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# Addressing Grid Interconnection and Power Infrastructure Challenges for Sustainable Data Center Expansion in the United States

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**Abstract- U.S. data center growth—driven by cloud services, artificial intelligence (AI), and digitalization—has become a power-system planning problem as much as a real-estate or information-technology problem. Recent federal analysis indicates data centers consumed about 176 terawatt-hours (TWh) in 2023 (about 4.4% of total U.S. electricity use) and could reach roughly 325–580 TWh by 2028 (about 6.7%–12%), depending on broader economic and electricity demand growth (U.S. Department of Energy [DOE], 2024). [1] These levels of load growth are material at a bulk-power-system scale and are arriving faster than most traditional generation, transmission, and distribution (T&D) investment cycles—especially in regions already constrained by transformer lead times, siting and permitting timelines, and limited interconnection and construction capacity. [2] Interconnection bottlenecks—historically framed as a generator problem—now collide with large-load connection timelines and cost responsibility debates. At the transmission level, DOE reports the interconnection queues have expanded from under 500 gigawatts (GW) in 2010 to roughly 2,600 GW "today," with more than 95% associated with zero-carbon generation and storage; DOE also notes that time-to-interconnect has more than doubled nationally. [3] Independently, Berkeley Lab's queue synthesis reports that, as of end-of-2024, thousands of projects and thousands of gigawatts remain in queues, and median durations from interconnection request to commercial operation have risen to over four years for recently completed projects in regions with available data. [4] Even when data centers are not themselves "in the queue" (because loads often follow different or less transparent processes than generation), the same constrained equipment, studies, and network upgrade construction resources govern whether new load can be served on feasible timescales. [5] Power infrastructure constraints are now observable in reliability performance. NERC identifies "large loads"—including data centers—among the most significant near-term reliability challenges, citing observed events in which approximately 1,500 MW of data centers disconnected simultaneously and unexpectedly from the bulk electric system (BES) in 2024 after a transmission fault, creating balancing and stability challenges analogous in magnitude to a large nuclear plant changing output unexpectedly. [6] This operational reality re-frames "speed-to-power" strategies: getting connected quickly is not sufficient if poor load observability, protection coordination, and flexibility arrangements raise system risk or shift costs to other customers. [7]**

**Keywords: U.S. Data Center Growth Electricity Demand (TWh), Artificial Intelligence (AI), Cloud Computing & Digitalization, Bulk Power System**

## I. INTRODUCTION

Data centers are critical infrastructure for the modern U.S. economy, enabling cloud computing, AI model training and inference, e-commerce, health systems, and government and defense information services. Their defining characteristic—high, concentrated, largely continuous electric load—creates direct coupling between digital infrastructure investment and the pace and structure of grid investment. Federal and laboratory assessments show that U.S. data center electricity use increased markedly between 2014 and 2023 and could plausibly double or triple again by 2028, with uncertainty driven by AI server deployment rates, cooling technology adoption, and broader economic demand. [14] The resulting question is not whether data centers will strain parts of the grid, but how to manage that strain through interconnection design, infrastructure investment, rate design, and operational flexibility—

while meeting decarbonization, air quality, water stewardship, and community impacts.

Three dynamics shape the problem. First, interconnection and upgrade processes were designed around incremental load growth and comparatively predictable generation additions; they are now confronting rapid large-load clustering and simultaneous generation, storage, and transmission queue backlogs. [15] Second, physical infrastructure—transformers, substation equipment, transmission rights-of-way, and qualified labor—has long lead times and is vulnerable to supply-chain shocks, constraining how quickly utilities can serve large new loads even when capital is available. [16] Third, reliability and ratepayer protection concerns are increasingly salient: large-load volatility and fault response can create stability events, and poorly structured tariffs can socialize infrastructure costs if large customers underutilize reserved capacity or exit early. [17]

**Research questions and scope**

**This study addresses the following research questions:**

1. What are the principal grid interconnection and power infrastructure constraints that limit sustainable data center expansion in the United States, and how do they vary across regions and market structures? [18]
2. How do interconnection reforms, utility tariffs, and permitting and siting processes affect data center "speed-to-power" outcomes, cost responsibility, and reliability? [19]
3. Which technical solutions (distributed energy resources, microgrids, storage, demand response, renewable integration) and policy solutions best mitigate constraints while aligning with sustainability and equity objectives, and what are their practical implementation steps? [20]
4. What are the economic implications—upgrade cost ranges, financing models, and tariff impacts—of alternative pathways to serve large data center loads, and how should costs be allocated to minimize inefficiency and inequity? [21]

The geographic scope is the United States without a single-region constraint. The technical scope includes bulk transmission planning, distribution upgrades that are material to large-load service, on-site and behind-the-meter options, and operational strategies for load flexibility. The sustainability scope includes greenhouse gas and criteria pollutant implications of backup and bridging generation, renewable integration challenges, and community impacts related to siting, water, and land use, noting that some environmental and cost details are not publicly disclosed for specific projects and must therefore be treated as unspecified. [22]

## II. LITERATURE REVIEW

This literature review integrates primary and official sources with peer-reviewed and high-quality industry analyses to characterize constraints and solution pathways for sustainable data center expansion.

**Grid interconnection and queue dynamics**

At the federal level, the most comprehensive recent framing of interconnection bottlenecks comes from DOE's Interconnection Innovation e-Xchange (i2X) Transmission Interconnection Roadmap. DOE reports that interconnection queues expanded from less than 500 GW in 2010 to roughly 2,600 GW, exceeding existing installed U.S. generation capacity in scale; DOE further emphasizes that time-to-interconnect has more than doubled. [3] This is primarily a generator and storage queue metric, but it directly influences data center expansion because network upgrades, engineering capacity, and construction backlogs are shared constraints across new generation, storage, and expanding loads. [23]

Complementing DOE, Berkeley Lab's queue synthesis reports that as-of end-of-2024 the queue remains extremely large and that median durations from interconnection request to commercial operation date have increased to more than four years for projects built in 2018–2024 (in regions where data are available). [4] Even projects with draft or executed interconnection agreements can remain "stuck" awaiting upgrade construction and final energization, revealing a gap between study completion and infrastructure delivery. [24]

FERC's Order No. 2023 responds to these conditions by requiring a shift toward cluster studies with standardized timelines, imposing penalties for late studies, and tightening financial readiness and site control requirements intended to reduce speculative queue entries and late-stage withdrawals (FERC, 2023). [25] Order No. 2023-A clarifies elements of this reform package, including limiting application corrections primarily to within the cluster request window while permitting minor technical corrections in some circumstances (FERC, 2024). [26] Although these reforms target generator interconnection, they affect data center expansion indirectly through generation availability, regional capacity adequacy, and transmission upgrade pipelines.

**Large-load reliability, modeling, and observability**

Traditional reliability discourse emphasizes generation adequacy and contingency response. Recent NERC assessments add a new emphasis: the "size and speed" of data center connections create near-term reliability challenges because collective data center behavior (including voltage sensitivity and response to faults) is not well captured in current models. [6] NERC cites observed events in which approximately 1,500 MW of data centers disconnected unexpectedly in response to a fault, producing rapid frequency and voltage effects; NERC also notes smaller but similar events in ERCOT. [6] These findings substantiate the need for explicit large-load interconnection procedures, telemetry requirements, and operational coordination analogous to those long applied to large generators. [7]

**Tariffs, cost responsibility, and anti–cost-shift mechanisms**

As large loads accelerate, regulators and utilities are increasingly addressing the risk that infrastructure investments made to serve data centers could be shifted to other customers if large-load forecasts are overstated or if customers leave before costs are recovered. [27] In Virginia, the SCC established a GS-5 class for customers demanding 25 MW or more, with minimum payment requirements (including minimum payments for 85% of contracted distribution and transmission demand and 60% of generation demand) beginning January 1, 2027, explicitly to insulate other ratepayers from rapid infrastructure build-out. [12]

In Arizona, SRP describes a large-customer process and rate design changes intended to keep "upgrade costs" with the requesting large-load customers, including an LCIP that determines required infrastructure and provides customer-specific cost estimates that must be paid upfront, alongside minimum billing for new ≥20 MW accounts based on the higher of actual demand or 80% of forecasted load. [13] Industry advisory work similarly emphasizes special contracts, collateral, minimum bills, and term commitments as common approaches to address cost recovery and cross-subsidy risks. [28]
Permitting, siting, and transmission constraints

Transmission and substation projects face multi-layered permitting: state utility commission determinations of need and route, local land-use approvals (especially for substations and distribution upgrades), environmental review, and sometimes federal land and endangered species processes. DOE's National Transmission Needs Study (published October 2023) characterizes a "pressing need" for additional transmission infrastructure across nearly all regions, with congestion and high prices persisting in multiple regions; it also emphasizes that increasing interregional transfer capability yields large benefits. [29]

At the project level, Dominion Energy's Culpeper Tech Zone 230 kV project illustrates how data center load growth can drive new substations and voltage upgrades, including multiple new substations and upgrades of existing 115 kV lines to 230 kV, with a documented timeline from filing (February 20, 2025) to a final order approval (March 12, 2026). [30] Such projects highlight how "data center expansion" can translate into many discrete right-of-way, substation, and line upgrade actions, each with its own permitting steps and exposure to supply-chain constraints.

**Distributed energy resources, microgrids, storage, and demand response**

A prominent solution theme is making data centers "grid-interactive" rather than purely passive loads. EPRI's DCFlex initiative (launched 2024) frames data centers as potential grid assets via computational flexibility and coordinated operations, describing a field demonstration in which an AI compute cluster reduced power consumption by 25% over a three-hour peak event without compromising essential services. [31] Berkeley Lab similarly argues that demand flexibility has not scaled commensurately with enabling technologies such as advanced meters and that surging load growth—including from data centers—makes demand flexibility urgently needed to mitigate capacity constraints and interruptions. [32]

Energy storage is central to both resilience and flexibility strategies, but it introduces material costs. NREL provides a 2025 update on utility-scale lithium-ion battery system costs, reporting a 2024 starting point near $334/kWh for a 4-hour battery system (in 2024 dollars) and projections that vary across low/mid/high scenarios. [33] These cost benchmarks enable structured economic comparison between grid upgrades and flexibility resources used to reduce peak demand and defer infrastructure.

**Renewable integration, backup generation, and environmental impacts**

Renewable procurement via power purchase agreements (PPAs) or utility green tariffs helps decarbonize energy supply, but it does not automatically solve local deliverability constraints, substation limitations, or the need for firm capacity during peaks. The persistence of high congestion costs suggests that deliverability and network constraints are economically significant. [34]

Backup generators—especially diesel—remain common for reliability compliance, but their use intersects with air permitting and regulatory limits. Federal emissions frameworks for emergency stationary reciprocating internal combustion engines (RICE) generally allow unlimited operation in actual emergencies and limited operation for maintenance/testing, with additional conditions on non-emergency operation (e.g., operation up to 50 hours per year in certain non-emergency contexts counted within a 100-hour allowance, depending on classifications and conditions). [35] These rules matter for data center strategies that propose shifting to generator power during grid stress or while awaiting interconnection, because increased operating hours can trigger compliance obligations and community air quality concerns, especially where large-scale concentrated backup capacity is deployed.

## III. METHODOLOGY

This research uses an expository analytical design integrating (a) structured policy and regulatory analysis, (b) comparative case studies, and (c) transparent cost benchmarking.

**Sources**

Primary and official sources include federal agency and reliability organization publications, including:

- Interconnection and planning rules and explainers from Federal Energy Regulatory Commission[36] (Orders 2023/2023-A and 1920 and related materials). [37]
- Interconnection backlog characterization and solutions frameworks from U.S. Department of Energy[38], including the i2X roadmap and the National Transmission Needs Study overview. [39]
- Reliability assessments and large-load risk frameworks from North American Electric Reliability Corporation[40], especially the 2025 State of Reliability overview and the emerging large loads white paper. [41]
- Supply-chain and equipment lead-time constraints from DOE's Large Power Transformer Resilience report. [9]
- Air emissions rules relevant to backup generation from U.S. Environmental Protection Agency[42], including eCFR summaries and guidance memoranda. [43]

**For quantitative cost benchmarks, we use:**

- Transmission and substation unit costs and $/mile estimates from Midcontinent

Independent System Operator[44]'s transmission cost estimation guide. [45]

- Utility-scale battery cost benchmarks from National Renewable Energy Laboratory[46]. [33]
- Congestion cost synthesis from Grid Strategies LLC[47], used as an indicator of economic value at stake in transmission constraints (with acknowledgment that compilation methodologies involve assumptions). [8]

**State and utility tariff responses are grounded in:**

- The Virginia State Corporation Commission[48] GS-5 class description and minimum demand provisions. [12]
- Salt River Project[49]'s published large-customer process and minimum billing descriptions. [13]
- An industry advisory report by Concentric Energy Advisors[50] providing contextual trends and rate design themes. [51]

**Analytic approach**

First, the literature and regulatory texts were synthesized into a constraint taxonomy spanning: (1) interconnection processes and queue dynamics, (2) transmission and distribution infrastructure and supply chains, (3) tariffs and cost allocation, (4) permitting and siting, (5) flexibility and DER integration, and (6) environmental and social impacts. [52]

Second, comparative case studies were selected to represent: the Mid-Atlantic (PJM and Virginia), the Southwest (Arizona), Texas (ERCOT), and the Intermountain West (Nevada). Cases were chosen based on availability of publicly documented load magnitude (MW), described interconnection or infrastructure timelines, and explicit strategies (e.g., utility partnerships, co-location, or tariff design). [53] Third, a cost benchmarking model was constructed using published unit costs ($/mile for transmission, $/substation upgrade, and $/kWh for storage) to provide order-of-magnitude comparisons between "grid upgrade" and "flexibility/onsite" strategies. All cost figures are treated as benchmarks rather than project-specific quotations unless the source explicitly ties the cost to a named project. [54]

## IV. CASE STUDIES

**Comparative table of regional examples**

The table below summarizes five U.S. cases across regions. Where public sources do not specify values (a frequent limitation for privately negotiated interconnection studies, distribution upgrade costs, and proprietary "speed-to-power" agreements), entries are marked as unspecified.

| Case | Region | Approx. load / capacity | Interconnection / infrastructure timeline (publicly stated) | Strategies / solutions applied | Costs (publicly stated) | Outcomes / status (as of 2026-03-18) |
|---|---|---|---|---|---|---|
| STACK Infrastructure[55] Stafford Technology Campus | Virginia[56] (Mid-Atlantic) | "1+ GW" campus; six 300 MW substations referenced | Announcement in Sep 2025; energized timeline not specified | Early power commitments with utility; campus-scale planning; reclaimed water for cooling | $58M capital investment program (CIP) elimination cited; ~$80M annual county tax revenue cited | Development positioned as large-scale campus with utility power commitments; detailed interconnection timeline and cost allocation not fully specified publicly |

| Case | Region | Approx. load / capacity | Interconnection / infrastructure timeline (publicly stated) | Strategies / solutions applied | Costs (publicly stated) | Outcomes / status (as of 2026-03-18) |
|---|---|---|---|---|---|---|
| Vantage Data Centers[57] NV1 campus | Nevada[58] (Intermountain West) | 224 MW campus; 500 MW on-site substation planned | First building scheduled to open Q2 2026 | On-site substation planning; higher-density design and cooling; water reduction via closed-loop chiller system | "Nearly $3 billion" investment cited | Expansion into Nevada framed as accelerating time-to-market; grid impacts managed via substation and site design details; full utility interconnection agreement details not publicly disclosed |
| Project Blue power deal dispute | Arizona[59] (Southwest) | 286 MW requested | Contract approved by regulators in Dec 2025; expansion potential noted | Utility contract for large load; regulatory scrutiny of rate impacts | $3.6B project cost cited | Active political and regulatory contest regarding ratepayer impacts and governance of large-load power deals |
| Susquehanna co-location proposal | Pennsylvania[60] (PJM region) | Up to 480 MW co-located load scale referenced | FERC rejection of amended arrangement in Nov 2024; FERC directed PJM tariff revisions in Dec 2025 | Co-location with generation; tariff and transmission service rulemaking to protect consumers and reliability | Cost specifics not stated in cited public summaries | Regulatory pathway evolving; FERC directs PJM to establish transparent rules and transmission service options for co-located loads |
| ERCOT emerging large loads pipeline | Texas[61] (ERCOT) | 239 GW "large load" requests reported (not all data centers) | As-of Sept 2025 reporting; planning processes evolving | Large-load discipline via front-end information requirements; grid planning for rapid load growth | System-level costs not stated in cited summary | Highlights magnitude of speculative and prospective large load and the need for process discipline and |

| Case | Region | Approx. load / capacity | Interconnection / infrastructure timeline (publicly stated) | Strategies / solutions applied | Costs (publicly stated) | Outcomes / status (as of 2026-03-18) |
|---|---|---|---|---|---|---|
| | | | | | | transmission planning |

Sources for Stafford campus and tax/capacity statements:
Sources for NV1 campus: [62]
Sources for Project Blue dispute: [63]
Sources for PJM co-located load rule direction: [64]
Sources for ERCOT large load request magnitude: [65]

**Case narratives and analytic implications**

Mid-Atlantic hyperscale clustering and utility partnership. The Stafford Technology Campus announcement illustrates a core "speed-to-power" thesis: developers attempt to de-risk power delivery by securing utility commitments at campus scale. The project references more than 1 GW of planned capacity and explicitly links scale to six 300 MW substations, while also highlighting local fiscal impacts (e.g., cited CIP elimination and annual tax revenue). The policy implication is that "campus-scale" planning can reduce fragmentation but can also create multi-county, multi-substation scale externalities that require tariff and cost responsibility mechanisms to prevent cross-subsidy when reserved capacity is not utilized. [66]

Intermountain West: time-to-market through substation-first design. The Nevada NV1 campus demonstrates a strategy increasingly visible in public siting narratives: building or planning a dedicated on-site substation (here referenced at 500 MW) to secure deliverable power while leveraging site design (e.g., high-density capability and water-reducing cooling design). [62] The implication is that "substation-first" approaches shift the bottleneck from real estate to utility and equipment procurement, where transformer lead times may be multi-year. [9]

Southwest: political contestation over rate impacts. The Project Blue dispute illustrates that even when interconnection is technically feasible, the political economy of contracts and tariffs can become a gating constraint. A 286 MW request and a $3.6B project were described alongside concern that contract terms could raise rates for other customers, motivating calls for reconsideration. [63] This aligns with broader utility trend reports emphasizing special contracts and financial assurances to address cost recovery and equity concerns. [67]

PJM co-location: regulatory evolution for novel load configurations. The Susquehanna co-location case illustrates an emerging structural issue: when data centers seek direct association with existing generation, tariff clarity and transmission service definitions become contested. FERC's public communications highlight consumer protection and reliability as the justification for directing PJM to establish transparent rules and transmission service options for co-located loads. [64] The implication is that "bring-your-own-generation" does not automatically avoid transmission cost allocation disputes; rather, it can relocate them into new tariff categories and jurisdictional debates. [68]

ERCOT: scale of prospective large-load demand. ERCOT's reported 239 GW of large load requests underscores a system-scale planning problem: the queue of load may be an order of magnitude larger than near-term feasible buildout, suggesting a need for readiness screens, staged energization, and deposit/collateral mechanisms analogous to generator queue reform. [69] This also reinforces NERC's emphasis that the speed and magnitude of data center connections create reliability modeling and balancing challenges. [6]

# V. TECHNICAL AND POLICY SOLUTIONS

This section evaluates solutions across interconnection process design, power infrastructure, and sustainable operations. The guiding principle is portfolio optimization: no single intervention solves the combined constraints of timelines, reliability, emissions, and cost allocation.
Interconnection and planning reforms

Cluster studies and "first-ready, first-served." FERC Order No. 2023 requires transmission providers to adopt cluster study processes, improve study timeline discipline, and strengthen readiness requirements (including site control and financial security) to reduce speculative entries and late withdrawals (FERC, 2023). [25] Order No. 2023-A clarified aspects of cure periods and expanded certain "option to build" interpretations where cluster participants mutually agree. [26] Although framed for generation, these reforms matter for data centers because adding new generation and storage is the principal scalable pathway to serve sustained load growth without relying on higher-emitting peakers or prolonged backup operation. [70]

Pros: improved throughput of viable projects, clearer timelines, and reduced drag from non-viable projects. [71]
Cons: higher upfront requirements can disadvantage smaller developers and may require complementary financing tools; cluster processes can still bottleneck at upgrade construction. [72]

Implementation steps: (1) standardize and publish data requirements and interconnection model assumptions; (2) adopt milestone-based withdrawal penalties and security that reflect actual study and construction costs; (3) align queue windows with long-term transmission planning cycles so that upgrades are anticipatory rather than purely reactive. [73]

Long-term transmission planning and cost allocation. FERC's Order No. 1920 requires reforms to long-term regional planning and cost allocation, with rehearing orders clarifying and elevating state involvement and consultation in cost allocation methods (FERC, 2024–2025). [11] DOE's Needs Study overview independently emphasizes the nationwide value of both within-region and interregional transmission investment and identifies regional congestion and high-price regions where transmission expansion could lower prices and improve resilience. [29] For data centers, the direct policy relevance is that long-lived load growth may justify proactive high-voltage corridors and substation reinforcements rather than serial, customer-triggered upgrades that arrive after multi-year delays. [34]

Pros: structural congestion relief, improved resource sharing during extreme events, better utilization of diverse generation portfolios, and the potential to reduce recurring congestion costs. [34]
Cons: siting resistance, multi-jurisdiction coordination costs, and disputes over beneficiary-pays allocation. [74]

Implementation steps: (1) integrate large-load forecasts into regional plans with probabilistic scenarios (not single-point estimates); (2) adopt portfolio-based benefits metrics that include reliability, congestion relief, and resilience; (3) pre-identify "data center growth zones" where transmission and substation upgrades can be routed with lower conflict while maintaining community engagement. [75]

**Utility tariff and contract design for large-load integration**
Minimum bills, take-or-pay demand commitments, and collateral. A recurring design goal is to reduce the risk of stranded assets and socialized costs when a large customer reserves capacity but underutilizes it or exits early. Virginia's GS-5 class formalizes this by requiring minimum payments tied to contracted demand (e.g., minimum payments for 85% of contracted distribution and transmission demand), intended to insulate other customers from infrastructure build-out costs. [12] SRP similarly describes minimum billing tied to forecasted load (80% for new ≥20 MW accounts) and requires new large loads to pay upfront for their specific infrastructure upgrades determined through its LCIP. [13]

Pros: reduces cross-subsidy risk, improves utility credit metrics, and encourages more accurate load forecasting. [76]

Cons: can increase barriers to entry and may distort siting decisions if tariffs differ sharply across territories; poorly designed minimums could reduce incentives for efficiency if bills are dominated by fixed demand charges. [28]

Implementation steps: (1) require staged load commitments with verification (e.g., energize in tranches with demonstrated equipment installation); (2) incorporate performance-based adjustments that reward demand flexibility participation; (3) harmonize distribution and transmission cost responsibility to avoid shifting costs between network layers. [77]

**Grid-interactive operations: demand response, flexibility, and DER integration**

NERC's large-load findings imply that the "grid-interactive" agenda is no longer optional: data centers must be observable and predictable during disturbances, and they can provide system value if managed with appropriate controls and market products. [6] EPRI's DCFlex initiative demonstrates operational feasibility of partial load reduction through workload management (e.g., 25% reduction over three hours in a field test) and frames a multi-stakeholder pathway to scale such practices. [31] Berkeley Lab's demand flexibility maturity model further suggests that demand flexibility has not advanced beyond traditional direct load control in many jurisdictions and argues that surging load growth makes DF urgently needed. [32]

**Key grid-interactive strategies include:**

1. Workload shifting and compute-aware dispatch. This includes shifting non-latency-critical compute to off-peak periods or geographically to lower-stress markets, subject to cybersecurity and data governance constraints. This pathway is directly aligned with demonstrations described in DCFlex field testing. [31]
2. UPS and power electronics coordination for fault response. Given NERC's concerns about voltage-sensitive load reductions and collective behavior, data center power electronics should be designed and tested as grid-interactive assets, not only as internal reliability devices. [78]
3. Demand response participation with clear environmental guardrails. Demand response that relies on emergency generators must comply with federal and state emissions rules, including limits on non-emergency operating hours and conditions for participation in certain reliability arrangements. [43]
4. On-site storage for peak shaving and ride-through. Storage can reduce coincident peak demand and provide short-duration back-up to avoid frequent generator starts, but it is capital intensive, and design should be justified by avoided network upgrade costs and reliability value. [79]

**Backup power decarbonization and compliance**

Data centers' reliability requirements often depend on N+1 or 2N redundancy, traditionally anchored by diesel generators. Federal rules for emergency engines allow unlimited operation in true emergencies but impose constraints on non-emergency operation for maintenance/testing and certain grid-support activities, with additional conditions and reporting expectations depending on the emission standard and engine classification. [35] The sustainability challenge is that "bridging" strategies (using generators more frequently while awaiting grid upgrades) can raise local air quality impacts and may conflict with decarbonization commitments unless alternative fuels, storage, and emissions controls are deployed. [80]

Implementation priorities include: (1) generator run-hour governance and independent monitoring; (2) evaluation of lower-emission backup options (renewable diesel, fuel cells, or hybrid storage-generator systems) where feasible; and (3) transparent community reporting on generator capacity, expected runtime, and emissions compliance. [81]

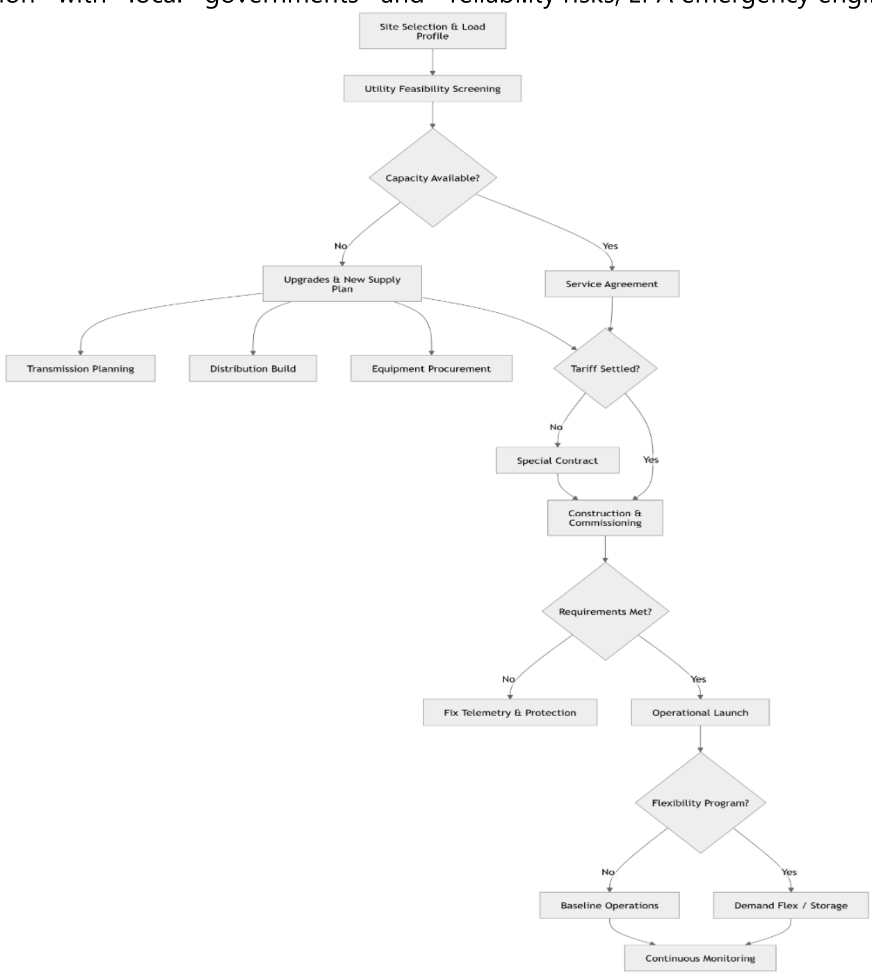
**Permitting acceleration with environmental and social safeguards**

Permitting and siting constraints are often the critical-path items for transmission lines and substations. Dominion's Culpeper Tech Zone project description highlights that the SCC is responsible for verifying need, approving route and structures, and reviewing environmental impacts for certain lines, illustrating the formal state regulatory pathway that must be navigated even for projects framed as supporting data center reliability and growth. [30] DOE's transmission needs overview similarly emphasizes that new transmission is needed broadly for reliability and congestion reduction, implying that permitting reform alone is insufficient without planning discipline and community engagement mechanisms. [29]

Sustainable permitting acceleration should include: early consultation with local governments and affected communities; use of standardized environmental assessment templates for substations and reconductoring projects; and transparent mitigation and benefit-sharing mechanisms (e.g., local workforce development, noise mitigation, and water stewardship commitments). [82]

**Systems integration overview diagram**

The following flowchart summarizes a practical "decision architecture" for sustainable data center power delivery that integrates interconnection, infrastructure, tariffs, flexibility, and compliance. (Supporting sources: FERC interconnection reforms, DOE interconnection roadmap, NERC large load reliability risks, EPA emergency engine rules.) [83]




## VI. ECONOMIC ANALYSIS

Economic analysis is organized around (1) the scale of system costs implied by congestion and upgrade needs, (2) benchmarked infrastructure and flexibility costs, and (3) financing and tariff impacts.

**Macro indicators: congestion and the cost of constrained power delivery**

Transmission congestion costs provide a market-based indicator of the economic impact of constrained deliverability in organized markets. A multi-market synthesis estimated congestion costs above $12 billion in 2024 and argued that $10–$20 billion per year has become a “new normal,” linking this persistence to limited transmission expansion, rising demand, extreme weather, and outages. [8] While congestion is not the only cost imposed by constrained grids (and data for non-RTO regions are less transparent), its persistence supports the inference that transmission constraints are large enough to influence data center siting and the rate impacts of serving incremental load in constrained areas. [84]

**Benchmark infrastructure costs: transmission lines and substations**

Public cost benchmarking is challenging because project costs vary with terrain, land acquisition, permitting, labor, and equipment. However, MISO’s Transmission Cost Estimation Guide provides standardized exploratory unit cost estimates for new lines and substation upgrades, including contingency (30%) and allowance for funds used during construction (AFUDC, 7.5%). [85] These values enable transparent “order-of-magnitude” comparisons that can be adapted to non-MISO regions as indicative benchmarks (with acknowledged uncertainty).

New 230 kV single-circuit line costs ($/mile). In MISO’s estimates, new single-circuit 230 kV transmission line costs range around ~$2.0M–$2.6M per mile depending on location (e.g., ~$2.2M in Illinois; ~$2.5M in Texas; ~$2.3M in Wisconsin). [86]
Substation upgrade and new substation costs. MISO provides exploratory costs for adding positions at substations (ring bus, breaker-and-a-half, double-breaker bus) and for building a new 4-position substation. For example, adding two positions at a 230 kV substation is estimated at ~$4.3M (ring bus) to ~$6.8M (double-breaker), and a new 4-position 230 kV substation (ring bus) is estimated at ~$11.1M (inclusive of contingency and AFUDC). [87]

These benchmarks can be used to quantify how much “grid-side capex” might be needed to serve a large campus under plausible configurations: connecting a load cluster often requires both a line extension and substation capacity additions, not merely one or the other. [88]

**Benchmark flexibility costs: utility-scale storage**

NREL reports a 2024 starting cost of approximately $334/kWh for a complete 4-hour lithium-ion battery system (2024$), derived from a bottom-up model and literature synthesis; this provides a basis for comparing storage deployment to avoid or defer some network upgrades. [33] On this basis, a 100 MW / 400 MWh battery would imply an overnight capital cost on the order of $134 million (400,000 kWh × $334/kWh), before site-specific interconnection, land, and operational integration costs. [33] This magnitude illustrates why storage is typically justified by a combination of values—resilience, demand charge reduction, reliability services, and deferral of specific upgrades—rather than as a universal substitute for T&D reinforcement. [89]

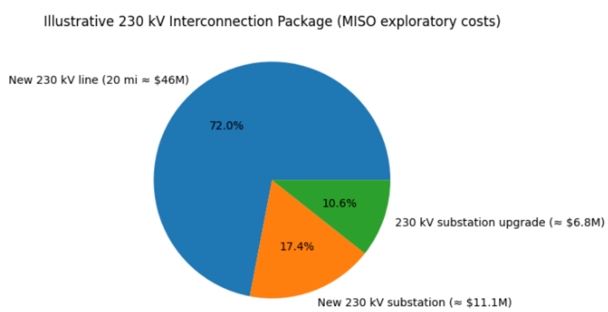
**Upgrade cost uncertainty as a barrier to new supply and, indirectly, to data center power access**

A major economic barrier is the unpredictability and volatility of network upgrade costs in interconnection studies. A working paper analyzing PJM interconnection study data argues that the “generator-pays” model for network upgrades, combined with insufficient proactive transmission investment, creates a bottleneck that impedes generation expansion; it also notes that interconnection cost data are not systematically collected by EIA and are not easily accessible. [90] The paper finds that greater prior transmission spending can reduce the probability of high network upgrade costs, implying a benefit from anticipatory transmission investment. [91]

For data centers, the analogous barrier is that uncertainty in when and at what cost upgrades can be delivered raises project financing costs and can encourage “off-grid” or behind-the-meter solutions that may reduce cost-shifting risks but can increase emissions or reduce system-wide benefits if not structured to provide grid services. [92]

**Illustrative MISO-based cost breakdown chart**

The chart below shows an illustrative grid-side interconnection package using MISO's exploratory cost benchmarks for a 230 kV solution comprising: (a) 20 miles of new single-circuit 230 kV line in a representative location with ~$2.3M/mile costs, (b) one new 4-position 230 kV substation (~$11.1M), and (c) one 230 kV substation upgrade adding two positions (double-breaker bus, ~$6.8M). Values include contingency and AFUDC per MISO assumptions. [93]




This illustrative breakdown underscores two planning points. First, even modest mileage line extensions can dominate the cost stack, which reinforces the value of reconductoring and advanced transmission technologies where feasible rather than always building new corridors. [34] Second, substation "position" costs are non-trivial, and transformer/switchgear procurement lead times can govern schedule feasibility even when capital is available. [94]

**Financing models and tariff impacts**

Ratebase financing vs. customer-funded upgrades. Traditional utility infrastructure is financed through ratebase investment recovered over time from all customers. However, large-load growth has triggered efforts to align incremental costs to incremental customers—through special contracts, minimum bills, and upfront contributions—especially where utilities fear stranded assets. [95] In practice, many hybrid models exist: utilities may build shared backbone upgrades via ratebase while requiring customer-specific connections and dedicated substations to be customer-funded or subject to take-or-pay commitments. [96]

Minimum bills and risk pricing. The Virginia GS-5 structure embodies a tariff-based risk pricing logic: requiring payment for a substantial fraction of contracted demand reduces risk that reserved capacity goes unused while other customers pay for infrastructure. [12] SRP's E-67 minimum billing design similarly aims to prevent over-forecasting and protect other customers by tying minimum bills to forecasted load. [13] These mechanisms have economic tradeoffs: they can enhance system planning by improving forecast credibility, but they can also raise the cost of experimentation and phased deployment for emerging AI infrastructure. [97]

Flexibility as a financial lever. A central policy opportunity is to treat demand flexibility participation as a basis for reducing required fixed infrastructure or relaxing minimum bill levels. This aligns with Berkeley Lab's argument that demand flexibility is underutilized relative to enabling technology deployment and with EPRI's empirical demonstration that some compute loads can be flexed materially for limited periods. [98]

## VII. RECOMMENDATIONS AND IMPLEMENTATION ROADMAP

Recommendations are organized by time horizon, recognizing that different constraints dominate at different stages (e.g., near-term transformer supply vs. long-term transmission siting). The roadmap is designed for implementation by utilities, grid operators, regulators, and data center developers.

**Near-term recommendations**

Establish standardized large-load interconnection and observability rules. Given NERC's documented reliability events and modeling gaps, large-load interconnection should include mandatory telemetry, fault ride-through compatibility expectations (as applicable), and validated load models for power-electronic behavior, coordinated between distribution utilities and transmission operators. [78]

Adopt staged energization with enforceable financial commitments. Utilities and regulators should require staged load commitments tied to verified construction milestones and should use minimum bills or take-or-pay contracts to reduce cost shifting. Virginia's GS-5 and SRP's large-customer approaches provide concrete models. [66]

Prioritize transformer and substation supply chain management. Utilities serving data center clusters should treat transformer procurement and spare strategies as strategic constraints, consistent with DOE's finding of lead times up to and exceeding 36 months and broader supply vulnerabilities. [9]

**Medium-term recommendations**

Align interconnection reform implementation with transmission planning reforms. Implementing Order 2023 reforms without parallel long-term planning can shift bottlenecks from studies to construction; implementing Order 1920 planning without queue discipline can create misaligned projects. Regulators and grid operators should align queue windows, interregional planning, and cost allocation approvals. [99]

Scale data center demand flexibility as a grid resource. Expand pilots and procurement mechanisms for data center flexibility (compute shifting, UPS-mediated services, short-duration reductions), using maturity-model frameworks to move beyond direct load control programs and integrate third-party technologies where performance verification is robust. [98]

Use targeted transmission upgrades and substation reinforcements in growth zones. Projects like Dominion's Culpeper Tech Zone illustrate practical multi-component upgrades tied to data center growth; regulators should encourage portfolio planning for such zones to reduce serial permitting and construction cycles. [100]

**Long-term recommendations**

Build interregional transfer capacity and modernize regional networks. DOE's needs assessment emphasizes broad national benefits of additional transmission and particularly interregional transfer expansion; meeting data center-driven load growth sustainably implies reducing congestion and expanding access to diverse and lower-cost resources. [84]

Transition backup generation toward lower-emission portfolios under enforceable rules. Ensure emissions compliance frameworks are incorporated into planning for "bridging" and demand response strategies that could increase generator run hours, using EPA operational constraints as guardrails and prioritizing hybrid solutions (storage plus limited generator use) where feasible. [101]

**Implementation roadmap timeline**

The following roadmap summarizes sequenced implementation. (Supporting sources: DOE interconnection roadmap; FERC Orders 2023 and 1920; NERC large load risks; Virginia and SRP tariff responses; DOE transformer report.) [102]

| Year | Implementation Milestone |
|---|---|
| 2026 | Large-load observability standards established; staged energization contracts adopted; transformer procurement accelerated |
| 2027 | Large-user tariff classes and minimum bill frameworks expand across jurisdictions; flexibility pilots scale |
| 2028 | Cluster interconnection reforms mature; transmission planning integrates long-term load scenarios |
| 2030 | Targeted high-voltage buildout in growth zones; advanced transmission technologies and reconductoring scale |
| 2035 | Interregional transfer capacity expands; grid-interactive data centers become standard resource participants |

## VIII. CONCLUSION AND RESEARCH GAPS

U.S. data center expansion is now tightly linked to the practical limits of grid interconnection processes, transmission deliverability, distribution and substation construction capacity, and equipment supply chains. DOE and Berkeley Lab analyses show data center electricity use is already a multi-hundred-TWh phenomenon with plausible growth to a substantial share of national electricity by 2028, implying an infrastructure challenge that cannot be addressed by isolated substation builds or by voluntary corporate procurement alone. [1] Interconnection queue backlogs, increasing time-to-interconnect, and persistent congestion costs indicate that the grid is operating under structural constraints, reinforcing the need for anticipatory transmission planning and reforms that reach beyond paperwork timelines to the physical delivery of upgrades. [103]

Reliability evidence from NERC demonstrates that large-load behavior—particularly data centers—has become a system operations issue, with documented high-magnitude disconnection events and explicit calls for improved modeling and planning tools. [6] As a result, sustainable expansion requires not only more infrastructure but also better integration rules: telemetry, load modeling, and operational protocols that make large-load response predictable during contingencies. [7]

From an equity and ratepayer protection perspective, emerging tariff models (e.g., GS-5 in Virginia and SRP's LCIP and minimum billing reforms) show that regulators are increasingly unwilling to socialize rapid large-load infrastructure costs without substantial customer commitments. [66] These mechanisms can reduce cost shifting but must be complemented by pathways that reward grid-supportive flexibility and efficiency so that "minimum bill" regimes do not inadvertently discourage innovation in load management. [104]

**Research gaps**

**Several gaps limit both scholarship and policy design:**

1. Transparency of large-load interconnection data. Unlike generator queues, large-load connection requests and associated upgrade costs are often opaque, limiting empirical assessment of cost drivers and the effectiveness of tariff mechanisms. [105]
2. Validated models of data center power electronics and collective behavior. NERC's findings suggest current models are insufficient for planning and operational practices as load clusters grow. Research is needed on standardized load models, fault response behavior, and protection coordination for data center UPS and on-site systems. [78]
3. Causal evaluation of flexibility programs for data centers. Pilot results are promising, but peer-reviewed evaluation is needed on performance, rebound effects, and reliability value across diverse grid conditions and market designs. [104]
4. Integrated environmental assessment of "speed-to-power" strategies. Bridging strategies that increase generator runtime raise complex interactions with emissions rules and local air quality; more systematic data are needed on actual runtime, fuel choices, and compliance outcomes. [106]
5. Capital structure and risk allocation design. Research should test how minimum bills, collateral, staged energization, and flexibility credits interact with investment incentives, local economic development, and long-term system efficiency in different regulatory environments. [107]

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