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Energy Transition: The Consequences of Variable Renewable Energy

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Executive Summary

Scaling renewables without strengthening the grid carries real costs

The global energy system is entering a decisive phase. Over the last two decades, renewable energy has moved from the margins to the centre of power generation, driven by falling costs, policy momentum, and the imperative to decarbonise. Solar and wind now represent the fastest-growing sources of new capacity worldwide, and in many markets, they are the most economical option for incremental generation. This progress marks a significant achievement. Yet it also exposes a deeper challenge: power systems lack the readiness necessary to reliably absorb and manage renewables.

The defining constraint in the next phase of the energy transition is no longer generation capacity. It is system resilience.

Renewable electricity differs fundamentally from conventional power. It is variable, geographically dispersed, and predominantly inverter-based. These characteristics alter how grids behave, how stability is maintained, and how supply and demand are balanced. As renewable penetration increases, responsibilities once embedded within generation assets shift toward transmission networks, distribution systems, storage, and digital control layers. The grid moves from a unidirectional delivery mechanism into a complex, multi-nodal system that must actively manage power, information, and risk.

Recent grid disruptions offer a clear warning. The Texas blackout of 2021 and the Iberian outage of 2024 illustrate how extreme weather, low inertia, limited interconnection, and insufficient flexibility can trigger cascading failures across highly stressed systems.

While the contexts differ, the underlying lesson is consistent: rapid renewable deployment without commensurate investment in grid strength, forecasting, storage, and operational readiness increases both economic and social risk.

India now stands at a similar inflection point. Ambitious renewable targets, particularly in solar-rich states such as Rajasthan and Gujarat, have accelerated capacity additions. However, evacuation constraints, transmission bottlenecks, and distribution-level fragilities are already leading to curtailment, inefficiencies, and rising system costs. The challenge is compounded by the financial health of distribution companies, which remain central to demand-side resilience and reform.

This report argues that comparing renewable energy with conventional power solely on generation cost misses the full picture. Renewables reduce fuel costs and emissions at the generation end. However, they demand sustained investment across the rest of the system. Transmission, distribution, storage, digital monitoring, and institutional reform all play critical roles in maintaining reliability.

The energy transition will succeed not by adding more renewable capacity alone, but by building systems that can operate securely under higher variability. The coming decade will test how effectively policy, investment, and execution align to deliver resilience alongside decarbonisation.

Introduction

Renewable energy (RE) has developed rapidly in the last decades from niche technologies to being the core of modern power systems. Envisaged originally to minimize the ecological impacts of energy generation and use, they now represent the fastest growing and, in some geographies, the lowest cost generator of energy ever conceived. At the beginning of 2000, total global renewable installed capacity was roughly 720 GW (about 640 GW large hydro and ~80 GW non-hydro renewables) generating roughly 3,200 TWh annually (≈2,900 TWh hydro, ≈300 TWh non-hydro).

Since large scale deployment began, approximately 2,100 GW of additional renewable capacity has been commissioned globally[1], with about 900 GW added between 2010 and 2020 and roughly 300 GW installed in the past five years[2].

Today, global renewable installed capacity is roughly 2,820 GW (≈1,200–1,300 GW large hydro and ≈1,520–1,620 GW non hydro including wind, solar PV, bioenergy, geothermal and small hydro), producing approximately 7,000–7,500 TWh annually (≈3,300–3,500 TWh hydro, ≈3,700–4,000 TWh non-hydro)[3]. From about 40GW around 2010, global solar capacity grew rapidly to about 750+GW by 2020. The growth from 2021 to 24 was even more rapid, growing to 1 TW in 2022 and doubling by 2024. The first TW had taken ~70 years, while the next had taken two, attesting to the growing role of Solar PV. The rapid growth of Solar then allowed solar generated electricity to rise to about 7% of total electricity generation, doubling in just about three years[4]. Ambitious pipelines aim to add several hundred more gigawatts by 2030 as countries pursue climate targets and rising electricity demand, making renewables the principal route to decarbonize power sectors worldwide[5].

This capacity expansion has required an enormous capital deployment. Over the last decade, global capex on generation and associated infrastructure exceeded US$1.5 trillion.

Investment trends increasingly favour renewables, batteries, and grid flexibility over new coal-fired plants; economics, emissions policy, and retirements are shifting coal from baseload toward peaking or managed decline roles in many markets. At the same time, natural gas plays a transitional role—serving as a flexible, lower-carbon dispatchable backup to balance variable renewables, support system reliability during ramps, and provide firming capacity while storage scales—so many investment plans still include gas-fired assets (often designed for fast cycling or co-firing with hydrogen) alongside accelerated deployment of storage and demand-side flexibility. Nuclear power also remains part of the low-carbon mix in many countries: existing reactors provide steady baseload, several markets are investing in life-extensions and new builds (including small modular reactors) to deliver firm, zero-emission capacity, though high upfront costs and long lead times constrain rapid global expansion.

Transmission and distribution build out is central to integrating these distributed and variable generation resources. Large scale renewables are often located far from load centres, requiring high voltage corridors, long transmission lines, expanded substation and transformer capacity, and grid automation to reduce curtailment and enable cross regional balancing. Globally, utilities and governments have added tens of thousands of kilometres of lines, upgraded transformers, and invested heavily in SCADA, protection systems, and smart meter rollouts. At the distribution level, feeder segregation, transformer retrofits, and advanced metering are necessary to host distributed PV, enable demand response, and reduce technical and commercial losses.

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[1] https://www.irena.org/Publications/2024/Apr/Renewable-Capacity-Statistics-2024
[2] https://www.iea.org/reports/renewables-2024 and https://www.iea.org/reports/renewables-2023
[3] https://www.ren21.net/reports/global-status-report/
[4] https://www.irena.org/Statistics and https://www.iea.org/data-and-statistics
[5] https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html

Yet integrating high shares of wind and solar brings operational challenges that are not purely technical but also institutional. Winter Storm Uri in Texas (2021) illustrated risks from extreme weather and system design: widespread generation losses across wind, gas, coal, and nuclear—combined with inadequate winterization, market design gaps, and limited interconnections—led to prolonged blackouts and huge social costs. In Spain, rapid renewable growth produced localized overvoltage, line overloads, and curtailment, revealing constraints in transmission capacity, reactive power management, forecasting, and market mechanisms to absorb excess generation.

> These cases highlight that generation expansion must be matched by resilient infrastructure, improved forecasting, responsive markets, and storage to ensure reliability.

India is also facing grid constraints and evacuation challenges, which are in turn limiting RE integration into the grid. Right-of-way (RoW) issues have placed further constraints on grid build-out with circuit kilometre (ckm) additions falling behind targets.

Energy storage is a linchpin for decarbonized grids. At the start of 2000, global non hydro storage deployments were negligible compared with today; since then, lithium ion batteries have seen steep cost declines (70–80% in a decade), supporting deployments for frequency response, peak shaving, and intra day shifting; pumped hydro remains the cheapest large scale option where feasible. For seasonal and long duration needs, emerging technologies—flow batteries, compressed air, and hydrogen—will be important. Systems increasingly procure renewables together with storage (hybrids) and value flexibility explicitly through ancillary markets and capacity mechanisms.

In this deep dive, we revisit the energy transition with a focus on India. Considering the scope of the energy transition, and the virtue of brevity, we will cover the consequences of rapid RE integration in this article, which will also lay the ground for subsequent articles. These will address grid resilience including battery and connectivity, and looking to India, the Distribution Company (DISCOM) dilemma.

How is renewable electricity different?

Ostensibly, both RE and conventional generators produce electricity, but the former is flow based, while the latter is based on extraction of electricity from a reservoir[6]. The physics of flow based RE electricity versus reservoir based conventional generation then leads to impacts on infrastructure planning such as storage, grids, and financial differences between the two modalities of electricity generation as illustrated in Exhibit 1.

Conventional energy focuses on securing the reservoirs of energy, namely the fuel. Therefore, in a conventional generation system, significant emphasis is laid on the generation assets. Further, due to the readily available nature of energy from conventional generators and tight control on supply quality in terms of voltage, current and frequency, the role of transmission and distribution (T&D) is merely to fulfil demand by moving electricity from the generators to the consumers.

Since fuel can be moved (more or less) easily to the generation location, it is advantageous to locate conventional energy generation close to sites of demand. The energy generated by conventional sources is an Alternating Current (AC) at high voltage, with the rotating machinery providing inertia and frequency control. All sources inject the required current (functioning as current sources) based on a reference value of frequency and voltage on the grid, set by the rotating generators such as steam turbines. Therefore, a conventional energy electric system is a hierarchical, unidirectional system with the generator at the top and the paying consumer at the bottom (Exhibit 1).

In contrast renewable energy is diffuse (lower plant load factor (PLF)), intermittent and variable.The generation is also typically direct current (DC), which must then be converted to AC by inverters and stepped up. Therefore, RE penetration requires teaming generation assets with electrical conditioning equipment such as inverters and transformers.

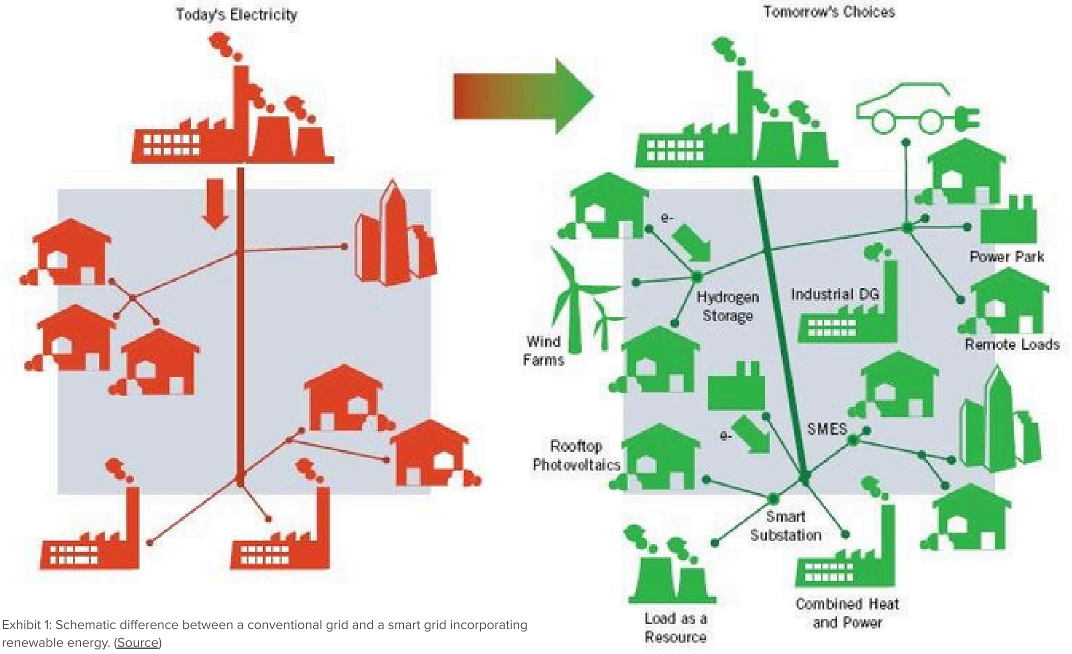

Exhibit 1: Schematic difference between a conventional grid and a smart grid incorporating renewable energy. (Source)

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[6] For this article, the reservoir of energy is the fuel, which typically are hydrocarbons (or nuclear fuels). When these are broken down in combustion (or nuclear fission) heat is produced, which in turn is converted into electricity by boiling water and using the resultant steam to run turbines. In contrast, RE sources generate electricity directly, which flows to the grid.

The displacement of rotating generation machinery by inverter driven systems challenges grid inertia and stability, which must be compensated by the inverters. In such a case, the inverter cannot follow the grid for reference voltage or frequency values and act as current sources as previously described. The inverters in an RE system act as voltage sources and can form micro-grids providing grid stability, becoming building blocks to the grid (grid formers) rather than being gateways for energy to enter the grid (grid followers).

The generation centres are also located in favourable regions (high solar or wind availability), which may be far from centres of demand. The variability, and the long distances then place an increased demand for transmission infrastructure, and other measures of grid resilience. The T&D infrastructure therefore becomes an integral part of the energy transition, to enable seamless distribution of electricity. Further, an RE dominated grid is inherently a two-way system where the consumers may also produce power (‘prosumers’).

> Since most of the generated power enters the grid by inverters, grid inertia,voltage and frequency regulation responsibility, previously a major obligation of the generator, also shifts to the grid.

An examination of Exhibit 1 shows that an energy system incorporating significant RE has a larger number of nodes, requires greater control and monitoring, which in turn necessitates secure communication flows of higher density than previously needed.

Smart Grid Conceptual Model

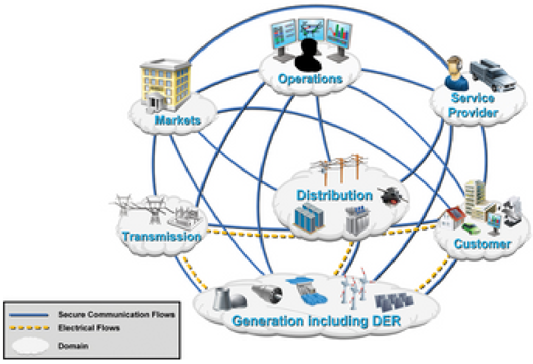


Exhibit 2: A conceptual model of an energy system with smart grid
Source: NIST Smart Grid Framework 4.0

A schematic model of a smart grid is presented in Exhibit 2 showing that the new energy system requires optimization and coordination between energy assets, service providers, consumers and regulators.

Therefore, instead of sitting at the top of a unidirectional hierarchy stretching down from generator to consumer with the T&D as an intermediary, incorporation of RE turns the generation assets into the first among equals, *primus inter pares*, in a conglomerated energy system.

> The effect of RE addition reduces fuel cost and improves predictability in generation but requires substantial effort and spending on strengthening the rest of the parts of Exhibit 2 for adequate resilience including T&D and storage.

The capex spends on previously impoverished parts of the energy system assumes even greater importance in the context of synchronising supply and demand. While this was previously managed largely at the supply side by ramping energy generation up or down as needed, the relatively inflexible generation profiles of RE assets emphasize demand side management, sometimes even at the consumers’ site, to ensure grid stability.

Finally, the flow of energy must also be supported by a suitable flow of information through secure communication channels (Exhibit 2) and must be adequately protected by physical and cybersecurity.

> Therefore, RE based energy systems can create substantial savings at the generation end but require substantial infrastructure upgrades in T&D to ensure reliable and dependable energy provision to consumers.

It follows consequently that comparing RE with conventional energy on a purely levelized cost of electricity (LCOE) basis is erroneous. A summary of key differences between conventional and RE is collated in Table 1 for ready reference.

Table 1: A comparison between conventional and RE energy. CAPEX costs are for utility scale indicative 2023-24

Aspect	Conventional Electricity (Fossil & Nuclear)	Renewable Electricity (Solar, Wind, Hydro, etc.)
Main energy sources	Coal, oil, natural gas, nuclear	Solar, wind, hydro, geothermal, biomass
Resource type	Non-renewable (finite fuels & uranium)	Renewable (naturally replenished flows)
Greenhouse gas emissions	High (especially coal & oil) over life cycle	Very low in operation; some life-cycle emissions
Air pollutants	SO_2, NOx, particulates, mercury, etc.	Minimal; some from biomass combustion if used
Climate impact	Major contributor to global warming	Key mitigation option; near-zero operational CO_2
Typical generation role	Baseload/mid-merit/peaking (esp. gas)	Variable (solar/wind); dispatchable (hydro, geothermal, biomass)
Infrastructure maturity	Very mature, long-established	Rapidly growing, integration/stability solutions improving
CAPEX – India, utility-scale (₹/MW)	• Supercritical coal: ₹70–80 crore/MW • Gas CCGT: ₹40–50 crore/MW • Nuclear: ₹150–200 crore/MW	• Solar PV: ₹30–40 crore/MW • Onshore wind: ₹50–60 crore/MW • Large hydro: ₹80–100 crore/MW
Fixed OPEX excl. fuel – India (₹ lakh/MW-yr)	• Coal: 25–35 • Gas CCGT: 10–15 • Nuclear: 40–60	• Solar PV: 6–8 • Onshore wind: 10–15 • Large hydro: 20–30
Fixed OPEX as % of CAPEX (approx.)	• Coal: 4–5%/yr • Gas CCGT: 2–3%/yr • Nuclear: 3–4%/yr	• Solar PV: 1.5–2%/yr • Onshore wind: 2–3%/yr • Large hydro: 2.5–3.5%/yr
Variable O&M excl. fuel – India (₹/kWh)	Coal & gas: 0.20–0.50	• Solar & wind: 0–0.05 (often bundled in tariff) • Hydro: 0.10–0.30 (project-specific)
Fuel cost – India (₹/kWh)	• Coal: 1.5–3.0 • Gas: 3–6+ • Nuclear: 0.5–1.0	• Solar/wind/hydro: ~0 fuel cost • Biomass (if used): 1.0–2.5
Cost volatility	High (fuel & carbon-price exposure)	Low fuel-price risk; main risk is policy/financing
LCOE trend (new build)	New coal/nuclear often relatively high; gas depends on fuel prices; old, depreciated plants cheaper to run	Strongly falling; solar & wind often lowest-cost new capacity in India
Project risk profile	Construction, regulatory, fuel and carbon-policy risk	Upfront financing and policy risk; lower operating risk
Revenue model	Energy sales, capacity payments; often baseload or mid-merit	Energy sales via auctions/PPAs; some capacity/ancillary services
Grid integration cost	Historically core of system; fewer flexibility needs	Needs flexibility (storage, demand response, interconnections)
External costs	High: climate, air pollution, health, mining & waste	Much lower per kWh; some land-use, materials, ecological impacts
Lifetime & decommissioning	Long life; coal ash & nuclear waste costly; decommissioning expensive	PV/wind 20–30 yrs; hydro 50–100+ yrs; decommissioning & recycling lower per kWh overall
Water use	High for thermal/nuclear cooling	Very low for PV/wind; hydro depends on hydrology but not for cooling
Typical plant examples	Coal-fired station, gas CCGT, nuclear plant	Utility-scale solar farm, onshore/offshore wind farm, large hydro

Based on the above, a rough comparison of RE integration costs is presented in Table 2.

Table 2: Typical grid integration costs of conventional and variable RE

Aspect	Conventional (thermal / hydro)	Renewable (wind / solar)	Typical incremental cost (INR/kWh)	Notes
Definition	Dispatchable, predictable generation; integration needs mainly scheduling and backup for outages	Variable, uncertain output; needs forecasting, balancing, flexibility	Conventional: ~0–0.05	Incremental costs beyond generation LCOE
Forecasting / uncertainty	Low forecasting error, minimal extra cost	Higher forecast error → additional intra-day balancing and reserves	RE: ~0.5–3.0	Wider range at high instantaneous penetration
Reserves & balancing	Routine reserves; marginal cost small	More frequent use of reserves; higher procurement cost	Conventional: near 0–0.05	Depends on market and reserve pricing
Ramping / cycling impacts	Low when run as scheduled; cycling raises fuel/maintenance costs	Causes additional ramping of thermal units → efficiency & wear costs	RE adds 0.1–0.5 (as part of total)	Significant if flexibility scarce
Transmission & congestion	Existing corridors often adequate; incremental needs for new large plants	New corridors/pooling often required (resource concentration)	RE: portion of 0.1–1.0	Higher if long-distance evacuation or network upgrades needed
Curtailment & energy value	Rare; dispatched as needed	Can be curtailed when supply > demand → lost energy value	Curtailment cost component varies (can be large locally)	Curtailment increases effective integration cost
Typical incremental system cost (average)	Very low per MWh in normal operation	Generally higher due to variability	Conventional: ~0–0.05 INR/kWh; RE: ~0.5–3.0 INR/kWh	RE cost rises with penetration unless mitigations applied
High-penetration effect	Integration cost rises if many inflexible units or low demand	Costs grow nonlinearly with penetration (more curtailment, reserves)	RE may exceed upper range without flexibility	Grid strength, storage, and markets matter
Key mitigations to lower cost	Improve unit scheduling; increase flexibility	Forecasting, storage, flexible gas/hydro, market reform, transmission	Can reduce RE incremental cost toward conventional levels	Policy and investment-dependent

Table 2 shows that RE integration into the grid entails a cost in the range of INR 0.5 - 3.0/kWh, with the following as dominant factors:

1. Forecasting errors and generation uncertainty
2. Transmission congestion & curtailment
3. Ramping impacts

Finally, if RE penetration increases without adequate flexibility, integration costs will increase non-linearly with penetration driven by the three factors listed above, while also compromising resilience and reliability.

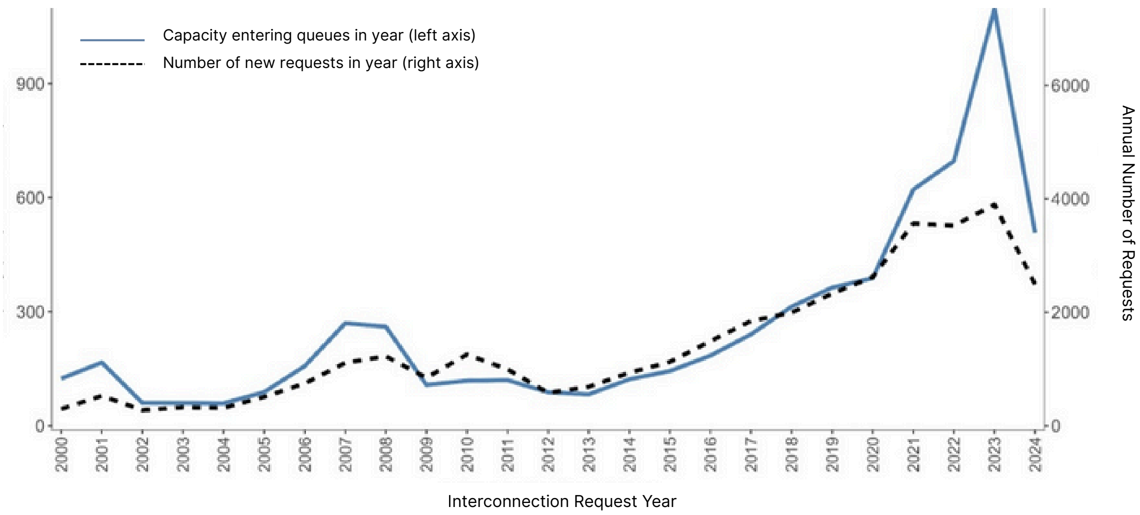
The next section discusses with examples various cases where integration challenges associated with RE penetration or weather outages led to grid failures. This section also highlights that RE capacity addition will need substantial T&D capex to allow seamless integration.

Case Studies in Intermittency

The vulnerability of electrical energy infrastructure has been demonstrated by various events in the recent past, where grid infrastructure adequacy, response, frequency control and connectivity were variously tested to the breaking point. While there are several examples, we will focus on the Texas blackout of 2021, and the Spanish blackout of 2024 as examples to highlight key factors of vulnerability, and how increased RE penetration creates further challenges for integration.

> We begin by reiterating that RE capacities can be built out faster than conventional generation assets (~18 months versus ~60 months), and grid infrastructure build-out cannot keep pace with the development of RE assets.

As a result, the quantity of RE awaiting grid connectivity is piling up. Exhibit 3 shows that as RE capacity build out has sped up, grid connectivity has lagged in the US, but this is indicative of the situation globally.



Note: (1) This total annual volume include projects with a current queue status of “active”, “suspended”, “withdrawn”, or “operational”. (2) All values - especially for earlier year - should be considered approximate.
Exhibit 3: The number of interconnection requests in the US slowed in 2024, but 500 GW of RE capacity still entered the queue
(Source)

> Indeed, the grid connectivity queues are a symptom of systematic underinvestment in grid infrastructure, leaving the electrical system over reliant on generation side interventions for load balancing and frequency regulation.

The Texas Outage of February 2021

The first event which we present as a case study is the Texas outage of February 2021 during the winter storm “Uri”.

> This case study highlights the fragility of the generation end of a (then) largely gas-powered grid and the effects of isolation.

The Texas Interconnected System is one of three large networks that together provide electric power to more than 150 million customers in the continental United States. The Electric Reliability Council of Texas (ERCOT) operates the 52,700-plus miles that make up this system, while individual generators and transmission companies own the physical infrastructure. Exhibit 4 presents a unified schematic from the North American Electric Reliability Corporation (NERC) highlighting the important grids in the United States of America and the Texas Interconnected Power System, operated by ERCOT.

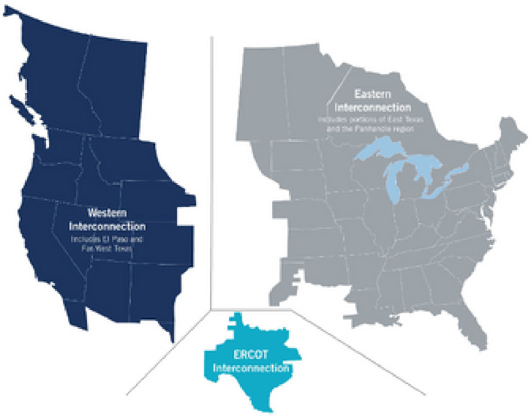


Exhibit 4: NERC schematic of the ERCOT interconnection
Source ERCOT.com) / (Source: Wikipedia)

It is important to also note that the Texas grid operates as a synchronized network of alternating current (AC) facilities. Part of ERCOT’s responsibility is to ensure that the network is stable, e.g., always cycling at or very close to 60 hertz (cycles per second). The network currently has four direct current (DC) ties — two links with the Eastern Interconnection and two links to Mexico — which are used for scheduled and emergency power trades and are not treated as interconnections supporting interstate or international trade.

In addition, 19 generators located at four different power plants are switchable, meaning they can deliver power into either the Texas grid or the Eastern Interconnection, but not at the same time. The Texas grid is also isolated from the rest of the country due to a combination of regulatory, political, technical and practical reasons, which are beyond the scope of this article.

The outage began with the arrival of winter storm “Uri” in Texas in mid-February 2021 causing extreme cold across various parts of the state. Demand for electricity surged while large portions of generation and fuel supply failed, triggering cascading outages. Peak demand exceeded 69 GW while available generation plunged. As a result, over 4.5 million households lost power at peak with at least 246 deaths later attributed to the storm. ERCOT, which operates ~90% of Texas grid, ordered statewide rotating outages beginning February 15th, 2021, to prevent complete grid collapse. Due to an absence of electrical heating, water froze in pipes leading to bursts and loss of water to entire communities. By the time power was normalised, the economic cost was estimated to be ~US$ 80 - 130 Bn.

The event was caused by the following factors:

- Inadequate winterization with generation units (natural gas, coal, nuclear) and fuel-supply equipment were not sufficiently winter-hardened leading to frozen equipment. Additionally, frozen wells/lines reduced supply.
- Natural gas supply shortfalls caused by high pipeline constraints, frozen wells, and market/operational issues reduced gas available to power plants at a critical juncture.
- Renewable generation losses driven by reduced wind and solar output due to icing and cold-related outages.

- Texas' isolated grid (ERCOT) was largely disconnected from neighbouring grids, limiting imports. Market incentives failed to sufficiently reward capacity/resilience for extreme cold events and not enough reserve was available in the ERCOT area of operation
- Forecasting and reserve margins were inadequate. Some generation assets were offline for maintenance while emergency procedures and communications proved inadequate for timely management

> The event highlighted the requirement for grid resilience, and connectivity with adequate interconnects, which in turn would have allowed imports to match demand and stabilize the grid as supply fell.

The next case study of the Spanish-Iberian blackout from 2024 highlights a cascading failure in an RE dominated grid, where the lack of system inertia, lack of storage and grid resilience caused a rolling blackout.

Iberian Grid Blackout of March 2024

The Iberian grid, supplying electricity to large parts of Spain and Portugal had seen increasing RE penetration, especially solar energy post 2020. By 2023, Spain was able to largely delink electricity prices from the price of natural gas, a first in the European region. There were also no clear regulations around grid resilience, and the overall interconnect density of the Iberian Peninsula was poor.

Further RE addition was encouraged as a part of the green initiative. With most generation assets in high solar availability regions, the Iberian region began to see low and even negative energy prices around midday.

At this time, most conventional generators backed down, and the grid was dominated by inverter-based power generation (solar injecting into the grid through inverters). This led to a grid that exhibited the following characteristics:

- High RE penetration and reliance on inverter-based sources (especially solar)
- Low synchronous inertia and therefore poor frequency control
- High Rate of Change of Frequency (ROCOF) in case of supply-demand mismatch
- Low interconnect availability to stabilize grid operations

On the 16th of March 2024, a major disturbance as shown in Exhibit 5 rippled across the transmission networks. The high ROCOF run down of the grid frequency triggered cascading protective trips of generators, lines and inverter-based plants leading to a loss of supply.

The lack of low-inertia protection, real time and rapid ROCOF monitoring and low HVDC interconnectivity meant that the rapid frequency drop could not be stabilized in time. In just over a minute[7], millions of consumers across the Iberian Peninsula experienced blackouts.

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[7] The speed at which the instability spread through the grid leading to a blackout was unprecedented. For comparison, the US forces required over six weeks of dedicated air strikes to paralyse Iraqi electrical grids in 1991 during Desert Storm. This illustrates that modern software monitored grids can be paralysed by cyber/online attacks, and hardening against these is a priority.

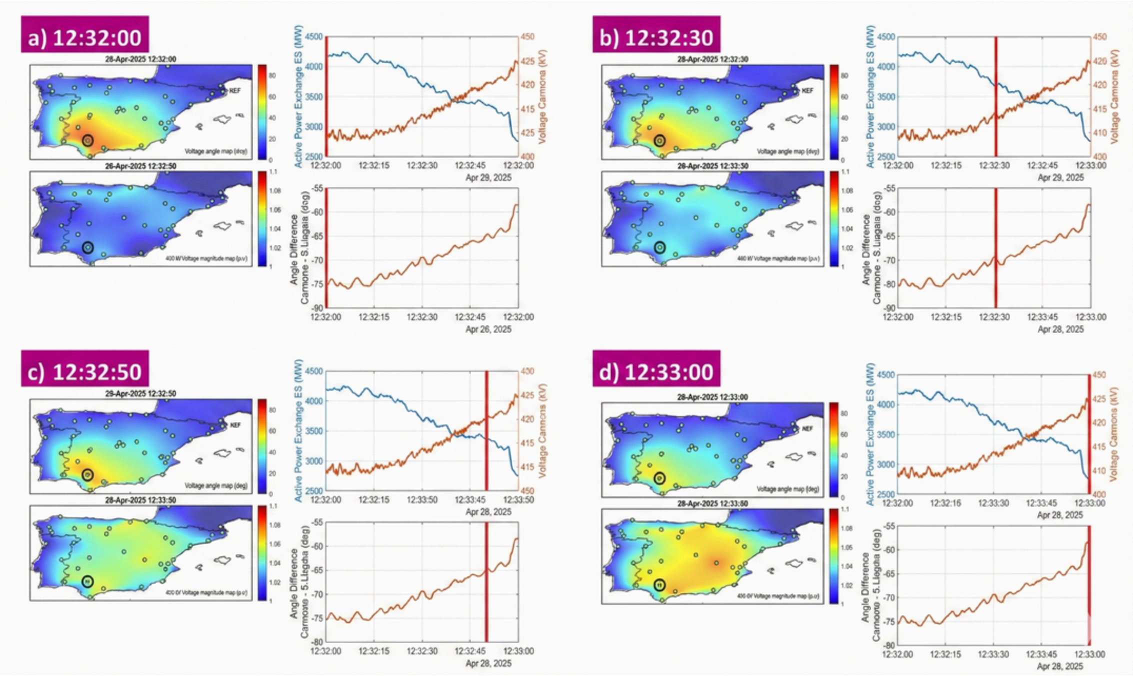

Exhibit 5: Four time-ordered snapshots (12:32:00–12:33:00) of the Iberian grid showing top/bottom spatial voltage-magnitude maps, active-power (blue) and voltage/frequency (orange) traces, and angle-difference trends. The sequence visualizes a rapid active-power collapse, deepening voltage/ frequency excursions (red vertical markers), and growing phase separation across the peninsula — illustrating how a sudden trip can propagate into a fast, cascading blackout under low inertia/high renewables conditions
Source: Bloomberg, Jefferies

The key reasons identified include:

- Low inertia and high renewable share amplifying ROCOF and deepening frequency nadirs, which in turn require synthetic inertia/Fast Frequency Response (FFR) and minimum synchronous capacity policies, which were largely ignored even as more RE capacities came online
- Protection coordination adapted to low-inertia conditions and FRT standards for inverters critical to avoid mass disconnections was poorly implemented
- Inadequate reserve products, poor standardization of inverter controls, and weak HVDC/interconnector reliability
- Low Phasor Measurement Unit (PMU) deployment, inadequate real-time inertia/ROCOF monitoring, and poor operator training for responding to rapid disturbances and restoration
- Weak cross-border coordination and joint contingency planning between Transmission System Operators (TSOs) and regulators

These events highlighted some common issues including:

- Rapid supply–demand imbalance: Both events featured a sudden, large gap between available generation and load that triggered system stress and cascading outages
- Cascading protection actions: In each case automatic protection and grid-control measures (underfrequency/overfrequency, line tripping, generator protection) contributed to progressive loss of service
- Operational strain and preparedness gaps: Both revealed weaknesses in planning for atypical contingencies and in real-time operational response under extreme stress
- Wide social/economic impacts: Large customer outages, disruption to critical services, and significant political and regulatory fallout followed both events
- Lessons about resilience: Each event highlighted needs for stronger planning, faster coordination, better instrumented grids, and clearer contingency procedures

Where India Stands Today

The Indian grid is organized into the Northern, Eastern, North-Eastern, Western and Southern grids as part of the national grid (Exhibit 6).

> While the Indian grid is more recent than many other countries and suffers less of the legacy issues affecting those systems, it is nevertheless a system designed for conventional energy generation

(left side, Exhibit 1) as discussed in the first part of this article and is therefore vulnerable to problems like those illustrated in the case studies.

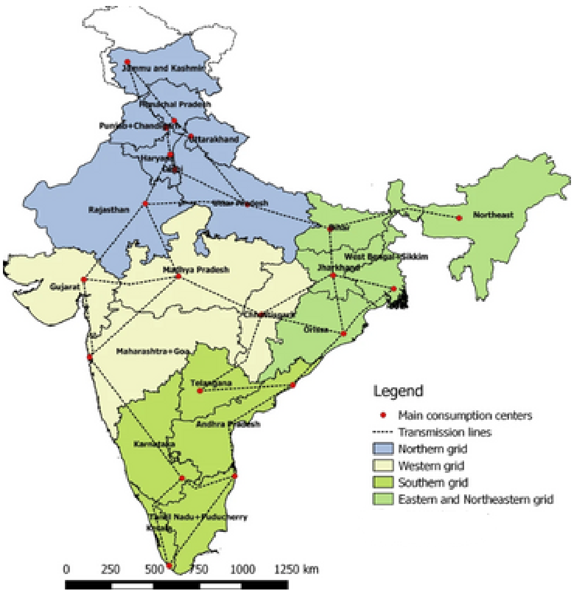

Exhibit 6: Map of India's regional electricity grids showing northern, western, southern, and eastern/northeastern grid boundaries, major transmission lines, main consumption centers (red dots). Gulagi, A., Ram, M., Bogdanov, D. et al. The role of renewables for rapid transitioning of the power sector across states in India. Nat Commun 13, 5499 (2022). (The extents on the map represent the grid and are not a reflection on the territory of the Indian Union.)
(Source)

The large additional capacity of RE (mainly solar generation) primarily in Rajasthan and Gujarat along with weak interconnections is now placing substantial demands on the Indian grid in terms of resilience and control. This is exemplified by the economic costs for the generators who bear the brunt of second order consequences such as curtailment.

For instance, as of January 2026 in Rajasthan, more than 4 GW of commissioned capacity is seeing a near-total shutdown during peak solar hours despite the recent commissioning of the 765 kV Khetri-Narela transmission line (source). To further drive home the point - Grid India has cited multiple technical constraints limiting renewable evacuation from Rajasthan, including voltage oscillations at renewable energy complexes, low short-circuit ratios at pooling stations and loading constraints on the certain transmission lines in Rajasthan.

Further, it is important to note that demand regulation and resilience at demand centres remains under the purview of the state-run distribution companies (DISCOM). The poor financial health of these entities also limits major reforms to the power sector even as the nature of electricity changes rapidly.

The infrastructure builds needed in terms of grid resilience, energy storage and in India’s case DISCOM restructuring will drive substantial investment with increased involvement from the private sector and promises to be one of the largest infrastructure buildouts of the 21st century requiring ₹ 200 trillion to be invested by the centenary of the Indian republic in 2047, by which time the per capita consumption of electricity is expected to exceed 4000 kWh. In this article we have attempted to frame the consequences of rapid RE integration and highlight the consequences of poor grid resilience and high RE integration. In the next article we will discuss grid and storage opportunities and will end this trio of articles focussing on the DISCOM dilemma in India.

Glossary

Energy: The capacity to do work or produce heat, often measured in kilowatt-hours (kWh) for electricity.

Power: The rate at which energy is used or produced, measured in watts (W) or kilowatts (kW).

Grid: The network of transmission and distribution lines, substations, and controls that delivers electricity from producers to consumers.

Substation: A facility that switches, transforms, and controls voltage between transmission and distribution systems.

Voltage: The electrical potential difference between two points, which drives current flow, measured in volts (V).

Frequency: The number of cycles per second of an AC waveform, measured in hertz (Hz); it indicates the grid's timing (e.g., 50 or 60 Hz). Therefore, the frequency must stay stable to ensure the entire power system remains synchronized.

Inverter: A device that converts direct current (DC) generated by the solar panel to an alternating current (AC) suitable for the grid or AC loads.

Transformer: An electrical device that increases (steps up) or decreases (steps down) AC voltage levels.

Direct Current (DC): Electric current that flows in one direction, with a constant polarity.

Alternating Current (AC): Electric current that periodically reverses direction and changes voltage polarity in a sinusoidal or other waveform.

Baseload: The minimum continuous level of demand on an electrical grid over a given period, typically met by reliably available generators.

Peak Shaving: Reducing or shifting electricity demand during periods of highest load to lower peak demand and costs.

Synchronous inertia: The rotational kinetic energy stored in spinning synchronous generators that resists changes in grid frequency and helps stabilize the system.

Reserve: Backup generation or capacity held available to respond quickly to supply shortfalls or sudden demand changes.

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