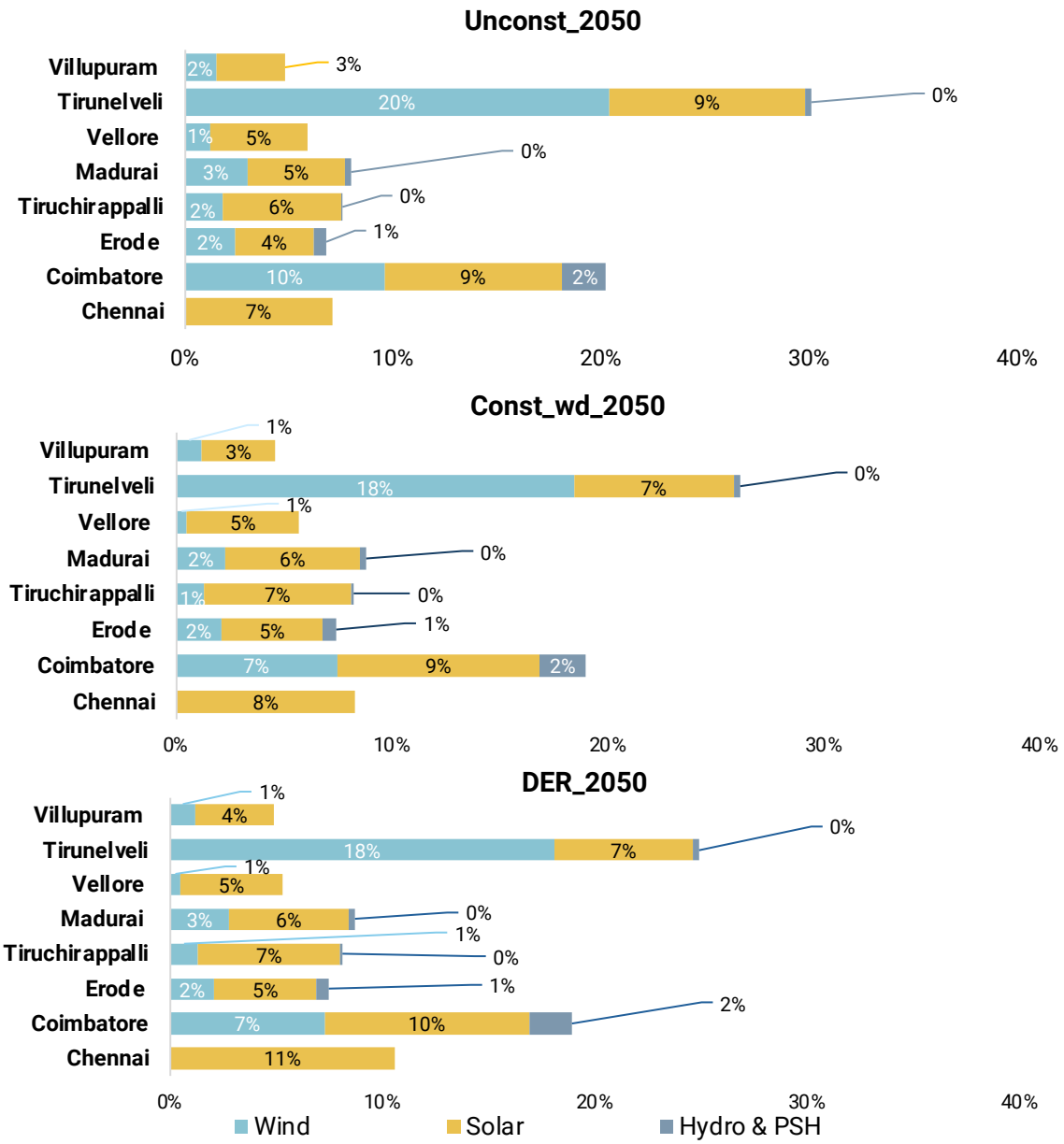
Transition modelling is important because it helps anticipate how future demand growth, renewable energy deployment, storage, and power flows may reshape the transmission system over time. Since transmission infrastructure has a long gestation period, early modelling can inform timely decisions on where capacity expansion, corridor strengthening, and grid flexibility will be required. It also supports more efficient planning by identifying opportunities to site new generation closer to demand centres, reducing avoidable transmission investments, evacuation constraints, and long-distance power transfer requirements.

7.1 Zonal Generation Capacity Distribution

The zonal generation capacity distribution shows where Tamil Nadu's 2050 power system is physically concentrated and which technologies dominate across different zones. Tirunelveli and Coimbatore emerge as major renewable generation hubs, with high concentrations of wind, solar and hydropower capacity. Madurai and Erode show a more diversified renewable portfolio, with contributions from multiple technologies, making them more balanced generation zones rather than single-resource hubs.

This spatial concentration has important planning implications. Southern and western Tamil Nadu is likely to play a central role in renewable power generation, while other zones may depend more heavily on transmission from these resource-rich areas. The distribution therefore highlights the potential need for targeted transmission reinforcement, strategically located storage, and coordinated grid planning to transfer renewable electricity from generation-rich zones to major demand centres.

Figure 39 Zonal Generation Capacity 2050

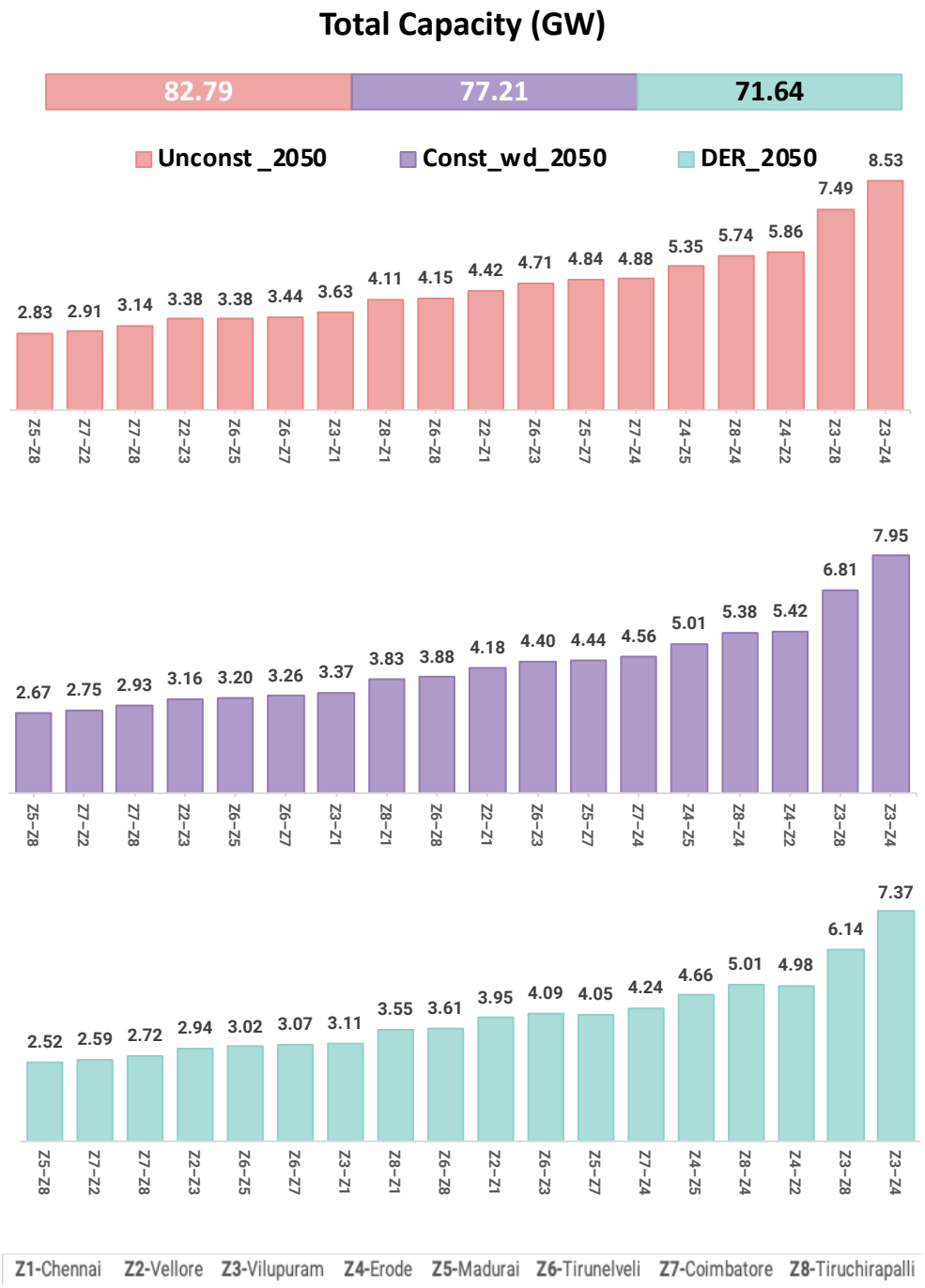


7.2 Inter-zonal Transfer Capacity

This indicator shows the bulk power transfer capability required for each identified transmission corridor between interconnected zones. It supports planning for transmission strengthening renewable evacuation, demand growth, and system balancing. The capacity requirement till 2035 is assumed to be the same and is based on the currently available transmission capacity and announced pipeline projects for transmission strengthening

By 2050, Z8–Z1, Z6–Z8, and Z7–Z8 become the most critical corridors for moving power from renewable-rich zones to demand centres. The unconstrained scenario has the highest total transmission requirement at about 82.79 GW, compared with 77.21 GW in the constrained-wind case and 71.64 GW in the DER case, mainly because higher wind generation is concentrated in one zone and drives stronger bulk power flows. The DER scenario requires the least inter-zonal capacity, as more generation is located closer to demand, highlighting a trade-off between wind-rich pathways that need more transmission and DER-led pathways that need more local balancing and storage.

Figure 40 Estimated transmission capacity requirement by 2050 by corridor and scenario in GW

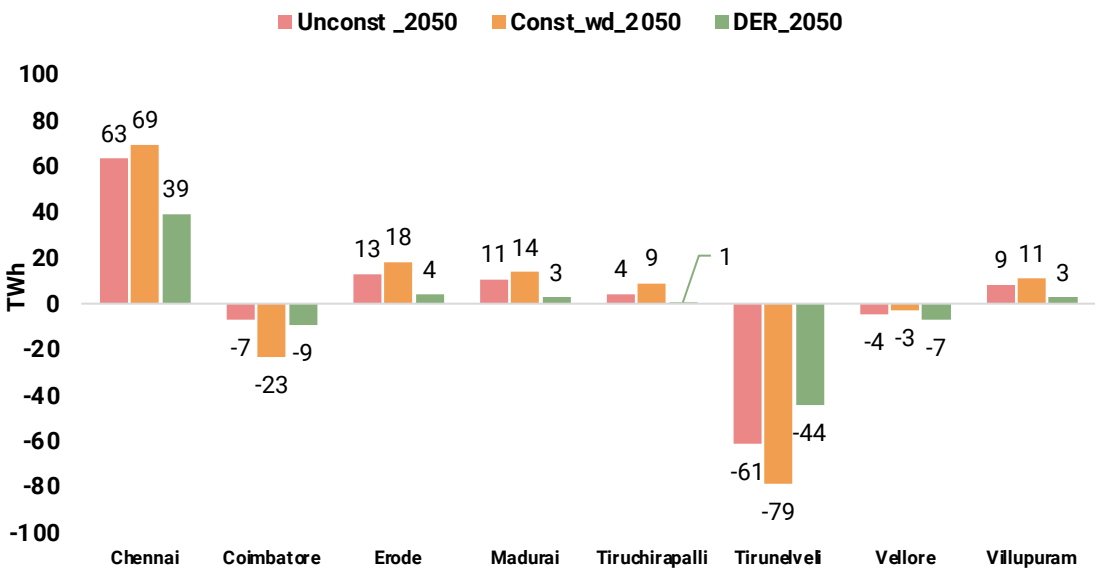


7.3 Zonal Net Energy Flow

Zonal net energy flow shows whether a zone is a net exporter or importer of power. Calculated as exports minus imports, it helps identify surplus generation regions, import-dependent demand centres, and the direction of inter-zonal power transfers.

The 2050 results show Chennai zone as the largest net importer across the scenarios, while Vellore is the largest net exporter, indicating a strong spatial imbalance between generation surplus and demand centres. Erode, Tiruchirappalli, Madurai, and Villupuram are all net energy importers, while Coimbatore and Tirunelveli are net exporters in all three scenarios. The DER scenario generally reduces the scale of both exports and imports, indicating that more distributed generation helps moderate inter-zonal energy transfers.

Figure 41 Zonal Net Energy 2050

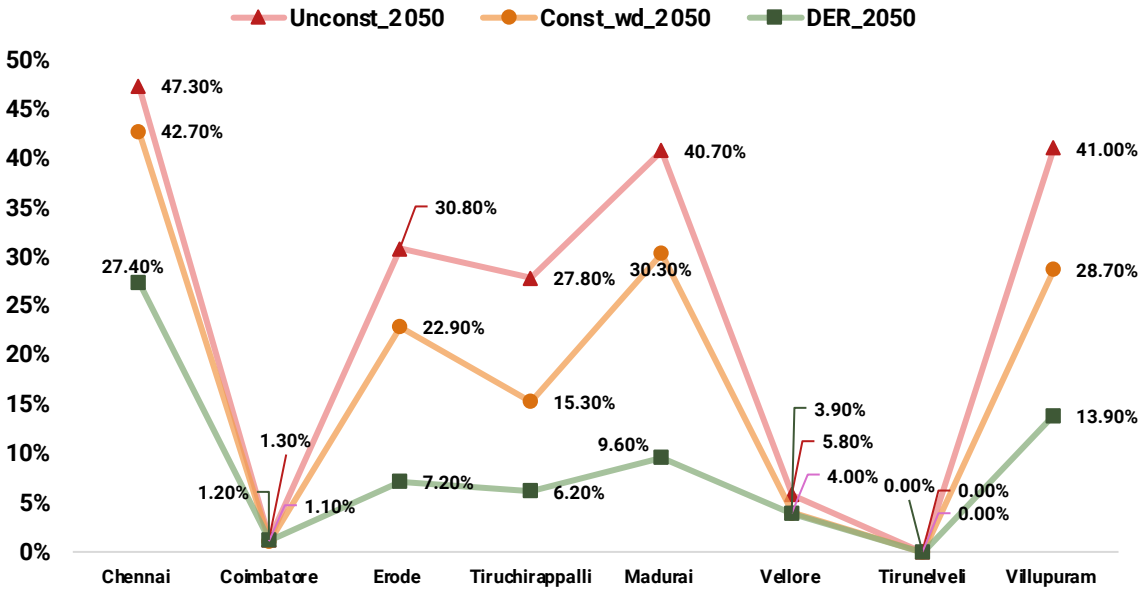


7.4 External Supply Dependence

External supply dependence shows the share of a zone's demand met through external power. Calculated as imports divided by demand, it indicates dependence on transmission support and helps assess the need for local generation or flexibility resources. Unlike net energy flow, which indicates whether a zone is exporting or importing power overall, this indicator measures the degree of import dependence relative to local demand.

The 2050 results show that zones with high external supply dependence require strong transmission support and may benefit from additional local generation, storage, or demand-side flexibility. In contrast, zones such as Tirunelveli and Coimbatore have close to 0% external supply dependence across all scenarios, indicating that local generation is sufficient to meet most of their demand. Lower dependence in the DER scenario further suggests that distributed generation can reduce the need for inter-zonal imports by serving more demand locally.

Figure 42 External supply dependence 2050

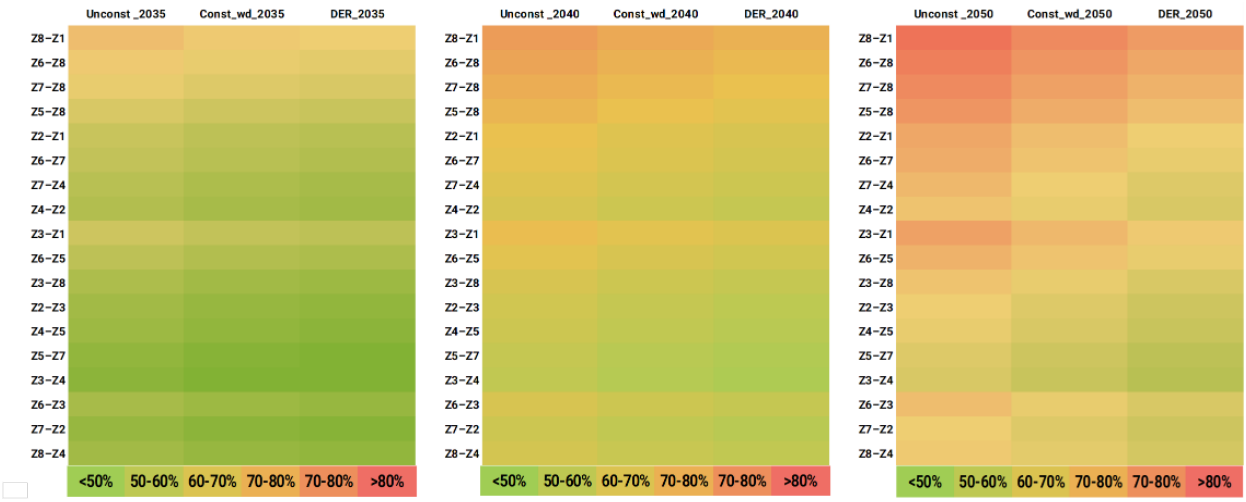


7.5 Transmission Corridor Utilisation

Transmission corridor utilisation shows how intensively available transfer capacity is being used. Calculated as corridor flow divided by transfer capacity, it helps identify heavily loaded corridors, renewable evacuation stress, underused infrastructure, and future reinforcement needs.

The figure shows that corridor utilisation increases significantly from 2035 to 2050 across all scenarios, reflecting growing demand, higher renewable penetration, and larger inter-zonal power transfers. By 2050, several corridors move into higher utilisation bands, especially in the unconstrained and constrained-wind scenarios, suggesting greater dependence on bulk transmission to move renewable power from generation-rich zones to demand centres. The DER scenario appears to show relatively lower utilisation in several corridors, indicating that more distributed generation can reduce pressure on long-distance transmission, although local balancing and storage needs may increase.

Figure 43 Transmission corridor utilization



7.6 Impact of Distributed Energy Resources and Storage

The DER scenarios demonstrate that distributed generation and battery storage can reduce inter-zonal transfer requirements by serving a larger proportion of demand locally and improving local balancing, particularly during daytime solar generation and evening peak periods.

However, the analysis also indicates that distributed resources alone are insufficient to eliminate the need for large-scale backbone transmission infrastructure. Significant inter-zonal transfer capability remains necessary to support renewable balancing, seasonal variability management, and long-distance power exchange across the state.

Table 17 Key: Transmission planning priorities

Area	Planning Implication
Southern RE evacuation	Strengthening of Z6–Z8 and Z7–Z8 corridors required
Chennai demand growth	Additional northward transfer capability needed
High renewable penetration	Greater balancing and operational flexibility required
DER integration	Local balancing improves but does not replace backbone transmission

Overall, the transmission assessment demonstrates that achieving a high-renewable electricity system requires coordinated expansion of both generation and transmission infrastructure. While geographically concentrated renewable resources increase the need for strategic inter-zonal transfer capacity, distributed energy resources and local storage can moderate transmission requirements by reducing long-distance power flows and supporting local demand. The results indicate that future transmission planning should combine targeted corridor reinforcement with distributed flexibility solutions to deliver a reliable, resilient, and cost-effective electricity network for Tamil Nadu.

08

₹0.65/kWh
DER's cost-of-supply saving over the Unconstrained pathway by 2050

21.23 GW
DER's highest maximum ramping event by 2050

77.21 GW
Constrained-Wind's transmission requirement by 2050

Summary & Recommendations

A zero-emission power system in Tamil Nadu is achievable by 2050 under all modelled scenarios, driven by large-scale renewable energy deployment, fossil fuel phase-out, and growing contributions from storage. The results also show that the DER pathway offers the most efficient overall transition, combining the lowest cost of supply with lower transmission requirements, reduced market dependence, and improved renewable integration, though substantial flexibility and network strengthening remain essential in every scenario.

8.1 Generation Transition and Decarbonization

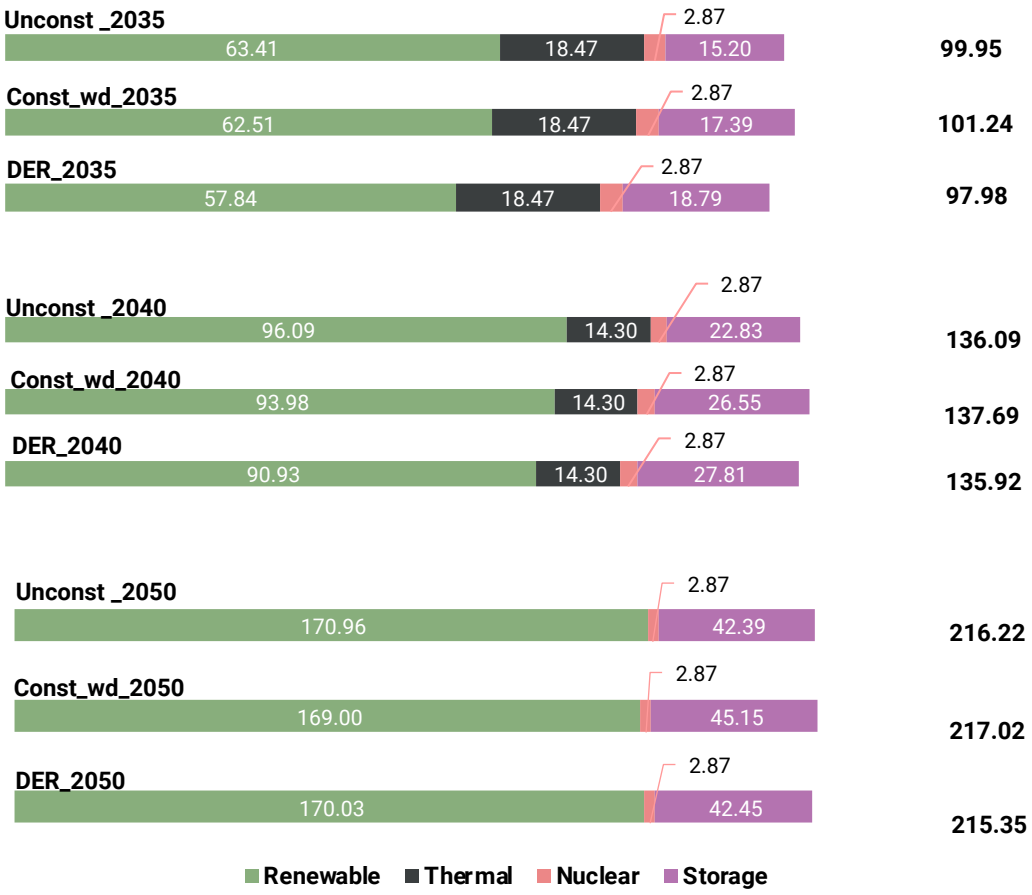
As the ToU tariffs and industrial demand response are added to the Wind Dominant (W_D) base case, total installed capacity falls because flexible, price-responsive loads reduce peak demand and the need for new supply.

Figure 44 shows a substantial expansion in installed generation capacity across all scenarios, from around 100 GW in 2035 to about 215–217 GW in 2050, alongside a marked shift toward a renewables-dominated system. Among the three scenarios, the DER pathway consistently has the lowest total installed capacity, suggesting a comparatively more capacity-efficient system configuration.

The transition away from fossil generation is similar across all scenarios. Coal and gas retirement is driven mainly by plant lifetime assumptions, and any units that remain operational by lifetime criteria but are still present in 2050 are assumed to be retired by the end of the modelling horizon. As a result, thermal capacity falls sharply from 2040 to 2050 in all scenarios, while renewable capacity and storage scale up to replace fossil generation.

Storage plays a critical enabling role in this transition. By 2050, energy storage accounts for roughly 20% of total installed capacity across the scenarios, underlining its importance in supporting a high-renewables system. The storage category includes BESS, DER BESS, and PSH, all of which contribute to system flexibility and reliability; however, the DER scenario shows the lowest storage capacity among the three scenarios in 2050.

Figure 44 Installed generation capacity in GW by generation classes, scenarios and analysis years

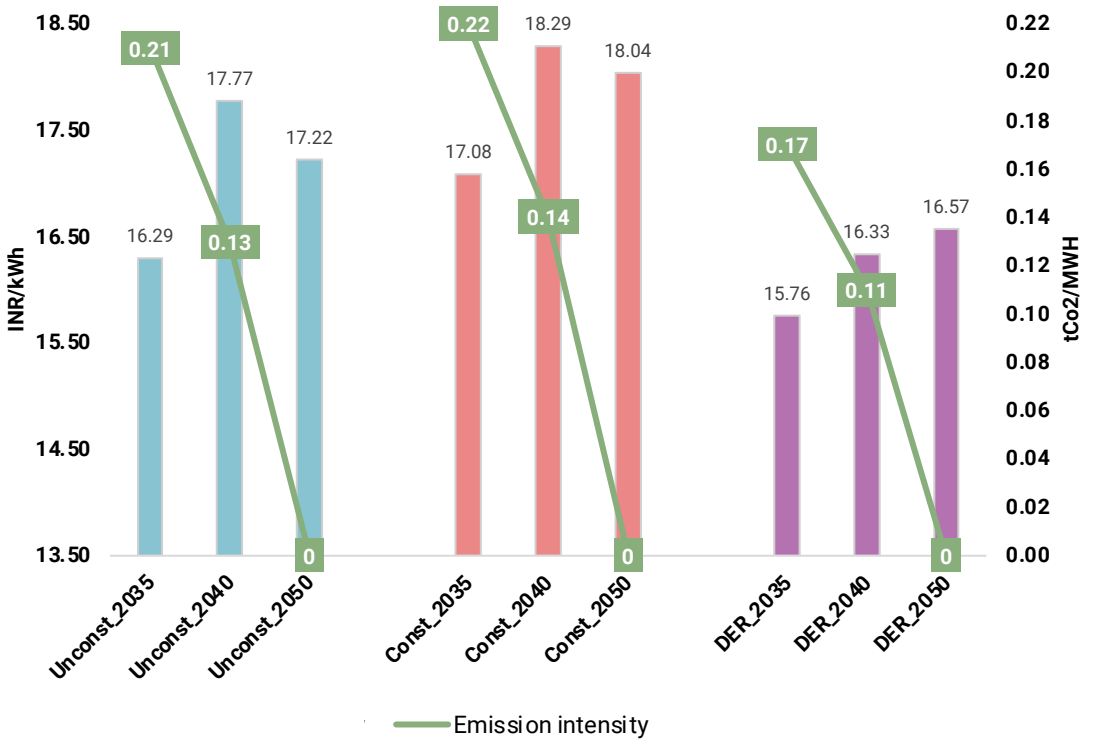


8.2 Decarbonization and Cost of Supply

Cost of supply changes as emissions intensity declines across the 2035, 2040, and 2050 milestones. Across all scenarios, emissions intensity falls steadily and reaches zero by 2050, showing that full power-sector decarbonisation is achievable across the three pathways. However, the cost implications differ: the DER scenario maintains the lowest cost of supply across all years, while the constrained-wind scenario remains the most expensive pathway.

The figure shows that faster decarbonisation does not necessarily require the highest cost pathway. In 2050, all scenarios reach zero emissions intensity, but the DER pathway achieves this at the lowest cost of supply, followed by the unconstrained scenario, while the constrained-wind scenario has the highest cost. For better readability, the chart could be split into one panel for each scenario, showing the change in cost of supply and emissions intensity from 2035 to 2050 within each pathway.

Figure 45 Emission intensity and cost of supply trends

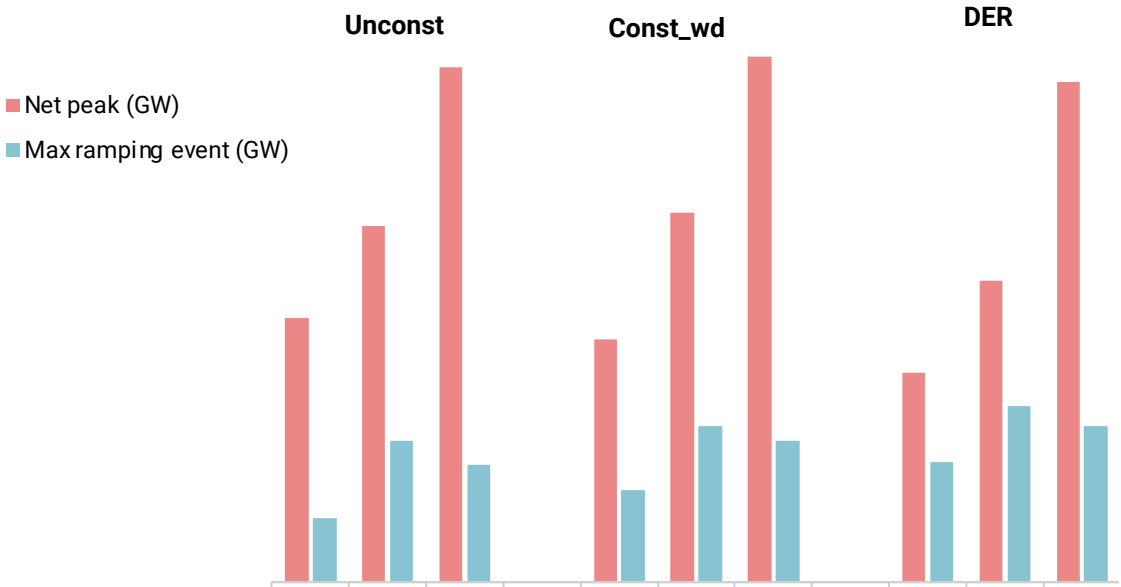


8.3 Net Load and Ramping Requirements

Net-load ramping requirements increase substantially from 2035 to 2050 across all scenarios, reflecting the growing challenge of balancing a power system with higher shares of variable renewable energy. The maximum ramping event rises over time, with the constrained-wind scenario generally showing the highest ramping stress, while the unconstrained wind-rich pathway performs better due to a more diversified renewable generation profile.

By 2050, the DER scenario achieves the lowest net peak demand but still shows high ramping requirements, indicating that distributed solar reduces peak load but creates sharper intraday transitions that must be managed through BESS, DER BESS, demand response, and other flexible resources. This highlights a key planning trade-off: wind-rich systems can moderate ramping but may need more transmission, while DER-heavy systems can reduce peak demand and system cost but require stronger local flexibility.

Figure 46 Net-load ramping instances



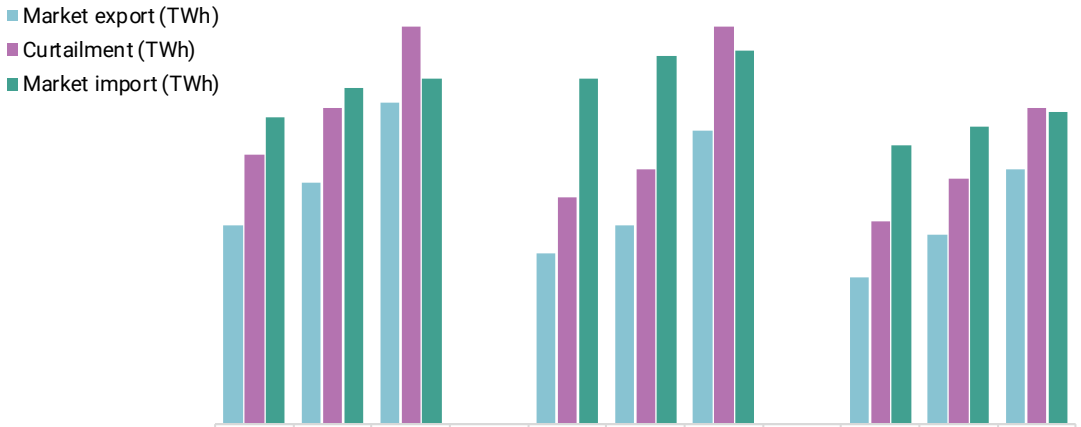
	2035	2040	2050		2035	2040	2050		2035	2040	2050
Net peak (GW)	35.97	48.56	70.22		33.11	50.34	71.73		28.53	41.03	68.12
Max ramping event (GW)	8.61	19.23	16.05		12.5	21.23	19.23		16.38	24.01	21.23

8.4 Renewable Integration and Energy Security

Market imports, exports, and RE curtailment all increase from 2035 to 2050, reflecting a larger and more renewable-heavy power system with greater periods of both surplus generation and residual supply gaps. The constrained-wind scenario shows the highest market imports across all years, rising from 7.3 TWh in 2035 to 7.9 TWh in 2050, indicating greater dependence on external supply when wind availability is limited. It also reaches the highest curtailment level by 2050, at 8.4 TWh, similar to the unconstrained case, suggesting that additional flexibility and transmission will be needed to absorb renewable generation.

The DER scenario performs better on both market dependence and curtailment. It has the lowest market imports in every year, increasing only from 5.9 TWh in 2035 to 6.6 TWh in 2050, and also maintains lower curtailment than the other scenarios, rising from 4.3 TWh to 6.7 TWh. This indicates that distributed solar, DER BESS, and local flexibility help improve renewable self-consumption, reduce reliance on market purchases, and limit renewable energy wastage compared with the more centralised pathways.

Figure 47 Market import, export and RE curtailment



	Unconst_2035	Unconst_2040	Unconst_2050		Const_wd_2035	Const_wd_2040	Const_wd_2050		DER_2035	DER_2040	DER_2050
Market export (TWh)	4.2	5.1	6.8		3.6	4.2	6.2		3.1	4.0	5.4
Curtailment (TWh)	5.7	6.7	8.4		4.8	5.4	8.4		4.3	5.2	6.7
Market import (TWh)	6.5	7.1	7.3		7.3	7.8	7.9		5.9	6.3	6.6

8.5 Transmission Infrastructure Requirements

A strong transmission network remains essential in 2050 to support renewable energy integration, system balancing, and reliable supply across Tamil Nadu's zones. The unconstrained scenario requires the highest total transmission capacity at about 82.79 GW, reflecting its higher dependence on inter-zonal transfers to move wind and renewable power from resource-rich zones to demand centres. The constrained-wind scenario requires a lower but still significant 77.21 GW, while the DER scenario has the lowest requirement at 71.64 GW because more generation is located closer to demand.

The results show that DER improves local self-sufficiency and reduces long-distance power transfer needs, but it does not eliminate the need for inter-zonal transmission. Key corridors connecting renewable-rich zones such as Tirunelveli, Madurai, Coimbatore, and Erode with major demand centres such as Chennai and Vellore will still require timely strengthening. Transmission expansion will be critical to reduce congestion, minimise renewable energy curtailment, improve system reliability, and support Tamil Nadu's Net Zero pathway.

Figure 48 Total transmission capacity requirements by scenario

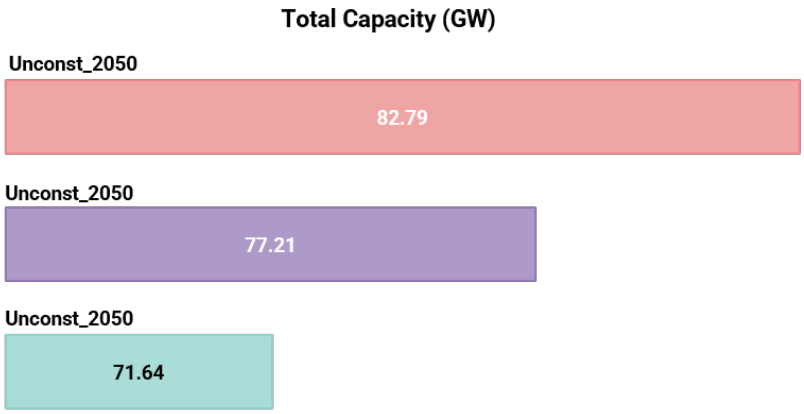


Table 18 Strategic role of each transmission zone in 2050

Zone	Strategic Role in 2050
Z1 (Chennai)	Major demand centre requiring continued transmission support.
Z2 (Vellore)	Renewable-rich export zone supporting neighbouring regions.
Z3 (Villupuram)	Moderately self-sufficient zone with balanced imports and exports.
Z4 (Erode)	Regional support zone contributing to inter-zonal power transfers.
Z5 (Tiruchirappalli)	Balancing and transfer hub with diverse renewable resources.
Z6 (Coimbatore)	Renewable and storage hub supporting system flexibility.
Z7 (Madurai)	Major renewable generation zone with increasing regional significance.
Z8 (Tirunelveli)	Key renewable export hub requiring strong evacuation infrastructure.

8.6 Recommendations

- **Accelerate renewable build-out:** Tamil Nadu should continue scaling solar, onshore wind, offshore wind, and distributed renewables to meet rising demand and replace fossil generation. A diversified renewable portfolio will also improve reliability and reduce dependence on any single resource.
- **Plan coal and gas retirement**: Coal and gas retirement can be planned early and transparently, based on plant lifetime, system value, and net-zero goals. Any fossil units still operating by 2050 should be assumed retired within the state's long-term decarbonization pathway.
- **Scale storage as core infrastructure:** Storage will be essential to balancing a high-renewables system and supporting evening peaks, congestion management, and reliability. Tamil Nadu should deploy a mix of BESS, DER BESS, and PSH, with investment aligned to renewable growth and zonal system needs.
- **Expand transmission proactively**: Transmission expansion should keep pace with renewable energy growth and rising demand in major load centres. Long-term corridor planning will be critical to move power reliably from renewable-rich zones to urban and industrial demand centres.
- **Make demand flexibility a planning resource:** Flexible demand should become a formal part of power system planning. Time-of-use tariffs, industrial demand response, EV charging management, and flexible green hydrogen or ammonia production can help absorb surplus renewable energy and reduce system stress.
- **Use DER strategically:** Distributed energy resources should be deployed where they reduce peak demand, support local reliability, and defer network upgrades. DER should complement, rather than replace, utility-scale renewables and transmission investment
- **Link power planning to industrial policy**: Reliable low-carbon electricity can strengthen Tamil Nadu's position as a hub for green manufacturing. Power sector planning should therefore align with industries such as electric vehicles, batteries, renewable energy equipment, and green hydrogen. Similarly, large new loads such as data centres should be strategically sited in areas with strong grid capacity, good renewable energy access, and low congestion, so they support more efficient power system planning and lower system costs.
- **Strengthen hydro and PSH:** Hydro and pumped storage hydropower were treated conservatively in this modelling, with their role as generators limited relative to their broader potential in a high-renewables system. In practice, both resources can provide significant value through flexible generation, balancing, reserve provision, and longer-duration storage, and they are likely to become increasingly important as renewable energy shares rise. Tamil Nadu may therefore establish dedicated programmes to unlock the full potential of hydro and PSH. These should include resource assessment, project identification, rehabilitation and modernisation of existing assets, streamlined approvals, and market or procurement mechanisms that properly value flexibility, peak support, and long-duration storage services.
- **Strengthen institutions and market design:** The transition will require stronger coordination across planning, regulation, utility operations, and industrial policy. Tamil Nadu should strengthen integrated resource planning, improve data transparency, and develop market and procurement frameworks that better value flexibility, storage, and clean capacity.
- **Strengthen long-term integrated planning:** Generation, transmission, storage, and demand-side flexibility should be planned through an integrated, long-term planning framework rather than independently. Coordinated planning can reduce overall system costs, improve renewable integration, avoid unnecessary network investments, and enhance system reliability.

Overall, the modelling results demonstrate that Tamil Nadu can achieve a reliable, affordable, and fully renewable electricity system by 2050 through coordinated investments in renewable energy, storage, transmission, and demand-side flexibility. While different transition pathways present distinct trade-offs, the results consistently show that integrated planning delivers the most cost-effective outcomes and enhances system resilience. The findings of this study provide an evidence base to support long-term policy development, infrastructure investment, and regulatory decision-making as Tamil Nadu advances towards its net-zero ambition.

09

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ANNEXURES

Appendix 1: Assumptions for Demand Forecasting

Table 19 Key Assumptions of Demand Forecasting

Factor (by 2050)	Low Growth	Moderate Growth	High Growth
Population	Decreases from 2036	Increases from 2036	Increases from 2036
Air Conditioner – Adoption Rate (%)	Rural – 35% Urban – 70%	Rural – 40% Urban – 80%	Rural – 45% Urban – 90%
Air Conditioner – Average number per household	Rural – 1.5 Urban – 1.6	Rural – 1.65 Urban – 1.8	Rural – 1.8 Urban – 2
Electric Cooking – Adoption Rate (%)	Rural – 30% Urban – 60%	Rural – 35% Urban – 70%	Rural – 40% Urban – 80%
EV – 2 Wheeler (2W) share	100%	100%	100%
EV – 3 Wheeler (3W) share	100%	100%	100%
EV – 4W Passenger share	50%	75%	100%
EV – 4W Passenger share	60%	80%	100%
Economy (Growth Rate)	Reduced Historical Compounded Annual Growth Rate (CAGR) by sector (of 2011-2019)	Historical CAGR by sector (of 2011-2019)	Historical CAGR by sector (of 2011-2019)

Appendix 2: Generation Modelling Assumptions

Table 20 Technical and Commercial: Potential for various technologies in Tamil Nadu

Technology type	Technical Potential	Commercial Potential
Onshore Wind	68.75 GW (120 m above ground level)	51.56 GW (75% of technical potential)
Offshore Wind	54 GW (World Bank, 2019) 35 GW (TN Energy Dept Policy Note)	26.25 GW (75% of technical potential as per Government of Tamil Nadu)
Utility-scale solar	150.425 GW (Auroville Consulting, 2025)	150.425 GW (Auroville Consulting, 2025)
DER	129.7 GW (CSTEP, 2025)	129.7 GW (CSTEP, 2025)
Pumped Hydro Storage (PSH)	132,386 GWh (66 GW*) (Auroville Consulting, 2025)	1.9 GW (as per pipeline, for the year 2035) 6 GW (15% of the technical potential, for the years 2040 and 2050)

Table 21 Transmission Costs from TNERC Order, Source: TNERC 2022

Category	FY23	FY24	FY25	FY26	FY27
LTOA Transmission Charges (Rs./MW/day)	5,159.26	5,365.63	5,580.26	5,803.47	6,035.61
STOA Transmission Charges (Rs./MW/Hr),	214.97	223.57	232.51	241.81	251.48

Table 22 Transmission Costs Projections

Category	2030	2035	2040	2050
LTOA Transmission Charges (Rs./MW/day)	6,789.23	8,590.54	10,451.71	16,089.94
STOA Transmission Charges (Rs./MW/Hr),	282.88	357.93	435.48	670.41

Table 23 Per Unit Distribution Costs as per TNERC 2023

Type	FY23	FY24	FY25	FY26	FY27
Total Cost (wheeling/ network charges) (in Rs. crore)	11,849.92	12,807.39	13,883.39	14,586.37	15,019.24
Energy sent (MU)	86,166.30	89,881.56	93,740.11	97,935.53	1,02,341.52
Charges per unit (Rs./ kWh)	1.38	1.42	1.48	1.49	1.47

Table 24 Projections using the CAGR calculated from the previous table

Projections	2030	2035	2040	2050
Charges per unit (Rs./kWh)	1.75	2.3576	3.170	5.73

The table below outlines the key assumptions and calculation steps used to estimate the electrolyser capacity needed to produce green ammonia. It follows industry-standard chemical ratios and energy use benchmarks from recent literature.

Table 25 Assumptions for estimating electrolyzer capacity

Step	Assumption/Formula	Source
Ammonia to Hydrogen Conversion	1 tonne of H_2 produces approximately 5.7 tonnes of NH_2. To find hydrogen needed: H_2 (t/y) = Ammonia (t/y) ÷ 5.7	(C-THRU Brief 2022; Nasry et al. 2023)
Hydrogen to Electricity Requirement	To produce 1 tonne of H_2 via electrolysis requires 39.4 MWh of electricity (LHV basis). Total MWh/year = H_2 (t/y) × 39.4	(Eswaran et al. 2025; C-THRU 2022)
Electrolyzer Output Calculation	With PLF of 30%, 1 MW electrolyzer produces 24×365×0.3 = 2,628 MWh/year.	(Nasry et al. 2023; Eswaran et al. 2025)
Required Electrolyzer Capacity	Capacity (MW) = Total MWh/year ÷ 2,628.	(Nasry et al. 2023; Eswaran et al. 2025)

This approach ensures all ammonia demand estimates are grounded in fundamental process chemistry and current electrolyser technology benchmarks, making the results robust and transparent.

Appendix 3: RTS Installed Capacities

Table 26 RTS Projections

Parameters	2024-25	2035	2040	2050
RPO (%) of energy demand	1.5%	5.25%	6%	8%
Energy Demand Moderate Growth Scenario (TWh)		233.4	317	506.8
Distributed Solar Capacity (GW)		7.36	11.43	24.36
Distributed Battery Energy Storage (GW)		7.36	11.43	24.36
Distributed Battery Energy Storage (GWh)		14.72	22.86	48.72

Appendix 4: Constraints for the Capacity Expansion Model and Production Cost Models

The following are the mathematical equations and constraints that have been followed for the integrated capacity expansion and economic dispatch model.

Table 27 Mathematical equations and constraints

No.	Constraint/Equation Name	Formula	Notes
1	Installed Capacity Constraint	$\sum$ Installed Capacity $\geq$ (1 + Operating Margin) × Peak Demand	Operating Margin (α) typically assumed as 10%
2	Demand Balance Constraint	$\sum P_{g,t} + \sum P_{st,dis} - \sum P_{st,ch} = D_t, \forall t$	Generation and storage discharge meet the demand
3	Generator Capacity Constraint	$0 \leq P_{g,t} \leq P_{g,max}, \forall g, t$	Generator output limits
4	SOC Update Equation	$SOC_{s,t} = SOC_{s,t-1} + \eta_{s,ch} \cdot P_{st,ch} \cdot \Delta t - (P_{st,dis} \cdot \Delta t / \eta_{s,dis}), \forall s, t$	Storage state of charge (SOC) update
5	SOC Limits	$SOC_{s,min} \leq SOC_{s,t} \leq SOC_{s,max}, \forall s, t$	SOC must be within min and max limits
6	Storage Charging Limit	$0 \leq P_{st,ch} \leq P_{st,ch,max}, \forall s, t$	Charging power limit for storage
7	Storage Discharging Limit	$0 \leq P_{st,dis} \leq P_{st,dis,max}, \forall s, t$	Discharging power limit for storage
8	Objective Function – Cost Minimization	$\sum Cg \cdot P_{g,t} \cdot T + \sum C_{s,storage} \cdot (P_{st,ch} + P_{st,dis})$	Minimize generation and storage cost
9	Operating Margin / Reserve Margin Constraint	$\sum P_{g,nom} \geq (1 + \alpha) \cdot$ Peak Demand	α is assumed to be 10%
10	Plant Load Factor (PLF) Calculation	$PLF_g = (\sum_t P_{g,t}) / (P_{g,nom} \cdot T) \cdot 100$	Measures the utilization of generator capacity
11	Power Output of Generator	$P_{g,t}$ = power output of generator g at time t	Description of variable
12	Rated Capacity of Generator	$P_{g,nom}$ = rated capacity of generator g	Description of variable

Adopted from pyPSA documentation

Assumptions:

- Economic dispatch includes generation ramping limits, minimum up/down times, and efficiency losses.
- Fixed Cost assumptions for coal and gas have been taken from JERC tariff orders and assumed to be escalating by 2% every year.
- Variable cost prices for coal-based generators have been assumed from JERC tariff orders.
- Plant retirements have been considered based on lifetime and based on overall system cost. Technical lifetime for plants has been taken from ICED portal.
- RE fleet and nuclear are assumed to be a must run generators, which implies there is no marginal cost of generation.
- Storage systems are charged at 50% of the average generational cost and 15% of the average generational cost.
- Load shedding costs have been assumed to be the top 1% of the day-ahead market
- Curtailment cost has been assumed to be Rs 15,000/MWh

Table 28 Technical Assumptions for Conventional Generators

Technology	Ramping (%/ min)	Minimum Operational condition (%)	Maximum Operational Condition (%)	Hot Start up time	Warm Start up time	Cold Start up time
Coal	1	40%	90%	2	5	10
Nuclear	Const. Load	50%	100%	-	-	-
Gas	5	40%	95%	1.5	2	3

Data Adopted from: CEA Technology Catalogue [2022]

