Alliance for Transportation Electrification

Summary of Publications: Recent Literature on EVs, EV Charging and the EV Ecosystem

November 2026

Overview

In November 2025, the Alliance for Transportation Electrification (ATE) issued a paper that summarized recent literature focusing on transportation electrification issues in small vehicle fleet markets and multi-family (MFH) housing. That summary of publications published by ATE in November 2025 was well received and ATE decided that summarizing new publications focusing on EVs, EV charging and the EV ecosphere on a periodic basis would be a useful service to ATE members and industry stakeholders. The second summary was published earlier this year in March and is available at https://ate-ev.org/resource/summary-of-publications-q1-2026/.

As in the other summaries, in this current edition we focus on reports which we think will be of the greatest interest to our membership and reports that have received significant attention. We cover eight different reports published since last spring that cover a broad range of issues including:

- newly developing policies that will help reduce EV charging station interconnection times – specifically flexible interconnection and proactive investment;
- several studies that while not specifically covering EV policy issues, present methodologies for examining the grid and rate impacts of large loads or distributed energy resources (DERs). These methodologies can be adopted to address the impacts of EVs as well;
- some recent work related to development and enforcement of weights and measures standards;
- a study characterizing state EV policies with recommendations;
- a case study on demonstrating the value of EV managed charging for EVs and EV charging; and,
- an analysis of the impacts of rates on charger economics

We hope these summaries continue to be useful to the EV policy and regulatory community.

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I. The National Case for a More Distributed Power Grid: New Evidence on Affordability and Demand Growth

Issuing Organizations: The Brattle Group (for The Pew Charitable Trusts)
Authors: Ryan Hledik, Kate Peters, Sophie Edelman, Prisha Tiwari, Carly McAdam, and Akhilesh Ramakrishnan
Publication Date: November 2026
Link: https://www.brattle.com/wp-content/uploads/2026/11/The-National-Case-for-a-More-Distributed-Power-Grid-New-Evidence-on-Affordability-Flexibility-and-the-Energy-Transition.pdf

Description: This Brattle Group report is the most recent of the reports covered in this Issue. This report is broader in scope than just EVs, focusing on how scaling all distributed energy resources (DERs)—including flexible demand, managed electric-vehicle charging, distributed solar, and batteries—could help the United States meet rapidly growing electricity demand while improving affordability, grid flexibility, and decarbonization. The report concludes that an ambitious but feasible expansion could increase DER capacity more than fourfold by 2050, avoid over $600 billion in power-system costs, reduce projected household electricity-bill increases by roughly half, lessen reliance on new natural-gas generation, and reduce the

financial risk of overbuilding infrastructure for uncertain data-center demand. The report also identifies better distribution planning, streamlined permitting, and interconnection reform as critical measures to accomplish these goals.

Key Takeaways

- An ambitious but feasible DER portfolio could grow from 113 GW today to 524 GW by 2050, making DERs the fourth-largest U.S. capacity resource.
- Expanded DERs could avoid more than $600 billion in cumulative power-system costs, reduce projected real household bill increases by about half, and lower the risk of overbuilding for uncertain data-center demand.
- The report identifies three high-impact reforms—distribution-system integration, permitting reform, and interconnection reform—that together could unlock 43% of the modeled benefits.

Introduction

- Rapid load growth, high infrastructure costs, long construction timelines of centralized generation, affordability concerns, and decarbonization needs all point to the need to change the status quo.
- DERs—including flexible demand, managed EV charging, solar, and batteries—can be deployed quickly, scaled modularly, and provide grid services.
- The study measures the incremental national benefits of expanding non-emitting DERs through 2050 relative to a status quo deployment path.
- The study also identifies key barriers to DER development are their inclusion in utility planning, utility incentives favoring capital intensive projects, slow permitting and interconnection processes, and restricted market access for DER grid services.

Estimating the Benefits of DERs

- The analysis includes demand flexibility, distributed solar, and distributed batteries including those deployed by residential, commercial, and industrial customers.
- The study looks at 25 regions through 2050 and combines bulk-power-system modeling with a top-down assessment of distribution-system upgrade deferrals.
- Adoption assumptions are ambitious but grounded in participation or deployment levels already achieved in leading markets; they are not forecasts or estimates of full technical potential.
- Results depend on factors such as customer participation, technology costs, load growth, policy implementation, and utilities' ability to see, control, and dispatch DERs when and where needed.

A More Distributed Power System

- The study estimates that expanded DER deployment would add about 411 GW of new nameplate capacity by 2050, roughly equal to projected total load growth over the same period.

- Demand flexibility is the largest source of growth, with smart HVAC controls and commercial and industrial programs important in the near term and managed, bidirectional EV charging increasingly important later.
- DERs could avoid roughly 70 GW of new gas capacity, or 22% of projected net gas additions, and replace about 105 GW of utility-scale storage additions with grid-edge flexibility.
- DERs could increase wind and solar generation by about 3% over baseline estimates.
- Strategically located and controlled DERs could defer up to 90% load-growth-driven distribution upgrades, but they cannot replace investments needed for aging infrastructure, resilience, or other non-capacity purposes.

An Affordability Solution

- Expanded DERs could avoid $614 billion in cumulative resource costs through 2050: $334 billion from avoided generation costs, $182 billion from deferred distribution upgrades, and $97 billion from lower distributed-solar costs enabled by process reforms.
- Annual avoided costs rise from $19 billion in 2035 to $43 billion in 2050 as deployment expands.
- After implementation and enabling costs, DERs could save the average household about $122 per year by 2050, offsetting roughly half of the projected electricity-bill increase beyond inflation.
- Savings can benefit both participants and non-participants; the split depends on program compensation. Under modeled cases, non-participants save $57–$90 per year while participants save $164–$206 per year by 2050.
- Equitable access requires targeted incentives, inclusive financing or ownership models, community-scale options, and lower-friction enrollment for low-income households.
- Additional benefits not fully quantified include faster capacity delivery, outage resilience, customer convenience, and potential transmission-system value.

A Hedge Against Highly Uncertain Load Growth

- DERs provide a hedge against uncertain data-center demand which could otherwise create stranded-asset risk.
- DERs provide planning flexibility because they have shorter lead times and can be added incrementally.
- With status quo DER growth, the system could be overbuilt by 153 GW in 2035 under a lower-load outcome; expanded DERs reduce that overbuild by about 43 GW.
- Greater DER reliance reduces modeled overbuild costs by $33 billion from 2030–2040, a roughly 40% reduction.
- The report supports planning across multiple demand scenarios, staging procurement, distinguishing committed from speculative large loads, and favoring resources that retain flexibility.

Enabling Decarbonization

- Without additional progress, the report projects U.S. power-sector emissions reductions will stall around 2035 despite existing state clean-energy policies.

- Expanded DER deployment reduces cumulative power-sector CO2 emissions by 3% through 2050 and annual 2050 emissions by 5%, primarily by avoiding gas generation and enabling more renewables.
- Flexible DERs also support beneficial electrification by mitigating peak-load and infrastructure impacts from EVs and heat pumps.

Moving from Potential to Results

- Achieving the modeled DER scale requires coordinated policy, regulatory, market, business-model, technology, and customer-engagement changes.
- Integrating DERs into distribution planning and operations could unlock $177 billion through 2050, or about 29% of total modeled value, by treating DERs as dependable local grid resources rather than merely changes in demand forecasts.
- Permitting reform could unlock $50 billion, or about 9%, by reducing fragmented and costly solar and storage approval processes; the analysis assumes a 90% reduction in U.S. solar permitting costs.
- Interconnection reform could unlock $39 billion, or about 6%, by allowing flexible exports from batteries and bidirectional EVs under grid-aware operating limits rather than blanket restrictions.
- Together, these three reforms could unlock 43% of total modeled benefits and help shift DERs from pilots or secondary resources to core grid-planning assets.

Conclusion

- DERs are not a replacement for all capital investments in generation, transmission, distribution, or for resilience, but the report finds they can materially lower costs and improve adaptability when deployed and operated at scale.
- The central implication is that utilities and regulators should plan for DERs as a resource that can meet identified grid needs, not simply accommodate them after customer adoption occurs.

II. The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability

Issuing Organization: The Brattle Group (for GridLab and Utilize Coalition)
Authors: Ryan Hledik, Long Lam, and Kate Peters
Publication Date: March 2026
Link: https://www.brattle.com/wp-content/uploads/2026/03/The-Untapped-Grid-Mar-2026.pdf

Description: This Brattle Group report, similar to the more recent report discussed above, argues that using existing grid capacity more efficiently rather than relying solely on costly new infrastructure can reduce customer costs. The report explains that the status quo power system was built to meet peak demand and is thus underused much of the year. It suggests that by adding flexible new load (e.g., managed EV charging) and using distributed energy resources

such as batteries, smart thermostats, targeted efficiency, and grid-enhancing technologies to reduce peak demand, utilities can spread fixed costs across more sales. In an illustrative utility analysis, a 10% improvement in system utilization lowers average rates by 3.4% relative to current conditions, raises utility earnings, and shortens connection times for new customers, while national-scale savings could reach $110–$170 billion over 10 years. The report emphasizes that results depend on local system conditions, cost-effective implementation, appropriate rate design, reliability limits, and tailored measures of generation, transmission, and distribution utilization.

Key Takeaways

Introduction

- U.S. electricity rates rose much faster from 2020 onward than during 2015–2020, intensifying affordability concerns.
- Data centers, electrification, and manufacturing are increasing demand while grid bottlenecks constrain new connections and may require costly upgrades.
- Better utilization offers a different approach: use spare capacity before building new infrastructure.
- The opportunity requires both new flexible load growth and the ability to shift, limit, or locate that load around system constraints.
- Average generation capacity utilization is about 50%, indicating that unused capacity exists but varies significantly by location and system type.
- The report is a scenario-based proof of concept, not a forecast or a specific policy proposal; local analysis is required before applying its findings.

How It Works

- Utilization improvements create or identify spare capacity, add load efficiently, recover more fixed costs through new sales, and reduce the share paid by existing customers.
- Demand flexibility alone has an estimated 200 GW of cost-effective national potential, with additional opportunity from storage and flexible large loads.
- New electricity sales can generate substantial revenue that spreads out the cost of existing grid assets.
- There are three core strategies: connect load in unconstrained locations, shift flexible new load to off-peak periods, and reduce existing customers' peak demand to create headroom.
- Key tools include batteries, HVAC and water-heating controls, managed EV charging, smart panels, time-varying rates, flexible interconnection agreements, targeted efficiency, grid-enhancing technologies, data-center flexibility, and improved planning.
- Prior research supports the underlying logic: load growth can reduce retail prices when its marginal cost is below the system's average cost.

Rate Impacts of Improved System Utilization

- Load growth alone does not guarantee affordability: if traditional infrastructure costs to serve new customer loads exceed the revenue they contribute, existing customers may face rate increases.
- The report compares a status quo case that relies on a conventional buildout with a utilization-focused case that combines flexible transmission-connected load and a 500 MW DER portfolio.
- In the status quo scenario, utilization rises only from 43% to 44%, and average rates increase from 14.0 to 14.2 cents/kWh, or 1.4%.
- Utilization rises to 53% and the average rate falls to 13.5 cents/kWh, or 3.4% below current levels and 4.8% below the status quo load-growth case.
- The utilization-focused approach still requires investment but directs capital toward the most critical needs while allowing utility earnings to grow.
- The rate reduction benefit remains directionally positive across tested alternatives, including lower DER capacity, higher DER costs, and no existing headroom; the extreme no-new-infrastructure case yields an 11% rate reduction.
- Scaling the base-case result to projected national sales growth suggests annual bill savings of $11–$17 billion by 2030, with larger savings possible if utilization gains exceed the base case.

Principles for Measuring System Utilization

- Utilization is defined as the energy delivered or produced over a period (kwH) divided by available system capacity (kW) during that same period.
- Generation, transmission, and distribution require distinct metrics because their operations, planning standards, and constraints differ.
- Generation utilization should reflect dependable capacity, including resource availability and planned outages; transmission should use firm transfer capability; distribution should assess feeder loading and the share of the system facing local constraints.
- A single universal utilization target would be inappropriate because customer mix, climate, network design, resource mix, and infrastructure conditions vary by utility and by region.
- Rate benefits depend on the price paid by new load and on cost-allocation rules, which determine whether savings reach existing customers.
- Higher utilization is valuable only when flexibility, DERs, or other solutions cost less than the conventional investments they avoid.
- Reliability requires limits: equipment needs, cooling periods, periods for maintenance, and reserves for extreme weather and contingencies.
- Measurement should account for timescale, geographic variation, weather effects, data confidentiality, regulatory incentives, and possible tradeoffs with decarbonization goals.

Summary and Conclusion

- The report's central finding is that strategically increasing use of existing grid capacity can make load growth a source of lower electricity rates rather than higher costs.

- The grid is designed for infrequent peak demand, leaving substantial capacity underused for much of the year.
- Adding new load where and when the system has headroom spreads fixed grid costs across more sales, putting downward pressure on rates.
- Flexible distributed energy resources (DERs), including batteries, managed EV charging, smart thermostats, and energy efficiency, can reduce peak demand and create capacity for new customers.
- Better system utilization can improve affordability, speed interconnection, and reduce the risk of overbuilding infrastructure if projected load growth does not materialize.
- Achieving these benefits requires utility-specific analysis rather than one-size-fits-all targets or programs.
- Reliable measurement and data sharing are foundational, particularly for confidential transmission and distribution capacity information.
- Utilities and regulators should characterize local system conditions, identify and rank cost-effective utilization options, and address market, regulatory, and technical barriers.

III. Have Data Centers Raised Your Electric Bill? Causal Evidence from the United States

Issuing Organization: Electric Power Research Institute
Author: Asa Watten, John Bistline, and Geoff Blanford
Publication Date: June 2026
Link: https://arxiv.org/pdf/2606.19777

Description: While this analysis is focused on the historical rate impact of data centers, it presents a new approach that can be adopted to look at the impacts of adding any new large loads. Specifically, the study uses an instrumental-variables approach - designed to isolate causal effects – to examine whether rapid U.S. data-center growth increased electricity bills between 2015 and 2024. It found that data center load growth had the opposite. On average, the analysis estimates that greater data-center capacity modestly reduced residential retail electricity prices. The authors argue that because power systems have substantial fixed costs, added long-lived demand can spread those costs over more electricity sales, improve utilization of generation and grid infrastructure, and support investment in newer, lower-cost resources. Their preferred estimate suggests that a doubling of data-center capacity reduced residential prices by about 3.5%, with efficiency gains appearing to accrue mainly to households rather than commercial and industrial customers. The paper cautions, however, that this historical result may not persist if generation, transmission, equipment, or fuel supply constraints make new capacity unusually expensive, or if utilities build infrastructure for projected data-center demand that does not ultimately materialize.

Key Takeaways

Core Findings

- The report finds that data-center growth modestly reduced average U.S. residential electricity rates during 2015–2024, while emphasizing that future results depend on whether the power system can expand without major supply constraints.
- The preferred causal estimate indicates that doubling data-center capacity lowered residential retail electricity prices by about 3.5%, holding residential electricity demand constant.
- The study estimates that the 160% average increase in state-level data-center capacity from 2019 to 2024 reduced residential rates by roughly 6%.

Cause and Effect

- The analysis aims to isolate cause and effect. Because data centers may choose locations with more favorable electricity rates, simple comparisons could be misleading. The authors use an instrumental-variables approach based on transportation planning methods, alongside population and GDP controls, to address this siting-related bias.
- The authors assert that under some circumstances, higher demand can lower average rates:
    - Electricity systems have large fixed costs for generation, transmission, and distribution.
    - When durable new demand uses existing infrastructure more fully, those costs are spread over more kilowatt-hours, lowering average costs and potentially customer rates.
- Investment needs make a difference. Unlike short-lived demand spikes, long-term demand growth can prompt investments in generation and grid capacity. If the cost of new supply is lower than the average cost of existing infrastructure, added demand can reduce overall average prices.
- One question affecting study outcomes is whether there are still economies of scale in utility investment. Utility-level data show that transmission, distribution, and generation costs generally rose more slowly than electricity delivered. The report also finds patterns consistent with lower average costs as demand grows across residential, commercial, and industrial customer classes.
- The report finds that residential customers appear to benefit most. Estimated effects for commercial and industrial prices were substantially smaller than for residential prices.,
- State comparisons alone are not sufficient. States with more data-center expansion did not show a simple pattern of higher prices. For example, Virginia had very high data-center demand, but rate increases near the national average, while California's large rate increases were associated largely with wildfire-related grid costs rather than data-center growth.
- Effects may take time to appear. First-difference results were near zero, consistent with the idea that rate effects emerge gradually as utilization improves and long-term investment decisions take effect, rather than immediately after new capacity comes online.
- The report also finds that major risks could reverse the result**.** Equipment shortages, costly gas turbines, transformer supply constraints, higher solar costs, and delays in

wind and solar development can make new capacity expensive. In those conditions, rapid data-center growth could raise rates instead of lowering them.

- Demand uncertainty is also a key concern. If utilities build infrastructure for anticipated data-center demand that does not materialize, the resulting fixed costs would be spread across fewer electricity sales, potentially increasing rates. Minimum bills and long-term contracts for large loads can help limit this risk.

Summary and Implications

- The findings are encouraging for all electrification use cases - not just data centers and AI. For example, growing electricity use from electric heat pumps and electric vehicles could also improve system utilization.
- However, their load patterns differ from data centers, and the grid must expand fast enough to serve concurrent demand growth without running into supply constraints
- The overall finding of the study is that historically, data centers have not raised average residential electricity rates in the study period; the report estimates they modestly lowered them by improving utilization and spreading fixed power-system costs across greater sales
- However, the study notes that this outcome is not guaranteed going forward: it depends on affordable, timely infrastructure expansion and on data-center demand proving durable enough to justify the investments made to serve it.

IV. Charging Up: States and EV Charging Deployment

Issuing Organization: Atlas Public Policy
Authors: Tina Hodges, John Kuna, and Jaclyn Lea
Publication Date: June 2026
Link: https://atlaspolicy.com/wp-content/uploads/2026/06/Charging-Up-States-and-EV-Charging-Deployment.pdf

Description: This report by Atlas Public Policy examines the rapidly evolving U.S. electric-vehicle charging landscape and offers practical guidance for state departments of transportation (DOTs) as they plan and deliver public charging infrastructure. It reviews EV adoption, the growth and uneven distribution of fast and Level 2 charging, federal programs such as the National Electric Vehicle Infrastructure program, and the complementary roles of state agencies, municipalities, metropolitan planning organizations (MPOs), utilities, and private providers. Drawing on state experiences and stakeholder input, it identifies best practices for setting program goals, selecting sites, designing incentives and contracts, coordinating with utilities and communities, streamlining permitting, and ensuring charger reliability over time. The report also emphasizes that state DOTs can make the greatest impact by preserving expertise, coordinating partners, targeting public funds to underserved gaps and emerging freight needs, and integrating charging into long-range transportation planning.

Key Takeaways

Introduction

- The 2021 Bilateral Investment Law (BIL), passed by Congress, shifted EV-charging deployment decisions from state energy and environmental agencies to state DOTs by directing substantial federal funding to them.
- Most state DOTs had to adapt highway-oriented processes to a technology-driven charging market and build new technical capacity quickly.
- The report focuses on publicly accessible charging for passenger vehicles and Medium and Heavy-Duty Vehicles (MHDVs), with state DOTs as the primary audience.

State of Play

- EV Adoption
  - More than 8 million EVs have been sold in the United States; EVs represented 9.8% of passenger-vehicle sales in 2025.
  - Growth has become less predictable after federal tax incentives ended, but the number of EVs on the road continues to rise in every state.
  - Adoption differs substantially by geography: rural states and states with long distances between population centers face network-coverage challenges.
  - State DOT implication: maintain sufficient network coverage even where current EV volumes are low.

- EV Charging Network Growth and Distribution
  - By the end of 2025, the United States had nearly 234,000 public charging ports, including more than 67,000 DC fast-charging ports and nearly 166,500 Level 2 ports.
  - DC fast charging has been growing faster than Level 2 charging recently in most states.
  - Charging needs should be measured differently as markets mature: corridor coverage first, then ports per registered vehicle, then capacity and congestion relative to the EV fleet.
  - Statewide averages can mask local gaps; county-, ZIP code-, and corridor-level analysis is more useful for siting decisions.

- Medium- and Heavy-Duty Vehicle Charging
  - Public MHDV charging is far less developed than passenger-vehicle charging, especially purpose-built truck charging.
  - Most MHDV charging will occur at depots, but long-haul intercity trucking requires accessible, high-power en-route charging on major highway corridors.
  - High equipment, grid-upgrade, and demand-charge costs make this an area where public support is particularly important.

- Federal Programs
  - NEVI is the largest federal corridor-charging program, with about $739 million awarded across 40 states for more than 4,000 DC fast-charging ports as of March 2026.
  - Program progress has been disrupted by a 2025 funding freeze, litigation, revised NEVI guidance, and a 2026 rescission affecting unobligated funds.

  - Flexible highway formula programs can fund charging, but states have used them sparingly because of competing transportation priorities.
  - DOT implication: protect existing resources through timely obligation, retain program capacity, and prepare for multiple funding scenarios.

- State Programs
  - State energy and environmental agencies have extensive experience using grants, rebates, Volkswagen settlement funds, and state appropriations for charging.
  - Grants enable tailored awards and stronger accountability; rebates can speed deployment for simpler, lower-cost projects.
  - State DOTs can expand their options by collaborating with sister agencies and braiding or stacking funding sources where permitted.

Best Practices

- Program Design
  - The report urges states to establish clear, prioritized goals before setting requirements; reliability of charging infrastructure and driver experience should be leading priorities.
  - Use data-driven siting that considers charging gaps, projected EV adoption, utility grid capacity, parking, construction feasibility, and nearby amenities.
  - Maintain flexibility in siting rules so strong proposals just outside preferred zones are not excluded.
  - Match incentives to program goals: use grants for complex or high-accountability projects and rebates for straightforward, lower-cost deployment.
  - Adjust cost-share levels to attract projects in rural or low-utilization areas where conventional economics are weak.

- Stakeholder Engagement
  - Charging station developers should coordinate with utilities early and often, prior to filing a load letter, because interconnection and energization schedules are major deployment constraints.
  - Standardized utility forms and hosting-capacity maps can reduce applicant burden and improve site selection.
  - Engage site hosts before releasing solicitations so they understand responsibilities and are committed to the project.
  - Include local businesses, community organizations, advocates, and first responders to improve awareness, identify local barriers, and support safe deployment.

- RFPs and Contracting
  - Use transparent scoring criteria that reflect state priorities, including site amenities, team experience, operations, and maintenance plans.
  - Avoid unnecessary requirements carried over from traditional construction procurement when they do not fit charging projects.

  - Require documented site-host commitment to reduce post-award cancellations and delays.
  - Share standardized contract language early, use milestone-based payments, and retain a portion of funds through the operating period.
  - Align technical requirements with market standards for uptime, interoperability, data reporting, and adequate charging capacity while avoiding technology lock-in.

- Permitting and Construction
  - Authorities having jurisdiction (AHJs such as cities and counties) are key organization in the permitting and siting process for site hosts and charging station developers and should be consulted early.
  - Inconsistent local zoning and permitting can substantially delay charging deployment.
  - Standardized, transparent, and expedited permitting processes reduce uncertainty and administrative burden.
  - Utility coordination before award and contract finalization helps prevent avoidable construction delays.
  - When delays occur, flexible management of equipment and resources across projects can bring near-complete sites online sooner.

- Operations, Reporting, and Compliance
  - Require operations and maintenance plans covering inspections, cybersecurity, outage reporting, and maintenance schedules.
  - Use proactive monitoring, regular reporting, corrective action plans, and escalating enforcement tools to sustain reliability.
  - Account for the financial risk of low-utilization sites through station bundling, committed site hosts, and time-limited operating support.
  - Reliability is central to driver confidence; performance requirements should be enforceable throughout the contract term.

- Long-Term Transportation Planning
  - EV charging should be embedded in long-range transportation plans, integrated with NEVI-funded stations and planning, and tracked through relevant performance measures.
  - This integration helps treat charging as a core mobility and system-planning function rather than a standalone initiative.

<u>Summary and Conclusions</u>

- EV charging is becoming a core transportation-system need, even though the pace of adoption has slowed somewhat due to the loss of federal vehicle incentives and to the overall federal policy uncertainty.
- EV adoption and public charging are growing nationwide, but access varies sharply by state and community.

- Public charging remains vital for long-distance travel, people without home charging, rural and tourism areas, and commercial trucking.
- State DOTs gained a major implementation role through NEVI, but should preserve the expertise and partnerships built during rollout.
- Federal funding uncertainty, including freezes, rescissions, and possible domestic-content changes, increases the value of obligating available funds promptly.
- Public dollars should complement private investment by targeting underserved areas, corridor gaps, and medium- and heavy-duty vehicle (MHDV) charging.
- The strongest state approach is to retain expertise, coordinate across public and private partners, plan with granular data, and direct public funds to needs the market is unlikely to meet on its own.

V. Delivering Affordability and Opportunity Through State Transportation Modernization

Issuing Organization: Atlas Public Policy
Authors: Rachael Nealer, Tina Hodges, and Eric Wood
Publication Date: September 2026
Link: https://atlaspolicy.com/wp-content/uploads/2026/09/Delivering-Affordability-and-Opportunity-Through-State-Transportation-Modernization.pdf

Description: This Atlas report argues that governors can improve affordability, mobility, safety, and economic opportunity by coordinating transportation, energy, housing, utility, environmental, and economic-development agencies around outcomes residents can directly experience. It emphasizes appointing experienced implementers, setting clear cross-agency goals and decision authority, removing institutional barriers, and measuring transparent results rather than focusing on announcements or spending alone. Drawing on examples from Colorado, Minnesota, New York, Maryland, and North Carolina, the report highlights practical approaches such as intercity and on-demand transit, delivery-fee funding, managed EV charging, transit-oriented development, and e-bike incentives to lower household transportation costs, expand access to jobs and services, strengthen grid reliability, and deliver visible public value.

Key Takeaways

- The report's core message is that states can make transportation more affordable and accessible when Governors organize and coordinate state agencies to focus on energy affordability and value to residential households.
- Transportation should be treated as a household-affordability issue. Transportation is the second-largest household expense after housing, and state decisions also affect electricity bills, commute times, housing choices, and access to jobs, schools, health care, and services.
- Organize government around outcomes, not agency silos. Transportation, energy, housing, utilities, environmental, and economic-development agencies need shared goals because

their decisions are interdependent. The most meaningful goals are lower travel costs, safer streets, reliable trips, and better access to opportunity.

- Appoint proven implementers. Senior leaders should be able to navigate budgeting, permitting, procurement, regulation, and stakeholder management—and state the concrete results they can deliver within a governor's term. Vision alone is insufficient without leadership and the capacity to execute programs.
- Set clear authority and accountability. Cross-agency initiatives need explicit decision rights, practical responsibilities, achievable timelines, and transparent performance measures without duplicating efforts.
- Match ambition to delivery capacity. Commitments should be backed by sufficient authority, funding, and staffing, and should have realistic goals and timelines. Goals that are ambitious, but feasible help staff make decisions and sustain progress; unrealistic targets can impede implementation.
- Expand practical mobility options. Colorado's Bustang shows demand for reliable, affordable intercity bus service: ridership grew nearly 280% as the network expanded from three to 20 routes. North Carolina's on-demand microtransit demonstrates that flexible, curb-to-curb service can fill rural and suburban gaps, surpassing one million rides.
- Use durable and equitable funding tools. Delivery fees in Colorado and Minnesota provide dedicated funding for transportation, safety, and electrification. These mechanisms can stabilize long-term investment, but states must weigh consumer costs, administrative burden, equity, and political durability.
- Connect EV adoption with grid reliability. New York's SmartCharge program pays drivers to charge EVs off-peak, lowering ownership costs while reducing peak electricity demand and avoiding unnecessary grid upgrades. Simple, customer-friendly incentives can align affordability with system reliability.
- Coordinate housing and transit investment. Maryland's transit-oriented development approach combines transportation investment, affordable-housing support, state land, and local zoning reform to create more homes near transit, reduce transportation costs, and attract private investment.
- Target incentives where they change behavior. Colorado's income-qualified e-bike rebates made e-bikes accessible to residents who otherwise would not have purchased them; 89% of surveyed recipients said the rebate was decisive. Effective programs pair financial support with safety, retail, and administrative coordination.
- Measure success by experienced results. States should publicly track progress toward outcomes residents can see: lower costs, safer travel, stronger access to jobs and services, more housing near transit, and dependable energy and transportation systems.

VI. Impacts of EV-Specific Electricity Rates on Charger Economics: Estimating the Impacts of Today's Commercial Electric Vehicle Electricity Rates, and the Potential Impact of Implementing them U.S.-Wide

Issuing Organization: Atlas Public Policy
Authors: Lucy McKenzie, Ben Sharpe, and Eric Wood
Publication Date: October 2026
Link: https://atlaspolicy.com/wp-content/uploads/2026/10/2026-10-23-Impacts-of-EV-Specific-Electricity-Rates-on-Charger-Economics_reissue.pdf

Description: This report also by Atlas Public Policy examines how commercial electricity rates designed specifically for electric-vehicle charging affect the economics of public DC fast-charging stations and Class 2B electric-van depots in the United States. Specifically, Atlas set about researching three questions: (1) How are today's commercial EV rates impacting electricity bills at charging sites?; (2) If EV rates become more widespread, how could they affect the economics of public DC fast charging, and resulting investment decisions?; and, (3) If EV rates become more widespread, how could they affect the economics of electric medium-duty vans, and resulting adoption? The authors looked at rates from 21 investor-owned utilities and found that well-designed EV rates—especially those that reduce or restructure demand charges—can substantially lower charging bills, improve fast-charger investment returns, and make fleet electrification more cost-competitive. Under an illustrative nationwide 50% reduction in electricity bills, fast-charging stations could reach financial viability at materially lower utilization levels, while roughly 42,000 additional Class 2B electric vans could achieve cost parity with gasoline alternatives. The report concludes that stable, flexible, use-case-specific EV rates can help mobilize private charging investment, expand EV adoption, and support air-quality and public-health goals.

Key Takeaways

Introduction

- Public charging availability remains a major barrier to broader EV adoption, while electricity costs are a durable operating-cost driver for EV charging operators and fleets.
- Utilities use EV-specific commercial rates to lower grid costs, attract flexible new load, improve customer economics, and support transportation or emissions policy goals.
- Common EV-rate tools include lower or restructured demand charges, time-of-use (TOU) energy pricing, and incentives to charge when the grid is less constrained or renewable generation is abundant.

Savings available from today's commercial EV electricity rates

- The analysis compares available commercial EV rates with baseline commercial rates for two use cases: public DC fast charging and overnight Class 2B electric-van depot charging.
- Rates were evaluated using modeled charging loads and annual bills, covering 21 investor-owned utilities offering an eligible EV rate as of June 2026.
- Results demonstrate wide variation: rate design, rather than the existence of a special EV tariff alone, determines whether customers save money.

Impact of today's EV rates on public DC fast-charging sites

- At 15% utilization, 9 of 20 applicable utilities reduce modeled DCFC electricity bills by at least 50%; 5 deliver savings of 10%–50%.
- The strongest performers reduce, eliminate, or restructure demand charges. SDG&E, Southern California Edison, and National Grid New York are among the largest savings cases.
- Six EV rates provide less than 10% savings or increase bills relative to baseline rates; high energy charges can overwhelm demand-charge relief as station utilization rises.
- Public stations have limited ability to shift demand because commercial drivers tend to charge when they need it - during daytime and evening hours, so rates built around overnight discounts may not translate into savings.
- Flexible opt-in and opt-out provisions are important because the rate that minimizes bills can change as station utilization grows.

Impact of today's EV rates on depot charging of Class 2B vans

- EV rates provide meaningful annual bill savings for depot charging at all but three utilities, ranging from 18% to 73%.
- Overnight depot charging benefits from rates with low off-peak energy prices and demand charges that apply mainly during daytime peak periods.
- Northern States Power (Xcel Energy) in Minnesota, PG&E in California, and Public Service Company of Colorado (Xcel Energy) produce the largest modeled savings through on-peak-only demand charges, subscription-based demand structures, or major demand-charge reductions.
- Black Hills is the exception: its sharply higher off-peak energy price more than offsets lower demand charges, increasing modeled annual depot bills by 10%.

Implications across both charging use cases

- Public DCFC and depot charging have very different load shapes, so a single EV rate can help one use case while underperforming for the other.
- Demand-charge relief is the most consequential design feature because demand charges dominate the overall costs of EV service providers with low utilization sites.
- TOU rates work only when customers can align charging with discounted periods: overnight depots can often do so, whereas public stations have less control over the charging behavior of the customer
- Features such as billing-demand floors, super-off-peak surcharges, and seasonal demand carryovers can create unintended costs and should be tested against realistic charging profiles.

Impacts of EV rates on public DCFC sites

- Under baseline commercial electricity prices, a modeled 1.5 MW DCFC station needs about 13%–23% utilization to break even, depending on the state electricity-price group.
- To meet lender-return expectations, stations need roughly 17%–28% utilization; higher-return equity thresholds require about 26%–38% utilization. Most states' average station utilization is below these levels.

- An illustrative 50% electricity-bill reduction lowers break-even utilization to about 10%–11%, lender thresholds to 12%–14%, and equity thresholds to 13%–22%.
- Very low utilization remains unprofitable even with lower electricity prices, while very high utilization can create driver wait times and weaken the customer experience.
- Ongoing public support, including incentives tied to operating costs, can further improve viability, particularly for sites needed for geographic coverage or public-benefit goals that may never achieve high utilization.

Impacts of EV rates on electric-van economics

- The report compares lifetime total cost of ownership for a Ford E-Transit and a comparable gasoline Ford Transit across electricity-price groups and annual-mileage levels.
- Under baseline electricity prices, electric vans reach cost parity only in low-price states and only at 30,000 annual miles or more.
- With a modeled 50% electricity-bill reduction, cost parity moves to 20,000–30,000 annual miles, depending on the electricity-price group.
- The modeled rate change makes approximately 41,600 additional Class 2B vans economic to electrify, equal to about 15% of the U.S. fleet in this segment.

Keys for commercial EV rate design

- Prioritize demand-charge reform: Eliminate, reduce, or replace conventional demand charges with structures such as subscriptions where appropriate.
- Design by use case: Evaluate rates separately for public DCFC and depot charging; distinct schedules may outperform a one-size-fits-all tariff.
- Phase charges in with utilization: Tie demand-charge phase-ins to load factor or utilization rather than fixed calendar dates and maintain relief until sites are financially sustainable.
- Preserve customer flexibility: Allow operators to move into and out of EV rates as station utilization and load patterns evolve.
- Avoid counterproductive terms: Do not offset demand-charge relief in tariffs with excessive energy prices, high billing-demand floors, or rules that lock in seasonal peak demand.
- Provide stability: Multi-year predictability and clear transition rules are essential for charging operators and fleets making long-lived investment decisions.

Conclusions

- Well-designed commercial EV rates can materially improve public charging and fleet-electrification economics, but their benefits depend on demand-charge treatment, charging patterns, and stable rate design.
- Commercial EV rates can lower charging-site electricity bills, strengthen public fast-charging investment economics, and improve electric-van total cost of ownership.
- Across 21 investor-owned utilities, EV-rate savings vary substantially, showing that a rate labeled for EV charging is not automatically beneficial. Case-by-case analysis is essential.
- The report's illustrative nationwide scenario, in which electricity bills fall 50%, reduces the utilization needed for DC fast-charging stations to become financeable and makes about 42,000 additional Class 2B vans economic to electrify.

VII. Weights & Measures Standards in an Evolving EV Market

Issuing Organization: Atlas Public Policy
Authors: Rachel Reolfi
Publication Date: October 2026
Link: https://atlaspolicy.com/wp-content/uploads/2026/10/Weights-and-Measures-for-EV-Charging.pdf

Description: This Atlas report examines how U.S. weights and measures rules can ensure accurate, transparent billing for electric vehicle charging while avoiding unnecessary barriers to charger deployment. Drawing on stakeholder interviews and early implementation experience in states including California, Maryland, Colorado, Texas, Florida, and Vermont, it finds that EV chargers, or Electric Vehicle Supply Equipment, or EVSE, as defined in NIST Handbook 44, can generally meet technical accuracy standards. But testing requirements, fees, enforcement practices, agency coordination, and inconsistent state and local rules can create avoidable costs, delays, and service disruptions. The report recommends risk-based and less burdensome testing, proportionate fees and enforcement, early coordination among regulators, funders, and industry, clear phase-in timelines for new and legacy equipment, exemptions for low-risk charging settings, and stronger national guidance and data-sharing to protect consumers while expanding reliable, affordable, and equitable charging access.

Key Takeaways

Introduction

- The report's central finding is that EV charging can meet accuracy standards, but implementation must be designed around actual consumer risk to avoid raising costs, delaying deployment, and reducing access.
- Weights and measures rules, originally developed for products such as fuel and grocery goods, must be adapted to EVSE hardware that includes a growing amount of integrated software.
- Rules generally apply when electricity is sold by measured quantity at public, workplace, or multifamily locations; home charging is usually outside this scope.
- Charging access at these locations is particularly important for drivers without home charging and for long-distance travel.
- The report draws on policy research and input from 19 organizations across government, industry, service providers, and research groups.

State of Play

- National standards provide a common technical framework, but states decide whether and how to make those standards enforceable.
- NIST publishes Handbook 44 standards (with updates on a regular basis), the National Council on Weights and Measures, or NCWM, is the state-based regulatory association that applies them through a consensus process and administers product certification, and states

or localities enforce compliance through state inspectors, county sealers, and registered service agents (RSAs)
- The EV charging code became permanent in 2023 after years as a tentative standard; states remain at very different stages of adoption of the final code and the enforcement of its provisions.
- State programs differ in testing frequency, per-port fees, deadlines for legacy equipment, exemptions, and whether enforcement is state or local.
- This flexibility can help states tailor programs to their resources, but it also creates a fragmented regulatory environment that increases uncertainty and compliance costs.

Challenges
- The key challenge is balancing consumer protection with requirements that are feasible for agencies and charging providers at the scale of EV deployment.
- The report states that the challenges with EVSE are often caused more by program design and administration by state inspectors, rather than the actual accuracy and tolerance levels of the EVSE
- Charging deployment already requires permitting, utility interconnection, safety compliance, and funding coordination, so additional regulatory friction can compound delays.
- Rapid technology changes, large deployment volumes, and evolving business models make traditional inspection approaches difficult to scale.

Compliance Costs and Shutdowns Impact Project Viability
- Registration, inspection, RSA services, testing equipment, corrective work, and downtime can materially affect already thin charging station margins of the EV service provider or site host.
- Many citations reportedly involve labels, displays, or administrative issues rather than inaccurate electricity measurement or billing.
- Fixed per-port fees disproportionately burden low-use Level 2 chargers, including multifamily installations that are important for equitable charging access.
- High costs can lead owners to pass costs to drivers, reduce project size, or cancel projects; shutdowns are especially damaging for revenue-dependent fast chargers.

Regulations Not Keeping Up with Technology
- Larger and more numerous EVSE deployments can overwhelm inspection staff, RSAs where authorized and the limited supply of specialized testing equipment.
- California illustrates the scale mismatch: its commercial charging network far exceeds the number of chargers registered and inspected to date.
- Requirements for initial and recurring field testing can delay charger operation and raise program costs.
- Product approval processes can also struggle to keep pace with frequent equipment and software changes.

Misalignment Between Regulators and Funding Agencies

- Weights and measures agencies, which are usually housed in Agriculture Departments, and state energy offices and other agencies with responsibility for state policy goals often have different mandates, expertise, and priorities.
- Without formal coordination, funding can support equipment that later requires costly modifications to comply with weights and measures rules.
- California experienced this problem when some funded installations lacked required certification or labeling.
- Sustained interagency communication improves technical understanding, funding alignment, and regulatory predictability.

Patchwork of Regulations Causes Confusion

- States and, in some cases, counties use different timelines, inspection processes, interpretations, fees, and legacy-equipment policies.
- Unclear or late communication makes it hard for providers and site hosts to know what is required and when.
- Variations in interpretation can result in citations for equipment or practices accepted in other jurisdictions.
- Enforcement should distinguish billing or accuracy risks from correctable administrative deficiencies so functional chargers are not unnecessarily removed from service.

Summary and Conclusions

- The three highest-priority actions are right-sizing testing and fees, coordinating agencies and stakeholders early, and phasing in the NIST Handbook 44 rules with a reasonable transition.
- Accurate measurement and transparent billing are essential to establishing the public trust in public EVSE that is based on a commercial transaction with billing and payment.
- The report states the major issues are how states structure testing, fees, enforcement, and implementation, not necessarily the accuracy of the equipment based on testing.
- Early state programs reveal risks of high compliance costs, operational shutdowns, approval delays, weak agency coordination, and inconsistent rules.
- States can protect consumers and preserve charging access by using risk-based, predictable, and proportionate programs. National best practices should be shared across state boundaries.
- Consumer protection and charging access can reinforce each other when rules focus on material billing risk and are implemented predictably.
- States can avoid the most significant early implementation problems through proportionate testing, fees, and enforcement; cross-agency coordination; clear transitions; and low-risk exemptions.

VIII. Pathways to Greater Load Flexibility: Bridging International Experience to U.S. Implementation Pathways

Issuing Organization: Charged
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Link: https://chargedinitiative.org/resources/pathways-to-greater-load-flexibility/

Description: *Pathways to Greater Load Flexibility* examines how the United States can expand the use of flexible electricity demand—such as smart thermostats, EV chargers, batteries, and building controls—to improve grid reliability, manage peak demand, reduce infrastructure costs, and support electrification. Drawing on stakeholder interviews and a comparative assessment of Great Britain, Australia, continental Europe, and eight U.S. states, the report finds that the strongest drivers of scaled deployment are open access for third-party aggregators, clear and standardized valuation of flexibility, and utility incentives that reward cost-effective alternatives to traditional grid investment. It identifies the United States' fragmented regulations, siloed programs, limited non-wires alternatives, and uneven implementation of wholesale-market access as key barriers, while outlining practical pathways such as shared-savings utility incentives, technology-neutral programs, locational compensation, coordinated dispatch, and stronger performance standards to make flexibility a trusted, scalable grid resource.

Key Takeaways

Overview

- The report finds that U.S. load flexibility can scale materially, but only if utility incentives, resource valuation, aggregator access, and program coordination move beyond today's fragmented, program-by-program approach.
- The Charged Initiative supports building and transportation electrification while protecting customer affordability and grid reliability.
- Charged convenes utilities, regulators, technology firms, and public-interest stakeholders to develop practical distribution-system solutions outside formal proceedings, test them, and spread successful models.
- Prior CHARGED work and study tours showed a gap between the U.S. focus on program delivery and the international focus on regulatory incentives and market-based procurement of flexibility.
- This study examines distribution-level flexibility under third-party ownership models, comparing Great Britain, Australia, continental Europe, and selected U.S. states.
- Cases are evaluated across market context, aggregator access, policy and regulation, flexibility mechanisms, and outcomes at scale.

Global Load Flexibility Landscape

- There are two main mechanisms for flexibility: (1) implicit flexibility uses price signals such as time-varying rates; (2) explicit flexibility contracts with customers or aggregators to provide defined grid services through markets, programs, VPPs, or non-wires alternatives.

- Flexibility can range from utility-only programs to competitive markets with multiple aggregators and multiple buyers. More open structures foster competition, innovation, and customer choice according to the authors.
- Clear and stackable compensation, innovation-friendly regulation, open aggregator access, technology-neutral service definitions, and utility incentives to pursue lower-cost flexible solutions are the key enablers.
- The U.S. and Great Britain use different approaches; U.S. utilities typically design a program after calculating value. Great Britain uses a standardized evaluation method to set a maximum flexibility price, then competitively procures resources below that price.

Cross-Case Comparison

- Across cases, open aggregator access and strong policy enablers are more closely associated with higher deployment than retail-market structure alone.
- Great Britain, Norway, the Netherlands, and Belgium combine open access with strong policy frameworks and achieve high or moderate-high flexibility outcomes. The U.S. overall has limited access, low-to-moderate policy support, and low-to-moderate outcomes.
- Within the U.S., California and New York pair strong policy support with open aggregator access and show comparatively stronger results. Colorado, Illinois, and Michigan have more limited access and lower deployment outcomes. Texas reaches high deployment despite moderate policy strength, indicating that strong wholesale price exposure and market-based incentives can independently drive flexibility.
- Opening participation and strengthening policy incentives are more powerful drivers of change than whether a state is restructured or vertically integrated.

Key Findings and Recommendations

- Utilities have long used demand response programs, but deployment remains uneven, fragmented, and difficult for customers and aggregators to access and deploy.
- Countries with open provider access and strong regulatory incentives have deployed flexibility more broadly than the U.S.
- U.S. offerings should be streamlined, easy to enroll, technology-agnostic, adaptable to changing grid needs, valued through clear methods, and held to common performance standards.
- Focus first on one measurable benefit, such as the value of deferring a substation upgrade, rather than attempting to capture every possible value stream at once.
- Use fixed, technology-neutral base payments with timely locational adders, regular valuation updates, coordinated dispatch, and standardized contracts.

Conclusions and U.S. Pathways

- The report states that technology is not the main constraint: Devices and platforms are largely available; the binding constraints are market design, customer value, utility incentives, data access, coordination, and credible performance measurement.

- Put customers first: Enrollment requires clear financial or other values, ; grid benefits alone will not drive sustained participation.
- Adopt shared-benefit incentives: Utilities should benefit when flexibility reduces customer costs relative to conventional infrastructure investment.
- Start simple and locational: Define a clear benefit metric, set a ceiling price based on the avoided grid build, and procure eligible flexibility below that threshold.
- Build a competitive pathway: Near-term price-taker programs with locational adders can scale before fully developed flexibility markets emerge.
- Coordinate retail and wholesale use: Flexibility should be visible and dispatchable across distribution and bulk-system needs without conflicting customer commitments.
- Use urgency constructively: Load growth, data-center interconnection needs, capacity concerns, and affordability pressures create a timely opening for faster flexibility deployment.