Harvard Project on Climate Agreements

Navigating the Grid's Perfect Storm: Building a Resilient and Reliable Power System

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The Harvard Project on Climate Agreements is a Harvard-University-wide initiative established in 2007 to identify and advance scientifically sound, economically sensible, and politically pragmatic public policy options for addressing global climate change. Drawing upon leading thinkers from around the world, the Harvard Project conducts research on policy architecture, key design elements, and institutional dimensions of international and domestic climate-change policy. The Harvard Project is directed by Robert N. Stavins, A.J. Meyer Professor of Energy and Economic Development, Harvard Kennedy School. For more information, see the Harvard Project's website: www.hks.harvard.edu/hpca.

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ABSTRACT

The impacts of a changing climate, which include shifts in average temperatures and more frequent, severe weather events, coupled with the rapid integration of variable renewable energy sources, pose unprecedented challenges to the reliability and resiliency of power grids globally. Traditional grid planning and operational paradigms, designed for predictable, centralized fossil fuel-based generation, are increasingly strained by these new realities — compounded by rapid, concentrated load growth from emerging industries like artificial intelligence and data centers — leading to heightened risks of large-scale outages and volatile operational conditions. This article addresses these critical issues by first dissecting the evolving nature of power systems and the nuanced definitions of reliability, resiliency, flexibility, and efficiency in this new context. It then analyzes the multifaceted challenges, from physical risks like extreme weather to operational complexities such as declining system inertia and the duck curve. Drawing upon a multi-disciplinary perspective that synergizes large-scale optimization, advanced control theory, artificial intelligence, power engineering, and economics, this paper discusses a suite of innovative solutions. These include next-generation stochastic and coordinated transmission-distribution planning methodologies; AI-enhanced forecasting and real-time adaptive optimization for grid operations and microgrid coordination; and reformed economic and policy frameworks, such as adaptive capacity markets and proactive regulatory incentives for grid modernization. The objective is to provide actionable insights for utilities, energy professionals, economists, and policymakers on navigating the transition to a resilient, reliable, and sustainable energy future.

1. THE SHIFTING ELECTRICAL LANDSCAPE

The modern power system is in the midst of a transformation more profound than any since its inception over a century ago. The grid that powered the late 20th century is rapidly becoming a relic, supplanted by a system that is more decentralized, dynamic, and complex. To fully appreciate the scale of the challenges and opportunities ahead, it is instructive to compare the grid of a quarter-century ago with the renewable-rich system emerging today.

The U.S. power grid at the close of the 1990s was the mature expression of a century-long paradigm built on centralization and predictability. This model, whose origins trace back to the victory of alternating current (AC) in the "War of the Currents," was predicated on large, dispatchable thermal power plants located far from urban centers (Jonnes, 2003). Fossil fuels were king, with coal dominating the generation mix, a role that natural gas would increasingly assume over the next decade. The flow of power was a one-way street, enabled by a vast network of high-voltage transmission lines and a business model of regulated monopolies that perfected one-way power flow to passive consumers (Bakke, 2016). These local distribution networks were little more than conduits, with minimal local generation and virtually no capacity to actively respond to changing grid conditions. The entire operational philosophy was predicated on the steady, predictable output of thermal generators meeting equally predictable load patterns — a paradigm that valued stability and control above all else.

Fast forward to the present, and the picture is almost unrecognizable. The most visible change is in the generation mix. Renewable resources, once a niche player, have experienced exponential growth. In the United States, between 2000 and 2024, installed wind capacity surged from a mere 2.4 gigawatts (GW) to approximately 150 GW, while total solar capacity exploded from less than 50 megawatts (MW) to over 200 GW (U.S. Energy Information Administration, 2024a; IRENA, 2025; Statista, 2025). This green revolution is part of a broader realignment of the nation's power supply. As of 2024, the U.S. generation mix is dominated by natural gas (approximately 43% of capacity), with the once-mighty coal fleet having shrunk to around 16%. Wind and solar now represent a combined 27% of the nation's capacity, while nuclear and hydropower each contribute roughly 8% (U.S. Energy Information Administration, 2024b; BloombergNEF, 2025). This transition has been accompanied by the rapid deployment of energy storage: utility-scale battery capacity in the U.S. is on track to nearly double in 2024 alone to over 30 GW, exceeding the total installed capacity of pumped hydro (23 GW) for the first time (BloombergNEF 2025).

Layered on top of this supply-side transformation is a demand-side shock unseen in recent decades: the explosive growth of artificial intelligence (AI) and the data centers required to power it. This is not the gradual, predictable load growth of the past. The energy consumption of data centers, cryptocurrencies, and AI is projected to more than double between 2022 and 2026, an increase roughly equivalent to the entire electricity consumption of Germany (International Energy Agency, 2024). This growth is creating intense, geographically concentrated pockets of demand in tech hubs across the United States, Europe, and China, with some individual data center campuses requiring as much power as a medium-sized city. This unprecedented surge presents a formidable challenge to grid reliability and resiliency. It threatens to outpace the traditional, often decade-long, planning and construction timelines for new transmission and generation, creating localized grid congestion and increasing the risk of outages in regions struggling to meet these new demands. The sheer scale and power density of these facilities create new, critical points of failure, where an infrastructure failure could have cascading economic and operational consequences.

This new reality has necessitated significant changes on the transmission side, with longer and higher-capacity lines being built to connect remote renewable-rich regions with urban load centers. But perhaps the most radical changes are occurring at the distribution level, as the very structure of the grid is evolving at its edge. The proliferation of Distributed Energy Resources (DERs) — such as rooftop solar, residential battery storage, and smart appliances — has created a new class of "prosumers" who both produce and consume energy (European Environment Agency, 2022). In the U.S., small-scale solar capacity is projected to exceed 50 GW in 2025. In PJM alone, the installed capacity of small-scale solar generation has grown to thousands of megawatts, fundamentally changing local power flows (PJM Interconnection, 2024). The number of prosumers in EU has more than doubled from 2.8 million in 2021 to 6.9 million in 2024 (U.S. Energy Information Administration, 2023; Eurelectric 2025). This bottom-up transformation is fundamentally altering distribution system dynamics, making the distribution grid smarter, more interactive, and creating bi-directional power flows, where in areas with high solar adoption excess energy from rooftops flows back onto the local grid, challenging grid stability (Horowitz *et al*, 2019).

To manage the new grid edge, new technical standards and grid codes, such as IEEE 1547–2018, the California Rule 21, Hawaii Rule 14H in the U.S. and EU's EN 50549, UK's G98, G99, and Italy's CEI 0-21 for low-voltage distribution grids, start to mandate smart inverters that interface DERs to the local grids to have grid support functionalities, such as frequency regulation, voltage control, and disturbance ride-through capabilities. The rise of electric vehicles (EVs) introduces both a massive new load and a potential grid asset through vehicle-to-grid (V2G) technologies, which allow EV batteries to act as a distributed network of mobile storage. The development of microgrids — localized grids that can disconnect from the main grid and operate autonomously — offers a proven tool for enhancing local resilience. Successful real-world deployments, such as the community microgrid in Borrego Springs, California, which kept the town powered during a major blackout, and the long-operating system at the Santa Rita Jail, which provides critical service reliability, demonstrate the tangible benefits of these systems (U.S. Department of Energy, 2021). This technological evolution is unfolding against a backdrop of shifting demand patterns, with climate change driving higher summer peaks and the electrification of industry creating new, large-scale loads that must be seamlessly integrated.

The grid of the past was a monologue; the grid of the future is a dynamic, multi-directional conversation.

2. REDEFINING GRID PERFORMANCE METRICS

As the physical and operational nature of the power grid evolves, so too must the conceptual framework we use to define its success. The terms reliability, resiliency, flexibility, and efficiency, while often used colloquially, represent distinct and critical attributes for the modern grid. Their precise definitions and complex interplay are foundational to navigating the transition to a sustainable energy future.

At its core, **reliability** has long been the bedrock of power system engineering. It is a broad concept that encompasses the system's ability to deliver electricity to all points of consumption, in the amount desired, under a wide range of normal operating conditions. The different facets of reliability can be understood through an analogy to a city's subway system. Traditionally, reliability is broken down into two primary components: adequacy and security (Billinton & Allan, 1996). **Resource adequacy** addresses the long-term view, ensuring that the system possesses sufficient generation and transmission capacity to meet projected peak loads over a planning horizon of years. In our subway analogy, this is equivalent to the transit authority having enough train cars and tracks to serve all passengers throughout the year. **System security**, in contrast, deals with the short-term, real-time ability of the system to withstand sudden disturbances — such as the unexpected failure of a large generator — without collapsing into a widespread blackout. This is akin to the subway's ability to handle a minor disruption, like a malfunctioning car, and adjust operations to keep the overall service schedule intact. Finally, a third, often overlooked, pillar of reliability is **power quality**. This refers to the maintenance of key electrical parameters, such as voltage and frequency, within very tight, standardized tolerances. Just as subway passengers expect a smooth, quiet ride even when the trains are on time, electricity consumers require a stable supply for their equipment to function correctly. Deviations from these standards can damage sensitive electronics and destabilize the grid, making power quality an especially critical aspect of reliability for modern distribution networks.

These foundational concepts of reliability are put into practice differently across the grid. On the high-voltage **transmission system**, resource adequacy is ensured either through long-term Integrated Resource Planning (IRP) in vertically integrated utility regions or through regulated market mechanisms in competitive regions. The IRP process is a cornerstone of long-term planning, typically involving a 15- to 20-year planning horizon to guide investments in large, capital-intensive assets (e.g., Duke Energy, 2025; Georgia Power, 2022; Keen, et. al., 2023). In deregulated areas, resource adequacy is often secured through centralized capacity markets. These markets, managed by Independent System Operators (ISOs) and Transmission System Operators (TSOs), organize forward auctions to pay resources for the commitment to be available in the future. For example, PJM Interconnection, the largest grid operator in the U.S., runs its main capacity auction three years in advance (Wilson, 2018). The results of its most recent auction for the 2026/2027 planning year underscore the growing pressures on resource adequacy: capacity clearing prices hit the regulatory cap, a 22% increase from the prior year, reflecting a tight supply-demand balance as forecasted peak demand surged from the growth of data centers and electrification (PJM Interconnection, 2025a). This dynamic is also seen in Europe; in Ireland, where demand from data centers is particularly acute, recent T-4 (four-year ahead) capacity auctions for delivery year 2028–2029 have cleared at a high price of €149,960/MW per year, after the natural gas plants' price cap was lifted, signaling an urgent need for new investment to maintain reliability (Single Electricity Market Operator, 2025).

The forward capacity commitments also contribute to the real-time operational reliability. For example, PJM enforces compliance through its Capacity Performance model. This model requires all capacity resources to be available to deliver their committed energy and reserves during declared real-time grid emergencies. Performance is measured during these critical events, known as Performance Assessment Intervals (PAIs), and resources that underperform face significant financial penalties, while those that overperform can earn bonuses. This penalty structure creates a financial incentive for generators to invest in maintenance and preparedness, ensuring that the capacity procured for long-term adequacy is truly available when needed for short-term system security (PJM Interconnection, 2025b). In European capacity markets, such as in Ireland and Italy, financial options are set up so that when the real-time energy market prices exceed regulated strike prices, generators receiving capacity payment need to pay the difference back to the operators, creating incentives for generators to produce during scarcity conditions, mitigating market power (Mastropietro *et al.*, 2024).

In distribution systems, where the customer experience is paramount, reliability is measured with aggregated indices that capture the customer experience, such as the **System Average Interruption Duration Index (SAIDI)**, which measures the average outage duration per customer, and the **System Average Interruption Frequency Index (SAIFI)**, which measures the average number of sustained interruptions per customer (IEEE Standard 1366–2012). Traditionally a reactive process, distribution planning is now shifting toward proactive planning and long-term forecasting. This transition is increasingly being mandated by state regulators; in Massachusetts, for instance, the Department of Public Utilities now oversees utility filings of comprehensive, multi-year Electric Sector Modernization Plans designed to proactively prepare the distribution grid for electrification and climate change (Massachusetts Department of Public Utilities, 2023). This is part of a broader trend toward performance-based regulation, where regulators may use metrics like Brazil's TMAE, meaning Average Emergency Response Time, to penalize slow emergency response to ensure equitable and swift service restoration for all customers during critical days (Joskow, 2008; Littell, et. al., 2017).

The proliferation of behind-the-meter and utility-scale DERs is fundamentally altering how reliability is secured, a transformation that began at the local level and is now reshaping both distribution and transmission grids. To harness the value and manage the impact of these new resources, new local reliability mechanisms have emerged. These include the use of DERs as **non-wires alternatives (NWAs)** to defer or avoid costly infrastructure upgrades, performance-based payments for availability during peak demand, and innovative **tariff structures** like time-of-use rates that incentivize customers to support the local grid. As the aggregate capacity of these distributed resources grew to be substantial, their collective operation began to have a significant impact on the bulk power system. This created a strong need for greater coordination between transmission and distribution systems. Recognizing this bottom-up evolution, federal regulators enacted policies like the USA FERC Order 2222, which was designed specifically to remove barriers and create a standardized pathway for aggregated DERs to participate in wholesale energy and capacity markets, thereby formally acknowledging their crucial role in system-wide reliability. As an example, PJM has more than 13,000 MW non-wholesale DERs in its territory and will allow DERs up to 5 MW to participate in their capacity market auction starting 2026.

In recent years, the concept of **resiliency** has emerged as a crucial complement to reliability, representing what some argue is a fundamental paradigm shift, not merely an incremental step (Cheng, Liao, & Elsayed, 2024). The distinction is critical: reliability is concerned with preventing failures from causes *within* the system's design limits, while resiliency confronts the system's ability to perform when external hazards push it far *beyond* those limits. These are the "black swan" or low-probability, high-impact (HILP) events that have historically fallen outside the scope of traditional planning — major hurricanes, widespread wildfires, or extreme cold snaps that cause massive, simultaneous failures (National Academies of Sciences, Engineering, and Medicine, 2017). For decades, planning has been built on probabilistic analysis of independent component failures, characterized by the "N-1" standard. This framework is fundamentally ill-equipped for a single event that causes widespread, correlated failures of many components, a scenario that violates the statistical assumptions underpinning conventional reliability metrics.

This recognition makes it necessary to treat resilience not as an abstract goal, but as a tangible outcome of strategic investment that requires better metrics. A major critique of existing metrics is that they often assume a simple, "unimodal" disruption curve (a single dip and recovery), which is unrealistic for complex events like an earthquake with aftershocks or a pandemic with multiple waves. This has led to calls for more sophisticated "multimodal" metrics that can capture these fluctuating recovery processes (Cheng, Elsayed, & Huang, 2021) and "multi-phase resilience trapezoid" as a quantitative approach for resiliency assessment for power systems (Panteli et. al., 2017). Concurrently, researchers are developing spatial-temporal models to quantify grid resiliency using customer outage data (Zhu et. al., 2025). On a larger scale, this forward-looking approach is being put into practice through improved modeling like the CANOPI, which use highly granular data to stress-test the future grid against a wider range of scenarios, thereby creating a strategic planning platform for assessing grid resiliency (Lee and Sun, 2025). A resilient system is not one that never fails, but one that is proactively designed to bend without breaking completely — to absorb shocks, adapt its operations, and restore service intelligently and rapidly (Xu. et. al., 2024).

The increasing penetration of variable renewable energy sources as well as the unprecedented growth of large loads from AI data centers have elevated the importance of a third attribute: **flexibility**. This is the power system's capacity to quickly and cost-effectively respond to the rapid and often unpredictable changes in net load — the total customer demand minus the output of variable renewables (Lannoye *et al*., 2012). The need for flexibility is famously illustrated by the "duck curve," a term coined by grid operators in California. On a sunny day in a solar-rich grid, the net load plummets during midday as solar generation peaks. As the sun sets, solar output vanishes, and the net load skyrockets, requiring conventional generators or storage to ramp up their output at an extremely high rate to meet the evening peak demand. This deep, rapid swing in net load strains the grid's traditional flexible resources, which have primarily been fast-ramping natural gas "peaking" plants. To manage this challenge, grid operators like the California ISO (CAISO) have pioneered new solutions, including massive deployments of battery storage and the creation of new market mechanisms like the "Flexible Ramping Product" to explicitly procure ramping capability from all available resources (California ISO, 2025a; Denholm, et. al., 2010). This approach is not unique to California; in jurisdictions across Europe and Latin America, similar flexibility mechanisms are being defined and approved by national regulators, underscoring the pivotal importance of coherent policy design in fostering system resilience.

Paradoxically, another major force shaping the need for grid flexibility comes from the demand side, with the rise of new, energy-intensive technologies that can also serve as a powerful resource. AI data centers, for example, are being added to the power grids at an unprecedented speed. The average demand from a new, large-scale data center can be immense, often in the range of 100–200 MW or more (Boston Consulting Group, 2025). While this presents a challenge, their operation also has a complex nature; some computational workloads are critical and time-sensitive, while others are more flexible and can be shifted or curtailed. Because a significant fraction of computing jobs are non-urgent batch processes, a data center can provide a substantial portion of its demand as flexible load (Shehabi *et al.*, 2016). Such a large amount of schedulable load is an invaluable resource that can provide significant savings to grid operation, help reduce emissions by consuming power when renewables are most abundant, and, crucially, act as an emergency reserve during grid contingencies (National Academies of Sciences, Engineering, and Medicine, 2025).

Finally, all these engineering objectives are bound by the overarching goal of economic **efficiency**. From a societal perspective, the aim is to plan and operate a power system that maximizes social welfare — the sum of benefits to all consumers and producers. Historically, there has often been a perceived trade-off between reliability and cost. However, a more sophisticated view of efficiency recognizes that reliability is not a luxury but a core component of economic value. A truly efficient system is one that internalizes the full spectrum of costs and benefits associated with electricity production and consumption. This includes not only the direct costs of fuel and infrastructure but also the economic costs of power outages and service disruptions, the value of capacity held in reserve to provide reliability and resiliency, the opportunity costs for resources that provide flexibility, and the external environmental and public health costs of pollution. By defining efficiency comprehensively, we can see that investing in a more reliable, resilient, and flexible grid is not a departure from economic prudence but an essential element of it.

3. COMPOUNDING THREATS TO THE MODERN GRID

The modern power grid faces a confluence of threats that are straining its foundational architecture and operational paradigms. The direct physical impacts of a changing climate are colliding with the profound operational shifts introduced by the transition to renewable energy, storage, distributed generation, and large AI data centers, creating a complex and challenging new risk landscape.

The most visceral threat comes from the increasing frequency and intensity of extreme weather events. Climate change is no longer a future projection; its impacts are being felt today in the form of more powerful hurricanes, more destructive wildfires, more severe droughts, and more extreme temperature swings. These events represent a direct assault on the physical infrastructure of the grid. In the last decade alone, the litany of climate-driven disasters in the U.S. has been relentless. The 2021 winter storm Uri in Texas led to the catastrophic failure of natural gas infrastructure and power plants, plunging millions into darkness for days in freezing temperatures and resulting in hundreds of deaths (Federal Energy Regulatory Commission, 2021). Hurricane Ida, in the same year, left a trail of destruction across Louisiana, causing what was described as the most extensive power outage in the state's history. Hurricane Maria in 2017 was even more devastating, causing the complete collapse of Puerto Rico's grid and the longest blackout in U.S. history, with some areas remaining without power for nearly a year (U.S. Government Accountability Office, 2018). The 2024 Atlantic hurricane season, with its above-average activity, saw major storms like Milton and Helene cause outages for more than 8.4 million homes and businesses across the southeastern United States. This trend is not unique to North America; grids worldwide are facing similar climate-driven challenges. In May 2023 and November 2024, the Emilia-Romagna region in Italy was hit by catastrophic floods triggered by heavy rain and cyclone, which submerged critical infrastructure, leaving thousands without power (Wikipedia, 2023; Reuters, 2024a). Similarly, major cities in Brazil have recently experienced prolonged blackouts affecting millions after exceptionally heavy rain and winds overwhelmed the local grid (Reuters, 2024b).

Analysis of historical outage data reveals deeply concerning patterns of vulnerability in both transmission and distribution grids, rooted in the grid's structural characteristics, control and protection strategies, and historical investment priorities. In the transmission grid, based on historical data for blackouts affecting at least 50,000 customers or 300 MW of load in the North American power grids from 1984–2006, researchers have discovered that the probability of blackouts follows something called a "power-law" distribution, which means that large blackouts happen with a much higher probability than one would predict from the more lenient exponential statistics (Hines, et. al., 2009). Several reasons contribute to this pattern. First, the transmission grid's network topology, with critical hubs like major power plants and substations, makes it inherently vulnerable to targeted disruptions that strike these central nodes (Albert, et. al., 2000). Second, the physics of the loop flows and the local, non-coordinating protection schemes make the grid susceptible to cascading failures, where the loss of one key element forces power to reroute in the meshed transmission grid, overloading and tripping adjacent lines in a domino effect that can lead to regional blackouts (National Academies of Sciences, Engineering, and Medicine, 2017).

For distribution grids, the pattern and causes of vulnerability are subtly different. Failures in a distribution grid during a severe weather event are largely due to local causes such as damaged poles or area flooding, and such failures in one distribution feeder typically do not cascade to other feeders, due to the radial power distribution topology. However, failures in one primary feeder would lead to outages in secondary feeder and end customers, even when these downstream devices are not damaged. Recent research has identified a "20–80 scaling law" for distribution system failures in upstate New York during the Super Storm Sandy in 2012, where the most impactful 20% of failures are responsible for 79–89% of customer service disruptions (Ji *et al*, 2016). This disproportionate impact stems from inherent vulnerabilities of the hierarchical radial design of the distribution grid. The study confirms that severe weather does not cause, but rather exacerbate, these existing vulnerabilities. While these are inherent properties, their severity can also be significantly exacerbated by a chronic underinvestment in proactive resilience measures, such as grid hardening, smart grid technologies for monitoring and protection, and distributed resources such as battery storage, an investment gap highlighted in numerous government analyses (Executive Office of the President, 2013). These same dynamics shape the recovery process, which often exhibits a skewed "30–60" pattern: 30% of small customer loads, often in remote or severely damaged areas, account for nearly 60% of total customer-hours of interruption. This "long tail" of recovery is a direct result of operational and logistical choices to prioritize repairs that restore power sources and the largest number of customers first, leaving the most difficult repairs for last, a practice detailed in industry best-practice documents (Ji, et. al., 2016). The length of this tail is directly related to investment in robust operational preparedness, such as pre-staging materials and ensuring adequate crew availability to tackle the final, most challenging phase of restoration.

Simultaneously, the operational fabric of the grid is being rewoven by the integration of renewable resources. While essential for decarbonization, the shift from conventional, synchronous generators to inverter-based resources like wind and solar introduces new forms of operational complexity. The first major challenge, as discussed, is managing the steep ramps and variability epitomized by the duck curve. This requires a level of system flexibility that many grids, built around slow-moving thermal generation, simply do not possess. Grid operators must now procure and dispatch fast-responding resources like natural gas peaker plants, batteries, pump storage, and demand response programs to fill the gaps and maintain the second-to-second balance between supply and demand. Markets have had to evolve, with operators like the California ISO (CAISO) creating new "ramping products" to specifically incentivize this kind of flexibility, a concept supported by advanced economic dispatch models designed to manage system ramp requirements under uncertainty (Thatte, Sun, & Xie, 2014; California ISO, 2025b).

A more subtle but equally critical challenge is the decline of **grid inertia**. Inertia is a physical property of large, rotating generators found in conventional power plants. The kinetic energy stored in these massive spinning turbines acts as a natural shock absorber for the grid, automatically resisting sudden changes in system frequency. When a large generator or transmission line suddenly trips offline, this stored inertia provides a crucial, instantaneous buffer, slowing the rate of frequency decline and giving grid operators precious seconds to deploy other resources to stabilize the system (Milano *et al.*, 2018). Inverter-based resources, which connect to the grid through power electronics, do not inherently provide this inertial response. As they displace conventional generators, the overall inertia of the system declines, making the grid more "brittle" and susceptible to rapid frequency deviations that can lead to blackouts. This erosion of a fundamental stabilizing property requires new solutions, such as advanced inverter controls that can synthetically mimic inertia, or new market mechanisms that explicitly value and procure this essential reliability service. The dual pressures of physical climate threats and the operational paradigm shift from renewables demand a fundamental rethinking of how we plan, build, and operate the power grid.

4. INTEGRATED SOLUTIONS FOR A RELIABLE AND RESILIENT GRID

Addressing the multifaceted challenges facing the modern power grid requires a departure from incremental, siloed solutions. The sheer complexity of this socio-economic-engineering ecosystem, where the overall reliability is often dictated by its weakest link, demands a systematic and holistic approach. The path forward lies in leveraging the synergies between large-scale optimization, advanced control theory, artificial intelligence (AI), power engineering, market design, and regulatory policies to reimagine every facet of the grid, from long-term planning to real-time operations, from normal operation to emergence response.

A foundational element of this new approach is the development of more sophisticated **planning methodologies**. For decades, grid planners have relied on simplified models that either aggregate vast regions of the grid into single "zones" or analyze only a small, "representative" sample of hours in a year. While computationally convenient, these simplifications are no longer sufficient. They can significantly underestimate the need for new transmission and generation capacity, particularly in a system with high geographic and temporal variability of renewable resources, thereby compromising long-term reliability. The consequences of this planning gap are becoming increasingly evident globally. In Brazil, for example, a rapid expansion of wind and solar capacity without commensurate transmission upgrades has led to significant curtailment, with projections showing an estimate of 20 TWh of renewable energy curtailment by 2025 (Rystad Energy, 2025; Fitch Ratings, 2025). Similarly, Chile, despite having world-class solar resources, was forced to curtail nearly 20% of its solar and wind generation in 2024 because of a lag in building new transmission lines from its resource-rich north to its demand-heavy center (Ember, 2025). These real-world examples highlight the urgent need to move toward more robust planning frameworks.

The new frontier is **contingency-aware** nodal transmission **planning**, which utilizes high-performance computing to model the entire high-voltage grid at the level of individual buses or nodes, across thousands of hours and multiple potential weather years. Recent advances in optimization algorithms, enhanced by AI, are making it possible to solve these massive computational problems, providing planners with the granular insights needed to make robust investment decisions (Lee and Sun, 2025, Conejo *et al.*, 2010). Furthermore, planning must explicitly embrace uncertainty. The traditional "predict-then-prescribe" approach, which relies on a single forecast for future load or renewable output, is dangerously brittle in a world of climate uncertainty and variable generation. The future must be planned for in terms of probabilities, not certainties. This requires the adoption of **stochastic and risk-aware planning models**. These tools do not just generate a single optimal plan; they generate strategies that are robust across a wide range of potential future scenarios, incorporating the risk preferences of decision-makers. This shift is already beginning to influence real-world operations. For instance, ISO New England, the grid operator for the northeastern U.S., has implemented market rules based on an adaptive robust optimization model to manage the uncertainty of intermittent resources, a tangible step toward operationalizing this new planning philosophy (Bertsimas, Litvinov, & Sun, 2013, Sun and Conejo, 2022).

This proactive mindset must also extend to the **distribution grid**. As the nexus of DER integration, EV charging, and direct climate impacts, the local grid can no longer be planned reactively to simple interconnection requests. A fundamental shift toward proactive, forward-looking **integrated distribution planning** is now underway globally. In the U.S., regulatory initiatives, such as New York's Reforming the Energy Vision (REV) and California's Distribution Resources Plan (DRP) proceedings, have required utilities to develop sophisticated, long-term forecasts for DER adoption and electrification (New York State Department of Public Service, 2016; California Public Utilities Commission, 2015). This trend is mirrored in the European Union, where the "Clean Energy for all Europeans" package legally requires Distribution System Operators (DSOs) to plan for future needs. This has led industry bodies to advocate for regulatory frameworks that permit "anticipatory investments" — building grid capacity *before* demand from EV charging or renewables fully materializes to avoid bottlenecks and accelerate decarbonization (European Commission, 2023). This new planning paradigm is supported by analytical techniques, such as detailed **hosting capacity analysis** to identify grid constraints and the economic evaluation of **non-wires alternatives (NWAs)**, where investments in DERs can defer or replace the need for costly traditional infrastructure.

This evolution in planning must be mirrored by reforms in **markets** and **operations**. The design of **capacity markets**, which are intended to ensure long-term resource adequacy, can be significantly improved by incorporating the outputs of these more sophisticated, stochastic planning models. By doing so, markets can better co-optimize for both adequacy and security, ensuring that investments are made not just in raw capacity, but in capacity that is flexible, resilient, and located where it is most needed to support the grid. Moreover, we would like to highlight that the evolution in planning and operations are fundamentally driven by coherent regulatory frameworks and policy design. It is these frameworks that define what gets incentivized, what gets paid for, and how value is distributed across the system. This applies not only to distribution planning but also to how markets are designed for bulk system reliability and ancillary services, such as how we value essential attributes like inertia or fast-frequency response, and how new technologies like energy storage are integrated. The energy-storage-focused capacity auction, MACSE, in the Italian capacity market in October 2025 is a breakthrough that procured 10 GWh battery capacity with exceptionally competitive prices. Looking to the future, these capacity remuneration mechanisms and market design and regulation framework innovations will continue to play significant roles in incentivizing decarbonization, encouraging renewable integration, and battery storage deployment, while strengthening grid reliability and resiliency.

The operational and regulatory toolkits must also expand to include the vast potential of the **demand side**. As discussed in the previous section, large, flexible loads, like AI-driven data centers, are becoming major electricity consumers. With the right incentives, they can also become active partners in grid reliability, participating in demand response programs to reduce consumption during peak hours or providing ancillary services to help stabilize the grid. The electrification of transportation offers an even greater opportunity. A large fleet of EVs represents a massive, distributed energy storage resource that can be orchestrated through V2G technology to absorb excess renewable generation and inject power back into the grid during times of need.

The increasing frequency of extreme weather events necessitates a greater emphasis on **distributed and flexible resources** that can enhance resilience. **Microgrids** can provide a critical lifeline during widespread outages by "islanding" from the main grid and powering critical facilities like hospitals and emergency shelters. **Energy storage systems**, from lithium-ion batteries that provide fast-frequency response to emerging long-duration technologies (e.g., pumped hydro, compressed air, or green hydrogen) that can provide power for days, are essential tools for balancing a variable grid and providing a buffer against prolonged disruptions. The strategic deployment of these distributed and flexible assets, guided by intelligent planning and enabled by modern market structures, is the cornerstone of building a power system that is not only clean but also fundamentally more resilient and reliable for the challenges of the 21st century.

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